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, 2017

or

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

Commission File No. 001-36719

ANTERO MIDSTREAM PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**46-4109058** (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 Units Representing Limited Partner Interests	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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

The aggregate market value of the registrant's common units representing limited partner interests held by non-affiliates of the registrant as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter was approximately $2.6 billion based on the closing price of Antero Midstream Partners LP's common units representing limited partner interests as reported on the New York Stock Exchange of $33.18.

As of February 8, 2018, there were 186,934,568 common units representing limited partner interests outstanding.

Documents incorporated by reference: None.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Some of the information in this Annual Report on Form 10-K may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Annual Report on Form 10-K. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- Antero Resources Corporation’s expected production and ability to meet its drilling and development plan;
- our ability to execute our business strategy;
- our ability to realize the anticipated benefits of our investments in unconsolidated affiliates;
- natural gas, natural gas liquids (“NGLs”) and oil prices;
- competition and government regulations;
- actions taken by third-party producers, operators, processors and transporters;
- legal or environmental matters;
- costs of conducting our operations;
- general economic conditions;
- credit markets;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

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 our business. These risks include, but are not limited to, commodity price volatility, inflation, environmental risks, drilling and completion and other operating risks, regulatory changes, the uncertainty inherent in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, conflicts of interest among holders of our common units, and the other risks described under “Risk Factors” in this Annual Report on Form 10-K.

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 COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in our industry:

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

"Bbl/d." Bbl per day.

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

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

"Bcfe/d." Bcfe per day.

"Btu." British thermal units.

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

"DOT.": Department of Transportation.

"Dry gas." A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

"EPA." Environmental Protection Agency.

"Expansion capital expenditures." Cash expenditures to construct new midstream infrastructure and those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system throughput.

"FERC." Federal Energy Regulatory Commission.

"*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.

"High pressure pipelines." Pipelines gathering or transporting natural gas that has been dehydrated and compressed to the pressure of the downstream pipelines or processing plants.

"Hydrocarbon." An organic compound containing only carbon and hydrogen.

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

"Low pressure pipelines." Pipelines gathering natural gas at or near wellhead pressure that has yet to be compressed (other than by well pad gas lift compression or dedicated well pad compressors) and dehydrated.

"Maintenance capital expenditures." Cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long term, our operating capacity or revenue.

"MBbl." One thousand Bbls.

"MBbl/d." One thousand Bbls per day.

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

"MMBtu." One million British thermal units.

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

"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.

"MMcf/d." One million cubic feet per day.

"MMcfe/d." One million cubic feet equivalent per day.

"Natural gas." Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

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

"Oil." Crude oil and condensate.

"SEC." United States Securities and Exchange Commission.

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

"Throughput." The volume of product transported or passing through a pipeline, plant, terminal or other facility.

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

PART I

References in this Annual Report on Form 10-K to "Predecessor," "we," "our," "us" or like terms, when referring to period prior to November 10, 2014, refer to Antero Resources Corporation's gathering, compression and water assets, our predecessor for accounting purposes. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods between November 10, 2014 and September 23, 2015 refer to the Partnership's gathering and compression assets and Antero Resources Corporation's water handling and treatment assets. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods since September 23, 2015 or when used in the present tense or prospectively, refer to Antero Midstream Partners LP.

Items 1 and 2. Business and Properties

Our Partnership

We are a growth-oriented limited partnership formed by Antero Resources Corporation ("Antero Resources") to own, operate and develop midstream energy assets to service Antero Resources' rapidly increasing production. Our assets consist of gathering pipelines, compressor stations, processing and fractionation plants and water handling and treatment assets, through which we provide midstream services to Antero Resources under long-term, fixed-fee contracts. Our assets are located in the rapidly developing liquids-rich Marcellus Shale and Utica Shale located in West Virginia and Ohio, two of the premier North American shale plays. We believe that our strategically located assets and our relationship with Antero Resources position us to become a leading midstream energy company serving the Marcellus and Utica Shales.

Since our initial public offering, we have grown our quarterly distribution 115% from our minimum quarterly distribution of $0.17 per unit ($0.68 per unit on an annualized basis) for the quarter ended December 31, 2014 (the initial quarter for which we paid a quarterly cash distribution) to $0.365 per unit ($1.46 per unit on an annualized basis) for the quarter ended December 31, 2017. Our ability to consistently grow our cash distributions is driven by a combination of Antero Resources' production growth and our accretive build-out of additional midstream infrastructure to service that production growth.

Antero Midstream Partners LP's (the "Partnership" or "Antero Midstream") assets consist of gathering pipelines, compressor stations, interests in processing and fractionation plants, and water handling and treatment infrastructure, through which Antero Midstream and its affiliates provide gathering, compression, processing, fractionation and integrated water services, including fresh water delivery services and other fluid handling services. These services are provided to Antero Resources under long-term, fixed-fee contracts, limiting Antero Midstream's direct exposure to commodity price risk. As of December 31, 2017, all of Antero Resources' approximate 705,000 gross acres (620,000 net acres) are dedicated to Antero Midstream for gathering, compression and water services, except for approximately 156,000 gross acres subject to third-party gathering and compression commitments. Antero Midstream also owns a 15% equity interest in the gathering system of Stonewall Gas Gathering LLC ("Stonewall") and a 50% equity interest in the Joint Venture to develop processing and fractionation assets in Appalachia with MarkWest, a wholly owned subsidiary of MPLX. In connection with Antero Midstream's entry into the Joint Venture with MarkWest, Antero Midstream released to the Joint Venture its right to provide certain processing and fractionation services on 195,000 gross acres held by Antero Resources in Ritchie, Tyler and Wetzel Counties in West Virginia. Under its agreements with Antero Midstream, and subject to any pre-existing dedications or other third-party commitments, Antero Resources has dedicated to Antero Midstream all of its current and future acreage in West Virginia, Ohio and Pennsylvania for gathering and compression services and all of its acreage within defined services areas in West Virginia and Ohio for water services. Antero Midstream also has certain rights of first offer with respect to gathering, compression, processing, and fractionation services, and water services for acreage located outside of the existing dedicated areas. The gathering and compression and water services agreements each have a 20-year initial term and are subject to automatic annual renewal after the initial term.

On September 23, 2015, Antero Resources contributed (the "Water Acquisition") (i) all of the outstanding limited liability company interests of Antero Water LLC ("Antero Water") to the Partnership and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero Resources and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero Resources' advanced wastewater treatment complex undergoing testing and commissioning in Doddridge County, West Virginia, to Antero Treatment LLC ("Antero

Treatment") (collectively, (i) and (ii) are referred to herein as the "Contributed Assets"). Our results for the year ended December 31, 2015 has been recast to include the historical results of Antero Water because the transaction was between entities under common control. Antero Water's operations prior to the Water Acquisition consisted entirely of fresh water delivery operations.

The agreement includes certain minimum fresh water delivery commitments that require Antero Resources to take delivery or pay a fee on a minimum volume of fresh water deliveries in calendar years 2016 through 2019. Minimum volume commitments are 90,000 barrels per day in 2016, 100,000 barrels per day in 2017 and 120,000 barrels per day in 2018 and 2019. We have a secondment agreement whereby Antero Resources provides seconded employees to perform certain operational services with respect to our assets for a 20-year period that commenced at the Water Acquisition date. Additionally, we have a services agreement whereby Antero Resources provides certain administrative services to us for a 20-year period, that commenced at the Initial Public Offering ("IPO") date.

In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if we deliver 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if we deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020.

Our gathering and compression assets consist of 8-, 12-, 16-, 20-, 24-, and 30-inch high and low pressure gathering pipelines, compressor stations, and processing and fractionation plants that collect and process natural gas, NGLs and oil from Antero Resources' wells in West Virginia and Ohio. The Partnership's water handling and treatment assets include two independent systems that deliver fresh water from sources including the Ohio River, local reservoirs as well as several regional waterways. The water handling and treatment assets also consist of flowback and produced water assets used to provide services for well completion and production operations in Antero Resources' operating areas. The fresh water delivery services systems consist of permanent buried pipelines, surface pipelines and fresh water storage facilities, as well as pumping stations and impoundments to transport fresh water throughout the systems. The flowback and produced water services assets consist of wastewater transportation, disposal, and a wastewater treatment facility that is currently undergoing testing and commissioning. As of December 31, 2017, we had the ability to store 5.4 million barrels of fresh water in 38 impoundments.

Due to the extensive geographic distribution of our water pipeline systems in both West Virginia and Ohio, we have provided water delivery services to other oil and gas producers operating within and adjacent to Antero Resources' operating area, and we are able to provide water delivery services to other oil and gas producers in the area, subject to our availability to provide the services, in an effort to further leverage our existing system to reduce water truck traffic.

As of December 31, 2017, in West Virginia, we owned and operated 122 miles of buried fresh water pipelines and 68 miles of surface fresh water pipelines that service Antero Resources' drilling activities in the Marcellus Shale, as well as 25 centralized water storage facilities equipped with transfer pumps. As of December 31, 2017, in Ohio, we owned and operated 55 miles of buried fresh water pipelines and 28 miles of surface fresh water pipelines that service Antero Resources' drilling activities in the Utica Shale, as well as 13 centralized water storage facilities equipped with transfer pumps. The water handling and treatment services include hauling, treatment and disposal or recycling of flow back and produced water.

Our operations are located in the United States and are organized into two reporting segments: (1) gathering and processing and (2) water handling and treatment. Financial information for our reporting segments is located under "Note 12. Reporting Segments" to our consolidated financial statements.

Developments and Highlights

Financial Results

For the year ended December 31, 2017, we generated cash flows from operations of $476 million, net income of $307 million, Adjusted EBITDA of $529 million, and Distributable Cash Flow of $421 million. This compares to cash flows from operations of $379 million, net income of $237 million, Adjusted EBITDA of $404 million, and Distributable Cash Flow of $353 million for the year ended December 31, 2016. See "—Non-GAAP Financial

Measures" for a definition of Adjusted EBITDA and Distributable Cash Flow (non-GAAP measures) and a reconciliation of Adjusted EBITDA and Distributable Cash Flow to net income.

Cash Distributions

The board of directors of our general partner has declared a cash distribution of $0.365 per unit for the quarter ended December 31, 2017. The distribution was paid on February 13, 2018 to unitholders of record as of February 1, 2018.

2018 Capital Budget

During 2018, we plan to expand our existing Marcellus and Utica Shale gathering, processing and fresh water delivery infrastructure to accommodate Antero Resources' development plans. Antero Resources' 2018 drilling and completion capital budget is $1.3 billion. Antero Resources plans to operate an average of five drilling rigs and complete between 120 and 125 horizontal wells in the Marcellus, all of which are located on acreage dedicated to us. In the Utica, Antero plans to operate one drilling rig and complete between 20 and 25 horizontal wells in 2018, all of which are located on acreage dedicated to us.

Our 2018 capital budget is approximately $650 million, which includes $585 million of expansion capital and $65 million of maintenance capital. The capital budget includes $385 million of capital for gathering and compression infrastructure, approximately 90% of which will be invested in the Marcellus Shale and the remaining 10% will be invested in the Utica Shale. The gathering and compression budget is expected to fund construction of over 51 miles of gathering pipelines in the Marcellus and Utica Shales combined. We also expect to invest $35 million for water infrastructure capital to construct 25 miles of additional buried fresh water pipelines and surface pipelines to support Antero Resources' completion activities. Approximately 85% of the water infrastructure budget will be allocated to the Marcellus Shale and the remaining 15% will be allocated to the Utica Shale. Our 2018 budget also includes $15 million of capital for the final completion of our advanced wastewater treatment facility, which is expected to be placed into full commercial service during the first quarter of 2018, and $215 million for our investment in the Joint Venture.

Joint Venture

On February 6, 2017, we formed the Joint Venture to develop processing and fractionation assets in Appalachia with MarkWest. We and MarkWest each own a 50% interest in the Joint Venture and MarkWest operates the Joint Venture assets. The Joint Venture assets consist of processing plants in West Virginia, and a one-third interest in a MarkWest fractionator in Ohio.

In conjunction with the Joint Venture, on February 10, 2017 we issued 6,900,000 common units, including common units issued pursuant to the underwriters' option to purchase additional common units, resulting in net proceeds of approximately $223 million (the "Offering"). We used the proceeds from the Offering to repay outstanding borrowings under our Credit Facility incurred to fund the investment in the Joint Venture, and for general partnership purposes.

Subordinated Unit Conversion

On January 11, 2017, the board of directors of our general partner declared a cash distribution of $0.28 per unit for the quarter ended December 31, 2016. The distribution was paid on February 8, 2017 to unitholders of record as of February 1, 2017. Upon payment of this distribution, the requirements for the conversion of all subordinated units were satisfied under our partnership agreement. As a result, effective February 9, 2017, the 75,940,957 subordinated units owned by Antero Resources were converted into common units on a one-for-one basis and thereafter will participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of the cash distributions paid by the Partnership or the total units outstanding.

Credit Facility

On October 26, 2017, we entered into a restated and amended senior revolving credit facility. The facility was amended to include fall away covenants and lower interest rates that are triggered if and when we are assigned an investment grade credit rating by either Standard and Poor's or Moody's.

Lender commitments under our new facility remained at $1.5 billion. The maturity date of the facility was extended from November 2019 to October 26, 2022. At December 31, 2017, we had borrowings of $555 million and no letters of credit outstanding under the Credit Facility. See "—Debt Agreements—Revolving Credit Facility" for a description of our revolving Credit Facility.

Antero Midstream GP LP Initial Public Offering

Antero Midstream GP LP ("AMGP") was originally formed as Antero Resources Midstream Management LLC ("ARMM") in 2013, to become our general partner. In April 2017, in connection with its proposed IPO, ARMM formed Antero Midstream Partners GP LLC ("AMP GP"), a Delaware limited liability company, as a wholly owned subsidiary, and assigned it the general partner interest in us. Concurrent with the assignment, AMP GP was admitted as our sole general partner and ARMM ceased to be Antero Midstream's general partner. On May 4, 2017, ARMM converted from a Delaware limited liability company to a Delaware limited partnership and changed its name to Antero Midstream GP LP in connection with its IPO. Subsequent to its IPO, AMGP indirectly controls the general partnership interest in us, through its ownership of AMP GP, as well as Antero IDR Holdings LLC ("IDR LLC"), which owns the incentive distribution rights in us. We received no proceeds from the sale of common shares in AMGP's IPO.

Our Assets

The following table provides information regarding our gathering and processing systems as of December 31, 2016 and 2017:

	Gathering and Processing System					
	Low-Pressure Pipeline (miles)		High-Pressure Pipeline (miles)		Compression Capacity (MMcf/d)	
	As of December 31,					
	2016	2017	2016	2017	2016	2017
Marcellus	115	126	98	116	1,015	1,590
Utica	58	68	36	36	120	120
Total	173	194	134	152	1,135	1,710

The following table provides information regarding our water handling and treatment systems as of December 31, 2016 and 2017:

	Water Handling and Treatment System							
	Buried Fresh Water Pipeline (miles)		Surface Fresh Water Pipeline (miles)		Wells Serviced by Water Distribution		Fresh Water Impoundments	
	As of December 31,							
	2016	2017	2016	2017	2016	2017	2016	2017
Marcellus	116	122	87	68	99	115	22	25
Utica	49	55	34	28	32	27	14	13
Total	165	177	121	96	131	142	36	38

As of December 31, 2017, our Marcellus and Utica Shale gathering systems included 242 miles and 123 miles of pipelines, respectively, and our water handling and treatment systems included 190 miles and 83 miles of pipelines, respectively.

In addition, our assets include a wastewater treatment facility that is currently undergoing testing and commissioning. We expect it to go into full commercial service in the first quarter of 2018.

Our Relationship with Antero Resources

Antero Resources is our most significant customer and is one of the largest producers of natural gas and NGLs in the Appalachian Basin, where it produced, on average, 2.3 Bcfe/d net (28% liquids) during 2017, an increase of 22% as compared to 2016. As of December 31, 2017, Antero Resources' estimated net proved reserves were 17.3 Tcfe, which were comprised of 64% natural gas, 34% NGLs, and 2% oil. As of December 31, 2017, Antero Resources' drilling inventory consisted of 4,133 identified potential horizontal well locations (approximately 3,200 of which were located on acreage dedicated to us) for gathering and compression and water handling and treatment services, which provides us with significant opportunities for growth as Antero Resources' active drilling program continues and its production increases. Antero Resources' 2018 drilling and completion budget is $1.3 billion, and includes plans to operate an average of six drilling rigs, including five rigs in the Marcellus Shale, and one rig in the Utica Shale. Antero Resources relies significantly on us to deliver the midstream infrastructure necessary to accommodate its production growth. For additional information regarding our contracts with Antero Resources, please read "—Contractual Arrangement with Antero Resources."

We are highly dependent on Antero Resources as our most significant customer, and we expect to derive most of our revenues from Antero Resources for the foreseeable future. Accordingly, we are indirectly subject to the business risks of Antero Resources. For additional information, please read "Risk Factors—Risks Related to Our Business." Because a substantial majority of our revenue is derived from Antero Resources, any development that materially and adversely affects Antero Resources' operations, financial condition or market reputation could have a material adverse impact on us.

Contractual Arrangements

Gathering and Compression

In connection with our IPO, Antero Resources dedicated all of its current and future acreage in West Virginia, Ohio and Pennsylvania to us for gathering and compression except for acreage attributable to third-party commitments in effect prior to the Antero Midstream IPO, or acreage we have acquired that contained pre-existing dedications. For a discussion of Antero Resources' existing third-party commitments, please read "—Antero Resources' Existing Third-Party Commitments." We also have an option to gather and compress natural gas produced by Antero Resources on any acreage it acquires in the future outside of West Virginia, Ohio and Pennsylvania on the same terms and conditions. Under the gathering and compression agreement, we receive a low pressure gathering fee of $0.30 per Mcf, a high pressure gathering fee of $0.18 per Mcf, and a compression fee of $0.18 per Mcf, in each case subject to CPI-based adjustments. If and to the extent Antero Resources requests that we construct new high pressure lines and compressor stations, the gathering and compression agreement contains minimum volume commitments that require Antero Resources to utilize or pay for 75% and 70%, respectively, of the capacity of such new construction for 10 years. Additional high pressure lines and compressor stations installed on our own initiative are not subject to such volume commitments. These minimum volume commitments on new infrastructure are intended to support the stability of our cash flows. For additional information, please read "Item 13. Certain Relationships and Related Transactions."

Water Handling and Treatment Services

In connection with the Water Acquisition on September 23, 2015, we entered in a Water Services Agreement with Antero Resources whereby we have agreed to provide certain water handling and treatment services to Antero Resources within an area of dedication in defined service areas in Ohio and West Virginia. Antero Resources agreed to pay us for all water handling and treatment services provided by us in accordance with the terms of the Water Services Agreement. The initial term of the Water Services Agreement is 20 years from September 23, 2015 and from year to year thereafter until terminated by either party. Under the agreement, Antero Resources will pay a fixed fee of $3.685 per barrel in West Virginia and $3.635 per barrel in Ohio and all other locations for fresh water deliveries by pipeline directly to the well site, subject to annual CPI adjustments. Antero Resources has committed to pay a fee on a minimum volume of fresh water deliveries in calendar years 2016 through 2019. Antero Resources is obligated to pay a minimum volume fee to us in the event the aggregate volume of fresh water delivered to Antero Resources under the Water Services Agreement is less than 90,000 barrels per day in 2016, 100,000 barrels per day in 2017 and 120,000 barrels per day in 2018 and 2019. Antero Resources also agreed to pay us a fixed fee of $4.00 per barrel for wastewater treatment at the advanced wastewater treatment complex and a fee per barrel for wastewater collected in trucks owned by us, in each case subject to annual CPI-based adjustments. In addition, we contract with third party service providers to provide Antero Resources flow back and produced water services and Antero Resources will reimburse us third party out-of-pocket costs plus 3%.

Gas Processing and NGL Fractionation

Prior to the formation of the Joint Venture, we did not have any gas processing or NGL fractionation infrastructure; however, we have a right-of-first-offer agreement with Antero Resources for the provision of such services, pursuant to which Antero Resources, subject to certain exceptions, may not procure any gas processing or NGL fractionation services with respect to its production (other than production subject to a pre-existing dedication) without first offering us the right to provide such services. For additional information, please read "—Antero Resources' Existing Third-Party Commitments" and "Item 13. Certain Relationships and Related Transactions."

In connection with the formation of the Joint Venture, we and Antero Resources amended and restated our right of first offer agreement in order to, among other things, amend the list of conflicting dedications set forth in such agreement to include the gas processing and NGL fractionation arrangement between Antero Resources and MarkWest. Pursuant to such gas processing and NGL fractionation agreements, Antero has dedicated 195,000 gross acres of processing and fractionation to MarkWest for processing and fractionation, which has separately agreed to use the Joint Venture for a portion of processing and fractionation services.

Antero Resources' Existing Third-Party Commitments

Excluded Acreage

Antero Resources previously dedicated a portion of its acreage in the Marcellus Shale to certain third parties' gathering and compression services. We refer to this acreage dedication as the "excluded acreage." As of December 31, 2017, the excluded acreage consisted of approximately 156,000 of Antero Resources' existing net leasehold acreage. At that same date, approximately 950 of Antero Resources' 4,133 potential horizontal well locations were located within the excluded acreage.

Other Commitments

In addition to the excluded acreage, Antero Resources has entered into take-or-pay contracts with volume commitments for certain third parties' high pressure gathering and compression services. Specifically, those volume commitments consist of up to an aggregate of 750 MMcf/d on four high pressure gathering pipelines and 1,020 MMcf/d on nine compressor stations.

Acreage Dispositions

In addition to the excluded acreage and Antero Resources' other commitments with third parties, each of the gathering and compression agreement, water services agreement and right of first offer agreement permit Antero Resources to sell, transfer, convey, assign, grant, or otherwise dispose of dedicated properties free of the dedication under such agreements, provided that the number of net acres of dedicated properties so disposed of, when added to the number of net acres of dedicated properties previously disposed of free of the dedication since the respective effective dates of the agreements, does not exceed the aggregate number of net acres of dedicated properties acquired by Antero Resources since such effective dates. Accordingly, under certain circumstances, Antero Resources may dispose of a significant number of net acres of dedicated properties free from dedication without our consent, and we have no control over the timing or extent of such dispositions.

Title to Properties

Our real property is classified into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our pipelines and major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our pipelines and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We have leased or owned these lands without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership of such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

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. In addition, certain natural gas end users, utilities and marketers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the spring, summer and fall, thereby smoothing demand for natural gas. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase demand for our services during the summer and winter months and decrease demand for our services during the spring and fall months.

Competition

As a result of our relationship with Antero Resources, we do not compete for the portion of Antero Resources' existing operations for which we currently provide midstream services and will not compete for future portions of Antero Resources' operations that are dedicated to us pursuant to our gathering and compression agreement and water handling and treatment services agreement with Antero Resources. For a description of this contract, please read "—Our Relationship with Antero Resources—Contractual Arrangements with Antero Resources." However, we face competition in attracting third-party volumes to our gathering and compression and water handling and treatment systems. In addition, these third parties may develop their own gathering and compression and water handling and treatment systems in lieu of employing our assets.

Regulation of Operations

Regulation of pipeline gathering services may affect certain aspects of our business and the market for our services.

Gathering Pipeline Regulation

Section 1(b) of the Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC, 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 the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. 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 some our gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by the FERC, the courts, or Congress. If the FERC were to consider the status of an individual facility and determine that the facility is not a gathering pipeline and the pipeline provides interstate transmission service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the Natural Gas Policy Act of 1978, or NGPA. Such FERC-regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

Unlike natural gas gathering under the NGA, there is no exemption for the gathering of crude oil or NGLs under the Interstate Commerce Act, or ICA. Whether a crude oil or NGL shipment is in interstate commerce under the ICA depends on the fixed and persistent intent of the shipper as to the crude oil's or NGL's final destination, absent a break in the interstate movement. Antero Midstream believes that the crude oil and NGL pipelines in its gathering system meet the traditional tests the FERC has used to determine that a pipeline is not providing transportation service in interstate commerce subject to FERC ICA jurisdiction. However, the determination of the interstate or intrastate character of shipments on Antero Midstream's crude oil and NGL pipelines depends on the shipper's intentions and the transportation of the crude oil or NGLs outside of Antero Midstream's system, and may change over time. If the FERC were to consider the status of an individual facility and the character of a crude oil or NGL shipment, and determine that the shipment is in interstate commerce, the rates for, and terms and conditions of, transportation services provided by such facility would be subject to regulation by the FERC under the ICA. Such FERC regulation could decrease revenue, increase operating costs, and, depending on the facility in question, could adversely affect Antero Midstream's results of operations and cash flows. In addition, if any of Antero Midstream's facilities were found to have provided services or otherwise operated in violation of the ICA, this could result in the imposition of administrative and civil remedies and criminal penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. States in which we operate may adopt ratable take and common purchaser statutes, which would require our gathering pipelines to take natural gas without undue discrimination in favor of one producer over another producer or one source of supply over another similarly situated source of supply. The regulations under these statutes may have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. States in which we operate may also adopt a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such regulation will be adopted and whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our system due to state regulations.

Our gathering operations could be adversely affected should they be subject in the future to more stringent application of state regulation of rates and services. Our gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

The Energy Policy Act of 2005, or EPAct 2005, amended the NGA and NGPA to prohibit fraud and manipulation in natural gas markets. The FERC subsequently issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC's jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. The FERC's anti-manipulation rules apply to intrastate sales and gathering activities only to the extent that there is a "nexus" to FERC-jurisdictional transactions. EPAct 2005 also provided the FERC with the authority to impose civil penalties of up to $1,000,000 per day per violation. On January 9, 2017, FERC issued an order (Order No. 834) increasing the maximum civil penalty amounts under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of up to $1,213,503 per violation per day.

Pipeline Safety Regulation

Some of our gas pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, or HLPSA, with respect to crude oil and NGLs. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002, or PSIA, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or 2011 Pipeline Safety Act. The NGPSA and HLPSA regulate safety requirements in the design, construction, operation and maintenance of natural gas, crude oil and NGL pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. crude oil, NGL and natural gas transmission pipelines in high-consequence areas, or HCAs.

The PHMSA has developed regulations that require pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;

- identify and characterize applicable threats to pipeline segments that could impact a HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

The 2011 Pipeline Safety Act, among other things, increased the maximum civil penalty for pipeline safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. Consistent with the act, PHMSA finalized rules that increased the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to $200,000 per violation per day, with a maximum of $2,000,000 for a series of violations. Effective April 27, 2017, those maximum civil penalties were increased to $209,002 per violation per day, with a maximum of $2,090,022 for a series of violations, to account for inflation. The PHMSA has also issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulation.

On June 22, 2016, the President signed into law new legislation entitled Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, or the PIPES Act. The PIPES Act reauthorizes PHMSA through 2019, and facilitates greater pipeline safety by providing PHMSA with emergency order authority, including authority to issue prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities to address imminent hazards, without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements, requiring a review of both natural gas and hazardous liquid integrity management programs, and mandating the creation of a working group to consider the development of an information-sharing system related to integrity risk analyses. The PIPES Act also requires that PHMSA publish periodic updates on the status of those mandates outstanding from the 2011 Pipeline Safety Act, of which approximately twelve remain to be completed. The mandates yet to be acted upon include requiring certain shut-off valves on transmission lines, mapping all high consequence areas, and shortening the deadline for accident and incident notifications.

PHMSA regularly revises its pipeline safety regulations. For example, in March of 2015, PHMSA finalized new rules applicable to gas and hazardous liquid pipelines that, among other changes, impose new post-construction inspections, welding, gas component pressure testing requirements, as well as requirements for calculating pressure reductions for immediate repairs on liquid pipelines. In addition, in May 2016, PHMSA proposed rules that would, if adopted, impose more stringent requirements for certain gas lines. Among other things, the proposed rulemaking would extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond ''high consequence areas'' to cover gas pipelines found in newly defined ''moderate consequence areas'' that contain as few as five dwellings within the potential impact area and would also require gas pipelines installed before 1970 that are currently exempted from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures, or MAOP. Other new requirements proposed by PHMSA under rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on natural gas gathering lines. More recently, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline's proximity to a high consequence area. The final rule would also impose new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, implementation of this rule has been delayed as a result of the change in U.S. Presidential Administrations, and the final rule is not expected to be published by the Federal Register until the second quarter of 2018. Separately, in March 2017, new PHMSA rules related to gas and hazardous liquid pipeline accident reporting, control room personnel training requirements, personnel drug and alcohol testing, and incorporating consensus standards by reference for integrity management issues such as in-line inspection and stress corrosion cracking direct assessment became effective.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We regularly review all existing and proposed pipeline safety requirements and work to incorporate the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and upcoming changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our natural gas gathering and compression and water handling and treatment activities are subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment, imposing emission or discharge limits or otherwise restricting the way we operate resulting in additional costs to our operations;

- limiting or prohibiting construction activities in areas, such as air quality nonattainment areas, wetlands, coastal regions or areas inhabited by endangered or threatened species;

- delaying system modification or upgrades during review of permit applications and revisions;

- requiring investigatory and remedial actions to mitigate discharges, releases or pollution conditions associated with our operations or attributable to former operations; and

- enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to or regulatory requirements imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and natural resource damages. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or solid wastes have been disposed or otherwise released. Moreover, neighboring landowners and other third parties may file common law claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or solid waste into the environment.

The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. As with the midstream industry in general, complying with current and anticipated environmental laws and regulations can increase our capital costs to construct, maintain and operate equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we do not believe they will have a material adverse effect on our business, financial position, results of operations or cash flows, nor do we believe that they will affect our competitive position since the operations of our competitors are generally similarly affected. In addition, we believe that the various activities in which we are presently engaged that are subject to environmental laws and regulations are not expected to materially interrupt or diminish our operational ability to gather natural gas and provide water handling and treatment services. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business.

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. Our primary customer, Antero Resources, uses hydraulic fracturing as part of its completion operations as does most of the U.S. onshore oil and natural gas industry. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies; however, in recent years the EPA, has asserted limited authority over hydraulic fracturing and has issued or sought to propose rules related to the control of air emissions, disclosure of chemicals used in the process, and the disposal of flowback and produced water resulting from the process. Some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by some members of Congress to provide for such regulation. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of water and natural gas that move through our systems, which in turn could materially adversely affect our revenues and results of operations.

Hazardous Waste

Antero Midstream and Antero Resources' operations generate solid wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws, which impose requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes intrinsically associated with the exploration, development, or production of crude oil and natural gas, including residual constituents derived from those exempt wastes. However, these oil and gas exploration and production wastes may still be regulated under state solid waste laws and regulations, and it is possible that certain oil and natural gas exploration and production wastes now classified as exploration and production-exempt non-hazardous waste could be classified as hazardous waste 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. Any revisions to Subtitle D would have to be finalized by 2021. Stricter regulation of wastes generated during our or our customer's operations could result in increased costs for our operations or the operations of our customers, which could in turn reduce demand for our services, increase our waste disposal costs, and adversely affect our business.

Our Clearwater Facility and adjacent Antero Landfill operate pursuant to West Virginia Department of Environmental Protection ("DEP") permits for the management of stormwater and waste water and the disposal and management of solid waste. The produced water, flowback water, and other waste associated with shale development treated at the Clearwater Facility are exempt from RCRA hazardous waste regulations. Likewise, the input (residual salt derived from the wastewater treated at the Clearwater Facility) and output (leachate derived from precipitation run-off contacting the non-hazardous salt) to and from the Antero Landfill also qualify as exploration and production-exempt non-hazardous wastes because they derive from non-hazardous exempt material. However, in the event that hazardous non-exempt waste streams are introduced to and mix with the exempt waste at the Clearwater Facility, or if we otherwise fail to handle or treat such exempt materials pursuant to our West Virginia DEP permits, we may be subject to penalties and/or corrective action measures. Additionally, in the event that we dispose of sludges containing naturally occurring radioactive material (generated at the Clearwater Facility) at the Antero Landfill or other third-party facility that is not authorized to receive such radioactive waste, we may be subject to significant liabilities in the form of administrative, civil or criminal penalties and/or remedial obligations to remove previously disposed radioactive wastes and remediate contaminated property.

Site Remediation

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 responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations, such as landfills. Although petroleum as well as natural gas is excluded from CERCLA's definition of "hazardous substance," in the course of our ordinary operations, our operations generate wastes that may be designated as hazardous substances. CERCLA authorizes the EPA, states, and, in some cases, third parties to take actions in response to releases or threatened releases of hazardous substances into the environment and to seek to recover from the classes of responsible persons the costs they incur to address the release. Under CERCLA, we could be subject to strict joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources.

We currently own or lease, and may have in the past owned or leased, properties that have been used for the gathering and compression of natural gas and the gathering and transportation of oil. Although we typically used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by it or on or under other locations where such substances have been taken for disposal. Such petroleum hydrocarbons or wastes may have migrated to property adjacent to our owned and leased sites or the disposal sites. In addition, some of the properties may have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed wastes, including waste disposed of by prior owners or operators; remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or perform remedial operations to prevent future contamination. We are not currently a potentially responsible party in any federal or state Superfund site remediation and there are no current, pending or anticipated Superfund response or remedial activities at or implicating our facilities or operations.

Air Emissions

The federal Clean Air Act, and comparable state laws, regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various emission limits, operational limits and monitoring, reporting and recordkeeping requirements on air emission sources. Failure to comply with these requirements could result in monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. These laws are frequently subject to change. 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. In November 2017, the EPA published a partial list of attainment designations for the 2015 ozone standard. The EPA issued preliminary non-attainment designations in December 2017, and has announced that they plan to issue final attainment status designations during the first half of 2018. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Applicable laws and regulations require pre- construction permits for the construction or modification of certain projects or facilities with the potential to emit air emissions above certain thresholds. These pre-construction permits generally require use of best available control technology, or BACT, to limit air emissions. In addition, 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. Several EPA new source performance standards, or NSPS, and national emission standards for hazardous air pollutants, or NESHAP, also apply to our facilities and operations. These NSPS and NESHAP standards impose emission limits and operational limits as well as detailed testing, recordkeeping and reporting requirements on the "affected facilities" covered by these regulations. Several of our facilities are “major” facilities requiring Title V operating permits which impose semi-annual reporting requirements.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, 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 the state. 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. 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. In September 2015, the EPA and U.S. Army Corps of Engineers issued a final rule defining the scope of the EPA’s and the Corps’ jurisdiction. The rule, which was supposed to have become effective in August 2015, 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. In January 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction to review the rule. Now that the Supreme Court has established the proper jurisdiction for the litigation, several district court cases that had been put on hold could be restarted, and it unclear how the Trump Administration will defend the rule. Following the issuance of a presidential executive order to review the rule, the EPA and the Corps proposed a rulemaking to repeal the rule in June 2017; the EPA and Corps also announced their intent to issue a new rule defining the CWA’s jurisdiction. In November 2017, the EPA and the Corps proposed postponing by two years the effective date of the rule until at least 2020, which would provide the agencies more time to potentially repeal and replace the rule. As a result, future implementation of the rule is uncertain at this time. 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.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of significant quantities of oil. These laws and regulations provide for administrative, civil, and criminal penalties for any discharges not authorized by the permit and may impose substantial potential liability for the costs of removal, remediation, and damages. We believe that we maintain all material discharge permits necessary to conduct our operations, and further believe that compliance with such permits will not have a material adverse effect on our business operations.

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. We do not believe that compliance with worker health and safety requirements will have a material adverse effect on our business or operations.

Endangered Species

The Endangered Species Act, or ESA, and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. 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 operating activities that could have an adverse impact on our results of operations.

Climate Change

The EPA has determined that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climatic changes. Based on these findings, EPA has adopted regulations under existing provisions of the federal Clean Air Act, that establish Prevention of Significant Deterioration, or PSD, pre-construction permits, and Title V operating permits for GHG emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet BACT standards for their GHG emissions established by the states or, in some cases, by the EPA, on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities. In June 2016, the EPA finalized new regulations that set emissions standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. In June 2017, the EPA proposed to stay these requirements for two years and revisit the entirety of the 2016 standards. Comments to the EPA's proposal were due in August 2017. The EPA has not yet published a final rule staying the methane NSPS. As a result of these developments, future implementation of the 2016 standards is uncertain at this time. These rules (and any additional regulations) could impose new compliance costs and permitting burdens on natural gas operations. In addition, the United States (along with numerous other nations) agreed to the Paris Agreement on climate change in December 2015, which agreement entered into force in November 2016. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and in August 2017, the U.S. State Department officially informed the United Nations of the United States' intent to withdraw from the Paris Agreement to seek negotiations either to re-enter the Paris Agreement on different terms or to establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. Additionally, 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. Although it is not possible at this time to predict how any new legislation or regulations (including any such matters relating to the Paris Agreement) that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit or otherwise address emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our midstream services. Finally, it should be noted that some 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, droughts and floods and other climatic events; if any such effects were to occur, it is uncertain if they would have an adverse effect on our financial condition and operations.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for energy infrastructure projects, such as pipelines and terminal facilities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time.

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 2017, nor do we anticipate that such expenditures will be material in 2018.

Employees

We do not have any employees. The officers of AMP GP and its subsidiaries and affiliates (our "general partner"), who are also officers of Antero Resources, manage our operations and activities. As of December 31, 2017, Antero Resources employed approximately 593 people who provide support to our operations. All of the employees required to conduct and support our operations are employed by Antero Resources. Antero Resources considers its relations with its employees to be satisfactory. Additionally, we have a secondment agreement whereby Antero Resources provides seconded employees to perform certain operational services with respect to our assets for a 20-year period that commenced on the Water Acquisition date.

Legal Proceedings

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. See "Item 3. Litigation."

We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Address, Website and Availability of Public Filings

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

We make available free of charge our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. These documents are located *www.anteromidstream.com* under the "Investors Relations" link.

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

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the following risk factors together with all of the other information included in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements," in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition, results of operations and cash available for distribution could be materially adversely affected.

Risks Related to Our Business

Because substantially all of our revenue is derived from Antero Resources, any development that materially and adversely affects Antero Resources' operations, financial condition or market reputation could have a material and adverse impact on us.

Antero Resources is our most significant customer and has accounted for substantially all of our revenue since inception, and we expect to derive most of our revenues from Antero Resources for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Antero Resources' production, drilling and completion schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Antero Resources, including, among others:

- a reduction in or slowing of Antero Resources' development program, which would directly and adversely impact demand for our gathering and compression services and our water handling and treatment services;
- a reduction in or slowing of Antero Resources' well completions, which would directly and adversely impact demand for our water handling and treatment services;
- the volatility of natural gas, NGLs and oil prices, which could have a negative effect on the value of Antero Resources' properties, its drilling programs or its ability to finance its operations;
- the availability of capital on an economic basis to fund Antero Resources' exploration and development activities as well as to fund our capital expenditure programs;
- Antero Resources' ability to replace reserves;
- Antero Resources' drilling and operating risks, including potential environmental liabilities;
- transportation and processing capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

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., and strong competition among some oil producing countries for market share. Commodity prices remained depressed prices in 2015 and 2016, although a modest recovery began in late 2016, and has continued intermittently in 2017 and 2018.

Changes in commodity prices can significantly affect Antero Resources' operations and financial condition, and therefore our capital resources, liquidity, and expected operating results. Because of the natural decline in production from existing wells, our success depends, in part, on Antero Resources' ability to replace declining production and our ability to secure new sources of natural gas from Antero Resources or third parties. Additionally, our water handling and treatment services are directly associated with Antero Resources' well completion activities and water needs, which are partially driven by horizontal lateral lengths and the number of completion stages per well. Any decrease in volumes of natural gas and produced water that Antero Resources produces or any decrease in the number of wells that Antero Resources completes could adversely affect our business and operating results.

Further, we are subject to the risk of non-payment or non-performance by Antero Resources, including with respect to our gathering and compression and water handling and treatment services agreements. We cannot predict the extent to which Antero Resources' business would be impacted if conditions in the energy industry deteriorate, nor can we estimate the impact such conditions would have on Antero Resources' ability to execute its drilling and development program or perform under our gathering and compression and water handling and treatment services agreements. Any material non-payment or non-performance by Antero Resources could reduce our ability to make distributions to our unitholders.

Also, due to our relationship with Antero Resources, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairment to Antero Resources' financial condition or adverse changes in its credit ratings.

Any material limitation on our ability to access capital as a result of such adverse changes at Antero Resources could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Antero Resources could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing, or could negatively affect our ability to engage in, expand, or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Please see Item 1A, "Risk Factors" in Antero Resources' Annual Report on Form 10-K for the year ended December 31, 2017 (which is not, and shall not be deemed to be, incorporated by reference herein) for a full disclosure of the risks associated with Antero Resources' business.

We may not generate sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to our unitholders.

In order to make our minimum quarterly distribution of $0.17 per common unit per quarter, or $0.68 per unit per year, we will require available cash of approximately $32 million per quarter, or approximately $127 million per year based on the common units outstanding at December 31, 2017, as well as grants made under the Antero Midstream Partners LP Long-term Incentive Plan. We may not generate sufficient cash flows each quarter to support the payment of the minimum quarterly distribution or to increase our quarterly distributions in the future from the fourth quarter of 2017 level of $0.365 per unit.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather and compress and the volume of water we handle and treat in connection with well completion operations;
- the rates we charge third parties, if any, for our water handling and treatment and gathering and compression services;
- market prices of natural gas, NGLs and oil and their effect on Antero Resources' drilling schedule as well as produced volumes;
- Antero Resources' ability to fund its drilling program;
- adverse weather conditions;
- the level of our operating, maintenance and general and administrative costs;

- regulatory action affecting the supply of, or demand for, natural gas, the rates we can charge for our services, how we contract for services, our existing contract, our operating costs or our operating flexibility; and

- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of maintenance and expansion capital expenditures we make;

- our debt service requirements and other liabilities;

- our ability to borrow under our debt agreements to pay distributions;

- fluctuations in our working capital needs;

- restrictions on distributions contained in any of our debt agreements;

- the cost of acquisitions, if any;

- fees and expenses of our general partner and its affiliates (including Antero Resources) we are required to reimburse;

- the amount of cash reserves established by our general partner; and

- other business risks affecting our cash levels.

Because of the natural decline in production from existing wells, our success depends, in part, on Antero Resources' ability to replace declining production and our ability to secure new sources of natural gas from Antero Resources or third parties. Additionally, our water handling and treatment services are directly associated with Antero Resources' well completion activities and water needs, which are partially driven by horizontal lateral lengths and the number of completion stages per well. Finally, under certain circumstances, Antero Resources may dispose of acreage dedicated to us free from such dedication without our consent. Any decrease in volumes of natural gas that Antero Resources produces, any decrease in the number of wells that Antero Resources completes, or any decrease in the number of acres that are dedicated to us could adversely affect our business and operating results.

The natural gas volumes that support our gathering business depend on the level of production from natural gas wells connected to our systems, which may be less than expected and will naturally decline over time. To the extent Antero Resources reduces its development activity or otherwise ceases to drill and complete wells, revenues for our gathering and compression and water handling and treatment services will be directly and adversely affected. Our ability to maintain water handling and treatment services revenues is substantially dependent on continued completion activity by Antero Resources or third parties over time, as well as the volumes of produced water from such activity. In addition, natural gas volumes from completed wells will naturally decline and our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering systems, we must obtain new sources of natural gas from Antero Resources or third parties. The primary factors affecting our ability to obtain additional sources of natural gas include (i) the success of Antero Resources' drilling activity in our areas of operation, (ii) Antero Resources' acquisition of additional acreage and (iii) our ability to obtain dedications of acreage from third parties. Our fresh water delivery services, which make up a substantial portion of our water handling and treatment services revenues, will be in greatest demand in connection with completion activities. To the extent that Antero Resources or other fresh water delivery customers complete wells with shorter lateral lengths, the demand for our fresh water delivery services would be reduced.

We have no control over Antero Resources' or other producers' levels of development and completion activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, our water handling and treatment business is dependent upon active development in our areas of operation. In order to maintain or increase throughput levels on our water handling and treatment systems, we must service new wells. We have no control over Antero Resources or other producers or their development plan decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected natural gas, NGLs and oil prices;
- demand for natural gas, NGLs and oil;
- quantities of reserves;
- geologic considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the costs of producing the gas and the availability and costs of drilling rigs and other equipment.

Fluctuations in energy prices can also greatly affect the development of reserves. 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., and strong competition among some oil producing countries for market share. Commodity prices remained depressed prices in 2015 and 2016, although a modest recovery began in late 2016, and has continued intermittently in 2017 and 2018.

These lower prices have compelled most natural gas and oil producers, including Antero Resources, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Natural gas and oil prices directly affect Antero Resources' production. If prices decrease further, it would reduce our revenues and ability to pay distributions. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization of our services.

Due to these and other factors, even if reserves are known to exist in areas served by our assets, producers have chosen, and may choose in the future, not to develop those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput on our systems, or our water handling and treatment services, or if reductions in lateral lengths result in a decrease in demand for our water handling and treatment services on a per well basis, those reductions could reduce our revenue and cash flows and adversely affect our ability to make cash distributions to our unitholders.

Finally, each of the gathering and compression agreement, water services agreement and right of first offer agreement permit between us and Antero Resources permit Antero Resources to sell, transfer, convey, assign, grant, or otherwise dispose of dedicated properties free of the dedication under such agreements, provided that the number of net acres of dedicated properties so disposed of, when added to the number of net acres of dedicated properties previously disposed of free of the dedication since the respective effective dates of the agreements, does not exceed the aggregate number of net acres of dedicated properties acquired by Antero Resources since such effective dates. Accordingly, under certain circumstances, Antero Resources may dispose of a significant number of net acres of dedicated properties free from dedication without our consent, and we have no control over the timing or extent of such dispositions. Any such dispositions could adversely affect our business and operating results.

The gathering and compression agreement only includes minimum volume commitments under certain circumstances.

The gathering and compression agreement includes minimum volume commitments only on new high pressure pipelines and compressor stations that we construct subsequent to our initial public offering in November 2014 at Antero

Resources' request. The high pressure pipelines and compressor stations that existed prior to our initial public offering are not supported by minimum volume commitments from Antero Resources. Any decrease in the current levels of throughput on our gathering and compression systems could reduce our revenue and cash flows and adversely affect our ability to make cash distributions to our unitholders.

We will be required to make substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and, as a result, we will be unable to raise the level of our future cash distributions. To fund our expansion capital expenditures and investment capital expenditures, we will be required to use cash from our operations or incur borrowings. Alternatively, we may sell additional common units or other securities to fund our capital expenditures. Such uses of cash from our operations will reduce cash available for distribution to our unitholders. Our ability to obtain bank financing or our ability to access the capital markets for future equity or debt offerings may be limited by our or Antero Resources' financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the then current distribution rate, which could materially decrease our ability to pay distributions at the prevailing distribution rate. Neither Antero Resources, our general partner or any of their respective Affiliates is committed to providing any direct or indirect support to fund our growth.

Our gathering and compression and water handling and treatment systems are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

We rely primarily on revenues generated from gathering and compression and water handling and treatment systems that we own, which are located in the Marcellus and Utica Shales. 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, market limitations or interruption of the compression or transportation of natural gas, NGLs or oil.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flows and not solely on profitability, which may prevent us from making distributions, even during periods in which we record net income.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record a net loss for financial accounting purposes, and conversely, we might fail to make cash distributions during periods when we record net income for financial accounting purposes.

Our construction or purchase of new gathering and compression, processing, water handling and treatment or other assets, including the water treatment facility currently undergoing testing and commissioning, may not be completed on schedule, at the budgeted cost or at all, and they may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our cash flows, results of operations and financial condition and, as a result, our ability to distribute cash to our unitholders.

The construction of additions or modifications to our existing systems and the construction or purchase of new assets, including the water treatment facility currently undergoing testing and commissioning, involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, the construction of the water treatment facility will occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future production growth in an area in which such growth does not materialize. As a result, new gathering and compression, water handling and treatment or other assets may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing assets may require us to obtain new rights-of-way prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way to connect new natural gas supplies to our existing gathering pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

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 business, results of operations and financial condition and, as a result, our ability to make cash distributions to our unitholders.

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

We own a 50% interest in the Joint Venture, which is operated by MarkWest Energy. While we have the ability to influence certain business decisions affecting the Joint Venture, the success of its investment in the Joint Venture will depend on MarkWest's operation of the Joint Venture.

On February 6, 2017, we entered into the Joint Venture with MarkWest. While we and MarkWest each own a 50% interest in the Joint Venture, MarkWest is the primary operator of the Joint Venture. Accordingly, we depend on MarkWest for the day-to-day operations of the Joint Venture. Our lack of control over the Joint Venture's day-to-day operations and the associated costs of operations could result in receiving lower cash distributions from the Joint Venture than currently anticipated, which could reduce our cash available for distribution to our unitholders. In addition, differences in views among the owners of the Joint Venture could result in delayed decisions or in failures to agree on significant matters, potentially adversely affecting the business and results of operations or prospects of the Joint Venture and, in turn, the amount of cash from the Joint Venture operations distributed to us.

If the Joint Venture is not successful or if the Joint Venture does not perform as expected, our future financial performance may be negatively impacted.

We may be exposed to certain risks in connection with our ownership interest in the Joint Venture, including regulatory, environmental and litigation risks. If such risks or other anticipated or unanticipated liabilities were to materialize, any desired benefits of our entry into the Joint Venture may not be fully realized, if at all, and its future financial performance may be negatively impacted.

In addition, the Joint Venture may result in other difficulties including, among other things:

- diversion of our management's attention from other business concerns;
- managing regulatory compliance and corporate governance matters;
- an increase in our indebtedness; and
- potential environmental or other regulatory compliance matters or liabilities and/or title issues, including certain liabilities arising from the operation of the Joint Venture assets prior to the closing of the Joint Venture.

Interruptions in operations at any of the Joint Venture's facilities may adversely affect its operations.

The Joint Venture assets consist of processing plants in West Virginia and a one third interest in a fractionator in Ohio (the "MarkWest fractionator"). Any significant interruption at these facilities would adversely affect the Joint Venture's operations.

We do not operate the MarkWest fractionator, and the operations of the Joint Venture's processing facilities and the MarkWest fractionator could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within its control, such as:

- unscheduled turnarounds or catastrophic events, including damages to facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, hurricanes, floods, fires, severe weather, explosions and other natural disasters;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of NGL's to the Joint Venture's processing and fractionation plants and associated facilities;
- disruption in the supply of power, water and other resources necessary to operate the Joint Venture's facilities
- damage to the Joint Venture's facilities resulting from NGLs that do not comply with applicable specifications; and
- inadequate fractionation capacity or market access to support production volumes, including lack of availability of rail cars, barges, trucks and pipeline capacity, or market constraints, including reduced demand or limited markets for certain NGL products.

In addition, MarkWest's NGL fractionation operations in the Marcellus and Utica regions are integrated, and as a result, it is possible that an interruption of these operations in other regions may impact operations in the regions in which the Joint Venture's facilities are located.

If additional takeaway pipelines under construction or other pipeline projects are not completed, Antero Resources', and correspondingly the Partnership's, future growth may be limited.

Antero Resources has secured sufficient long term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of its core operating areas to accommodate its current development plans; however, any failure of any pipeline under construction to be completed, or any unavailability of existing takeaway pipelines, could cause Antero Resources to curtail its future development and production plans. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization of our, which could adversely affect our operating margin, cash flows and ability to make cash distributions to our unitholders.

A shortage of equipment and skilled labor in the Appalachian Basin could reduce equipment availability and labor productivity and increase labor and equipment costs, which could have a material adverse effect on our business and results of operations.

Gathering and compression and water handling and treatment services require special equipment and laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. The employees supporting our operations are employees of Antero Resources. If Antero Resources experiences shortages of necessary equipment or skilled labor in the future, our allocation of labor and equipment costs and overall productivity could be materially and adversely affected. If our allocation of equipment or labor prices increase or if Antero Resources experiences materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

If third-party pipelines or other midstream facilities interconnected to our gathering and compression systems become partially or fully unavailable, our operating margin, cash flows and ability to make cash distributions to our unitholders could be adversely affected.

Our gathering and compression assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, compressor stations and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs or if any of these pipelines or other midstream facilities become unable to receive or transport natural gas, our operating margin, cash flows and ability to make cash distributions to our unitholders could be adversely affected.

Our exposure to commodity price risk may change over time.

We currently generate all of our revenues pursuant to fee-based contracts under which we are paid based on the volumes of natural gas that we gather and compress and water that we handle and treat, rather than the underlying value of the commodity. Consequently, our existing operations and cash flows have little direct exposure to commodity price risk. Although we intend to enter into similar fee-based contracts with new customers in the future, our efforts to negotiate such contractual terms may not be successful. In addition, we may acquire or develop additional midstream assets in a manner that increases our exposure to commodity price risk. Future exposure to the volatility of natural gas, NGL and oil prices, especially in light of the recent declines, could have a material adverse effect on our business, results of operations and financial condition and, as a result, our ability to make cash distributions to our unitholders.

Restrictions in our existing and future debt agreements could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Our revolving credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The indenture governing our senior notes contains similar restrictive covenants. In addition, our revolving credit facility also contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet any such ratios and tests. Additionally, we may not be able to borrow the full amount of commitments under our revolving credit facility if doing so would cause us to not meet a financial covenant.

The provisions of our revolving credit facility and the indenture governing our senior notes may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility or the indenture governing our senior notes could result in a default or an event of default that could enable our lenders or noteholders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

If our assets become subject to FERC regulation or federal, state or local regulations or policies change, or if we fail to comply with market behavior rules, our financial condition, results of operations and cash flows could be materially and adversely affected.

Our gathering and transportation operations are exempt from regulation by the FERC, under the NGA. Section 1(b) of the NGA, exempts natural gas gathering facilities from regulation by the FERC 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 the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. 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 the FERC, the courts, or Congress. If the FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows.

State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, as well as complaint-based rate regulation. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, compression and sale.

Moreover, FERC regulations indirectly impact our businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, gas quality, capacity release and market center promotion, indirectly affect the intrastate natural gas market. Should we fail to comply with any applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines, which could have a material adverse effect on our results of operations and cash flows. The FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations of up to $1,213,503 per day for each violation and disgorgement of profits associated with any violation.

For more information regarding federal and state regulation of our operations, please read "Business—Regulation of Operations."

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas, NGLs and oil production by our customers, which could reduce the throughput on our gathering and compression systems and the number of wells for which we provide water handling and treatment services, which could adversely impact our revenues.

All of Antero Resources' natural gas, NGLs and oil production is being developed from unconventional sources, such as shale formations. These reservoirs require hydraulic fracturing completion processes to release the liquids and natural gas from the rock so it can flow through casing to the surface. Hydraulic fracturing is a well stimulation process that utilizes large volumes of water and sand (or other proppant) combined with fracturing chemical additives that are pumped at high pressure to crack open previously impenetrable rock to release hydrocarbons. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies. Some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. In addition, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. 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. At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by some members of Congress from time to time to provide for such regulation. Antero Midstream cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of liquids and natural gas that move through our gathering systems or reduce the number of wells drilled and completed that require fresh water for hydraulic fracturing activities, which in turn could materially adversely affect our revenues and results of operations.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may incentivize water recycling efforts by oil and natural gas producers, which would decrease the demand for our fresh water delivery services.

Our business includes fresh water delivery for use in our customers' natural gas, NGL and oil exploration and production activities. Water is an essential component of natural gas, NGL and oil production during the drilling, and in particular, the hydraulic fracturing process. We depend on Antero Resources to source the fresh water we deliver. The availability of Antero Resources' water supply may be limited due to reasons such as prolonged drought. Some state and local governmental authorities have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to ensure adequate local water supply. Any such decrease in the demand for water handling and treatment services would adversely affect our business and results of operations.

Antero Resources or any third-party customers may incur significant liability under, or costs and expenditures to comply with, environmental and occupational health and workplace safety regulations, which are complex and subject to frequent change.

As an owner, lessee or operator of gathering pipelines and compressor stations, we are subject to various stringent federal, state, provincial and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. These laws and regulations may impose various obligations that are applicable to our and our customer's operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our or our customers' operations, the imposition of specific standards addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer's operations. Failure to comply with these laws, regulations and permits may result in joint and several, strict liability and the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which our gathering systems pass and facilities where wastes resulting from our operations are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues, which in turn could affect our profitability. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability. For example, 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 a 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.

Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from 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, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Please read "Business—Regulation of Environmental and Occupational Safety and Health Matters" for more information.

Stricter regulation of wastes generated during our or our customers' operations, or the introduction of hazardous non-exempt waste to our Clearwater Facility, could result in liability under, or costs and expenditures to comply with, environmental laws and regulations governing the handling, storage, treatment and disposal of solid and hazardous wastes, and the permits issued under them.

Our and Antero Resources' operations generate solid wastes, including some hazardous wastes, that are subject to RCRA, and comparable state laws, which impose requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes intrinsically associated with the exploration, development, or production of crude oil and natural gas, including residual constituents derived from those exempt wastes. However, these oil and gas exploration and production wastes may still be regulated under state solid waste laws and regulations, and it is possible that certain oil and natural gas exploration and production wastes now classified as exploration and production-exempt non-hazardous waste could be classified as hazardous waste 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. Stricter regulation of wastes generated during our or our customers' operations could result in increased costs for our operations or the operations of our customers, which could in turn reduce demand for our services and adversely affect our business.

Our Clearwater Facility and adjacent Antero Landfill operate pursuant to West Virginia DEP permits for the management of stormwater and waste water and the disposal and management of solid waste. The produced water, flowback water, and other waste associated with shale development treated at the Clearwater Facility are exempt from RCRA hazardous waste regulations. Likewise, the input (residual salt derived from the wastewater treated at the

Clearwater Facility) and output (leachate derived from precipitation run-off contacting the non-hazardous salt) to and from the Antero Landfill also qualify as exploration and production-exempt non-hazardous wastes because they derive from non-hazardous exempt material. However, in the event that hazardous non-exempt waste streams are introduced to and mix with the exempt waste at the Clearwater Facility, or if we otherwise fails to handle or treat such exempt materials pursuant to our West Virginia DEP permits, we may be subject to penalties and/or corrective action measures.

Climate change laws and regulations restricting emissions of "greenhouse gases" ("GHG") could result in increased operating costs and reduced demand for the natural gas that we gather 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.

The EPA has determined that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, EPA has adopted regulations under existing provisions of the federal Clean Air Act, that establish Prevention of Significant Deterioration, or PSD, pre-construction permits, and Title V operating permits for GHG emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet BACT standards for their GHG emissions established by the states or, in some cases, by the EPA, on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities. As noted above, in June 2016, the EPA finalized new regulations that set emissions standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. However, in June 2017, the EPA proposed to stay implementation of the new regulations for two years and revisit the entirety of the 2016 standards. Comments to the EPA's proposal were due in August 2017. The EPA has not yet published a final rule. As a result of these developments, future implementation of the 2016 standards is uncertain at this time. These rules (and any additional regulations) could impose new compliance costs and permitting burdens on natural gas and midstream operations.

In addition, the United States (along with numerous other nations) agreed to the Paris Agreement on climate change in December 2015, which agreement entered into force in November 2016. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and in August 2017, the U.S. State Department officially informed the United Nations of the United States' intent to withdraw from the Paris Agreement to seek negotiations either to re-enter the Paris Agreement on different terms or to establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. 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. 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 that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our midstream services.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for energy infrastructure projects, such as pipelines and terminal facilities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time.

Finally, it should be noted that some 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, droughts and floods and other 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 financial condition and operations.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair or preventative or remedial measures.

The United States Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in “high consequence areas.” The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, among other things, increased the maximum civil penalty for pipeline safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. Consistent with the 2011 Pipeline Safety Act,, the Pipelines and Hazardous Materials Safety Administration, or PHMSA, finalized rules consistent with the signed act that increased the maximum administrative civil penalties for violations of the pipeline safety laws and regulations to $200,000 per violation per day, with a maximum of $2,000,000 for a related series of violations. In April 2017, those maximum civil penalties were increased to $209,002 and $2,090,022, respectively, to account for inflation. Should our operations fail to comply with DOT or comparable state regulations, we could be subject to substantial penalties and fines. Additionally, in May 2011, PHMSA published a final rule adding reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner.

In June 2016, The President signed into law important new legislation entitled Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, or the PIPES Act. The PIPES Act reauthorizes PHMSA through 2019, and facilitates greater pipeline safety by providing PHMSA with emergency order authority, including authority to issue prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities to address imminent hazards, without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements, requiring a review of both natural gas and hazardous liquid integrity management programs, and mandating the creation of a working group to consider the development of an information-sharing system related to integrity risk analyses. The PIPES Act also requires that PHMSA publish periodic updates on the status of those mandates outstanding from 2011 Pipeline Safety Act, of which approximately twelve remain to be completed. The mandates yet to be acted upon include requiring certain shut-off valves on transmission lines, mapping all high consequence areas, and shortening the deadline for accident and incident notifications.

PHMSA regularly revises its pipeline safety regulations. For example, in March of 2015, PHMSA finalized new rules applicable to gas and hazardous liquid pipelines that, among other changes, impose new post-construction inspections, welding, gas component pressure testing requirements, as well as requirements for calculating pressure reductions for immediate repairs on liquid pipelines. More recently, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline’s proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, implementation of this rule has been delayed as a result of the change in U.S. Presidential Administrations, and the final rule is not expected to be published in the Federal Register until the second quarter of 2018. Separately, in March 2017, new PHMSA rules related to gas and hazardous liquid pipeline accident reporting, control room personnel training requirements, personnel drug and alcohol testing, and incorporating consensus standards by reference for integrity management issues such as in-line inspection and stress corrosion cracking direct assessment became effective. Additional future regulatory action expanding PHMSA jurisdiction and imposing stricter integrity management requirements is likely. For example, in May 2016, PHMSA proposed rules that would, if adopted, impose more stringent requirements for certain gas lines. Among other things, the proposed rulemaking would extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond "high consequence areas" to cover gas pipelines found in newly defined "moderate consequence areas" that contain as few as 5 dwellings within the potential impact area and would also require gas pipelines installed before 1970 that are currently exempted from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures, or MAOP. Other new requirements proposed by PHMSA under the rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on gathering lines. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our cash flow. Please read "Business—Pipeline Safety Regulation" for more information.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could curtail our operations and have a material adverse effect on our ability to distribute cash and, accordingly, the market price for our common units.

Our operations are subject to all of the hazards inherent in the provision of the gathering and compression and water handling and treatment services, including:

- unintended breach of impoundment and downstream flooding, release of invasive species or aquatic pathogens, hazardous spills near intake points, trucking collision, vandalism, excessive road damage or bridge collapse and unauthorized access or use of automation controls;
- damage to pipelines, compressor stations, pump stations, impoundments, related equipment and surrounding properties caused by natural disasters, acts of terrorism and acts of third parties;
- damage from construction, farm and utility equipment as well as other subsurface activity (for example, mine subsidence);
- leaks of natural gas, NGLs or oil or losses of natural gas, NGLs or oil as a result of the malfunction of equipment or facilities;
- fires, ruptures and explosions;
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations; and
- hazards experienced by other operators that may affect our operations by instigating increased regulations and oversight.

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 under policies we are covered under, and neither we nor AMP GP on our behalf have obtained pollution insurance. 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 do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

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

Our operations are subject to complex and stringent federal, state and local 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 and the permits and other approvals issued thereunder. In addition, our costs of compliance may increase or operational delays may occur if existing laws and regulations are revised or reinterpreted, or if new laws and regulations apply to our operations. 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. Also, we might not be able to obtain or maintain all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

In addition, new or additional regulations, new interpretations of existing requirements or changes in our operations could also trigger the need for Environmental Assessments or more detailed Environmental Impact Statements under the National Environmental Policy Act and analogous state laws, or that impose new permitting requirements on our operations could result in increased costs or delays of, or denial of rights to conduct, our development programs. For example, in September 2015, the EPA and U.S. Army Corps of Engineers, or the Corps, issued a final rule under the federal Clean Water Act, or, the CWA, defining the scope of the EPA’s and the Corps’ jurisdiction. 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. Such potential regulations or litigation 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 business, financial condition and results of operations. Further, the discharges of natural gas, NGLs, oil, and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties. Please read “Item 1. Business—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of laws and regulations that affect us.

The loss of key personnel could adversely affect our ability to operate.

We depend on the services of a relatively small group of our general partner's 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 general partner's senior management or technical personnel, including Paul M. Rady, Chairman and Chief Executive Officer, and Glen C. Warren, Jr., President, could have a material adverse effect on our business, financial condition and results of operations.

We do not have any officers or employees and rely solely on officers of our general partner and employees of Antero Resources.

We are managed and operated by the board of directors of our general partner. Affiliates of Antero Resources conduct businesses and activities of their own in which we have no economic interest. As a result, there could be material competition for the time and effort of the officers and employees who provide services to our general partner and Antero Resources. If our general partner and the officers and employees of Antero Resources do not devote sufficient attention to the management and operation of our business, our financial results may suffer, and our ability to make distributions to our unitholders may be reduced.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures (including required drilling pad connections and well connections pursuant to our gathering and compression agreements as well as acquisitions) or other purposes may be impaired or such financing may not be available on favorable terms;

- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;

- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, investments or capital expenditures, selling assets or issuing equity. We may not be able to effect any of these actions on satisfactory terms or at all.

If we cease to be eligible to utilize the equity distribution agreement, our financial flexibility and liquidity could be adversely affected.

We have historically used sales of common units pursuant to the equity distribution agreement to partially fund capital expenditures. As of December 31, 2017, we had approximately $157 million of available capacity under the equity distribution agreement. If we cease to be eligible to utilize the equity distribution agreement, we may be required to find alternate sources to fund capital expenditures, which could reduce our financial flexibility and adversely affect our liquidity.

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

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

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

Risks Inherent in an Investment in Us

Antero Resources, our general partner and their respective affiliates, including AMGP, which owns our general partner, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

AMGP owns and controls our general partner and appoints all of the officers and directors of our general partner. All of the officers and a majority of the directors of our general partner are officers or directors of AMGP GP LLC, the general partner of AMGP ("AMGP GP"). Similarly, all of the officers and a majority of the directors of our general partner are also officers or directors of Antero Resources. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, AMGP. Further, our general partner's directors and officers who are also directors and officers of Antero Resources have a fiduciary duty to manage Antero Resources in a manner that is beneficial to Antero Resources. Conflicts of interest will arise between Antero Resources, AMGP, and our general partner, on the one hand, and us and our common unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of AMGP or Antero Resources over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- actions taken by our general partner may affect the amount of cash available to pay distributions to unitholders;
- the directors and officers of AMGP have a fiduciary duty to make decisions in the best interests of AMGP and its owners, which may be contrary to our interests;
- the directors and officers of Antero Resources have a fiduciary duty to make decisions in the best interests of the owners of Antero Resources, which may be contrary to our interests;

- our general partner is allowed to take into account the interests of parties other than us, such as AMGP, in exercising certain rights under our partnership agreement;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions,
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditure and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus, and this determination can affect the amount of cash from operating surplus that is distributed to our unitholders;
- our partnership agreement limits the liability of, and replaces the duties owed by, our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us;
- contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not and will not be the result of arm's length negotiations;
- our partnership agreement permits us to distribute up to $75.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus, which may be used to fund distributions on the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates (including Antero Resources) are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates (including Antero Resources) own more than 80% of the common units;
- our general partner controls the enforcement of obligations that it and its affiliates (including Antero Resources) owe to us;
- we may not choose to retain separate counsel for ourselves or for the holders of common units;
- our general partner's affiliates may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us; and
- the holder or holders of our incentive distribution rights may elect to cause us to issue common units to it in connection with a resetting of incentive distribution levels without the approval of our unitholders, which may result in lower distributions to our common unitholders in certain situations.

Certain of our common unitholders have investments in our affiliates that may conflict with the interests of other holders of our common units.

Certain funds affiliated with Warburg Pincus LLC ("Warburg"), certain funds affiliated with Yorktown Partners LLC ("Yorktown"), Paul M. Rady and Glen C. Warren, Jr. (collectively, the "Sponsors") own a significant interest in us. Affiliates of Warburg and Yorktown, Mr. Rady and Mr. Warren serve as members of the board of directors of our general partner and the board of directors of Antero Resources and AMGP GP, and each of Warburg and Yorktown are controlled in part by individuals who serve as members of the board of directors of AMGP and the board of directors of Antero Resources. The Sponsors also own the membership interests in AMGP GP, a majority of the common shares in AMGP, a majority of the Series B Units in IDR LLC, the holder of our IDRs, and a significant portion of the shares of common stock of Antero Resources. Please see "Item 11. Executive Compensation—Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table—Series B Units in IDR LLC" for more information regarding the Series B Units in IDR LLC. As a result of their investments in AMGP, AMGP GP and Antero Resources, the Sponsors may have conflicting interests with other holders of our common units. Conflicts of interest could arise in the future between us, on the one hand, and the Sponsors, on the other hand, regarding, among other things, decisions related to our financing, capital expenditure and growth plans, decisions to modify or limit the IDRs in the future, the terms of our agreements with Antero Resources and AMGP and their respective subsidiaries, and the pursuit of potentially competitive business activities or business opportunities.

Ongoing cost reimbursements due to our general partner and its affiliates for services provided, which are determined by our general partner, will be substantial and will reduce our cash available for distribution to our unitholders.

Prior to making distributions on our common units, we reimburse our general partner and its affiliates for all expenses they incur on our behalf. These expenses include all costs incurred by our general partner and its affiliates in managing and operating us, including costs for rendering administrative staff and support services to us and reimbursements paid by our general partner to Antero Resources for customary management and general administrative services. There is no limit on the amount of expenses for which our general partner and its affiliates may be reimbursed under the services agreement. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in good faith. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

We expect to distribute a significant portion of our cash available for distribution to our partners, which could limit our ability to grow and make acquisitions.

We plan to distribute most of our cash available for distribution, which may cause our growth to proceed at a slower pace than that of businesses that reinvest their cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. In addition, the incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the cash that we have available to distribute to our unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions, in its individual capacity, as opposed to in its capacity as our general partner, or otherwise, free of fiduciary duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the parties where the language in our partnership agreement does not provide for a clear course of action. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Unitholders are treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement limits the liability of, and replaces the duties owed by, our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decision was not adverse to the interest of the partnership, and, with respect to criminal conduct, did not act with the knowledge that its conduct was unlawful;
- our general partner and its officers and directors will not be liable for monetary damages or otherwise to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of the conduct of our general partner or such officer or director engaged in by it in bad faith or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful; and
- in resolving conflicts of interest, it will be presumed that in making its decision our general partner, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

Our partnership agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders' ability to choose the judicial forum for disputes with us or our general partner's directors, officers or other employees. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful action.

Our partnership agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") or (5) asserting a claim against us governed by the internal affairs doctrine. In addition, if any unitholder brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. Limited partners who own common units irrevocably consent to these limitations, provisions and potential reimbursement obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us and our general partner's directors and officers.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Compared to the holders of common stock in a corporation, unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by AMGP, as a result of it owning our general partner, and not by our unitholders. Please read "Item 10. Directors, Executive Officers, and Corporate Governance—Management of Antero Midstream Partners LP" and "Certain Relationships and Related Transactions." Unlike publicly-traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

The holder or holders of our incentive distribution rights may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

The holder or holders of a majority of our incentive distribution rights have the right, at any time they have received incentive distributions at the highest level to which they are entitled (50%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. Following a reset election, a baseline distribution amount will be calculated equal to an amount equal to the prior cash distribution per common unit for the fiscal quarter immediately preceding the reset election (such amount is referred to as the ''reset minimum quarterly distribution''), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

We anticipate that the holder of our incentive distribution rights would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per unit without such conversion. However, the holder of our incentive distribution rights may transfer the incentive distribution rights at any time. It is possible that the holder of our incentive distribution rights or a transferee could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the incentive distribution rights expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the incentive distribution rights may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the incentive distribution rights and may therefore desire to be issued our common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for them to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new common units to the holders of the incentive distribution rights in connection with resetting the target distribution levels.

The incentive distribution rights may be transferred to a third party without unitholder consent.

The holder of our incentive distribution rights may transfer the incentive distribution rights to a third party at any time without the consent of our unitholders. If the incentive distribution rights are transferred to a third party but our general partner retains its general partner interest, our general partner (and its owner, AMGP) may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained indirect ownership of the incentive distribution rights.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity, to incur debt to capture growth opportunities or for other purposes, or to make cash distributions at our intended levels.

If interest rates rise, the interest rates on our revolving credit facility, future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity, to incur debt to expand or for other purposes, or to make cash distributions at our intended levels.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates (including Antero Resources), their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a "change of control" without the vote or consent of the unitholders.

We may issue additional units, including units that are senior to the common units, without unitholder approval, which would dilute our unitholders' existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Future sales of common units in the public markets or otherwise, which sales could have an adverse impact on the trading price of the common units.

As of February 13, 2018, Antero Resources holds 98,870,335 common units. Additionally, we have agreed to provide Antero Resources with certain registration rights, pursuant to which we may be required to register the common units they hold under the Securities Act and applicable state securities laws. Pursuant to the registration rights agreement and our partnership agreement, we may be required to undertake a future public or private offering of common units and use the net proceeds from such offering to redeem an equal number of common units held by Antero Resources.

In November 2014, we filed a registration statement on Form S-8 under the Securities Act to register common units issuable under the Antero Midstream Partners Long-Term Incentive Plan (the "Midstream LTIP"). Subject to applicable vesting requirements, Rule 144 limitations applicable to affiliates and the expiration of lock-up agreements, common units registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

Future sales of common units in public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates (including Antero Resources) own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (i) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (ii) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, or the Exchange Act. Our general partner and its affiliates (including Antero Resources) own an aggregate of 52.9% of our common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we own assets and conduct business in West Virginia and Ohio. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

The New York Stock Exchange does not require a publicly-traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE under the symbol "AM." Because we are a publicly-traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. Please read "Item 10. Directors, Executive Officers, and Corporate Governance—Management of Antero Midstream Partners LP."

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for federal income tax purposes, or if we were to become subject to entity-level taxation for state tax purposes, our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. We have requested and obtained a favorable private letter ruling from the IRS to the effect that, based on the facts presented in the private letter ruling request, income from fresh water delivery services is qualifying income for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on us. We own assets and conduct business in West Virginia and Ohio. Several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, Ohio imposes a commercial activity tax of 0.26% on taxable gross receipts with a "substantial nexus" with Ohio. Imposition of a similar tax on us in other jurisdictions that we may expand to could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

However, any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or ultimately will be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. Our unitholders are urged to consult with their own tax advisors with respect to the status of regulatory or administrative developments and proposals and their potential effect on their investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any

taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Even if unitholders do not receive any cash distributions from us, unitholders will be required to pay taxes on their share of our taxable income.

Unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due from them with respect to that income.

In response to current market conditions, we may engage in transactions to deliver and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, unitholders may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If a unitholder sells common units, such unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease such unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units that unitholder sells will, in effect, become taxable income to such unitholder if the units are sold at a price greater than the unitholder's tax basis in those units, even if the price the unitholder receives is less than its original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its common units, the unitholder may incur a tax liability in excess of the amount of cash it receives from the sale.

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit. 1 Note to Draft: To be discussed with Antero.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interest in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

We treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of our common units and because of other reasons, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury regulations. Our counsel is unable to opine as to the validity of this approach. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain recognized from the sale of our common units, have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements.

We own assets and conduct business in West Virginia and Ohio, each of which imposes a personal income tax on individuals. If we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is each unitholder's responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. However, we are not currently subject to any material litigation.

We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

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 Units

Our common units are listed on the New York Stock Exchange and traded under the symbol "AM." On February 9, 2018, our common units were held by 8 holders of record. The number of holders does not include the holders for whom units are held in a "nominee" or "street" name. In addition, as of February 13, 2018, Antero Resources and its affiliates owned 98,870,335 of our common units, which represents a 52.9% limited partner interest in us.

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

	Common Unit		Distributions per
	High	Low	Common Unit
2017:			
Quarter ended December 31, 2017	$ 32.20	25.71	$ 0.3650
Quarter ended September 30, 2017	35.10	30.48	0.3400
Quarter ended June 30, 2017	35.55	29.62	0.3200
Quarter ended March 31, 2017	35.74	30.45	0.3000
2016:			
Quarter ended December 31, 2016	$ 31.39	25.93	$ 0.2800
Quarter ended September 30, 2016	28.72	24.61	0.2650
Quarter ended June 30, 2016	27.96	20.52	0.2500
Quarter ended March 31, 2016	27.01	17.00	0.2350

Issuer Purchases of Equity Securities

The issuer purchases of equity securities during the fourth quarter of 2017 primarily relates to shares purchased to cover the tax resulting from units that vested in November 2017 under the Midstream LTIP.

Period	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, 2017 - October 31, 2017	601	$ 31.11	—	N/A
November 1, 2017 - November 30, 2017	182,302	$ 27.40	—	N/A
December 1, 2017 - December 31, 2017	—	$ —	—	N/A

Securities Authorized for Issuance Under Equity Compensation Plans

In connection with the completion of our IPO, our general partner adopted the Midstream LTIP, which permits the issuance of up to 10,000,000 common units. Restricted unit grants have been made to each of the independent directors of our general partner and phantom unit grants have been made to each of the executive officers of our general partner under the Midstream LTIP. Please read the information under "Item 11. Executive Compensation – Compensation Discussion and Analysis – Equity Compensation Plan Information."

Our Minimum Quarterly Distribution

Our partnership agreement provides for a minimum quarterly distribution of $0.17 per unit for each whole quarter, or $0.68 per unit on an annualized basis.

The board of directors of our general partner has adopted a policy pursuant to which distributions for each quarter will be paid to the extent we have sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors.

If cash distributions to our unitholders exceed $0.1955 per common unit in any quarter, our unitholders and the holders of our IDRs will receive distributions according to the following percentage allocations:

Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions Unitholders	IDR Holders
above $0.1955 up to $0.2125	85 %	15 %
above $0.2125 up to $0.2550	75 %	25 %
above $0.2550	50 %	50 %

There is no guarantee that we will make cash distributions to our unitholders. We do not have a legal or contractual obligation to pay distributions quarterly or on any other basis or at our minimum quarterly distribution rate or at any other rate. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including our partnership agreement, our credit facility and applicable partnership law.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, the owner of our general partner controls the owner of our IDRs and is entitled to receive a portion of the distributions on our IDRs due to its indirect ownership of our IDRs.

Cash Distributions and Conversion of Subordinated Units

Antero Resources was issued all of our subordinated units in connection with our IPO. The principal difference between our common units and subordinated units was that, for any quarter during the subordination period, holders of the subordinated units were not entitled to receive any distribution from operating surplus until the common units had received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units did not accrue arrearages. Under the terms of our partnership agreement, the subordination period was to end on the first business day after distributions from operating surplus equaled or exceeded $1.02 per unit (150% of the annualized minimum quarterly distribution) on all outstanding common units and subordinated units for a four-quarter period immediately preceding that date.

Upon payment of the February 8, 2017 distribution to unitholders, the requirements for the conversion of all subordinated units were satisfied under our partnership agreement. As a result, effective February 9, 2017, the 75,940,957 subordinated units owned by Antero Resources were converted into common units on a one-for-one basis and now participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of the cash distributions paid by the Partnership or the total units outstanding.

On January 16, 2018, the board of directors of our general partner declared a cash distribution of $0.365 per unit for the quarter ended December 31, 2017. The distribution was paid on February 13, 2018 to unitholders of record as of February 1, 2018.

Item 6. Selected Financial Data

The following table presents our selected historical financial data, for the periods and as of the dates indicated, for the Partnership and our Predecessor. Our Predecessor for accounting purposes consisted of Antero Resources' gathering and compression assets and related operations on a carve-out basis. The Partnership was originally formed as Antero Resources Midstream LLC and converted into a limited partnership in connection with the completion of the Partnership's IPO on November 10, 2014. The information in this report includes periods prior to the Water Acquisition, which occurred on September 23, 2015. Consequently, the Partnership's consolidated financial statements have been retrospectively recast for all periods presented to include the historical results of Antero Water, because the Water Acquisition was between entities under common control. Antero Water's operations through September 23, 2015 consist entirely of fresh water delivery.

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,				
	2013	2014	2015	2016	2017
	($ in thousands, except per unit amounts)				
Revenue:					
Revenue - Antero Resources	$ 58,234	258,029	386,164	585,517	772,233
Revenue - third-party	—	8,245	1,160	835	264
Gain on sale of assets	—	—	—	3,859	—
Total revenue	58,234	266,274	387,324	590,211	772,497
Operating expenses:					
Direct operating	7,871	48,821	78,852	161,587	232,538
General and administrative (before equity-based compensation)	9,716	18,748	28,736	28,114	31,529
Equity-based compensation	24,349	11,618	22,470	26,049	27,283
Impairment of property and equipment	—	—	—	—	23,431
Depreciation	14,119	53,029	86,670	99,861	119,562
Accretion of contingent acquisition consideration	—	—	3,333	16,489	13,476
Total operating expenses	56,055	132,216	220,061	332,100	447,819
Operating income	2,179	134,058	167,263	258,111	324,678
Interest expense, net	(164)	(6,183)	(8,158)	(21,893)	(37,557)
Equity in earnings of unconsolidated affiliates	—	—	—	485	20,194
Net income and comprehensive income	$ 2,015	127,875	159,105	236,703	307,315
Pre-IPO net income attributed to parent	(2,015)	(98,219)	—	—	—
Pre-Water Acquisition net income attributed to parent	—	(22,234)	(40,193)	—	—
Net income attributable to incentive distribution rights	—	—	(1,264)	(16,944)	(69,720)
Limited partners' interest in net income	$ —	7,422	117,648	219,759	237,595
Net income per limited partner unit - basic and diluted	$ —	0.05	0.74	1.24	1.28
Weighted average limited partner units outstanding - basic	—	151,882	158,479	176,647	185,630
Weighted average limited partner units outstanding - diluted	—	151,882	158,527	176,801	186,083

	December 31,				
	2013	2014	2015	2016	2017
	(in thousands)				
Balance sheet data (at period end):					
Cash and cash equivalents	$ —	230,192	6,883	14,042	8,363
Property and equipment, net	793,330	1,531,595	1,893,826	2,195,879	2,605,602
Total assets	808,337	1,816,610	1,980,032	2,349,895	3,042,209
Long-term indebtedness	—	115,000	620,000	849,914	1,196,000
Total capital	732,061	1,620,903	1,082,745	1,222,810	1,516,469
Cash flows data:					
Net cash provided by operating activities	$ 38,245	169,433	259,678	378,607	475,796
Net cash used in investing activities	(598,177)	(797,505)	(445,455)	(478,163)	(779,818)
Net cash provided by (used in) financing activities	559,932	858,264	(37,532)	106,715	298,343
Other financial data:					
Adjusted EBITDA[1]	40,647	198,705	279,736	404,353	528,625

(1) For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read "—Non-GAAP Financial Measures" below.

Non-GAAP Financial Measures

We view Adjusted EBITDA as an important indicator of our performance. We define Adjusted EBITDA as net income before interest expense, impairment expense, depreciation expense, accretion of contingent acquisition consideration, equity-based compensation expense, gain on asset sale, excluding equity in earnings of unconsolidated affiliates, and including cash distributions from unconsolidated affiliates.

We use Adjusted EBITDA to assess:

- the financial performance of our assets, without regard to financing methods in the case of Adjusted EBITDA, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other publicly traded partnerships in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and other capital expenditure projects.

We define Distributable Cash Flow as Adjusted EBITDA less interest paid, income tax withholding payments and cash reserved for payments of income tax withholding upon vesting of equity-based compensation awards, cash reserved for bond interest, and ongoing maintenance capital expenditures paid, excluding pre-acquisition amounts attributable to the parent. We use Distributable Cash Flow as a performance metric to compare the cash generating performance of the Partnership from period to period and to compare the cash generating performance for specific periods to the cash distributions (if any) that are expected to be paid to unitholders. Distributable Cash Flow does not reflect changes in working capital balances.

Adjusted EBITDA and Distributable Cash Flow are non-GAAP financial measures. The GAAP measure most directly comparable to Adjusted EBITDA and Distributable Cash Flow is net income. The non-GAAP financial measures of Adjusted EBITDA and Distributable Cash Flow should not be considered as alternatives to the GAAP measure of net income. Adjusted EBITDA and Distributable Cash Flow are not presentations made in accordance with GAAP and have important limitations as an analytical tool because they include some, but not all, items that affect net income and Adjusted EBITDA. You should not consider Adjusted EBITDA and Distributable Cash Flow in isolation or as a substitute for analyses of results as reported under GAAP. Our definition of Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other partnerships.

"Segment Adjusted EBITDA" 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 EBITDA is a non-GAAP financial measure that we define as operating income before equity-based compensation expense, interest expense, impairment expense, depreciation expense, accretion of contingent acquisition consideration, gain on asset sale, excluding pre-acquisition income and expenses attributable to the parent and equity in earnings of unconsolidated affiliates, and including cash distributions from unconsolidated affiliates. Operating income represents net income before interest expense and equity in earnings of unconsolidated affiliates, and is the most directly comparable GAAP financial measure to Segment Adjusted EBITDA because we do not account for interest expense on a segment basis. The following tables represent a reconciliation of our operating income to Segment Adjusted EBITDA for the periods presented (in thousands):

	Gathering and Processing	Water Handling and Treatment	Consolidated Total
Year ended December 31, 2013			
Operating income (loss)	$ (14,186)	16,365	2,179
Depreciation expense	11,346	2,773	14,119
Equity-based compensation	15,931	8,418	24,349
Segment and consolidated Adjusted EBITDA	$ 13,091	27,556	40,647
Year ended December 31, 2014			
Operating income	$ 21,452	112,606	134,058
Depreciation expense	36,789	16,240	53,029
Equity-based compensation	8,619	2,999	11,618
Segment and consolidated Adjusted EBITDA	$ 66,860	131,845	198,705
Year ended December 31, 2015			
Operating income	$ 103,523	63,740	167,263
Depreciation expense	60,838	25,832	86,670
Accretion of contingent acquisition consideration	—	3,333	3,333
Equity-based compensation	17,840	4,630	22,470
Segment and consolidated Adjusted EBITDA	$ 182,201	97,535	279,736
Year ended December 31, 2016			
Operating income	$ 170,861	87,250	258,111
Depreciation expense	69,962	29,899	99,861
Accretion of contingent acquisition consideration	—	16,489	16,489
Equity-based compensation	19,714	6,335	26,049
Distributions from unconsolidated affiliates	7,702	—	7,702
Gain on sale of assets	(3,859)	—	(3,859)
Segment and consolidated Adjusted EBITDA	$ 264,380	139,973	404,353
Year ended December 31, 2017			
Operating income	$ 207,075	117,603	324,678
Impairment of property and equipment expense	23,431	—	23,431
Depreciation expense	86,372	33,190	119,562
Accretion of contingent acquisition consideration	—	13,476	13,476
Equity-based compensation	19,730	7,553	27,283
Distributions from unconsolidated affiliates	20,195	—	20,195
Segment and consolidated Adjusted EBITDA	$ 356,803	171,822	528,625

The following table represents a reconciliation of our Segment and consolidated Adjusted EBITDA and Distributable Cash Flow to the most directly comparable GAAP financial measures for the periods presented (in thousands):

	Year ended December 31,				
	2013	2014	2015	2016	2017
Reconciliation of Net Income to Segment and consolidated Adjusted EBITDA and Distributable Cash Flow:					
Net income	$ 2,015	127,875	159,105	236,703	307,315
Interest expense	164	6,183	8,158	21,893	37,557
Impairment of property and equipment expense	—	—	—	—	23,431
Depreciation expense	14,119	53,029	86,670	99,861	119,562
Accretion of contingent acquisition consideration	—	—	3,333	16,489	13,476
Equity-based compensation	24,349	11,618	22,470	26,049	27,283
Equity in earnings of unconsolidated affiliates	—	—	—	(485)	(20,194)
Distributions from unconsolidated affiliates	—	—	—	7,702	20,195
Gain on sale of assets	—	—	—	(3,859)	—
Segment and consolidated Adjusted EBITDA	40,647	198,705	279,736	404,353	528,625
Pre-IPO net income attributed to parent	(2,015)	(98,219)	—	—	—
Pre-IPO depreciation expense attributed to parent	(14,119)	(43,419)	—	—	—
Pre-IPO equity-based compensation expense attributed to parent	(24,349)	(8,697)	—	—	—
Pre-IPO interest expense attributed to parent	(164)	(5,358)	—	—	—
Pre-Water Acquisition net income attributed to parent	—	(22,234)	(40,193)	—	—
Pre-Water Acquisition depreciation expense attributed to parent	—	(3,086)	(18,767)	—	—
Pre-Water Acquisition equity-based compensation expense attributed to parent	—	(654)	(3,445)	—	—
Pre-Water Acquisition interest expense attributed to parent	—	(359)	(2,326)	—	—
Interest paid	—	(331)	(5,149)	(13,494)	(46,666)
Increase (decrease) in cash reserved (paid) for bond interest[(1)]	—	—	—	(10,481)	291
Income tax withholding upon vesting of Antero Midstream Partners equity-based compensation awards[(2)]	—	—	(4,806)	(5,636)	(5,945)
Maintenance capital expenditures[(3)]	—	(1,157)	(13,097)	(21,622)	(55,159)
Distributable cash flow	$ —	15,191	191,953	353,120	421,146

(1) Cash reserved for bond interest expense on Antero Midstream's 5.375% senior notes outstanding during the period that is paid on a semi-annual basis on March 15th and September 15th of each year.

(2) Estimate of current period portion of expected cash payment for income tax withholding attributable to vesting of Midstream LTIP equity-based compensation awards to be paid in the fourth quarter.

(3) Maintenance capital expenditures represent that portion of our estimated capital expenditures associated with (i) the connection of new wells to our gathering and processing systems that we believe will be necessary to offset the natural production declines Antero Resources will experience on its wells over time, and (ii) water delivery to new wells necessary to maintain the average throughput volume on our systems.

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 information provided below supplements, but does not form part of, our financial statements. This discussion contains forward-looking statements that are based on the views and beliefs of our management, as well as assumptions and estimates made by our management. Actual results could differ materially from such forward-looking statements as a result of various risk factors, including those that may not be in the control of management. For further information on items that could impact our future operating performance or financial condition, please read see "Item 1A. Risk Factors." and the section entitled "Cautionary Statement Regarding Forward-Looking Statements." We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

References in this report to "Predecessor," "we," "our," "us" or like terms, when referring to periods prior to November 10, 2014, refer to Antero Resources' gathering and compression, our predecessor for accounting purposes. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods between November 10, 2014 and September 23, 2015 refer to the Partnership's gathering and compression assets, and Antero Resources' water assets. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods since September 23, 2015 or when used in the present tense or prospectively, refer to Antero Midstream Partners LP.

Overview

We are a growth-oriented master limited partnership formed by Antero Resources to own, operate and develop midstream energy assets to service Antero Resources' increasing production. Our assets consist of gathering pipelines, compressor stations, and interests in processing and fractionation plants that collect and process natural gas and NGLs from Antero Resources' wells in the Marcellus and Utica Shales in West Virginia and Ohio. Our assets also include two independent fresh water delivery systems that deliver fresh water from the Ohio River, several regional waterways, and wastewater handling services for well completion and production operations in Antero Resources' operating areas. These fresh water delivery systems consist of permanent buried pipelines, surface pipelines and fresh water storage facilitates, as well as pumping stations and impoundments to transport the fresh water throughout the pipelines. The wastewater handling services consist of wastewater transportation, disposal, and treatment, including a water treatment facility, currently undergoing testing and commissioning. We believe that our strategically located assets and our relationship with Antero Resources position us to become a leading midstream energy company serving the Marcellus and Utica shale plays.

During the second quarter of 2017, in connection with its initial public offering, Antero Resources Midstream Management LLC ("ARMM") formed Antero Midstream Partners GP LLC ("AMP GP"), a Delaware limited liability company, as a wholly owned subsidiary, and, on April 11, 2017, assigned to AMP GP the general partner interest in us. Concurrent with the assignment, AMP GP was admitted as the Partnership's sole general partner and ARMM ceased to be our general partner. Upon closing its initial public offering, ARMM converted into a Delaware limited partnership and changed its name to Antero Midstream GP LP ("AMGP"). We received no proceeds from the sale of common shares in the offering.

Recent Trends and Uncertainties

The gathering and compression agreement with Antero Resources provides for fixed fee structures, and we intend to continue to pursue additional fixed fee opportunities with Antero Resources and third parties in order to avoid direct commodity price exposure. However, to the extent that our future contractual arrangements with Antero Resources or third parties do not provide for fixed fee structures, we may become subject to commodity price risk. We are subject to commodity price risks to the extent that they impact Antero Resources' development plan and therefore our gathering volumes.

During 2018, we plan to expand our existing Marcellus and Utica Shale gathering, compression, and water handling and treatment infrastructure to accommodate Antero Resources' development plans. Antero Resources' 2018 drilling and completion capital budget is $1.3 billion. Antero Resources plans to operate an average of five drilling rigs and complete between 120 and 125 horizontal wells in the Marcellus, all of which are located on acreage dedicated to us. In the Utica, Antero plans to operate one drilling rig and complete between 20 to 25 horizontal wells in 2018, all of which are located on acreage dedicated to us. A further or extended decline in commodity prices could cause some of the development and production projects of Antero Resources or third parties to be uneconomic or less profitable, which could reduce gathering and water handling and treatment volumes in our current and future potential areas of operation. Those reductions in gathering and water handling and treatment volumes could reduce our revenue and cash flows and adversely affect our ability to make cash distributions to our unitholders.

Cash Distributions

The board of directors of our general partner has declared a cash distribution of $0.365 per unit for the quarter ended December 31, 2017. The distribution was paid on February 13, 2018 to unitholders of record as of February 1, 2018.

Joint Venture

On February 6, 2017, we formed the Joint Venture to develop processing and fractionation assets in Appalachia with MarkWest. We and MarkWest each own a 50% interest in the Joint Venture and MarkWest operates the Joint Venture assets. The Joint Venture assets consist of processing plants in West Virginia, and a one-third interest in a recently commissioned MarkWest fractionator in Ohio.

In conjunction with the Joint Venture, on February 10, 2017 we issued 6,900,000 common units, including common units issued pursuant to the underwriters' option to purchase additional common units, resulting in net proceeds of approximately $223 million (the "Offering"). We used the proceeds from the Offering to repay outstanding borrowings under our Credit Facility incurred to fund the investment in the Joint Venture, and for general partnership purposes.

Credit Facility

On October 26, 2017, we entered into a restated and amended senior revolving credit facility. The facility was amended to include fall away covenants and lower interest rates that are triggered if and when we are assigned an investment grade credit rating by either Standard and Poor's or Moody's.

As of December 31, 2017, lender commitments under our revolving credit facility were $1.5 billion, with a letter of credit sublimit of $150 million. At December 31, 2017, we had borrowings of $555 million and no letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in October 2022. See "—Debt Agreements—Revolving Credit Facility" for a description of our revolving credit facility.

Sources of Our Revenues

Our gathering and compression revenues are driven by the volumes of natural gas we gather and compress, and our water handling and treatment revenues are driven by wastewater services and quantities of fresh water delivered to our customers to support their well completion operations. Pursuant to our long-term contracts with Antero Resources, we have secured 20-year dedications covering a significant portion of Antero Resources' current and future acreage for gathering and compression services. We have also entered into a 20-year water handling and treatment services agreement covering Antero Resources' 620,000 net acres in West Virginia and Ohio, with a right of first offer on all future areas of operation. Under the agreement, we will receive a fixed fee for all fresh water deliveries by pipeline directly to the well site, subject to annual CPI adjustments. In addition, Antero Resources has agreed to pay a fee on a minimum volume of fresh water deliveries in calendar years 2016 through 2019. Minimum volume commitments are 90,000 barrels per day in 2016, 100,000 barrels per day in 2017 and 120,000 barrels per day in 2018 and 2019. All of Antero Resources' existing acreage is dedicated to us for gathering and compression services except for existing third-party commitments. Approximately 156,000 net leasehold acres characterized by dry gas and liquids-rich production that have been previously dedicated to third-party gatherers.

Our gathering and compression operations are substantially dependent upon natural gas and oil production from Antero Resources' upstream activity in its areas of operation. In addition, there is a natural decline in production from existing wells that are connected to our gathering systems. Although we expect that Antero Resources will continue to devote substantial resources to the development of oil and gas reserves, we have no control over this activity and Antero Resources has the ability to reduce or curtail such development at its discretion.

Our water handling and treatment operations are substantially dependent upon the number of wells drilled and completed by Antero Resources, as well as Antero Resources' production. As of December 31, 2017, Antero Resources' estimated net proved reserves were 17.3 Tcfe, of which 64% was natural gas, 34% were NGLs, and 2% were oil. As of December 31, 2017, Antero Resources' drilling inventory consisted of 4,133 identified potential horizontal well locations, approximately 3,200 of which were located on acreage dedicated to us, providing us with significant opportunity for growth as Antero Resources' robust drilling program continues and its production increases.

Under the terms of the Water Services Agreement, Antero Resources will pay a fixed fee of $3.685 per barrel in West Virginia and $3.635 per barrel in Ohio and all other locations for fresh water deliveries by pipeline directly to the well site, subject to annual CPI adjustments. Antero Resources also agreed to pay us a fixed fee of $4.00 per barrel for wastewater treatment at the advanced wastewater treatment complex and a fee per barrel for wastewater collected in trucks owned by us, in each case subject to annual CPI-based adjustments. In addition, we contract with third party service providers to provide Antero Resources flow back and produced water services and Antero Resources will reimburse us third party out-of-pocket costs plus 3%.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to evaluate our performance. These metrics help us identify factors and trends that impact our operating results, profitability and financial condition. The key metrics we use to evaluate our business are provided below.

Adjusted EBITDA and Distributable Cash Flow

We use Adjusted EBITDA and Distributable Cash Flow as performance measures to assess the ability of our assets to generate cash sufficient to pay interest costs, support indebtedness and make cash distributions. Adjusted EBITDA and Distributable Cash flow are non-GAAP financial measures. See "Item 6. Selected Financial Data—Non-GAAP Financial Measures" for more information regarding these financial measures, including a reconciliation of Adjusted EBITDA and Distributable Cash Flow to the most directly comparable GAAP measures.

Gathering and Compression Throughput

We must continually obtain additional supplies of natural gas and oil to maintain or increase throughput on our systems. Our ability to maintain existing supplies of natural gas and oil and obtain additional supplies is primarily impacted by our acreage dedication and the level of successful drilling activity by Antero Resources and, to a lesser extent in the future, the potential for acreage dedications with and successful drilling by third party producers. Any increase in our throughput volumes over the near term will likely be driven by Antero Resources continuing its robust drilling and development activities on its Marcellus and Utica Shale acreage. In the short term, we expect increases in high pressure gathering and compression throughput volumes to be less than that for low pressure gathering revenues, in part because a percentage of Antero Resources' high pressure gathering and compression needs are and will continue to be met by existing third-party providers.

Water Handling and Treatment Volumes

Because our fresh water and other fluid handling volumes are primarily driven by hydraulic fracturing activities conducted as part of well completions, our water volumes are not directly impacted by ongoing production volumes. Antero Resources' consolidated acreage positions allow us to provide fresh water and other fluid handling services for Antero Resources' completion activities in a more efficient manner. However, to the extent that Antero Resources' drilling and completion schedule is not met, or Antero Resources uses less fresh water and other fluid handling services in its well completion operations than expected (for example, due to a reduction in completions), our water volumes may decline.

We contract with third party service providers to provide Antero Resources flow back and produced water services. As such, our wastewater treatment volumes currently consist of third party volumes.

Principal Components of Our Cost Structure

The primary components of our operating expenses that we evaluate include direct operating expense, general and administrative expenses, impairment expense, depreciation expense and interest expense.

Direct Operating Expense

We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. We schedule maintenance over time to avoid significant variability in our direct operating expense and minimize the impact on our cash flow. Gathering and compression operating costs consist primarily of labor costs, water disposal, pigging, fuel, monitoring costs, repair and non-capitalized maintenance costs, utilities and contract services comprise the most significant portion of our direct operating expense. Gathering and compression operating costs vary directly with the miles of pipeline and number of compressor stations in our gathering and compression system. Fresh water operating expenses consist primarily of labor costs, pigging, monitoring costs, repair and non-capitalized maintenance costs and contract services. Fresh water operating costs vary directly with the miles of pipeline and to a lesser extent the number well completions in the Marcellus and Utica Shales for which we deliver fresh water and number of impoundments our fresh water system. Other water handling costs include contract services and vary directly with the costs level of services that we provide to Antero Resources. These costs are billed to Antero Resources at our cost plus 3%. Once the wastewater treatment complex is placed in service, our other water handling costs will consist of labor costs, monitoring costs, repair, and non-capitalized maintenance costs. Wastewater treatment costs will vary directly with the water volumes treated. We schedule maintenance over time to avoid significant variability in our direct operating expense and minimize the impact on our cash flow. The other primary drivers of our direct operating expense include: maintenance and contract service costs, regulatory and compliance costs and ad valorem taxes.

General and Administrative Expenses

Our general and administrative expenses include direct charges for operations of our assets and costs allocated by Antero Resources. These costs relate to: (i) various business services, including payroll processing, accounts payable processing and facilities management, (ii) various corporate services, including legal, accounting, treasury, information technology and human resources and (iii) compensation, including equity-based compensation. These expenses are charged or allocated to us based on the nature of the expenses and are allocated based on a combination of our proportionate share of Antero Resources' gross property and equipment, capital expenditures and labor costs, as applicable. Management believes these allocation methodologies are reasonable.

Our general and administrative expenses include equity-based compensation costs allocated by Antero Resources to us for grants made pursuant to: (i) Antero Resources' Long-Term Incentive Plan (the "Antero Resources LTIP") and (ii) grants made to Antero Resources employees under our own plan.

Impairment Expense

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair value, which are based on discounted future cash flows using assumptions as to revenues, costs and discount rates typical of third party market participants. In 2017, our impairment expense relates to condensate gathering lines which Antero Resources no longer uses.

Depreciation Expense

Depreciation expense consists of our estimate of the decrease in value of the assets capitalized in property and equipment as a result of using the assets throughout the applicable year. Depreciation is computed over the asset's estimated useful life using the straight-line basis. Gathering pipelines and compressor stations are depreciated over a 20 year useful life. Fresh water delivery systems are depreciated over a 5 to 20 year useful life. Specifically, we use a useful life of 5 years for our surface pipelines and equipment, 10 years for our above ground storage tanks, and 20 years for our permanent buried pipeline systems.

Interest Expense

In 2016 and 2017, interest expense represents interest related to: (i) borrowings under our revolving credit facility, (ii) borrowings of $650 million under our 5.375% senior notes due September 15, 2024 (the “2024 Notes”), (iii) capital leases, and (iv) amortization of deferred financing costs incurred in connection with the revolving credit facility and the issuance of the 2024 Notes. In addition, we capitalize interest during the construction period of the water treatment facility.

Items Affecting Comparability of Our Financial Results

Certain of the historical financial results discussed below may not be comparable to our future financial results primarily as a result of the significant increase in the scope of our operations over the last several years. Our gathering and compression and water handling and treatment systems are relatively new, having been substantially built within the last four years. Accordingly, our revenues and expenses over that time reflect the significant ramp up in our operations. Similarly, Antero Resources has experienced significant changes in its production and drilling and completion schedule over that same period. Accordingly, it may be difficult to project trends from our historical financial data going forward.

On September 23, 2015, Antero Resources contributed (the “Water Acquisition”) (i) all of the outstanding limited liability company interests of Antero Water to the Partnership and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero Resources and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero Resources’ advanced wastewater treatment complex undergoing testing and commissioning in Doddridge County, West Virginia, to Antero Treatment. Results of operations and cash flows for periods prior to the Water Acquisition have been recast to include the Water Acquisition as the entities were under common control.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2017

We have two operating segments: (1) gathering and processing, and (2) water handling and treatment. The operating results and assets of our reportable segments were as follows for the year ended December 31, 2016 and 2017 (in thousands):

	Gathering and Processing	Water Handling and Treatment	Consolidated Total
Year ended December 31, 2016			
Revenues:			
Revenue - Antero Resources	$ 303,250	282,267	585,517
Revenue - third-party	835	—	835
Gain on sale of assets	3,859	—	3,859
Total revenues	307,944	282,267	590,211
Operating expenses:			
Direct operating	27,289	134,298	161,587
General and administrative (before equity-based compensation)	20,118	7,996	28,114
Equity-based compensation	19,714	6,335	26,049
Depreciation	69,962	29,899	99,861
Accretion of contingent acquisition consideration	—	16,489	16,489
Total expenses	137,083	195,017	332,100
Operating income	$ 170,861	87,250	258,111
Segment and consolidated Adjusted EBITDA[(1)]	$ 264,380	139,973	404,353
Year ended December 31, 2017			
Revenues:			
Revenue - Antero Resources	$ 396,202	376,031	772,233
Revenue - third-party	264	—	264
Total revenues	396,466	376,031	772,497
Operating expenses:			
Direct operating	39,251	193,287	232,538
General and administrative (before equity-based compensation)	20,607	10,922	31,529
Equity-based compensation	19,730	7,553	27,283
Impairment of property and equipment	23,431	—	23,431
Depreciation	86,372	33,190	119,562
Accretion of contingent acquisition consideration	—	13,476	13,476
Total expenses	189,391	258,428	447,819
Operating income	$ 207,075	117,603	324,678
Segment and consolidated Adjusted EBITDA[(1)]	$ 356,803	171,822	528,625

(1) For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please "Item 6. Selected Financial Data—Non-GAAP Financial Measures".

The following sets forth selected financial and operating data for the year ended December 31, 2016 compared to the year ended December 31, 2017:

	Year Ended December 31, 2016	Year Ended December 31, 2017	Amount of Increase (Decrease)	Percentage Change
	($ in thousands, except average realized fees)			
Revenue:				
Revenue - Antero Resources	$ 585,517	772,233	186,716	32 %
Revenue - third-party	835	264	(571)	(68)%
Gain on sale of assets	3,859	—	(3,859)	*
Total revenue	590,211	772,497	182,286	31 %
Operating expenses:				
Direct operating	161,587	232,538	70,951	44 %
General and administrative (before equity-based compensation)	28,114	31,529	3,415	12 %
Equity-based compensation	26,049	27,283	1,234	5 %
Impairment of property and equipment	—	23,431	23,431	*
Depreciation	99,861	119,562	19,701	20 %
Accretion of contingent acquisition consideration	16,489	13,476	(3,013)	(18)%
Total operating expenses	332,100	447,819	115,719	35 %
Operating income	258,111	324,678	66,567	26 %
Interest expense	(21,893)	(37,557)	(15,664)	72 %
Equity in earnings of unconsolidated affiliates	485	20,194	19,709	4,064 %
Net income	$ 236,703	307,315	70,612	30 %
Adjusted EBITDA(1)	$ 404,353	528,625	124,272	31 %
Operating Data:				
Gathering—low pressure (MMcf)	513,390	605,719	92,329	18 %
Gathering—high pressure (MMcf)	481,646	646,054	164,408	34 %
Compression (MMcf)	271,060	436,695	165,635	61 %
Fresh water delivery (MBbl)	45,112	55,892	10,780	24 %
Wastewater handling (MBbl)	10,602	14,549	3,947	37 %
Wells serviced by fresh water delivery	131	142	11	8 %
Gathering—low pressure (MMcf/d)	1,403	1,660	257	18 %
Gathering—high pressure (MMcf/d)	1,316	1,770	454	34 %
Compression (MMcf/d)	741	1,196	455	61 %
Fresh water delivery (MBbl/d)	123	153	30	24 %
Wastewater handling (MBbl/d)	29	40	11	37 %
Average realized fees:				
Average gathering—low pressure fee ($/Mcf)	$ 0.31	0.32	0.01	3 %
Average gathering—high pressure fee ($/Mcf)	$ 0.19	0.19	—	*
Average compression fee ($/Mcf)	$ 0.19	0.19	—	*
Average fresh water delivery fee ($/Bbl)	$ 3.68	3.71	0.03	1 %
Joint Venture Operating Data:				
Processing - Joint Venture (MMcf)	—	97,276	97,276	*
Fractionation - Joint Venture (MBbl)	—	1,861	1,861	*
Processing - Joint Venture (MMcf/d)	—	267	267	*
Fractionation - Joint Venture (MBbl/d)	—	5	5	*

* Not meaningful or applicable.

(1) For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please "Item 6. Selected Financial Data—Non-GAAP Financial Measures".

Sources of Water Handling and Treatment Revenue. Water handling and treatment revenues are generated from fresh water delivery and other fluid handling services. Fresh water delivery is billed at a fixed fee per barrel. Other fluid handling services include the disposal and treatment of wastewater and high rate transfer of fresh water and are billed at our cost plus 3%.

Revenue - Antero Resources. Revenues from Antero Resources increased by 32%, from $586 million for the year ended December 31, 2016 to $772 million for the year ended December 31, 2017. Gathering and compression revenues increased by 30%, from $304 million for the year ended December 31, 2016 to $396 million for the year ended December 31, 2017. Water handling and treatment revenues increased by 34%, from $282 million for the year ended December 31, 2016 to $376 million for the year ended December 31, 2017. These fluctuations are primarily the result of the following, and are offset by a $2 million decrease in condensate gathering revenue:

- high pressure gathering revenue increased $32 million due to an increase of throughput volumes of 164 Bcf, or 454 MMcf/d, primarily as a result of the addition of three new high pressure gathering lines placed in service in 2017 and the expansion of our high pressure gathering system by 18 miles in 2017;

- compression revenue increased $31 million due to an increase of throughput volumes of 166 Bcf, or 455 MMcf/d, primarily due to the addition of five new compressor stations that were placed in service during 2017;

- low pressure gathering revenue increased $31 million period over period due to an increase of throughput volumes of 92 Bcf, or 257 MMcf/d, which was primarily due to 109 new wells added in 2017 and the expansion of our low pressure gathering system by 21 miles in 2017;

- other fluid handling services revenue increased $52 million due to an increase in wastewater handling and treatment volumes of 3,947 MBbl, or 11 MBbl/d; and

- fresh water delivery revenue increased $42 million, due to an increase in fresh water delivery of 10,780 MBbl, or 30 MBbl/d, primarily due to an increase in the amount of water used in well completions by Antero Resources.

Direct operating expenses. Total direct operating expenses increased by 44%, from $162 million for the year ended December 31, 2016 to $233 million for the year ended December 31, 2017. Gathering and compression direct operating expenses increased from $27 million for the year ended December 31, 2016 to $39 million for the year ended December 31, 2017. The increase was primarily due to an increase in the number of gathering pipelines and compressor stations in 2017. Water handling and treatment direct operating expenses increased from $135 million for the year ended December 31, 2016 to $194 million for the year ended December 31, 2017. The increase was primarily due to an increase in wastewater handling and treatment volumes as well as an increase in the number of wells serviced by freshwater delivery services.

General and administrative expenses. General and administrative expenses (before equity-based compensation expense) increased by 12%, from $28 million for the year ended December 31, 2016 and $32 million for the year ended December 31, 2017. The increase was primarily due to an increase in the proportion of general and administrative expenses allocated from Antero Resources as a result of increased capital expenditures, as well as increased direct general and administrative expenses to support our growth.

Equity-based compensation expenses. Equity-based compensation expense remained relatively consistent at $26 million for the year ended December 31, 2016 and $27 million for the year ended December 31, 2017. Equity-based compensation expense allocated to us from Antero Resources has no effect on our cash flows.

Accretion of contingent acquisition consideration. Total contingent acquisition consideration accretion expense decreased from $17 million for the year ended December 31, 2016 to $14 million for the year ended December 31, 2017. The decrease is due to a change in our estimate of weighted average cost of capital. In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if we deliver 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if we deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and

December 31, 2020. In conjunction with the Water Acquisition on September 23, 2015, we recorded a liability for the discounted net present value of the contingent acquisition consideration and, as time passes, we recognize accretion expense to increase the discounted liability to the expected liability amounts in 2019 and 2020. As of December 31, 2017, we expect to pay the entire amount of the contingent consideration amounts in 2019 and 2020.

Impairment of property and equipment expense. Total impairment increased from $0 for the year ended December 31, 2016 to $23 million for the year ended December 31, 2017. The impairment was related to certain condensate gathering lines that Antero Resources no longer uses.

Depreciation expense. Total depreciation expense increased by 20%, from $100 million for the year ended December 31, 2016 to $120 million for the year ended December 31, 2017. The increase was primarily due to additional assets placed into service.

Interest expense. Interest expense increased by 72%, from $22 million, net of $4 million in capitalized interest, for the year ended December 31, 2016 to $38 million, net of $12 million in capitalized interest, for the year ended December 31, 2017. The increase was due to a full year of interest incurred on our $650 million of 2024 Notes, and an increase in interest expense incurred on increased borrowings outstanding under the revolving credit facility.

Operating income. Total operating income increased by 26%, from $258 million for the year ended December 31, 2016 to $325 million for the year ended December 31, 2017. Gathering and compression operating income increased from $171 million for the year ended December 31, 2016 to $207 million for the year ended December 31, 2017. The increase was primarily due to an increase in gathering and compression throughput volumes in 2017. Water handling and treatment operating income increased from $87 million for the year ended December 31, 2016 to $118 million for the year ended December 31, 2017. This increase was due to an increase in fresh water delivery volumes in 2017.

Adjusted EBITDA. Adjusted EBITDA increased by 31%, from $404 million for the year ended December 31, 2016 to $529 million for the year ended December 31, 2017. The increase was primarily due to an increase revenue resulting from an in gathering, compression, and water volumes. For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read "Item 6. Selected Financial Data—Non-GAAP Financial Measures."

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

The operating results and assets of our reportable segments were as follows for the year ended December 31, 2015 and 2016 (in thousands):

	Gathering and Processing	Water Handling and Treatment	Consolidated Total
Year Ended December 31, 2015			
Revenues:			
Revenue - Antero Resources	$ 230,210	155,954	386,164
Revenue - third-party	382	778	1,160
Total revenues	230,592	156,732	387,324
Operating expenses:			
Direct operating	25,783	53,069	78,852
General and administrative (before equity-based compensation)	22,608	6,128	28,736
Equity-based compensation	17,840	4,630	22,470
Depreciation	60,838	25,832	86,670
Accretion of contingent acquisition consideration	—	3,333	3,333
Total expenses	127,069	92,992	220,061
Operating income	$ 103,523	63,740	167,263
Segment and consolidated Adjusted EBITDA[(1)]	$ 182,201	97,535	279,736
Year Ended December 31, 2016			
Revenues:			
Revenue - Antero Resources	$ 303,250	282,267	585,517
Revenue - third-party	835	—	835
Gain on sale of assets	3,859	—	3,859
Total revenues	307,944	282,267	590,211
Operating expenses:			
Direct operating	27,289	134,298	161,587
General and administrative (before equity-based compensation)	20,118	7,996	28,114
Equity-based compensation	19,714	6,335	26,049
Depreciation	69,962	29,899	99,861
Accretion of contingent acquisition consideration	—	16,489	16,489
Total expenses	137,083	195,017	332,100
Operating income	$ 170,861	87,250	258,111
Segment and consolidated Adjusted EBITDA[(1)]	$ 264,380	139,973	404,353

(1) For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please "Item 6. Selected Financial Data—Non-GAAP Financial Measures".

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

	Year ended December 31, 2015	Year ended December 31, 2016	Amount of Increase (Decrease)	Percentage Change
	($ in thousands, except average realized fees)			
Revenue:				
Revenue - Antero Resources	$ 386,164	585,517	199,353	52 %
Revenue - third-party	1,160	835	(325)	(28)%
Gain on sale of assets	—	3,859	3,859	*
Total revenue	387,324	590,211	202,887	52 %
Operating expenses:				
Direct operating	78,852	161,587	82,735	105 %
General and administrative (before equity-based compensation)	28,736	28,114	(622)	(2)%
Equity-based compensation	22,470	26,049	3,579	16 %
Depreciation	86,670	99,861	13,191	15 %
Accretion of contingent acquisition consideration	3,333	16,489	13,156	395
Total operating expenses	220,061	332,100	112,039	51 %
Operating income	167,263	258,111	90,848	54 %
Interest expense	(8,158)	(21,893)	(13,735)	168 %
Equity in earnings of unconsolidated affiliates	—	485	485	*
Net income	$ 159,105	236,703	77,598	49 %
Adjusted EBITDA(1)	$ 279,736	404,353	124,617	45 %
Operating Data:				
Gathering—low pressure (MMcf)	370,830	513,390	142,560	38 %
Gathering—high pressure (MMcf)	432,861	481,646	48,785	11 %
Compression (MMcf)	157,515	271,060	113,545	72 %
Condensate gathering (MBbl)	1,117	503	(614)	(55)%
Fresh water delivery (MBbl)	35,044	45,112	10,068	29 %
Wastewater handling (MBbl)	4,811	10,602	5,791	120 %
Wells serviced by fresh water delivery	124	131	7	6 %
Gathering—low pressure (MMcf/d)	1,016	1,403	387	38 %
Gathering—high pressure (MMcf/d)	1,186	1,316	130	11 %
Compression (MMcf/d)	432	741	309	72 %
Condensate gathering (MBbl/d)	3	1	(2)	(67)%
Fresh water delivery (MBbl/d)	96	123	27	28 %
Wastewater handling (MBbl/d)	13	29	16	123 %
Average realized fees:				
Average gathering—low pressure fee ($/Mcf)	$ 0.31	0.31	—	*
Average gathering—high pressure fee ($/Mcf)	$ 0.19	0.19	—	*
Average compression fee ($/Mcf)	$ 0.19	0.19	—	*
Average gathering—condensate fee ($/Bbl)	$ 4.16	4.17	0.01	*
Average fresh water delivery fee - Antero Resources ($/Bbl)	$ 3.64	3.68	0.04	1 %

* Not meaningful or applicable.

(1) For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read "Item 6. Selected Financial Data—Non-GAAP Financial Measures".

Sources of Water Handling and Treatment Revenue. Water handling and treatment revenues are generated from fresh water delivery and other fluid handling services. Fresh water delivery is billed at a fixed fee per barrel. Other fluid handling services include the disposal and treatment of wastewater and high rate transfer of fresh water and are billed at our cost plus 3%.

Revenue - Antero Resources. Revenues from Antero Resources increased by 52%, from $386 million for the year ended December 31, 2015 to $586 million for the year ended December 31, 2016. Gathering and compression revenues increased by 32%, from $230 million for the year ended December 31, 2015 to $303 million for the year ended December 31, 2016. Water handling and treatment revenues increased by 80%, from $156 million for the year ended December 31, 2015 to $282 million for the year ended December 31, 2016. These fluctuations are primarily the result of:

- low pressure gathering revenue increased $45 million period over period due to an increase of throughput volumes of 143 Bcf, or 387 MMcf/d, which was primarily due to 156 new wells added in 2016 and the expansion of our low pressure gathering system by 12 miles in 2016;

- compression revenue increased $22 million due to an increase of throughput volumes of 114 Bcf, or 309 MMcf/d, primarily due to the addition of two new compressor stations that were placed in service during 2016;

- high pressure gathering revenue increased $9 million due to an increase of throughput volumes of 49 Bcf, or 130 MMcf/d, primarily as a result of the addition of two new high pressure gathering lines placed in service in 2016 and the expansion of our high pressure gathering system by 22 miles in 2016;

- other fluid handling services revenue increased $87 million because the other fluid handling operations began in September 2015, and are billed to Antero Resources at our cost plus 3%. Other fluid handling service revenues were $29 and $116 million during the year ended December 31, 2015 and 2016, respectively; and

- fresh water delivery revenue increased $38 million, due to an increase in fresh water delivery of 10,068 MBbl, or 27 MBbl/d, primarily due to an increase in the amount of water used in well completions by Antero Resources.

Direct operating expenses. Total direct operating expenses increased by 105%, from $79 million for the year ended December 31, 2015 to $162 million for the year ended December 31, 2016. Gathering and compression direct operating expenses increased from $26 million for the year ended December 31, 2015 to $27 million for the year ended December 31, 2016. The increase was primarily due to an increase in the number of gathering pipelines and compressor stations in 2015. Water handling and treatment direct operating expenses increased from $53 million for the year ended December 31, 2015 to $134 million for the year ended December 31, 2016. The increase was primarily due to other fluid handling services which began in the fourth quarter of 2015.

General and administrative expenses. General and administrative expenses (before equity-based compensation expense) remained relatively consistent at $29 million for the year ended December 31, 2015 and $28 million for the year ended December 31, 2016.

Equity-based compensation expenses. Equity-based compensation expense increased by 16%, from $23 million for the year ended December 31, 2015 to $26 million for the year ended December 31, 2016. This increase was due to additional awards under Antero Resources' and our equity-based compensation plans. Equity-based compensation expense allocated to us from Antero Resources has no effect on our cash flows.

Accretion of contingent acquisition consideration. Total contingent acquisition consideration accretion expense increased from $3 million for the year ended December 31, 2015 to $17 million for the year ended December 31, 2016. In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if we deliver 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if we deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. At the time of the Water Acquisition, we recorded a liability for the discounted net present value of the contingent acquisition consideration, and as time passes, we recognize accretion expense. The liability is revalued each reporting period for any changes in assumptions. Based on Antero Resources' drilling plans we project to meet both water delivery targets. The increase was due to one quarter of accretion incurred in the fourth quarter of 2015, compared to four quarters in 2016.

Depreciation expense. Total depreciation expense increased by 15%, from $87 million for the year ended December 31, 2015 to $100 million for the year ended December 31, 2016. The increase was primarily due to assets placed in service and depreciated in 2016, as well as a full period of depreciation for the assets placed in service during 2015.

Interest expense. Interest expense increased from $8 million for the year ended December 31, 2015 to $22 million, net of $4 million in capitalized interest, for the year ended December 31, 2016. The increase was primarily due to interest incurred on our 2024 Notes beginning in the third quarter of 2016, increased amounts outstanding under the revolving credit facility, and increased commitment fees on the increased amount of lender commitments under the facility.

Operating income. Total operating income increased by 54%, from $167 million for the year ended December 31, 2015 to $258 million for the year ended December 31, 2016. Gathering and compression operating income increased from $104 million for the year ended December 31, 2015 to $171 million for the year ended December 31, 2016. The increase was primarily due to an increase in gathering and compression throughput volumes in 2016. Water handling and treatment operating income increased from $64 million for the year ended December 31, 2015 to $87 million for the year ended December 31, 2016. This increase was primarily due to an increase in fresh water delivery volumes in 2016.

Adjusted EBITDA. Adjusted EBITDA increased by 45%, from $280 million for the year ended December 31, 2015 to $404 million for the year ended December 31, 2016. The increase was primarily due to an increase in revenue resulting from an increase in gathering, compression, and water volumes. For a discussion of the non-GAAP financial measure Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read “Item 6. Selected Financial Data—Non-GAAP Financial Measures.”

Capital Resources and Liquidity

Sources and Uses of Cash

Capital and liquidity is provided by operating cash flow, cash on our balance sheet, borrowings under our revolving credit facility and capital market transactions. We expect that the combination of these capital resources will be adequate to meet our working capital requirements, capital expenditures program and expected quarterly cash distributions for at least the next 12 months.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we intend to distribute at least the minimum quarterly distribution of $0.17 per unit ($0.68 per unit on an annualized basis) on all of our units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates. For the year ended December 31, 2017, we made distributions of $1.24 per unit, or a total of $284 million, to the holders of our limited partner units. The board of directors of our general partner has declared a cash distribution of $0.365 per unit for the quarter ended December 31, 2017. The distribution was paid on February 13, 2018 to unitholders of record as of February 1, 2018.

We expect our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions to our partners will be funded from cash flows internally generated from our operations. Our expansion capital expenditures will be funded by borrowings under our revolving credit facility or from potential capital markets transactions.

The following table and discussion presents a summary of our net cash provided by (used in) operating activities, investing activities and financing activities for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2015**	**2016**	**2017**
Operating activities	$ 259,678	378,607	475,796
Investing activities	(445,455)	(478,163)	(779,818)
Financing activities	(37,532)	106,715	298,343
Net increase (decrease) in cash and cash equivalents	$(223,309)	7,159	(5,679)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $260 million, $379 million, and $476 million for the years ended December 31, 2015, 2016 and 2017, respectively. The increase in cash flows from operations in 2017 from 2016 and in 2016 from 2015 was primarily the result of increased throughput volumes and revenues as a result of new gathering, compression, and water systems placed in service in 2017 and 2016, respectively.

Cash Flows Used in Investing Activities

During the years ended December 31, 2015, 2016, and 2017, we used cash flows in investing activities of $445 million, $478 million, and $780 million, respectively, primarily for our capital expenditures for gathering systems, compressor stations, and water handling and treatment systems. Cash flows used in investing activities during the year ended December 31, 2017 includes $235 million invested in the Joint Venture. The increase in cash flows used in investing activities from 2015 to 2016 was primarily a result of capital expenditures for the water treatment facility, which commenced construction in 2016 and is currently undergoing testing and commissioning, as well as a $76 million investment in Stonewall Gas Gathering, LLC.

The board of directors of our general partner has approved a capital budget of $650 million for 2018, which includes $585 million of expansion capital and $65 million of maintenance capital. Our capital budgets 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 acceptable levels or costs increase to levels above acceptable levels, Antero Resources could choose to defer a significant portion of its budgeted capital expenditures until later periods. As a result, we may also defer a significant portion of our budgeted capital expenditures to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in Antero Resources' development plans, changes in prices, availability of financing, acquisition costs, industry conditions, the timing of regulatory approvals, success or lack of success in Antero Resources' drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Cash Flows Provided by (Used in) Financing Activities

Net cash provided by financing activities for the year ended December 31, 2017 of $298 million is the result of the following: (i) $345 million in net borrowings under the Credit Facility, (ii) $223 million in net proceeds from the issuance of 6,900,000 common units in February 2017, and (iii) $26 million of net proceeds the sale of common units under the Distribution Agreement. The following cash used in financing activities partially offset net cash provided by financing activities: (i) $284 million in quarterly cash distributions to our unitholders (representing an increase in distributions to unitholders of $102 million from 2016), (ii) $6 million of employee tax withholding for settlement of equity compensation awards, and (iii) the payment of $6 million of deferred financing costs on the 2024 Notes.

Net cash provided by financing activities for the year ended December 31, 2016 of $107 million is the result of the following: (i) $650 million in proceeds from the issuance of the 2024 Notes and (ii) $65 million in proceeds from the Distribution Agreement. The following cash used in financing activities partially offset net cash provided by financing activities (described above): (i) the repayment of $410 million on the revolving credit facility, (ii) $182 million in quarterly cash distributions to our unitholders (representing an increase in distributions to unitholders of $75 million from 2015), (iii) the payment of $10 million of deferred financing costs on the 2024 Notes, and (iv) $6 million of employee tax withholding for settlement of equity compensation awards.

Net cash used in financing activities for the year ended December 31, 2015 of $38 million is the result of the following: (i) $621 million in net cash distributions to Antero Resources, primarily in connection with the Water Acquisition, (ii) $107 million in quarterly cash distributions to our unitholders, (iii) $53 million in deemed cash distributions to Antero Resources, and (iv) the payment of $3 million of deferred financing costs. The following cash provided by financing activities partially offset net cash used in financing activities (described above): (i) $505 million in net borrowings under the revolving credit facility and water facility in connection with the Water Acquisition and (ii) $241 million in net proceeds paid to Antero Resources for the private placement of common units in connection with the Water Acquisition.

Debt Agreements

Revolving Credit Facility

On October 26, 2017, we entered into a restated and amended senior revolving credit facility. The facility was amended to include fall away covenants and lower interest rates that is triggered if and when we are assigned an investment grade credit rating by either Standard and Poor's or Moody's.

Lender commitments under our new facility remained at $1.5 billion. The maturity date of the facility was extended from November 2019 to October 26, 2022. At December 31, 2017, we had $555 million of borrowings and no letters of credit outstanding under the Credit Facility. Borrowings under the Credit Facility are limited by certain financial ratio covenants which may increase the interest rate we owe under the Credit Facility.

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

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

During any period that is not an Investment Grade Period, the revolving credit facility is guaranteed by our subsidiaries and is secured by mortgages on substantially all of our and our subsidiaries' properties; provided that the liens securing the revolving credit facility shall be automatically released during an Investment Grade Period. The revolving credit facility contains restrictive covenants that may limit our 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.

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

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

We were in compliance with the applicable covenants and ratios as of December 31, 2016 and 2017. The actual borrowing capacity available to us may be limited by the interest coverage ratio, consolidated total leverage ratio, and consolidated senior secured leverage ratio covenants.

5.375% Senior Notes Due 2024

On September 13, 2016, the Partnership and its wholly-owned subsidiary, Finance Corp, as co-issuers, issued $650 million in aggregate principal amount of 5.375% senior notes due September 15, 2024 (the "2024 Notes") at par. The 2024 Notes are unsecured and effectively subordinated to the revolving credit facility to the extent of the value of the collateral securing the revolving credit facility. The 2024 Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by the Partnership's wholly-owned subsidiaries (other than Finance Corp) and certain of its future restricted subsidiaries. Interest on the 2024 Notes is payable on March 15 and September 15 of each year. The Partnership may redeem all or part of the 2024 Notes at any time on or after September 15, 2019 at redemption prices ranging from 104.031% on or after September 15, 2019 or 100.00% on or after September 15, 2022. In addition, prior to September 15, 2019, the Partnership may redeem up to 35% of the aggregate principal amount of the 2024 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 Notes, plus accrued and unpaid interest. At any time prior to September 15, 2019, the Partnership may also redeem the 2024 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Notes plus "make-whole" premium and accrued and unpaid interest. If the Partnership undergoes a change of control, the holders of the 2024 Notes will have the right to require the Partnership to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2024 Notes, plus accrued and unpaid interest.

Contractual Obligations

At December 31, 2017, we had $555 million of borrowings and no letters of credit outstanding under the revolving credit facility. Commitment fees on the unused portion of the revolving credit facility are due quarterly at rates ranging from 0.25% to 0.375% based on the leverage ratio, during a period that is not an Investment Grade Period, and 0.175% to 0.375% based on the Partnership's rating, during an Investment Grade Period, of the unused facility.

Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance. A summary of our contractual obligations by maturity date as of December 31, 2017 is provided in the following table.

(in millions)		Year Ended December 31, 2018	2019	2020	2021	2022	Thereafter	Total
Credit Facility [1]	$	—	—	—	—	555	—	555
5.375% senior notes due 2024—principal		—	—	—	—	—	650	650
5.375% senior notes due 2024—interest		35	35	35	35	35	70	245
Water treatment [2]		27	—	—	—	—	—	27
Contingent acquisition consideration [3]		—	125	125	—	—	—	250
Total	$	62	160	160	35	590	720	1,727

(1) Includes outstanding principal amounts on the Credit Facility at December 31, 2017. This table does not include future commitment fees, interest expense or other fees on our revolving credit facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.

(2) Includes obligations related to the construction of our wastewater treatment facility.

(3) In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if we deliver 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if we deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020.

Critical Accounting Policies and Estimates

The following discussion relates to the critical accounting policies and estimates for both the Partnership and our Predecessor. The discussion and analysis of our financial condition and results of operations are based upon our financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated 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 financial statements. We provide 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 preparation of our financial statements. See Note 2—Summary of Significant Accounting Policies to the financial statements for a discussion of additional accounting policies and estimates made by management.

General and Administrative and Equity-Based Compensation Costs

General and administrative costs are charged or allocated to us based on the nature of the expenses and are allocated based on our proportionate share of Antero Resources' gross property and equipment, capital expenditures and labor costs, as applicable. These allocations are based on estimates and assumptions that management believes are reasonable.

Equity-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Estimating the fair value of each award, the number of awards that will ultimately vest, and the forfeiture rate requires management to apply judgment to estimate the tenure of our employees.

Equity-based compensation expenses are allocated to us based on our proportionate share of Antero Resources' labor costs. These allocations are based on estimates and assumptions that management believes are reasonable.

Fair Value Measurement

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

In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if we deliver 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 we deliver 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. This contingent consideration liability is valued based on Level 3 inputs related to the expected average volumes and weighted average cost of capital.

We account for contingent consideration in accordance with applicable accounting guidance pertaining to business combinations. We are contractually obligated to pay Antero Resources contingent consideration in connection with the Water Acquisition, and therefore recorded this contingent consideration liability at the time of the Water Acquisition. We update our assumptions each reporting period based on new developments and adjust such amounts to fair value based on revised assumptions, if applicable, until such consideration is satisfied through payment upon achievement of the specified objectives or it is eliminated upon failure to achieve the specified objectives.

New Accounting Pronouncements

On May 28, 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU replaced most existing revenue recognition guidance in GAAP when it became effective. The new standard became effective for us on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method. We have elected the cumulative effect method. 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.

During 2017, we completed our analysis of the impact of the standard on our contract types, and do not believe that the adoption of ASU 2014-09 will have a material impact on our financial results. We do not believe that adoption of the standard will impact our operation 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 Partnership on January 1, 2019. Although early application is permitted, the Partnership does not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. The Partnership is evaluating the effect that ASU 2016-02 will have on our consolidated financial statements and related disclosures. We are evaluating the standard's applicability to our various contractual arrangements with Antero and have tentatively concluded that the application of the ASU to our contractual arrangements with Antero could be subject to differing interpretations. The accounting treatment for these arrangements under the ASU could include (i) recognition of our Antero contracts as leases under the ASU, (ii) characterization of our servicing revenues from gathering, compression, and water handling and treatment as revenues from leasing or financing, and (iii) derecognition of assets on our balance sheet that are used to provide services under contracts containing variable payment terms. Other interpretations and applications of the standard are also possible. We continue to monitor relevant industry guidance regarding implementation of ASU 2016-02 and will adjust our implementation of the standard 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 us on January 1, 2020. We do not believe that this standard will have a material impact on our ongoing financial reporting upon adoption.

Off-Balance Sheet Arrangements

As of December 31, 2017, we did not have any off-balance sheet arrangements.

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 commodity prices and 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.

Commodity Price Risk

Our gathering and compression and water services agreements with Antero Resources provide for fixed-fee structures, and we intend to continue to pursue additional fixed-fee opportunities with Antero Resources and third parties in order to avoid direct commodity price exposure. However, to the extent that our future contractual arrangements with Antero Resources or third parties do not provide for fixed-fee structures, we may become subject to commodity price risk. We are subject to commodity price risks to the extent that they impact Antero Resources' development program and production and therefore our gathering, compression, and water handling and treatment volumes. We cannot predict to what extent our business would be impacted by lower commodity prices and any resulting impact on Antero Resources' operations.

Interest Rate Risk

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility, which has a floating interest rate. We do not currently, but may in the future, hedge the interest on portions of our borrowings under our revolving credit facility from time-to-time in order to manage risks associated with floating interest rates. At December 31, 2017, we had $555 million of borrowings and no letters of credit outstanding under the Credit Facility. A 1.0% increase in our Credit Facility interest rate would have resulted in an estimated $3.4 million increase in interest expense, for the year ended December 31, 2017.

Credit Risk

We are dependent on Antero Resources as our primary customer, and we expect to derive a substantial majority of our revenues from Antero Resources for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Antero Resources' production, drilling schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution.

Further, we are subject to the risk of non-payment or non-performance by Antero Resources, including with respect to our gathering and compression and water handling and treatment services agreements. We cannot predict the extent to which Antero Resources' business would be impacted if conditions in the energy industry were to deteriorate further, nor can we estimate the impact such conditions would have on Antero Resources' ability to execute its drilling and development program or to perform under our agreement. Any material non-payment or non-performance by Antero Resources could reduce our ability to make distributions to our unitholders.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F-1 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 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, 2017.

Management's Annual Report on Internal Control Over Financial Reporting

The management of our general partner 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 our general partner concluded that our internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 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, 2017, as stated in their report which appears on page F-2 in this report.

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 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 Midstream Partners LP, 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 US economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term “affiliate” broadly, it includes any entity under common “control” with us (and the term “control” is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC (“WP”), affiliates of which: (i) beneficially own more than 10% of our outstanding common units and/or are members of our general partner’s board of directors and (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 Antero Midstream Partners LP; 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, 2017 were negligible relative to the overall revenues and profits of Banco Santander SA.

(b) 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, 2017. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. No revenues or profits were generated by Santander UK on this account in the year ended December 31, 2017.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Management of Antero Midstream Partners LP

We are managed and operated by the board of directors and executive officers of our general partner, Antero Midstream Partners GP LLC ("AMP GP"). Our general partner is controlled by Antero Midstream GP LP ("AMGP"). All of the officers and certain of the directors of our general partner are also officers and directors of Antero Resources and AMGP GP LLC, the general partner of AMGP ("AMGP GP"). Neither our general partner nor its board of directors is elected by our unitholders. AMGP is the sole member of our general partner and has the right to appoint our general partner's entire board of directors, including at least three independent directors meeting the independence standards established by the NYSE. Our unitholders are not entitled to directly participate in our management or operations. Our general partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

Our general partner has seven directors. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act.

All of the executive officers of our general partner listed below allocate their time between managing our business and affairs and the business and affairs of Antero Resources and AMGP. The amount of time that our general partner's executive officers devote to our business and the businesses of Antero Resources and AMGP will vary in any given year based on a variety of factors. Our general partner's executive officers intend, however, to devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs.

Antero Resources provides customary management and general administrative services to us pursuant to a services agreement. Our general partner reimburses Antero Resources at cost for its direct expenses incurred on behalf of us and a proportionate amount of its indirect expenses incurred on behalf of us, including, but not limited to, compensation expenses. Under a services agreement, Antero Resources charges us a general and administrative fee for services it provides us. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Please read "Item 13. Certain Relationships and Related Transactions and Director Independence." Neither our general partner nor Antero Resources receives any management fee or other compensation.

Board Leadership Structure

The Board does not have a formal policy addressing whether or not the roles of Chairman and Chief Executive Officer should be separate or combined. The directors serving on the Board possess considerable professional and industry experience, significant experience as directors of both public and private companies and a unique knowledge of the challenges and opportunities that we face. As such, the Board believes that it is in the best position to evaluate our needs and to determine how best to organize AMP GP's leadership structure to meet those needs.

At present, AMP GP's Board has chosen to combine the positions of Chairman and Chief Executive Officer. While the Board believes it is important to retain the flexibility to determine whether the roles of Chairman and Chief Executive Officer should be separated or combined in one individual, the Board believes that the current Chief Executive Officer is an individual with the necessary experience, commitment and support of the other members of the Board to effectively carry out the role of Chairman.

The Board believes this structure promotes better alignment of strategic development and execution, more effective implementation of strategic initiatives and clearer accountability for our success or failure. Moreover, the Board believes that combining the Chairman and Chief Executive Officer positions does not impede independent oversight of the Partnership. Five of the seven members of the Board are independent under NYSE rules.

Board's Role in Risk Oversight

In the normal course of our business, we are exposed to a variety of risks, including market risks relating to changes in commodity prices, interest rates, technical risks affecting our facilities, political risks and credit and investment risk. The Board oversees our strategic direction, and in doing so considers the potential rewards and risks of our business opportunities and challenges, and monitors the development and management of risks that impact our strategic goals.

Executive Sessions

To facilitate candid discussion among our directors, the non-management directors meet in regularly scheduled executive sessions. The director who presides at these meetings is chosen by the Board prior to such meetings.

Interested Party Communications

Unitholders and other interested parties may communicate by writing to: Antero Midstream Partners LP, 1615 Wynkoop Street, Denver, Colorado 80202. Unitholders may submit their communications to the Board, any committee of the Board or individual directors on a confidential or anonymous basis by sending the communication in a sealed envelope marked "Unitholder Communication with Directors" and clearly identify the intended recipient(s) of the communication.

Our Chief Administrative Officer will review each communication and other interested parties and will forward the communication, as expeditiously as reasonably practicable, to the addressees if: (1) the communication complies with the requirements of any applicable policy adopted by the Board relating to the subject matter of the communication; and (2) the communication falls within the scope of matters generally considered by the Board. To the extent the subject matter of a communication relates to matters that have been delegated by the Board to a committee or to an executive officer of the general partner, then the general partner's Chief Administrative Officer may forward the communication to the executive officer or chairman of the committee to which the matter has been delegated. The acceptance and forwarding of communications to the members of the Board or an executive officer does not imply or create any fiduciary duty of the Board members or executive officer to the person submitting the communications.

Information may be submitted confidentially and anonymously, although we may be obligated by law to disclose the information or identity of the person providing the information in connection with government or private legal actions and in other circumstances. Our policy is not to take any adverse action, and not to tolerate any retaliation, against any person for asking questions or making good faith reports of possible violations of law, our policies or our Corporate Code of Business Conduct and Ethics.

Available Governance Materials

The Board has adopted the following materials, which are available on our website at *www.anteromidstream.com*:

- Charter of the Audit Committee of the Board;
- Corporate Code of Business Conduct and Ethics;
- Financial Code of Ethics; and
- Corporate Governance Guidelines.

Unitholders may obtain a copy, free of charge, of each of these documents by sending a written request to Antero Midstream Partners LP, 1615 Wynkoop Street, Denver, Colorado, 80202. We intend to disclose any amendments to, or waivers from, our Code of Business Conduct and Ethics on our website.

Directors and Executive Officers

The following table shows information for our general partner's executive officers and directors. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board. There are no family relationships among any of the directors or executive officers. Some of the directors and all of the executive officers also serve as executive officers of Antero Resources.

Name	Age	Position With Our General Partner
Paul M. Rady	64	Chairman and Chief Executive Officer
Glen C. Warren, Jr.	62	Director, President and Secretary
Michael N. Kennedy	43	Chief Financial Officer and Senior Vice President
Kevin J. Kilstrom	63	Senior Vice President—Production
Alvyn A. Schopp	59	Chief Administrative Officer, Senior Regional Vice President and Treasurer
Ward D. McNeilly	67	Senior Vice President—Reserves, Planning and Midstream
Richard W. Connor	68	Director
Peter R. Kagan	49	Director
W. Howard Keenan, Jr.	67	Director
John C. Mollenkopf	56	Director
David A. Peters	59	Director

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors of our general partner since February 2014. Mr. Rady has also served as Chief Executive Officer and Chairman of the Board of Directors of Antero Resources since May 2004 and of its predecessor company, Antero Resources Corporation, from its founding in 2002 until its sale to XTO Energy, Inc. in April 2005, as well as Chief Executive Officer and Chairman of the Board of Directors of AMGP GP since April 2017. Prior to Antero Resources, 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 and Secretary and as a director of our general partner since January 2016, prior to which he served as President, Chief Financial Officer and Secretary and as a director of our general partner beginning in February 2014. Mr. Warren has also served as President, Chief Financial Officer and Secretary and as a director of Antero Resources since May 2004 and of its predecessor company, Antero Resources Corporation, from its founding in 2002 until its sale to XTO Energy, Inc. in April 2005, as well as President and Secretary and as a director of the Board of Directors of AMGP GP since April 2017. Prior to Antero Resources, 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 Chief Financial Officer of our general partner and Senior Vice President of Finance since January 2016, prior to which he served as Vice President of Finance of our general partner beginning in February 2014. Mr. Kennedy has also served as Senior Vice President of Finance of Antero Resources since January

2016, prior to which he served as Vice President of Finance of Antero Resources beginning in August 2013. Mr. Kennedy was Executive Vice President and Chief Financial Officer of Forest Oil Corporation (“Forest”) from 2009 to 2013. Mr. Kennedy has also served as Chief Financial Officer and Senior Vice President of Finance of AMGP GP since April 2017. From 2001 until 2009, Mr. Kennedy held various financial positions of increasing responsibility within Forest. From 1996 to 2001, Mr. Kennedy was an auditor with Arthur Andersen LLP focusing on the Natural Resources industry. Mr. Kennedy holds a B.S. in Accounting from the University of Colorado at Boulder.

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

Alvyn A. Schopp has served as Chief Administrative Officer, Senior Regional Vice President, and Treasurer of our general partner since January 2016, prior to which he served as Chief Administrative Officer, Regional Vice President and Treasurer of our general partner beginning in February 2014. Mr. Schopp has also served as Chief Administrative Officer, Senior Regional Vice President, and Treasurer of Antero Resources since January 2016, 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 Antero Resources’ predecessor company, Antero Resources Corporation, from January 2005 until its sale to XTO Energy, Inc. in April 2005. Mr. Schopp has also served as Chief Administrative Officer, Senior Regional Vice President, and Treasurer of AMGP GP since April 2017. 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. Mr. Schopp holds a B.B.A. from Drake University.

Ward D. McNeilly has served as Senior Vice President of Reserves, Planning and Midstream of our general partner since January 2016, prior to which he served as Vice President of Reserves, Planning and Midstream of our general partner beginning in February 2014. Mr. McNeilly also has served as Senior Vice President of Reserves, Planning & Midstream of Antero Resources since January 2016, prior to which he served as Vice President of Reserves, Planning & Midstream of Antero Resources beginning in October 2010. Mr. McNeilly has also served as Senior Vice President of Reserves, Planning and Midstream of AMGP GP since April 2017. 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.

Richard W. Connor joined the board of our general partner in connection with our listing on the NYSE, and serves as the Chairman of the audit committee. Mr. Connor has served as a director and Chairman of the audit committee of Antero Resources 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 Holdings, Inc. (NYSE: ZAYO), 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 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 the audit committee.

Peter R. Kagan has served as a director of our general partner since February 2014. Mr. Kagan also has served as a director of Antero Resources since 2004 and as a director of AMGP GP since April 2017. Mr. Kagan has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus LLC's Executive Management Group. Mr. Kagan received a B.A. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of the following public companies: Laredo Petroleum Holdings, Inc., MEG Energy Corp. and Targa Resources Corp., as well as the boards of several private companies. 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 of our general partner since February 2014. Mr. Keenan also has served as a director of Antero Resources since 2004 and as a director of AMGP GP since April 2017. Mr. Keenan has over 40 years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private investment manager focused on the energy industry. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Portfolio companies and currently serves as a director of the following public companies: Ramaco Resources, Inc. and Solaris Oilfield Infrastructure, Inc. Mr. Keenan holds an B.A. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

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

John C. Mollenkopf has served as a director of our general partner since April 2017, and serves as a member of the audit committee. Mr. Mollenkopf retired from MPLX, L.P. (NYSE:MPLX) in October 2016. He previously served MPLX as Executive Vice President and Chief Operating Officer, MarkWest operations, from December 2015 through September 2016 following the merger of MPLX and MarkWest. From 2011 through 2015, he served as Executive Vice President and Chief Operating Officer of MarkWest. Mr. Mollenkopf began his employment with MarkWest Hydrocarbon, Inc. in 1996 as Manager New Projects and progressed to General Manager and later to Vice President of the Michigan Business unit. In 2002, Mr. Mollenkopf was one of the founders of MarkWest Energy GP, LLC, the general partner of MarkWest. Between 2002 and 2011, Mr. Mollenkopf served MarkWest as Vice President — Business Development, Senior Vice President — Southwest Business Unit, Senior Vice President and Chief Operations Officer, Senior Vice President and Chief Operating Officer. Between 1982 and 1996, Mr. Mollenkopf worked for ARCO Oil and Gas Company in California and Texas, holding positions of increasing responsibility in facilities, project, process and plant engineering as well as operations supervision. Mr. Mollenkopf holds a Bachelor of Science degree in mechanical engineering from the University of Colorado at Boulder 1983. He serves on the Engineering Advisory Council for the college of engineering at the University of Colorado at Boulder.

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

David A. Peters joined the board of our general partner in connection with our listing on the NYSE, and serves as a member of the audit committee. Mr. Peters served as a director of TransMontaigne GP L.L.C., the general partner of TransMontaigne Partners L.P. (NYSE: TLP), from May 2005 to August 2014, and served as a member of the audit and compensation committees and as the chair of the conflicts committee. Since 1999, Mr. Peters has been a business consultant with a primary client focus in the energy sector. In addition, Mr. Peters also served as a member of the board of directors of QDOBA Restaurant Corporation from 1998 to 2003. From 1997 to 1999, Mr. Peters was a managing director of a private investment fund, and from 1995 to 1997 he served as an executive vice president at Duke Energy Field Services/PanEnergy Field Services Inc., responsible for natural gas gathering, compression and storage operations. Prior to joining Duke Energy Field Services/PanEnergy Field Services Inc., Mr. Peters held various positions with Associated Natural Gas Corporation, and from 1980 to 1984, he worked in the audit department of Peat Marwick Mitchell & Co. Mr. Peters holds a B.B.A. from the University of Michigan.

Mr. Peters has extensive knowledge of the energy industry as a business consultant and a former director of the general partner of a master limited partnership and significant financial and accounting knowledge. We believe his background and skill set make Mr. Peters well-suited to serve as a member of our board of directors and of the audit committee.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee. We do not have a compensation committee, but rather the board of directors of our general partner approves equity grants to directors and Antero Resources employees. The board of directors of our general partner may establish a conflicts committee to review specific matters that the board believes may involve conflicts of interest.

Audit Committee

Rules implemented by the NYSE and SEC require us to have an audit committee comprised of at least three directors who meet the independence and experience standards established by the NYSE and the Exchange Act. Messrs. Connor, Mollenkopf, and Peters serve on our audit committee, and Mr. Connor serves as the Chairman of the committee. As required by the rules of the SEC and listing standards of the NYSE, the audit committee consists solely of independent directors. SEC rules also require that a public company disclose whether or not its audit committee has an “audit committee financial expert” as a member. An “audit committee financial expert” is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. Our board of directors believes that Mr. Connor possesses substantial financial experience based on his extensive experience in technical accounting and auditing matters as a former audit partner of KPMG, LLP. As a result of these qualifications, we believe Mr. Connor satisfies the definition of “audit committee financial expert.”

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We adopted an audit committee charter defining the committee’s primary duties in a manner consistent with the rules of the SEC and NYSE.

Conflicts Committee

Our general partner may, from time to time, have a conflicts committee to which the board will appoint at least two independent directors and which may be asked to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is adverse to the interest of the partnership. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including AMGP and Antero Resources, and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and managing board members of our general partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC and to furnish us with copies of all such reports.

Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required, we believe that all of the officers and managing board members of our general partner and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements during fiscal year 2017, except that one transaction by Antero Resources related to conversion of our subordinated units on February 9, 2017 was not timely reported on Form 4.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview

Neither we nor our general partner have any employees. All of the executive officers of our general partner and other personnel who provide services to our business are employed by Antero Resources. This Item 11 provides information relating to the compensation of the following named executive officers of our general partner, whom we refer to herein collectively as our "Named Executive Officers":

2017 Named Executive Officers

Name	Principal Position
Paul M. Rady	Chairman of the Board and Chief Executive Officer
Glen C. Warren, Jr.	Director, President and Secretary
Michael N. Kennedy	Chief Financial Officer and Senior Vice President
Alvyn A. Schopp	Chief Administrative Officer, Regional Senior Vice President and Treasurer
Kevin J. Kilstrom	Senior Vice President—Production
Ward D. McNeilly	Senior Vice President—Reserves, Planning and Midstream

Our Named Executive Officers currently receive all of their compensation and benefits for services provided to our business from Antero Resources, Antero Midstream and IDR LLC. All decisions regarding the compensation of our Named Executive Officers, other than with respect to long-term equity incentive awards under the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream LTIP") and Series B Units issued by IDR LLC, are made by the compensation committee of Antero Resources' board of directors (the "Compensation Committee"). Pursuant to the services agreement that we have entered into with Antero Resources and our general partner, we are required to reimburse Antero Resources for a proportionate amount of compensation expenses incurred on our behalf. Although we bear an allocated portion of Antero Resources' costs of providing such compensation and benefits to our Named Executive Officers, we have no control over such costs and do not establish or direct the compensation policies or practices of Antero Resources or IDR LLC.

The following Compensation Discussion and Analysis provides an overview of compensation policies and programs applicable to our Named Executive Officers and describes the compensation objectives, policies and practices with respect to our Named Executive Officers. The elements of compensation provided by Antero Resources and the Compensation Committee's decisions with respect to our Named Executive Officers' compensation are not subject to approval by the Board. Certain members of the Board are members of the board of directors of Antero Resources. Messrs. Kagan, Keenan and Connor served on our Board and the board of directors of Antero Resources in 2017. As used in this Item 11 (other than in this "Overview" and the "Compensation of Directors" section below), references to "our," "we," "us," the "Company," and similar terms refer to Antero Resources, references to the "Board" or "Board of Directors" refer to the board of directors of Antero Resources, and references to the Partnership refer to us, Antero Midstream Partners LP.

How We Responded to Our Shareholders Following the 2017 Say-on-Pay Vote

The Company's annual advisory vote on the compensation of our Named Executive Officers (commonly known as "say-on-pay") received 67% support at the 2017 Annual Meeting of Shareholders. Although the compensation of our Named Executive Officers was approved, the level of support was lower than it has been in the past; it was not a level that is acceptable to the Company.

Over the past year, the Company has contacted our top 25 shareholders representing approximately 80% of our outstanding shares. Approximately one-third of these shareholders agreed to meet with us and provide feedback on our executive compensation program. Robert J. Clark, the Compensation Committee Chairman, Alvyn A. Schopp, our Chief Administrative Officer and Senior Regional Vice President, Michael N. Kennedy, Senior Vice President of Finance, and John Giannaula, Vice President of Human Resources and Administration, participated in these conversations, which covered shareholder concerns and explored specific changes we could make to our executive compensation program to address those concerns. Mr. Clark, our Compensation Committee Chairman, participated in eight out of nine of these meetings.

At the 2018 Annual Meeting of Shareholders, the Company will again hold an annual advisory vote to approve executive compensation. The Compensation Committee will continue to engage with shareholders throughout the year so that we may understand their perspectives and address their feedback regarding our practices going forward.

The chart below summarizes the key points we heard from our shareholders, what action the Compensation Committee has taken to address their feedback, and when the changes will become effective.

What we heard	How we responded	When effective	Where to find more information
The annual incentive plan is difficult to understand, and it is unclear how final payouts are determined	Simplified the annual incentive plan by reducing the number of performance metrics and selecting metrics that are more objective	2018 Annual Incentive Plan	Changes to 2018 Annual Incentive Plan
	Improved disclosures to make the mechanics easier to understand	CD&A in this Proxy Statement	Annual Cash Incentive Awards
Annual incentive plan should utilize fewer key performance measures, and focus on those that are more closely tied to current corporate strategy	Reduced the number of performance measures to four—all key metrics that are aligned with shareholder expectations: Debt-Adjusted Net Production Growth per Share, Net Debt/EBITDAX, Free Cash Flow, and safety and environmental	2018 Annual Incentive Plan	Changes to 2018 Annual Incentive Plan
An absolute performance measure and certain key financial measures should be incorporated into the executive compensation program	Added absolute total shareholder return ("TSR") and return on capital employed as performance measures for the long-term equity performance share unit awards	Performance share unit awards for 2018–2020	2018 AR LTIP Grants
Reevaluate the target compensation level for long-term equity incentive awards	Lowered our target compensation level for long-term equity grants to the 50th percentile relative to our peers, consistent with all other elements of compensation	Long-term equity grants in 2018	2018 AR LTIP Grants
Reevaluate the portion of our long-term equity incentive program that consists of performance-based awards	Increased the portion of our long-term incentive program that is performance-based to 100% for our Named Executive Officers	Long-term equity grants in 2018	2018 AR LTIP Grants

We enthusiastically embrace these changes. We believe they will strengthen the link between our executive compensation program and shareholder value creation, and directly support the achievement of Company goals.

The following discussion provides information about our compensation decisions and policies with regard to our Named Executive Officers for the 2017 fiscal year, and is intended to provide investors with the information necessary to understand our compensation policies and decisions. It also provides context for the disclosure included in the executive compensation tables below.

2017 Company Performance Highlights

In 2017, our Company:

- Achieved 16% debt-adjusted net production growth per share;

- Reduced our finding and development costs by 13% from 2016 and 48% from 2015;
- Monetized over $1 billion of non-exploration and production assets to pay off all outstanding borrowings on the credit facility in the third quarter of 2017; and
- Recorded a 0.03 lost time incident rate (“LTIR”) and 0.57 total recordable incident rate (“TRIR”) in 2017, representing reductions of 80% and 18%, respectively, from the prior year and the lowest annual LTIR and TRIR on record for the Company.

These concepts will drive our compensation plan metrics in the future, and our 2018 plan will focus on capital efficiency and positive cash flow.

Compensation Philosophy and Objectives of Our Compensation Program

Since our inception, our compensation philosophy has been predominantly focused on recruiting individuals who are motivated to help us achieve superior performance and growth. Our company was founded by entrepreneurs whose strategy was to employ high-impact executives who are extremely effective at sparking superior performance with low overhead. These highly qualified and experienced individuals have contributed to the continued success of our Company, driving an 18% compound annual growth rate in debt-adjusted net production per share and a 23% compound annual growth rate in oil and gas net proved reserves since the Company’s 2013 IPO.

Historically, to achieve our objectives, we sought to implement a compensation program that reflected the unique strategy and entrepreneurial culture of our organization. Specifically, we sought to reward our Named Executive Officers by emphasizing long-term equity-based incentive compensation, which allowed our senior leaders to build significant ownership in the Company. We believe this approach served to motivate our Named Executive Officers and align their interests with those of the Company and our shareholders. Our Named Executive Officers currently hold approximately 9% of our outstanding shares, which ensures they identify with the best interests of our shareholders.

As our Company matures, we are transitioning from an entrepreneurial-based management incentive structure to a more traditional compensation program. This transition calls for us to consider certain modifications to our compensation philosophy. As our company continues to change, we expect to adjust our compensation program. More specifically, our goal is to shift the emphasis of our incentive-based compensation program from operational performance and absolute growth metrics to performance metrics focused on returns and value creation per share that will reward more disciplined capital investment, efficient operations, and free cash flow generation. In addition, for calendar year 2018, as discussed below, we have adopted a simplified annual incentive program that focuses on four key performance metrics. Further, our compensation program will target the market median for all elements of our Named Executive Officers’ compensation. We believe these changes to our compensation philosophy will promote a stronger alignment between Named Executive Officer pay and Company performance, and deliver greater value to our shareholders as our Company continues to grow and mature.

Compensation Best Practices

The following table highlights the compensation best practices we follow:

What We Do	What We Don't Do
✓ Use a representative and relevant peer group	✗ No tax gross ups for executive officers
✓ Apply robust minimum stock ownership guidelines	✗ No "single-trigger" change-in-control cash payments
✓ Link annual incentive compensation to the achievement of objective pre-established performance goals tied to operational and strategic priorities	✗ No excessive perquisites
✓ Evaluate the risk of our compensation programs	✗ No severance arrangements for Named Executive Officers
✓ Use and review compensation tally sheets	✗ No guaranteed bonuses for Named Executive Officers
✓ Provided more than 50% of 2017 long-term incentive awards in the form of performance-based equity (for 2018, 100% of long-term incentive awards will be performance-based equity)	✗ No management contracts
✓ Use an independent compensation consultant	✗ No re-pricing, backdating or underwater cash buy-outs of options or stock appreciation rights
	✗ No hedging or pledging of Company stock
	✗ No separate benefit plans for Named Executive Officers
	✗ No granting of stock options with an exercise price less than the fair market value of the Company's common stock on the date of grant

Implementing Our Compensation Program Objectives

Role of the Compensation Committee

The Compensation Committee oversees all matters of our executive compensation program and has the final decision-making authority on all executive compensation matters. Each year, the Compensation Committee reviews, modifies (if necessary), and approves our peer group, corporate goals and objectives relevant to the compensation of the Company's Chief Executive Officer ("CEO") and other executive officers, and the executive compensation program. In addition, the Compensation Committee is responsible for reviewing the performance of the CEO and the Company's President, Chief Financial Officer and Secretary ("President/CFO") within the framework of our executive compensation goals and objectives. Based on this evaluation, the Compensation Committee sets the compensation of the CEO and the President/CFO.

The CEO and the President/CFO typically provide recommendations to the Compensation Committee regarding the compensation levels for the other executive officers and for our executive compensation program as a whole. In making their recommendations, the CEO and the President/CFO consider each executive officer's performance during the year, the Company's performance during the year, and comparable company compensation levels and independent oil and gas company compensation surveys. The Compensation Committee considers these recommendations when reviewing the performance of, and setting compensation for, the other executive officers.

Role of External Advisors

The Compensation Committee has the authority to retain an independent executive compensation consultant. For 2017, the Compensation Committee retained Frederic W. Cook & Co., Inc. ("F.W. Cook"). In compliance with the SEC and the NYSE disclosure requirements, the Compensation Committee reviewed the independence of F.W. Cook under six independence factors. After its review, the Compensation Committee determined that F.W. Cook was independent.

In 2017, F.W. Cook:

- Collected and reviewed all relevant company information, including our historical compensation data and our organizational structure;

- With input from management, established a peer group of companies to use for executive compensation comparisons;
- Assessed our compensation program's position relative to market for our Named Executive Officers and stated compensation philosophy;
- Prepared a report of its analysis, findings and recommendations for our executive compensation program; and
- Completed other ad hoc assignments, such as helping with the design of incentive arrangements and special awards.

F.W. Cook's reports were provided to the Compensation Committee in 2017. In addition, Messrs. Rady and Warren used F.W. Cook's report dealing with competitive compensation levels when making their recommendations to the Board for fiscal 2017 compensation decisions.

Competitive Benchmarking

When assessing the soundness of our compensation programs, the Compensation Committee compares the pay practices for our Named Executive Officers against the pay practices of other companies. This process recognizes our philosophy that our compensation practices should be competitive, though marketplace information is only one of the many factors we consider.

Messrs. Rady and Warren used market compensation data provided by F.W. Cook to assess the total compensation levels of our top six executives relative to market, and to make recommendations to the Compensation Committee for fiscal 2018 decisions. Market data is developed by comparing each executive officer's compensation with that of officers in similar positions with companies in our Peer Group (described below) and with those in the E&P industry in general. To the extent possible, we consider the specific responsibilities assumed by our executives and those assumed by executives at other organizations (based on peer SEC filings) to determine whether the positions are comparable. We give greater weight to Peer Group data if a position appears comparable to the position of one of our Named Executive Officers. Otherwise, we supplement Peer Group data with industry data from the 2017 Oil and Gas E&P Industry Compensation Survey prepared by Effective Compensation, Incorporated.

Peer Group. In 2017, F.W. Cook identified a peer group of onshore publicly traded oil and gas companies that are reasonably similar to us in terms of size and operations. The peer group identified by F.W. Cook, which we refer to as the "Peer Group," consists of the following 16 companies:

- Cabot Oil & Gas Corporation
- Cimarex Energy Co.
- Concho Resources Inc.
- Continental Resources Corporation
- Devon Energy Corporation
- Energen Corporation
- EQT Corporation
- Newfield Exploration Company
- Noble Energy, Inc.
- Pioneer Natural Resources Company
- QEP Resources, Inc.
- Range Resources Corporation
- SM Energy Company
- Southwestern Energy Company
- Whiting Petroleum Corporation
- WPX Energy, Inc.

Positioning versus market. Due to the broad responsibilities of our Named Executive Officers, applying survey data to them can be difficult. However, as discussed above, our compensation objective is to be competitive with our peer companies. Therefore, in assessing the competitive positioning of our Named Executive Officers' compensation relative to the market, the Compensation Committee also considered our productivity relative to our peers.

We determined that it was appropriate to target the median of the Peer Group for base salaries and annual cash incentive awards and, for 2017, the 75th percentile of the Peer Group for long-term equity-based incentive awards. As the Company continues to mature, we regularly assess how our incentive program is structured to retain key management employees and align their interests with those of our shareholders, as indicated by the changes to our compensation strategy and incentive plans for 2018.

As a result of our 2017 say-on-pay vote and shareholder outreach program, beginning in 2018, the Compensation Committee determined that long-term equity-based incentives should target the 50th percentile of the Peer Group. We believe this better reflects our compensation philosophy and provides the necessary incentive at this stage in the Company's progression. For the 2017 program, the Compensation Committee considered, among other things, publicly available data of direct peer companies matching our operational profile that measures productivity using various individual employee metrics. These metrics included EBITDAX per employee, drilling and completion capital per employee, production per employee, proved reserves per employee, and market value per employee. Our performance with respect to these metrics continues to excel (in each case we ranked first or second amongst the direct peer group), and we believe these metrics provided a reasonable basis for our 2017 compensation decisions. However, we recognize that we must continually ensure that our incentive program is aligned with the interests of our shareholders. Therefore, the Compensation Committee determined that, beginning in 2018, the relative performance of our Named Executive Officers should more closely match the performance of the Peer Group and that our compensation amounts should be adjusted to match the median of the Peer Group.

Actual compensation decisions for individual officers are the result of a subjective analysis of a number of factors, including the individual officer's role within our organization, performance, experience, skills or tenure with us, changes to the individual's position, and relevant trends in compensation practices. The Compensation Committee also considers a Named Executive Officer's current and prior compensation when setting future compensation. Specifically, current compensation is considered a base, and the Compensation Committee determines whether adjustments to that base are necessary to retain the executive in light of competition and to provide continuing performance incentives. Thus, the Compensation Committee's decisions regarding compensation are the result of the exercise of judgment based on all reasonably available information and, to that extent, are discretionary.

Elements of Direct Compensation

Our Named Executive Officers' compensation includes the following key components:

- Base salaries;
- Annual cash incentive payments; and
- Long-term equity-based incentive awards.

Base Salaries

Base salaries are designed to provide a minimum, fixed level of cash compensation for services rendered during the year. In addition to providing a base salary that is competitive with salaries paid by other independent oil and gas exploration and production companies, the Compensation Committee also considers whether our pay levels appropriately align each Named Executive Officer's base salary level relative to the base salary levels of our other officers. Our objective is to have base salaries that accurately reflect each officer's relative skills, responsibilities, experience and contributions to the Company. To that end, annual base salary adjustments are based on a subjective analysis of many individual factors, including:

- the responsibilities of the officer;
- the period over which the officer has performed these responsibilities;
- the scope, level of expertise, and experience required for the officer's position;
- the strategic impact of the officer's position; and

· the potential future contribution and demonstrated individual performance of the officer.

In addition to the individual factors listed above, the Compensation Committee considers our overall business performance and implementation of Company objectives when determining annual base salaries. While these metrics generally provide context for making salary decisions, base salary decisions do not depend on attainment of specific goals or performance levels and no specific weighting is given to one factor over another.

Base salaries are reviewed annually, but are not necessarily increased if the Compensation Committee believes that (1) our executives are currently compensated at proper levels in light of Company performance or external market factors, or (2) an increase or addition to other elements of compensation would be more appropriate in light of our stated objectives.

The following table provides an overview of the changes in base salary for the Named Executive Officers from 2016 to 2017. These changes reflect market adjustments intended to maintain the base salaries of our Named Executive Officers in line with base salary increases in the competitive market. The adjusted base salary amounts approximated the median of the Peer Group.

Executive Officer	Base Salary as of March 2016	Base Salary as of March 2017	Percentage Increase
Paul M. Rady	$ 833,000	$ 858,000	3 %
Glen C. Warren, Jr.	$ 626,000	$ 645,000	3 %
Alvyn A. Schopp	$ 419,000	$ 432,000	3 %
Kevin J. Kilstrom	$ 419,000	$ 432,000	3 %
Ward D. McNeilly	$ 379,000	$ 391,000	3 %
Michael N. Kennedy	$ 364,000	$ 375,000	3 %

Annual Cash Incentive Awards

Purpose and Operation

Annual cash incentive payments, which we also refer to as cash bonuses, are a key component of each Named Executive Officer's annual compensation package. Historically, the Compensation Committee used an annual discretionary cash bonus. However, based on recommendations from F.W. Cook, the Compensation Committee implemented a formal annual incentive plan design beginning in fiscal 2014. This annual incentive plan is based on a balanced scorecard that is used to measure our performance.

As part of a more structured annual incentive program, we adopted bonus targets for each of the Named Executive Officers, expressed as a percentage of base salary. These targets, which were determined based on our compensation strategy of providing incentive compensation opportunities that are competitive with the market median, are listed below.

Executive Officer	2017 Target Bonus (as a % of base salary)
Paul M. Rady	120 %
Glen C. Warren, Jr.	100 %
Alvyn A. Schopp	85 %
Kevin J. Kilstrom	85 %
Ward D. McNeilly	85 %
Michael N. Kennedy	80 %

Performance Metrics

For fiscal 2017 annual incentive compensation, the Compensation Committee selected financial, operational and strategic metrics that aligned with our business strategy and would lead to long-term shareholder value. The Compensation Committee then established relative weightings for each category of measure. The level of each weighting was intended to indicate the relative importance of management focus for the year. The Compensation Committee then established threshold, target and maximum bonus levels for each individual metric. No credit is provided if the Company fails to meet a minimum target with respect to a metric, 50% credit is provided if the Company meets the minimum target with respect to a metric, 100% credit is provided if the Company achieves the target with respect to a metric, and a maximum of 200% credit is provided if the Company meets or exceeds the maximum performance level with respect to a metric. Bonus levels between threshold, target and maximum are calculated using straight line interpolation.

The following table shows the results of the 2017 annual incentive program.

Performance Category	Weighting Factor(1)	Selected Metric	Minimum	Target	Maximum	Actual	Performance Score
Financial	25 %	EBITDAX (YE 2016 Strip) ($MM)(2)	1,440	1,544	1,640	1,557	14%
		Net Debt / EBITDAX(2)	3.7x	3.5x	3.3x	3.1x	25%
Operational	35 %	Net Production vs. Plan (Mcfe/d)	2,160	2,238	2,300	2,253	6%
		Development Costs ($/Mcfe)(3)	$ 0.70	$ 0.65	$ 0.60	$ 0.53	10%
		Cash Production Expense ($/Mcfe)(4)	$ 1.81	$ 1.74	$ 1.67	$ 1.69	9%
		G&A Expense ($/Mcfe)(5)	$ 0.21	$ 0.19	$ 0.17	$ 0.18	8%
		Capital Expenditures vs. Plan ($MM)(6)	$ 2,200	$2,100	$ 2,000	$2,041	6%
		Drilling Rate of Return (%) at predrill commodity prices and actual costs	43 %	53 %	63 %	50 %	4%
		Lost Time Incident Rate (LTIR)	0.30	0.10	0.08	0.03	10%
Strategic	40 %	Succession Planning		(7)		(7)	10%
		Strategic Planning		(7)		(7)	10%
		Safety Training and Contractor Management		(7)		(7)	10%
		No Meaningful Environmental Incidents		(7)		(7)	10%
Total	**100 %**						**132%**

(1) Equal weighting among performance metrics for each performance category.
(2) Excludes $98 million EBITDAX impact from previously disclosed contractual disputes relating to natural gas sales contracts.
(3) Represents well-by-well net capital costs divided by well-by-well net reserves for all Company-operated wells completed in 2017.
(4) Includes marketing revenues and expenses.
(5) Excludes non-cash stock-based compensation.
(6) Includes drilling and completion, leasehold acquisitions, water and midstream capital. Excludes proved property acquisitions.
(7) Target for these items is at the discretion of the Compensation Committee, taking into account specific actions and plans incurred throughout the course of the year. The Compensation Committee determines the amount of progress in each case and considers the actions taken by management and the level of contribution to the overall success of the Company.

Additional Information Regarding Achievement of Performance Metrics in 2017

Financial. The Company met its target with respect to the “Financial” performance metrics by reaching both its EBITDAX and Net Debt/EBITDAX targets. Reductions in long-term debt as a result of our monetization program helped us exceed the Net Debt/EBITDAX target.

Operational. Overall, the Company exceeded target performance for all the “Operational” performance metrics. The production, development cost, cash production expense, and general and administrative expense metrics were positively affected by increased production, well cost reductions, and operational efficiency gains, including from longer lateral drilling, improved cycle times, and enhanced recoveries. The Company’s increased focus on controlling capital expenditures also contributed to superior performance in this category. Additionally, the Company substantially outperformed the LTIR target by continuing to focus on training and education and key safety policy changes.

Strategic. The Company met target performance for the “Strategic” performance category. This was primarily because management was able to focus on additional key aspects of the Company’s strategic initiatives while achieving the “Financial” and “Operational” performance targets. This included making key senior management hires to address succession planning, and implementing a plan to monetize over $1 billion of non-exploration and production assets in order to reduce our overall leverage. Additionally, we continued our strong focus on safety and environmental issues. In our safety program, we continually address training and contractor management. We had several initiatives that contributed directly to meeting our targets, including a Safety Leadership Program, which focuses on educating field managers on how to build a strong safety culture. We also initiated Field Safety Committees, increased contractor auditing, and instituted new safe workplace practices across all phases of our operations. In addition, the Company was very successful in managing environmental stewardship and regulatory compliance in our field operations. As a result of these efforts, the Company received minimal Notice of Violations and was not subject to any regulatory fines or penalties during 2017.

2017 Annual Incentive Program Payouts

The Compensation Committee evaluated the 2017 annual incentive scorecard and considered the factors noted above. In addition, the Compensation Committee considered the Company's stock price performance during 2017 and other factors reflective of our shareholders' experience. Although our actual performance indicated a payout calculation of 132%, the Compensation Committee determined that, in order to better align the 2017 Annual Incentive Program payouts with the interests of shareholders, payouts under the 2017 annual incentive scorecard should be capped at 80% of target for Messrs. Rady and Warren and 100% of target for Messrs. Schopp, Kilstrom, McNeilly and Kennedy. The Compensation Committee elected to pay 2017 bonuses in March 2018 in the amounts shown below for the Named Executive Officers. There were no adjustments for individual performance.

Executive Officer	2017 Target Bonus ($)	Performance Achievement Level (Percentage of Target)	Unadjusted 2017 Bonus Result ($)	Performance Capped Maximum (Percentage of Target)	Actual 2017 Bonus ($)
Paul M. Rady	$1,029,600	132 %	$ 1,359,072	80 %	$ 823,680
Glen C. Warren, Jr.	$ 645,000	132 %	$ 851,400	80 %	$ 516,000
Alvyn A. Schopp	$ 367,200	132 %	$ 484,704	100 %	$ 367,200
Kevin J. Kilstrom	$ 367,200	132 %	$ 484,704	100 %	$ 367,200
Ward D. McNeilly	$ 332,350	132 %	$ 438,702	100 %	$ 332,350
Michael N. Kennedy	$ 300,000	132 %	$ 396,000	100 %	$ 300,000

We are aware that equity prices for E&P companies remain depressed. Therefore, we believe that, with the Compensation Committee's adjustments to the annual incentive payouts, the results of our annual incentive program are appropriate. We consider the results of this program to have a direct correlation to the actions of our management team. Payments under the annual incentive plan will help us to retain and reward the executive team that is responsible for our success. We also believe that, with the adjustments discussed above, the 2017 annual incentive payouts are better aligned with the interests of our shareholders.

Long-Term Equity-Based Incentive Awards

Long-Term Incentive Awards Granted in 2017

For 2017, the Compensation Committee adjusted our approach for equity-based awards to include a combination of performance share units (weighted 75%) and restricted stock units (weighted 25%) granted under the Antero Resources Corporation Long-Term Incentive Plan (the "AR LTIP"). The Compensation Committee believed this allocation struck the appropriate balance between performance-based equity awards and time-based equity awards that would help us attract and retain top executive talent. However, for 2018, 100% of the long-term equity-based incentive awards for our Named Executive Officers will be performance-based.

The restricted stock units granted in 2017 vest ratably over a period of four years, subject to continued employment with the Company. The performance share units awarded in 2017 will be earned, if at all, based upon the Company's three-year total shareholder return performance measured against the Peer Group.

In order to achieve a payout under the performance share unit awards, our total shareholder return performance relative to the Peer Group over the performance period must rank at or above the 30th percentile for a threshold payout, the 55th percentile for a target payout, or the 80th percentile for the maximum payout. The payout will be determined as follows:

Performance Level	Relative Total Shareholder Return Percentile Ranking	Performance Payout%*
Maximum	80 %	200 %
Target	55 %	100 %
Threshold	30 %	50 %

* Regardless of our relative ranking, if our total shareholder return is negative for the performance period, the number of performance share units earned will not exceed 100% of target. If our relative total shareholder return percentile ranking falls between performance levels, the performance payout percentage will be determined by linear interpolation between such performance levels.

Status of Outstanding Performance-Based Long-Term Incentives

Since the performance-based incentive awards granted in 2016 and 2017 each have three-year performance periods, we are currently in the midst of two performance cycles. The table below shows our current standing for the performance periods in progress.

Performance Period	Performance Measure	Relative Total Shareholder Return Percentile Ranking		Current Performance Status
		Performance Level	*Payout*	
2016–2018	**Three-year relative total shareholder return performance**	*Maximum*: *Target*: *Threshold*: *Below Threshold*:	80 % 55 % 30 % 0 %	As of December 31, 2017, actual performance is projected to be below threshold. Results will be certified by the Compensation Committee in April 2018.
2017–2019	**Three-year relative total shareholder return performance**	*Maximum*: *Target*: *Threshold*: *Below Threshold*:	80 % 55 % 30 % 0 %	As of December 31, 2017, actual performance is projected to be below threshold. Results will be certified by the Compensation Committee in April 2019.

Antero Midstream Phantom Units

Our Named Executive Officers spend a portion of their time providing services to the Partnership, and thus are entitled to receive grants of equity-based awards under the Midstream LTIP. In November 2014, each of our Named Executive Officers was granted phantom units under the Midstream LTIP in connection with the initial public offering of the Partnership. In April 2016 and 2017, each of our Named Executive Officers was granted additional phantom units under the Midstream LTIP as compensation for their additional services provided to the Partnership. Twenty-five percent of those phantom units will become vested on each of the first four anniversaries of the grant date so long as the executive remains continuously employed by us until the applicable vesting date. Phantom units granted under the Midstream LTIP generally represent the right to receive common units of the Partnership upon vesting. For a further discussion of the vesting terms and other restrictions applicable to the phantom units, see the discussion under the heading "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table—Phantom Unit Awards" below.

Other Benefits

Health and Welfare Benefits

Our Named Executive Officers are eligible to participate in all of our employee health and welfare benefit arrangements on the same basis as other employees (subject to applicable law). These arrangements include medical, dental and disability insurance, as well as health savings accounts. We provide these benefits in order to ensure that we can competitively attract and retain officers and other employees. This is a fixed component of compensation, and these benefits are provided on a non-discriminatory basis to all employees.

Retirement Benefits

We maintain an employee retirement savings plan through which employees may save for retirement or future events on a tax-advantaged basis. Participation in the 401(k) plan is at the discretion of each individual employee, and our Named Executive Officers participate in the plan on the same basis as all other employees. The plan permits us to make discretionary matching and non-elective contributions. Since January 1, 2014, the Company has matched 100% of the first 4% of eligible compensation that employees contribute to the plan. Matching contributions provided by the Company are immediately fully vested.

Perquisites and Other Personal Benefits

We believe the total mix of compensation and benefits provided to our Named Executive Officers is currently competitive. Therefore, perquisites do not play a significant role in our Named Executive Officers' total compensation.

2018 Compensation Decisions

2018 Base Salaries

In February 2018, after comparing base salary levels to those of similarly situated executives in the Peer Group, and considering the individual and business factors described above, Messrs. Rady and Warren recommended to the Compensation Committee that the Named Executive Officers other than themselves receive 3% base salary increases, as reflected in the table below. The Compensation Committee approved this recommendation.

Named Executive Officer	Base Salary as of March 2017	Base Salary as of March 2018	Percentage Increase
Paul M. Rady	$ 858,000	$ 858,000	0 %
Glen C. Warren, Jr.	$ 645,000	$ 645,000	0 %
Alvyn A. Schopp	$ 432,000	$ 444,960	3 %
Kevin J. Kilstrom	$ 432,000	$ 444,960	3 %
Ward D. McNeilly	$ 391,000	$ 402,730	3 %
Michael N. Kennedy	$ 375,000	$ 386,250	3 %

Changes to 2018 Annual Incentive Plan

For 2018, based on the feedback received from our shareholders in connection with the Company's outreach program, the Compensation Committee decided to alter the structure of our annual incentive program. We believe the new, simplified design of the annual incentive program implemented for 2018 will provide a more transparent bonus structure with more objectively determinable payouts. We also believe the new structure is more consistent with our shareholders' investment experience.

	Selected Metrics	Approximate Weighting
1.	Debt-Adjusted Net Production Growth per Share(1)	25 %
2.	Net Debt/EBITDAX(2)	25 %
3.	Free Cash Flow(3)	25 %
4.	Safety and Environmental(4)	25 %
		100 %

The Compensation Committee selected the four metrics described below for the 2018 fiscal year under our annual incentive plan. These metrics, which were specifically chosen for their importance in supporting the strategic initiatives we have established for 2018, are weighted equally in calculating annual bonuses.

(1) Debt-Adjusted Net Production Growth per Share

Definition. Annual production volumes *divided by* debt-adjusted shares. Debt-adjusted shares represent current shares outstanding *plus* the quotient of total debt at year end 2018, *divided by* the weighted average share price during 2018.

Rationale. Production volumes are critical to our profitability. Measuring those volumes on a debt-adjusted per-share basis motivates management to produce those volumes in a capital-efficient manner.

(2) Net Debt/EBITDAX

Definition. Year-end 2018 net debt *divided by* 2018 full-year adjusted EBITDAX.

Rationale. Managing the balance sheet leverage is essential for growing the business efficiently. Net Debt/EBITDAX is a key debt coverage ratio that motivates management to minimize debt relative to cash flow.

(3) Free Cash Flow

Definition. Stand-alone E&P adjusted operating cash flow, *less* stand-alone E&P drilling and completion capital, *less* land maintenance capital.

Rationale. Measuring and rewarding Free Cash Flow directly supports our go-forward strategy of sustainable free cash flow growth by motivating management to optimize operating cash flow relative to upstream capital budgets.

(4) Safety and Environmental

Definition. The Company will measure performance in the Safety and Environmental performance category through several lagging indicators, including Lost Time Incident Rate ("LTIR") and Total Recordable Incident Rate ("TRIR"):

- *LTIR.* This metric refers to the number of lost time injuries (*i.e.*, work-related injuries that result in an employee being unable to perform normal work duties the work day following the injury event). LTIR is calculated first by *multiplying* the total number of lost time injuries *by* 200,000, and then *dividing* that product by the number of labor hours for the recording period.

- *TRIR*. This metric refers to the number of OSHA recordable injuries/illnesses (*i.e.*, work-related injuries/illnesses that result in medical intervention beyond first aid). TRIR is calculated first by *multiplying* the total number of recordable injuries/illnesses *by* 200,000, and then *dividing* that product by the number of labor hours for the recording period.

- *Environmental*. Performance with respect to this metric is attained if there are no major environmental related Notices of Violation (fines not exceeding $100,000) occurring during the measurement period.

  In addition, the Company will monitor several leading indicators in determining performance for the Safety and Environmental performance category. Leading indicators are proactive, preventative and predictive measures that provide current information regarding the effective performance, activities and processes of a Safety and Environmental system that may help identify, eliminate or control risks in the workplace. Management will review the progress of each leading indicator throughout 2018 and assess if performance was adequate in light of the Company's operation. These leading indicators include: HSSE training, Operational Safety Steering Team activities, Corrective Action/Preventative Action closeout, Environmental Compliance Audit Score, Operational Risk Register Reviews, and Field Safety Committee meeting compliance.

Rationale. Maintaining a safe work environment and sustainable environmental record is critical to the success of the business and execution of our strategy. Measuring safety and environmental metrics motivates all participants to maintain focus on these metrics.

2018 AR LTIP Grants

Based on feedback received from our shareholders in connection with our outreach program, the Compensation Committee adjusted our compensation philosophy with respect to long-term equity-based awards to better reflect our shareholders' investment experience in the Company. Specifically, equity awards granted in 2018 will target the market 50th percentile of the Peer Group, resulting in a reduced grant value for each Named Executive Officer. The performance metrics applicable to long-term equity-based awards granted in 2018 will include absolute TSR with a relative TSR modifier and return on capital employed. Effective for 2018, all long-term incentive awards for our Named Executive Officers will be in the form of performance-based equity.

Other Matters

Employment, Severance or Change-in-Control Agreements

We do not maintain any employment, severance or change-in-control agreements with any of our Named Executive Officers.

As discussed below under "Potential Payments Upon a Termination or a Change in Control," any of Messrs. Rady, Warren, Schopp, Kilstrom, McNeilly or Kennedy could be entitled to receive accelerated vesting of his restricted stock units in the Company, Series B Units in IDR LLC, or phantom units in the Partnership, as applicable, that remain unvested upon his termination of employment with us under certain circumstances or upon the occurrence of certain corporate events.

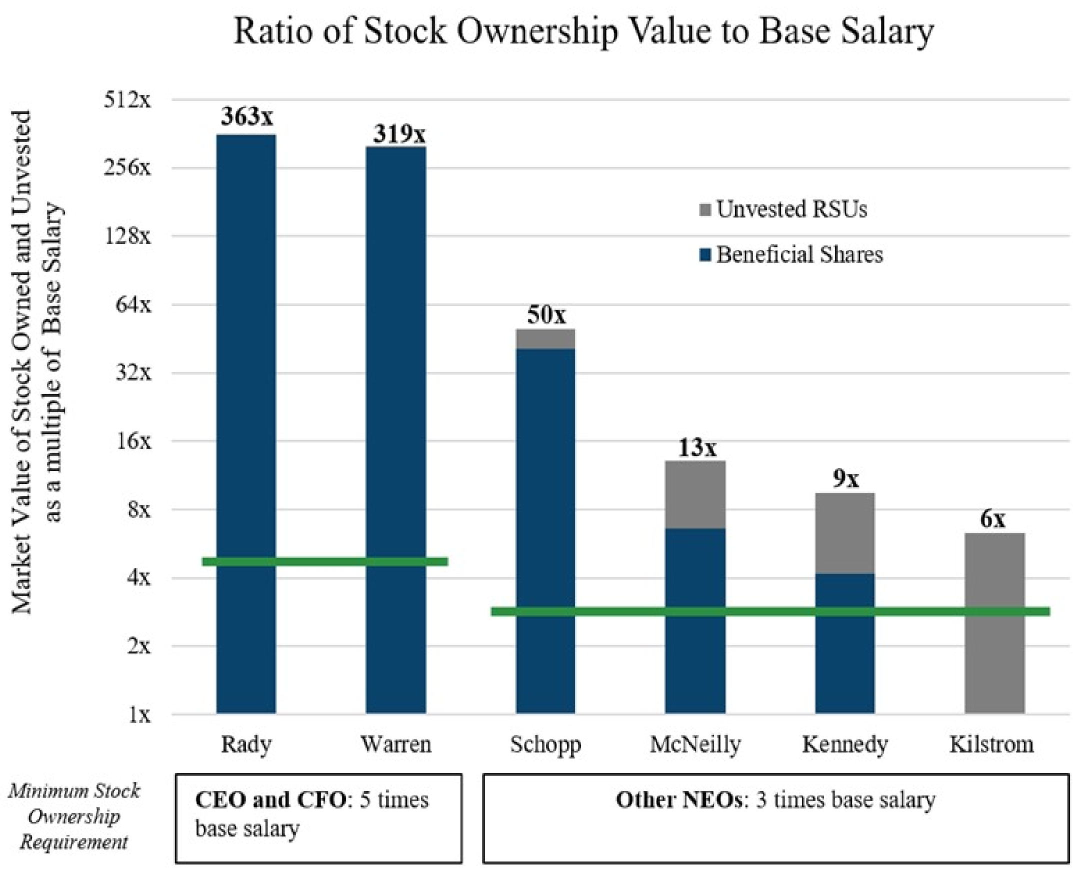
Stock Ownership Guidelines

Under our stock ownership guidelines adopted in 2013, our executive officers and certain of our non-employee directors are required to own a minimum number of shares of our common stock within five years of the adoption of the guidelines, or within five years of becoming an executive officer or being appointed to the Board, as applicable. In particular, each of our executive officers is required to own shares of our common stock having an aggregate fair market value equal to at least a designated multiple of the executive officer's base salary. The guidelines for executive officers are set forth in the table below.

Officer Level	Ownership Guideline
Chief Executive Officer, President, and Chief Financial Officer	5x annual base salary
Vice President	3x annual base salary
Other Officers (if applicable)	1x annual base salary

In addition, each of our non-employee directors other than Messrs. Kagan, Keenan and Levy are required to hold shares of our common stock with a fair market value equal to at least five times the amount of the annual cash retainer we pay to our non-employee directors. These stock ownership guidelines are designed to align our executive officers' and directors' interests more closely with those of our shareholders.

The chart below shows the significant levels of stock ownership of our Named Executive Officers and the ratio of their ownership to their respective base salaries. We believe the high level of ownership demonstrates significant alignment with our shareholders.



Shares directly and beneficially owned by our Named Executive Officers count towards satisfaction of our stock ownership guidelines. Vested and unvested stock options, unvested restricted stock units, and other conditional equity-based awards (including performance-based awards) do not count towards satisfaction of our stock ownership guidelines. However, for purposes of the chart above, unvested restricted stock units held by our Named Executive Officers are included.

Tax and Accounting Treatment of Executive Compensation Decisions

Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code"), generally imposes a $1 million limit on the amount of compensation paid to certain executive officers that a public corporation may deduct for federal income tax purposes in any year. During 2017, the Code provided an exception to the Section 162(m) deduction limitation for compensation qualifying as "performance-based compensation" within the meaning of the Code and the applicable Treasury Regulations. At our 2013 Annual Meeting, our shareholders approved the material terms of the AR LTIP so that we could grant qualified "performance-based compensation" if determined by the Compensation Committee to be in our best interest and in the best interest of our shareholders. During 2017, the Compensation Committee designed and administered our executive compensation program with the intent that certain portions of the compensation paid to our Named Executive Officers would qualify as performance-based compensation under Section 162(m).

The "Tax Cuts and Jobs Act," enacted in 2017, repealed the performance-based compensation exception to the Section 162(m) deduction limitation for tax years beginning after December 31, 2017. While we will continue to monitor our compensation programs in light of the deduction limitation imposed by Section 162(m) of the Code, our Compensation Committee considers it important to retain the flexibility to design compensation programs that are in the best long-term interests of the Company and our shareholders. As a result, we have not adopted a policy requiring that all compensation be deductible. The Compensation Committee may conclude that paying compensation at levels that are subject to limits under Section 162(m) of the Code is nevertheless in the best interests of the Company and our shareholders. Given changes made to Section 162(m) by the "Tax Cuts and Jobs Act," which took effect in 2018, it is likely that the Company will not be able to deduct for federal income tax purposes a portion of the compensation paid to our Named Executive Officers in 2018.

Many other Code provisions and accounting rules affect the payment of executive compensation and are generally taken into consideration as our compensation arrangements are developed. Our goal is to create and maintain compensation arrangements that are efficient, effective and in full compliance with these requirements.

Risk Assessment

We have reviewed our compensation policies and practices to determine if they create risks that are reasonably likely to have a material adverse effect on our Company. In connection with this risk assessment, we reviewed the design of our compensation and benefits program and related policies and determined that certain features of our programs and corporate governance generally help mitigate risk. Among the factors considered were the mix of cash and equity compensation, the balance between short- and long-term objectives of our incentive compensation, the degree to which programs provide for discretion to determine payout amounts, and our general governance structure.

Our Compensation Committee believes that our approach of evaluating overall business performance and implementation of Company objectives assists in mitigating excessive risk-taking that could harm our value or reward poor judgment by our executives. Several features of our programs reflect sound risk-management practices. The Compensation Committee believes our overall compensation program provides a reasonable balance between short- and long-term objectives, which helps mitigate the risk of excessive risk-taking in the short term. Further, the metrics that determine ultimate value awarded under our incentive compensation programs are associated with total Company value. We do not believe these metrics create pressure to meet specific financial or individual performance goals. In addition, the performance criteria reviewed by the Compensation Committee in determining cash bonuses are based on overall individual performance relative to continually evolving Company objectives, and the Compensation Committee uses its subjective judgment in setting bonus levels for our officers. This is consistent with the Compensation Committee's belief that applying Company-wide objectives encourages decision-making that is in the best long-term interests of our Company and our stakeholders as a whole. Finally, the multi-year vesting of our equity awards discourages excessive risk-taking and undue focus on short-term gains that may not be sustainable. Accordingly, the Compensation Committee concluded that our compensation policies and practices for all employees, including our Named Executive Officers, are not reasonably likely to have a material adverse effect on the Company.

Hedging Prohibitions

Our Insider Trading Policy prohibits our Named Executive Officers from engaging in speculative transactions involving our common stock, including buying or selling puts or calls, short sales, purchases of securities on margin, or otherwise hedging the risk of ownership of our common stock.

Clawback Policy

We have adopted a general clawback policy covering long-term incentive award plans and arrangements. The clawback policy applies to our current Named Executive Officers as well as certain of our former Named Executive Officers. Generally, recoupment of compensation would be triggered under the policy in the event of a financial restatement caused by fraud or intentional misconduct. In the event of such misconduct, we may recoup performance-based equity compensation that was granted, earned or vested based wholly or in part upon the attainment of any financial reporting measure during the period in which such misconduct took place. The clawback policy gives the policy administrator discretion to determine whether a clawback of compensation should be initiated in any given case, as well as the discretion to make other determinations, including whether a covered individual's conduct meets a specified standard, the amount of compensation to be clawed back, and the form of reimbursement to the Company.

In order to comply with applicable law, the clawback policy may be updated or modified once the SEC adopts final clawback rules pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. In addition, the AR LTIP generally provides that, to the extent required by applicable law or any applicable securities exchange listing standards, or as otherwise determined by the Compensation Committee, all awards under the AR LTIP are subject to the provisions of any clawback policy the Company implements.

Board Report

The material in this report is not "soliciting material," is not deemed "filed" with the SEC, and is not to be incorporated by reference into any filing under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in such filing.

The Board of Directors of our general partner has reviewed and discussed the foregoing Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, the Board of Directors of our general partner has determined that the Compensation Discussion and Analysis shall be included in this Annual Report on Form 10-K.

Antero Midstream Partners GP LLC Board Members:

Peter R. Kagan
W. Howard Keenan, Jr.
Richard W. Connor
David A. Peters
John C. Mollenkopf
Paul M. Rady
Glen C. Warren, Jr.

Summary Compensation Table

The following table summarizes, with respect to our Named Executive Officers, information relating to the compensation earned for services rendered in all capacities during the fiscal years ended December 31, 2017, 2016 and 2015.

Summary Compensation Table for the Years Ended December 31, 2017, 2016 and 2015

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Option Awards ($)	All Other Compensation ($)(4)	Total ($)
Paul M. Rady	2017	$853,833	$ 823,680	$ 8,240,720	$ —	$ 6,983	$ 9,925,217
(Chairman of the Board of	2016	$831,667	$1,249,500	$ 8,185,133	$ — (5)	$ 10,600	$10,276,900
Directors and Chief Executive Officer)	2015	$820,833	$ 990,000	$ 6,000,009	$1,474,000 (6)	$ 10,600	$ 9,295,442
Glen C. Warren, Jr.	2017	$641,833	$ 516,000	$ 5,493,827	$ —	$ 10,800	$ 6,662,461
(Director, President and	2016	$625,000	$ 782,500	$ 5,456,802	$ — (5)	$ 10,600	$ 6,874,902
Chief Financial Officer of the Company and Secretary)	2015	$616,667	$ 620,000	$ 3,999,992	$ 982,672 (6)	$ 10,600	$ 6,229,931
Alvyn A. Schopp	2017	$429,833	$ 367,200	$ 2,032,733	$ —	$ 6,418	$ 2,836,185
(Chief Administrative	2016	$418,333	$ 445,188	$12,805,262	$ —	$ 10,600	$13,679,383
Officer and Sr. Regional Vice President)	2015	$412,500	$ 352,750	$ 1,500,013	$ 368,500 (6)	$ 10,600	$ 2,644,363
Kevin J. Kilstrom	2017	$429,833	$ 367,200	$ 2,032,733	$ —	$ 8,553	$ 2,838,320
(Sr. Vice President—	2016	$418,333	$ 445,188	$ 6,739,263	$ —	$ 10,600	$ 7,613,384
Production)	2015	$412,500	$ 352,750	$ 1,500,013	$ 368,500 (6)	$ 10,600	$ 2,644,363
Ward D. McNeilly	2017	$389,000	$ 332,350	$ 2,032,733	$ —	$ 10,800	$ 2,764,884
(Sr. Vice President—	2016	$378,333	$ 402,688	$ 6,739,263	$ —	$ 10,600	$ 7,530,884
Reserves, Planning and Midstream)	2015	$372,500	$ 300,000	$ 1,349,995	$ 331,650 (6)	$ 10,600	$ 2,364,745
Michael N. Kennedy	2017	$373,167	$ 300,000	$ 2,032,733	$ — (5)	$ 10,800	$ 2,716,700
(Sr. Vice President—	2016	$363,333	$ 364,000	$ 2,021,264	$ —	$ 9,680	$ 2,758,277
Finance, and Chief Financial Officer of the Partnership)	2015	$358,333	$ 288,000	$ 3,439,439	$ 368,500 (6)	$ 10,600	$ 4,464,872

(1) The amounts in this column may differ from those reported above under "Compensation Discussion and Analysis —Elements of Direct Compensation—Base Salaries" due to the fact that adjustments to the base salaries of our Named Executive Officers for the 2016 and 2017 fiscal years took effect on March 1, 2016, and March 1, 2017, respectively.

(2) Represents the aggregate amount of the annual discretionary cash bonuses paid to each Named Executive Officer.

(3) The amounts in this column represent the grant date fair value of (i) restricted stock unit awards and performance share unit awards granted to the Named Executive Officers pursuant to the AR LTIP and (ii) phantom units (which include Midstream DERs, as discussed in "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table—Phantom Unit Awards" below) granted to the Named Executive Officers pursuant to the Midstream LTIP, each as computed in accordance with Financial Accounting Standards Board ("FASB") Accounting Standard Codification ("ASC") Topic 718. See Note 6 to our consolidated financial statements for additional detail regarding assumptions underlying the value of these equity awards.

(4) The amounts in this column represent the amount of the Company's 401(k) match for fiscal 2015, 2016 and 2017 for each participating Named Executive Officer.

(5) In December 2016, Messrs. Rady and Warren were each issued Series B Units in IDR LLC, two-thirds of which were unvested as of December 31, 2017. Mr. Kennedy was granted Series B Units in IDR LLC on January 10, 2017, two-thirds of which were unvested as of December 31, 2017. As discussed below under the heading "Payments Upon Termination or Change in Control—Series B Units in IDR LLC," the Series B Units in IDR LLC are intended to constitute "profits interests" for federal tax purposes. Accordingly, if IDR LLC had been liquidated as of the date these Series B Units were granted, Messrs. Rady, Warren and Kennedy would not have been entitled to receive any distributions with respect to such Series B Units. Please see "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table—Series B Units in IDR LLC" for more information regarding the Series B Units in IDR LLC.

(6) These amounts reflect the grant date fair value of stock option awards granted to our Named Executive Officers pursuant to the AR LTIP in April 2015, computed in accordance with FASB ASC Topic 718. See Note 6 to our consolidated financial statements for additional detail regarding assumptions underlying the value of these equity awards.

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Grants of Plan-Based Awards for Fiscal Year 2017

Name	Grant Date	Number of Shares of Stock or Units (#) (1) Threshold (#)	Target (#)	Maximum (#)	Number of Securities Underlying Options (#)	Exercise of Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) (2)
Paul M. Rady							
Restricted Stock Units	4/15/17		59,497		—	$ —	$ 1,312,504
Performance Share Units[3]	4/15/17	89,245	178,490	356,980	—	$ —	$ 4,678,223
Phantom Units	4/15/17		69,380		—	$ —	$ 2,249,993
Glen C. Warren, Jr.							
Restricted Stock Units	4/15/17		39,665		—	$ —	$ 875,010
Performance Share Units[3]	4/15/17	59,497	118,994	237,988	—	$ —	$ 3,118,833
Phantom Units	4/15/17		46,253		—	$ —	$ 1,499,984
Alvyn A. Schopp							
Restricted Stock Units	4/15/17		14,676		—	$ —	$ 323,753
Performance Share Units[3]	4/15/17	22,014	44,028	88,056	—	$ —	$ 1,153,974
Phantom Units	4/15/17		17,114		—	$ —	$ 555,006
Kevin J. Kilstrom							
Restricted Stock Units	4/15/17		14,676		—	$ —	$ 323,753
Performance Share Units[3]	4/15/17	22,014	44,028	88,056	—	$ —	$ 1,153,974
Phantom Units	4/15/17		17,114		—	$ —	$ 555,006
Ward D. McNeilly							
Restricted Stock Units	4/15/17		14,676		—	$ —	$ 323,753
Performance Share Units[3]	4/15/17	22,014	44,028	88,056	—	$ —	$ 1,153,974
Phantom Units	4/15/17		17,114		—	$ —	$ 555,006
Michael N. Kennedy							
Restricted Stock Units	4/15/17		14,676		—	$ —	$ 323,753
Performance Share Units[3]	4/15/17	22,014	44,028	88,056	—	$ —	$ 1,153,974
Phantom Units	4/15/17		17,114		—	$ —	$ 555,006
Series B Units in IDR LLC[4]	1/10/17				4,000	N/A(4)	$ N/A(4)

(1) The equity awards that are disclosed in this Grants of Plan-Based Awards for Fiscal Year 2017 table are restricted stock unit awards and performance share units of the Company granted under the AR LTIP on April 15, 2017, and phantom unit awards of the Partnership granted under the Midstream LTIP on April 15, 2017.

(2) The amounts in this column represent the grant date fair value of (i) restricted stock unit awards and performance share unit awards granted to the Named Executive Officers pursuant to the AR LTIP and (ii) phantom units (which include Midstream DERs) granted to the Named Executive Officers pursuant to the Midstream LTIP, each as computed in accordance with FASB ASC Topic 718. See Note 6 to our consolidated financial statements for additional detail regarding assumptions underlying the value of these equity awards.

(3) The performance share unit awards granted on April 15, 2017, are earned (or not) based upon our three-year total shareholder return performance as measured against a peer group of comparable E&P companies. Pursuant to these performance share unit awards, our Named Executive Officers are eligible to receive threshold, target and maximum payouts of 50%, 100% and 200%, respectively, of the target amount of performance share units awarded. In order to achieve threshold, target and maximum payouts under the performance share awards, the Company's total shareholder return performance relative to the designated peer group over the performance period must rank at or above the 30th percentile, 55th percentile or 80th percentile, respectively. Regardless of our ranking, if the Company's total shareholder return is negative for the performance period, performance share units earned will not exceed 100% of target. If the Company's total shareholder return over the performance period ranks below the threshold performance level, all of the performance share units will be forfeited.

(4) The Series B Units in IDR LLC granted to Mr. Kennedy on January 10, 2017 are not traditional options, and, therefore, there is no exercise price associated with them. In addition, as discussed below under the heading "Payments Upon Termination or Change in Control—Series B Units in IDR LLC," the Series B Units in IDR LLC issued to Mr. Kennedy are intended to constitute "profits interests" for federal tax purposes. Accordingly, if IDR LLC had been liquidated as of the date these Series B Units were granted, Mr. Kennedy would not have been entitled to receive any distributions with respect to such Series B Units.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards for Fiscal Year 2017 table.

Restricted Stock Unit Awards and Performance Share Units

The Compensation Committee granted restricted stock unit awards and performance share unit awards under the AR LTIP to each of our Named Executive Officers in April 2017. The restricted stock unit awards will vest pro rata on each of the first four anniversaries of the date of grant. The performance share unit awards will be earned based upon our relative three-year total shareholder return. In each case, the applicable Named Executive Officer must remain continuously employed by us from the grant date through the applicable vesting date. All of the restricted stock units and performance share unit awards will also vest in full upon a termination of a Named Executive Officer's employment due to his death or disability.

Vested restricted stock units (less any restricted stock units withheld to satisfy applicable tax withholding obligations) will be settled through the issuance of common stock within 30 days following the vesting date. Named Executive Officers holding unvested restricted stock units are entitled to receive dividend equivalent right credits (the "AR DERs"), if any, equal to cash distributions paid in respect of a share of our common stock. The AR DERs will be paid in cash within 30 days following the vesting of the associated restricted stock units, or, if applicable, will be forfeited at the same time the associated restricted stock units are forfeited. The potential acceleration and forfeiture events related to these restricted stock units are described in greater detail under the heading "Potential Payments Upon Termination or Change in Control" below.

Phantom Unit Awards

On April 15, 2017, the board of directors of the general partner of the Partnership granted phantom units under the Midstream LTIP to each of our Named Executive Officers in connection with the Company's annual compensation program to recognize the Named Executive Officers' contributions to the operations of the Partnership. The phantom unit awards granted to our Named Executive Officers will vest, in four equal installments, on each of the first four anniversaries of the grant date so long as the applicable Named Executive Officer remains continuously employed by us from the grant date through the applicable vesting date. All of the phantom units granted to a Named Executive Officer will become fully vested immediately if such Named Executive Officer's employment terminates due to death or disability or the consummation of a change in control (as defined in the Midstream LTIP). Vested phantom units (less any phantom units withheld to satisfy applicable tax withholding obligations) will be settled through the issuance of common units within 30 days following the vesting date. Named Executive Officers holding unvested phantom units are entitled to receive distribution equivalent right credits (the "Midstream DERs") equal to cash distributions paid in respect of a common unit of the Partnership. The Midstream DERs will be paid in cash within 30 days following the vesting of the associated phantom units, or, if applicable, will be forfeited at the same time the associated phantom units are forfeited. The potential acceleration and forfeiture events relating to these phantom units are described in greater detail under the heading "Potential Payments Upon Termination or Change in Control" below.

Series B Units in IDR LLC

IDR LLC was formed to hold 100% of the Partnership's IDRs. As of December 31, 2017, Messrs. Rady, Warren and Kennedy held 48,000, 32,000 and 4,000, respectively, of the 98,600 outstanding Series B Units in IDR LLC. To the extent vested, the Series B Units in IDR LLC entitle the holders thereof to receive, subject to the terms and provisions of the limited liability company agreement of IDR LLC (the "IDR LLC Agreement") and the incentive unit award agreements pursuant to which the awards were granted, a proportionate amount of up to 6% of any future profits of IDR LLC that result from any distributions on the Partnership's IDRs that are held by IDR LLC in excess of $7.5 million per quarter. Unvested Series B Units in IDR LLC are not entitled to receive any distributions; however, in connection with any subsequent distribution on the Partnership's IDRs following the date an unvested Series B Unit in IDR LLC becomes vested, the holder of such vested Series B Unit in IDR LLC is entitled to receive an additional distribution equal to the aggregate amount of distributions that would have been made with respect to such Series B Unit in IDR LLC during the period in which such Series B Unit was unvested if such Series B Unit had been vested.

With respect to vested Series B Units in IDR LLC, Messrs. Rady, Warren and Kennedy have the right, upon delivery of notice to IDR LLC, to require IDR LLC to redeem all or a portion of their vested Series B Units for a number of newly issued AMGP common shares, equal to the quotient determined by dividing (a) the product of (i) the Per Vested B Unit Entitlement (as defined below) and (ii) the number of vested Series B Units being redeemed, by (b) the volume-weighted average price of an AMGP common share for the 20 trading days ending on and including the trading day prior to the date of such notice (the “AMGP VWAP Price”). However, in no event will the aggregate number of AMGP common shares issued by AMGP pursuant to all such redemptions by owners of Series B Units exceed 6% of the aggregate number of issued and outstanding AMGP common shares.

For purposes of the redemption right described above, the “Per Vested B Unit Entitlement” is calculated in accordance with the IDR LLC Agreement, and will equal, as of the date of determination, the quotient obtained by dividing (a) the product of (i) the fair market value of IDR LLC (which for this purpose is based on the equity value of AMGP calculated on the applicable date of determination by multiplying the AMGP VWAP Price and the number of then-outstanding AMGP common shares) as of such date minus $2.0 billion and (ii) the product of (A) 6%, (B) the percentage of authorized Series B Units that are outstanding at such time and (C) the percentage of outstanding Series B Units that have vested, by (b) the total number of vested Series B Units outstanding at such time. In addition, upon the earliest to occur of (x) December 31, 2026, (y) a change of control transaction of AMGP or of IDR LLC, or (z) a liquidation of IDR LLC, AMGP may redeem each outstanding Series B Unit in exchange for AMGP common shares in accordance with the ratio described above, subject to certain limitations.

The remaining unvested Series B Units in IDR LLC issued to Messrs. Rady and Warren on December 31, 2016, will become vested in two equal installments on December 31 of each of 2018 and 2019, so long as the applicable executive remains continuously employed by us or one of our affiliates through each vesting date. The remaining unvested Series B Units in IDR LLC issued to Mr. Kennedy on January 10, 2017 will become vested in two equal installments on December 31 of each of 2018 and 2019, so long as Mr. Kennedy remains continuously employed by us or one of our affiliates through each vesting date. The potential acceleration and forfeiture events relating to these units are described in greater detail under the heading “Potential Payments Upon Termination or Change of Control” below.

Liquidation of Antero Resources Investment LLC and Antero Resources Employee Holdings LLC

Certain reorganization transactions were effected (the “Reorganization”) in connection with the initial public offering of AMGP on May 3, 2017. As part of the Reorganization, Antero Resources Investment LLC (“Antero Investment”) liquidated and distributed the cash proceeds it received from the AMGP initial public offering, along with its remaining common shares in AMGP, to its members on a pro rata basis. Antero Resources Employee Holdings LLC (“Holdings”), which held a direct membership interest in Antero Investment, also liquidated as part of the Reorganization. Units in Holdings held by our Named Executive Officers at the time of its liquidation were terminated without consideration.

Outstanding Equity Awards at 2017 Fiscal Year-End

The following table provides information concerning equity awards that have not vested for our Named Executive Officers as of December 31, 2017.

	Option Awards(1)				Stock Awards(6)	
Name	Number of Securities Underlying Unexercised Options Unexercisable (#)(2)	Number of Securities Underlying Unexercised Options Exercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#) (7)	Market Value of Units That Have Not Vested ($) (8)
Paul M. Rady						
Restricted Stock Units	—	—	$ —	—	215,878	$4,101,687
Performance Share Units	—	—	—	—	253,005	$4,807,101
Phantom Units	—	—	$ —	—	170,346	$4,946,841
Stock Options[(3)]	50,000	50,000	$ 50.00	4/15/2025		
Series B Units in IDR LLC [(4)]	32,000	16,000	N/A (5)	N/A (5)		
Glen C. Warren, Jr.						
Restricted Stock Units	—	—	$ —	—	143,920	$2,734,471
Performance Share Units	—	—	—	—	168,671	$3,204,755
Phantom Units	—	—	$ —	—	113,564	$3,297,891
Stock Options[(3)]	33,333	33,334	$ 50.00	4/15/2025		
Series B Units in IDR LLC [(4)]	21,333	10,667	N/A (5)	N/A (5)		
Alvyn A. Schopp						
Restricted Stock Units	—	—	$ —	—	217,837	$4,138,898
Performance Share Units	—	—	—	—	196,083	$3,725,580
Phantom Units	—	—	$ —	—	41,473	$1,204,361
Stock Options[(3)]	12,500	12,500	$ 50.00	4/15/2025		
Kevin J. Kilstrom						
Restricted Stock Units	—	—	$ —	—	142,837	$2,713,898
Performance Share Units	—	—	—	—	121,278	$2,304,274
Phantom Units	—	—	$ —	—	41,473	$1,204,361
Stock Options[(3)]	12,500	12,500	$ 50.00	4/15/2025		
Ward D. McNeilly						
Restricted Stock Units	—	—	$ —	—	133,340	$2,533,455
Performance Share Units	—	—	—	—	121,375	$2,306,121
Phantom Units	—	—	$ —	—	41,473	$1,204,361
Stock Options[(3)]	11,250	11,250	$ 50.00	4/15/2025		
Michael N. Kennedy						
Restricted Stock Units	—	—	$ —	—	105,030	$1,995,567
Performance Share Units	—	—	—	—	62,750	$1,192,246
Phantom Units	—	—	$ —	—	39,973	$1,160,801
Stock Options[(3)]	12,500	12,500	$ 50.00	4/15/2025		
Stock Options	—	60,000	$ 54.15	10/16/2023		
Series B Units in IDR LLC [(4)]	2,667	1,333	N/A (5)	N/A (5)		

(1) The equity awards that are disclosed in this Outstanding Equity Awards at 2017 Fiscal Year-End table under Option Awards are (i) stock option awards granted under the AR LTIP and (ii) for Messrs. Rady, Warren and Kennedy, Series B Units in IDR LLC that are intended to constitute profits interests for federal tax purposes rather than traditional option awards.

(2) Awards reflected as “Unexercisable” are Series B Units in IDR LLC and stock option awards that have not yet vested.

(3) One-half of the unvested stock option awards reflected in this row will become vested and exercisable on each of April 15, 2018, and April 15, 2019, so long as the applicable Named Executive Officer remains continuously employed by us or one of our affiliates through each such date.

(4) For Messrs. Rady, Warren and Kennedy, one-half of the unvested Series B Units in IDR LLC reflected in this row will become vested and exercisable on each of December 31, 2018, and December 31, 2019, so long as the applicable Named Executive Officer remains continuously employed by us or one of our affiliates through each such date.

(5) These equity awards are not traditional options and, therefore, there is no exercise price or expiration date associated with them.

(6) The equity awards that are disclosed in this Outstanding Equity Awards at 2017 Fiscal Year-End table under the Stock Awards column consist of the following awards granted under the AR LTIP: (i) restricted stock units, (ii) performance share units, and (iii) performance share units granted as special retention awards to Messrs. Schopp, Kilstrom and McNeilly in February 2016 for

which the applicable stock price hurdle has been achieved. This Stock Awards column also includes phantom units granted under the Midstream LTIP.

(7) Except as otherwise provided in the applicable award agreement, (1) 2016 restricted stock unit awards will vest on April 15 of each of 2018, 2019 and 2020, (2) 2015 restricted unit awards will vest on April 15 of each of 2018 and 2019, (3) the restricted stock units granted in 2014 to Messrs. Schopp, Kilstrom, and McNeilly will vest on April 1, 2018, (4) phantom units granted in 2016 will vest on April 15 of each of 2018, 2019 and 2020, (5) the phantom units granted in 2014 will vest on November 12, 2018, (6) performance share unit awards granted in 2016 will vest following the Committee's determination of our relative three-year total shareholder return achievement for the performance period ending April 15, 2019, and (7) the 2016 performance share units granted as special retention awards to Messrs. Schopp, Kilstrom and McNeilly for which the applicable stock price hurdle has been achieved will vest in equal increments on February 8 of each of 2018 and 2019, in each case, so long as the applicable Named Executive Officer remains continuously employed by us from the grant date through the applicable vesting date.

(8) The amounts reflected in this column represent the market value of (i) common stock underlying the restricted stock unit awards granted to the Named Executive Officers, computed based on the closing price of our common stock on December 31, 2017, which was $19.00 per share, (ii) common stock underlying the target number of performance share units granted to the Named Executive Officers, computed in accordance with FASB ASC Topic 718, and (iii) common units of the Partnership underlying the phantom unit awards granted to the Named Executive Officers, computed based on the closing price of the Partnership's common units on December 31, 2017, which was $29.04 per unit. See Note 6 to our consolidated financial statements for additional detail regarding assumptions underlying the value of these equity awards.

Option Exercises and Stock Vested in Fiscal Year 2017

The following table provides information concerning equity awards that vested or were exercised by our Named Executive Officers during the 2017 fiscal year.

	Option Awards(1)		Stock Awards(2)	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#) (2)	Value Realized on Vesting ($) (3)
Paul M. Rady				
Restricted Stock Units	—	$ —	217,876	$ 4,406,836
Phantom Units	—	$ —	65,655	$ 1,887,752
Glen C. Warren, Jr.				
Restricted Stock Units	—	$ —	145,302	$ 2,938,891
Phantom Units	—	$ —	43,770	$ 1,258,501
Alvyn A. Schopp				
Restricted Stock Units	—	$ —	135,673	$ 3,261,326
Phantom Units	—	$ —	16,119	$ 462,379
Kevin J. Kilstrom				
Restricted Stock Units	—	$ —	85,673	$ 2,020,326
Phantom Units	—	$ —	16,119	$ 462,379
Ward D. McNeilly				
Restricted Stock Units	—	$ —	77,083	$ 1,825,068
Phantom Units	—	$ —	16,119	$ 462,379
Michael N. Kennedy				
Restricted Stock Units	—	$ —	67,312	$ 1,357,963
Restricted Stock Awards	—	$ —	3,750	$ 75,338
Phantom Units	—	$ —	14,619	$ 421,279

(1) There were no other stock option exercises during the 2017 fiscal year.

(2) The equity awards that vested during the 2017 fiscal year disclosed under the Stock Awards columns consist of restricted stock units and restricted stock awards granted under the AR LTIP (including the vested portion of the performance share unit awards granted as special retention awards in February 2016 to Messrs. Schopp, Kilstrom and McNeilly) and phantom units granted under the Midstream LTIP.

(3) The amounts reflected in this column represent the aggregate market value realized by each Named Executive Officer upon vesting of (i) the restricted stock unit awards and restricted stock awards held by such Named Executive Officer, computed based on the closing price of our common stock on the applicable vesting date, and (ii) the phantom unit awards held by such Named Executive Officer, computed based on the closing price of the Partnership's common units on the applicable vesting date.

Pension Benefits

We do not provide pension benefits to our employees.

Nonqualified Deferred Compensation

We do not provide nonqualified deferred compensation benefits to our employees.

Payments Upon Termination or Change in Control

Restricted Stock Units, Phantom Units and Stock Options

Any unvested restricted stock units, unvested phantom units or unvested stock options subject to time-based vesting criteria granted to our Named Executive Officers under the AR LTIP or the Midstream LTIP, as applicable, will become immediately fully vested (and, in the case of stock options, fully exercisable) if the applicable Named Executive Officer's employment with us terminates due to his death or "disability" or in the event of a "change in control" (as such terms are defined in the AR LTIP or the Midstream LTIP, as applicable). For performance share unit awards, any continued employment conditions will be deemed satisfied on the date of the applicable Named Executive Officer's termination due to his death or "disability" or upon the occurrence of a "change in control," the performance period will end on the date of such termination or "change in control," and such performance share unit awards will be settled based on the actual level of performance achieved as of such date.

For purposes of these awards, a Named Executive Officer will be considered to have incurred a "disability" if the executive is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or which has lasted or can be expected to last for a continuous period of at least 12 months.

For purposes of the AR LTIP awards, "change in control" generally means the occurrence of any of the following events:

- A person or group of persons acquires beneficial ownership of 50% or more of either (a) the outstanding shares of our common stock or (b) the combined voting power of our voting securities entitled to vote in the election of directors, in each case with the exception of (i) any acquisition directly from us, (ii) any acquisition by us or any of our affiliates, or (iii) any acquisition by any employee benefit plan sponsored or maintained by us;

- The incumbent members of the Board cease for any reason to constitute at least a majority of the Board;

- The consummation of a reorganization, merger or consolidation, or sale or other disposition of all or substantially all of our assets, or an acquisition of assets of another entity (a "Business Combination"), in each case, unless, following such Business Combination, (A) our outstanding common stock immediately prior to such Business Combination represents more than 50% of the outstanding common equity interests and the outstanding voting securities entitled to vote in the election of directors of the surviving entity, (B) no person or group of persons beneficially owns 20% or more of the common equity interests of the surviving entity or the combined voting power of the voting securities entitled to vote generally in the election of directors of such surviving entity, and (C) at least a majority of the members of the board of directors of the surviving entity were members of the incumbent board at the time of the execution of the initial agreement or corporate action providing for such Business Combination; or

- Approval by our shareholders of a complete liquidation or dissolution of the Company.

For purposes of the Midstream LTIP awards, “change in control” means the occurrence of any of the following events:

- A person or group of persons, other than certain affiliates of the Partnership, becomes the beneficial owner, by way of merger, acquisition, consolidation, recapitalization, reorganization, or otherwise, of 50% or more of the voting power of the equity interests in the general partner of the Partnership;

- The sale or disposition by either the Partnership or the general partner of the Partnership of all or substantially all of its assets;

- The general partner of the Partnership’s approval of a complete liquidation or dissolution of the Partnership;

- A transaction resulting in a person or group of persons other than the general partner of the Partnership, the Partnership, the Company or one of their respective affiliates becoming the general partner of the Partnership; or

- A “Change in Control” as defined in the AR LTIP.

Series B Units in IDR LLC

The Series B Units in IDR LLC held by Messrs. Rady, Warren and Kennedy will vest upon the consummation of a change of control transaction (as defined in the IDR LLC Agreement) or upon an involuntary termination without cause or due to death or disability. As discussed above, the Series B Units in IDR LLC issued to Messrs. Rady and Warren on December 31, 2016 and to Mr. Kennedy on January 10, 2017 are intended to constitute “profits interests” for federal tax purposes and are not traditional options.

As used in the IDR LLC Agreement and the award agreements pursuant to which the Series B Units in IDR LLC were granted, “change of control transaction” means the occurrence of any of the following events:

- Any consolidation, conversion, merger or other business combination involving IDR Holdings or AMGP, in which a majority of the outstanding Series A Units of IDR LLC or a majority of the outstanding common shares of AMGP (the “AMGP common shares”) are exchanged for or converted into cash, securities of a corporation or other business organization, or other property;

- A sale or other disposition of all or a material portion of the assets of IDR LLC;

- A sale or other disposition of all or substantially all of the assets of AMGP followed by a liquidation of AMGP or a distribution to the members of AMGP of all or substantially all of the net proceeds of such disposition after payment of liabilities and other obligations of AMGP;

- The sale by all the members of IDR LLC of all or substantially all of the outstanding IDR LLC membership interests in a single transaction or series of related transactions; or

- The sale of all of the outstanding AMGP common shares in a single transaction or series of related transactions.

As discussed above, each of Messrs. Rady, Warren and Kennedy have the right, upon delivery of written notice to IDR LLC, to require IDR LLC to redeem all or a portion of their vested Series B Units for a number of newly issued AMGP common shares, as determined in accordance with the formula described in “Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table— Series B Units in IDR LLC” above.

The above mechanisms are subject to customary conversion rate adjustments for equity splits, equity dividends and reclassifications.

Potential Payments Upon Termination or Change in Control Table for Fiscal 2017

If the employment of any of our Named Executive Officers would have terminated due to any Named Executive Officer's death or disability, the unvested portion of his restricted stock units, phantom units and stock options, as applicable, would have become vested. The restricted stock units (and, if exercised, the stock options) represent a direct interest in shares of our common stock, which had a closing price on December 31, 2017, of $19.00 per share. The phantom units represent a direct interest in the Partnership's common units, which had a closing price on December 31, 2017, of $29.04 per unit.

The amounts that each of our Named Executive Officers would receive in connection with the accelerated vesting of their equity awards (other than stock options) upon a termination due to their death or disability (assuming such termination occurred on December 31, 2017) are reflected in the last column of the Outstanding Equity Awards at 2017 Fiscal Year-End table above. Because the exercise price of stock options held by our Named Executive Officers exceeded the fair market value of the Company's common stock on December 31, 2017, no value would have been received by our Named Executive Officers with respect to their stock options in connection with the accelerated vesting of these awards.

Quantification of Benefits

The following table summarizes the compensation and other benefits that would have become payable to each Named Executive Officer assuming a change in control of the Company and the Partnership occurred on December 31, 2017.

	Potential Payments upon a Change in Control of the Company as of December 31, 2017						
Name	Restricted Stock Awards ($)	Restricted Stock Units ($)	Performance Share Unit Awards ($)	Phantom Units ($)	Stock Options ($)(1)	Series B Units in IDR LLC ($)	Total ($)
Paul M. Rady	NA	$4,101,687	$4,807,101	$4,946,841	$ —	$ — (2)	$13,855,629
Glen C. Warren, Jr.	NA	$2,734,471	$3,204,755	$3,297,891	$ —	$ — (2)	$ 9,237,117
Alvyn A. Schopp	NA	$4,138,898	$3,725,580	$1,204,361	$ —	NA	$ 9,068,839
Kevin J. Kilstrom	NA	$2,713,898	$2,304,274	$1,204,361	$ —	NA	$ 6,222,534
Ward D. McNeilly	NA	$2,533,455	$2,306,121	$1,204,361	$ —	NA	$ 6,043,938
Michael N. Kennedy	NA	$1,995,567	$1,192,246	$1,160,801	$ —	$ — (2)	$ 4,348,614

(1) Because the exercise price of stock options held by our Named Executive Officers exceeded the fair market value of the Company's common stock on December 31, 2017, no value would have been received by our Named Executive Officers with respect to their stock options in connection with the accelerated vesting of these awards.
(2) The Series B Units in IDR LLC held by each of Messrs. Rady, Warren and Kennedy will vest upon the consummation of a change of control transaction or upon an involuntary termination of the applicable executive's employment without cause or due to death or disability. The Series B Units in IDR LLC are not traditional options. The redemption right described above only applies upon a change of control transaction applicable to IDR LLC or the general partner of the Partnership (not a change of control of the Company or the Partnership), and, therefore, the redemption value is not disclosed in this table.

Compensation of Directors

General

Our non-employee directors are entitled to receive compensation consisting of retainers, fees and equity awards as described below. The Compensation Committee reviews and approves non-employee director compensation on a periodic basis.

Our employee directors, Messrs. Rady and Warren, do not receive additional compensation for their services as directors. All compensation that Messrs. Rady and Warren received from the Company as employees is disclosed in the Summary Compensation Table above.

Messrs. Kagan and Keenan have agreed or are otherwise obligated to transfer all or a portion of the compensation they receive for their service as directors to the sponsor with which they are affiliated.

Annual Retainers

Each non-employee director received the following compensation for the 2017 fiscal year:

- an annual retainer of $70,000;
- an additional retainer of $7,500 for each member of the audit committee, plus an additional $12,500 for the chairperson;
- an additional retainer of $10,000 for each member of the conflicts committee, plus an additional $5,000 for the chairperson.

All retainers are paid in cash on a quarterly basis in arrears, but directors have the option to elect, on an annual basis, to receive all or a portion of their retainers in the form of common units. Directors do not receive any meeting fees, but each director is reimbursed for (1) travel and miscellaneous expenses to attend meetings and activities of the Board or its committees, and (2) travel and miscellaneous expenses related to the director's participation in general education and orientation programs for directors.

Equity-Based Compensation

In addition to cash compensation, our non-employee directors receive annual equity-based compensation consisting of fully vested common units with an aggregate grant date value equal to $100,000, subject to the terms and conditions of the Midstream LTIP and the award agreements pursuant to which such awards are granted. As discussed above under "Compensation Discussion and Analysis—Other Matters—Unit Ownership Guidelines," by the later of October 7, 2018, or within five years after being appointed to the Board, each of our non-employee directors other than Messrs. Kagan and Keenan are required to hold common units with a fair market value equal to at least five times the amount of their annual cash retainer.

Total Non-Employee Director Compensation

The following table provides information concerning the compensation of our non-employee directors for the fiscal year ended December 31, 2017.

Name	Fees Earned or Paid in Cash ($)(1)	Unit Awards ($)(2)	Total ($)
Peter R. Kagan	$ 70,000	$ 100,000	$ 170,000
W. Howard Keenan, Jr.	$ 70,000	$ 100,000	$ 170,000
Richard W. Connor	$ 90,000	$ 100,000	$ 190,000
David A. Peters	$ 92,500	$ 100,000	$ 192,500
John C. Mollenkopf(3)	$ 65,625	$ 75,000	$ 140,625
Brooks J. Klimley(4)	$ 43,750	$ 25,000	$ 68,750

(1) Includes annual cash retainer, committee fees and committee chair fees for each non-employee director during fiscal 2017, as more fully explained above.
(2) Effective December 15, 2016, the Company adopted a non-employee director compensation policy that calls for quarterly grants of fully vested common units. Amounts in this column reflect the aggregate grant date fair value of common units granted under the Midstream LTIP in fiscal year 2017, computed in accordance with FASB ASC Topic 718. See Note 6 to our consolidated financial statements on Form 10-K for the year ended December 31, 2017, for additional detail regarding assumptions underlying the value of these equity awards. The grant date fair value for common unit awards is based on the closing price of our common units on the grant date.
(3) Mr. Mollenkopf joined the Board in April 2017.
(4) In April 2017, Mr. Klimley resigned as a Board member.

Effective December 19, 2017, the Company adopted a non-employee director compensation policy that maintains the annual base retainer of $70,000 and provides for quarterly grants of fully vested common units with an aggregate value equal to $100,000 per year.

Equity Compensation Plan Information

The following table sets forth information about our common stock that may be issued under all existing equity compensation plans of the Company as of December 31, 2017.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted–average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Antero Resources Corporation Long-Term Incentive Plan (1)	5,368,439	$ 50.48 (4)	8,402,389
Antero Midstream Partners LP Long-Term Incentive Plan (2)	1,042,963	N/A (5)	7,864,621
Antero Midstream Partners GP LP Long-Term Incentive Plan (3)	N/A	N/A (6)	919,089
Equity compensation plans not approved by security holders	—	—	—
Total	6,411,402		17,186,099

(1) The Antero Resources Corporation Long-Term Incentive Plan (the “AR LTIP”) was approved by our sole shareholder prior to our IPO and by our shareholders at the 2014 annual meeting of shareholders.
(2) The Antero Midstream Partners LP Long-Term Incentive Plan (the “Midstream LTIP”) was approved by the Company and the general partner of the Partnership prior to its IPO.
(3) The Antero Midstream Partners GP LP Long-Term Incentive Plan (the “AMGP LTIP”) was approved by the general partner of the general partner of the Partnership prior to its IPO.
(4) The calculation of the weighted-average exercise price of outstanding options, warrants and rights excludes restricted stock unit awards granted under the AR LTIP.
(5) Only phantom unit awards and restricted unit awards have been granted under the Midstream LTIP; there is no weighted average exercise price associated with these awards.
(6) Only common shares representing limited partner interests have been granted under the AMGP LTIP; there is no weighted average exercise price associated with these awards. Awards under the AMGP LTIP have only been issued to non-employee directors of AMGP GP LLC, AMGP’s general partner. No awards have been made to our Named Executive Officers under the AMGP LTIP.

CEO Pay Ratio

Pursuant to Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, this section provides information regarding the relationship of the annual total compensation of all of our employees to the annual total compensation of our CEO, Mr. Rady. For 2017, the median of the annual total compensation of all Company employees (other than our CEO), calculated in accordance with paragraph (c)(2)(x) of Item 402 of Regulation S-K, was $87,186, and the annual total compensation of our CEO, as reported in the Summary Compensation Table, was $9,925,217.

Based on this information, for 2017, the ratio of the annual total compensation of Mr. Rady to the median of the annual total compensation of all of our employees was 114 to 1.

Methodology and Assumptions

We selected December 31, 2017, as the date on which to determine our employee population for purposes of identifying the median of the annual total compensation of all of our employees (other than the CEO), because it was efficient to collect payroll data and other necessary information as of that date. As of December 31, 2017, our employee population consisted of 596 individuals, including all individuals employed by the Company or any of its consolidated subsidiaries, whether as full-time, part-time, seasonal or temporary workers. This population does not include independent contractors engaged by the Company. All of our employees are located in the United States.

In identifying our median employee, we utilized the annual total compensation as reported in Box 1 of each employee's Form W-2 for 2017 provided to the Internal Revenue Service. We believe this methodology provides a reasonable basis for determining each employee's total annual compensation and is an economical method of evaluating our employee population's total annual compensation and identifying our median employee. For the 120 employees hired during 2017, we utilized the annual total compensation reported on each such employee's Form W-2 for 2017 without annualization adjustments. No cost-of-living adjustments were made in identifying our median employee, as all of our employees (including our CEO) are located in the United States. This calculation methodology was consistently applied to our entire employee population, determined as of December 31, 2017, in order to identify our median employee.

After we identified our median employee, we calculated each element of our median employee's annual compensation for 2017 in accordance with paragraph (c)(2)(x) of Item 402 of Regulation S-K, which resulted in annual total compensation of $87,186. The difference between our median employee's total compensation reported on Form W-2 and our median employee's annual total compensation calculated in accordance with paragraph (c)(2)(x) of Item 402 of Regulation S-K was $171. This amount reflects the difference in the value of equity-based awards held by our median employee that vested in 2017 and the grant date fair value of the equity-based awards granted to our median employee in 2017. Similarly, the 2017 annual total compensation of our CEO was calculated in accordance with paragraph (c)(2)(x) of Item 402 of Regulation S-K, as reported in the "Total" column of the Summary Compensation Table.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of common units of Antero Midstream that were issued and outstanding as of February 13, 2018 held by:

- our general partner;
- beneficial owners of 5% or more of our common units;
- each director and Named Executive Officer; and
- all of our general partner's directors and executive officers as a group.

Except as otherwise noted, the person or entities listed below have sole voting and investment power with respect to all of our common units beneficially owned by them, except to the extent this power may be shared with a spouse. All information with respect to beneficial ownership has been furnished by the respective directors, officers or beneficial owners of 5% or more of our common units, as the case may be. Unless otherwise noted, the address for each beneficial owner listed below is 1615 Wynkoop Street, Denver, Colorado 80202.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Antero Resources Corporation[1]	98,870,335	52.9 %
Antero Midstream Partners GP LLC[2]	—	— %
Goldman Sachs Asset Management[3]	9,267,930	5.0%
Tortoise Capital Advisors, L.L.C.[4]	8,460,503	4.5%
Neuberger Berman Group LLC[5]	5,182,743	2.8%
Richard W. Connor	16,968	* %
Peter R. Kagan[6]	11,968	* %
W. Howard Keenan, Jr. [7]	11,968	* %
John C. Mollenkopf	2,367	* %
David A. Peters	17,968	* %
Paul M. Rady	146,605	* %
Glen C. Warren, Jr.	101,107	* %
Kevin J. Kilstrom	21,430	* %
Alvyn A. Schopp	27,430	* %
Ward D. McNeilly	21,430	* %
Michael N. Kennedy	8,410	* %
All directors and executive officers as a group (11 persons)	387,651	* %

* Less than 1%.

(1) Under Antero Resources' amended and restated certificate of incorporation and bylaws, the voting and disposition of any of our common units held by Antero Resources will be controlled by the board of directors of Antero Resources. The board of directors of Antero Resources, which acts by majority approval, comprises Peter R. Kagan, W. Howard Keenan, Jr., Robert J. Clark, Richard W. Connor, Benjamin A. Hardesty, James R. Levy, Paul M. Rady and Glen C. Warren, Jr. Each of the members of Antero Resources' board of directors disclaims beneficial ownership of any of our units held by Antero Resources.

(2) Under our general partner's amended and restated limited liability company agreement, the voting and disposition of any of our common units or the Series A Units of IDR LLC will be controlled by its sole member, AMGP. The board of directors of AMGP GP, which acts by majority approval, comprises Peter R. Kagan, W. Howard Keenan, Jr., Brooks J. Klimley, James R. Levy, Rose M. Robeson, Paul M. Rady and Glen C. Warren, Jr. Each of the members of AMGP GP's board of directors disclaims beneficial ownership of any of our securities held by our general partner.

(3) Goldman Sachs Asset Management, L.P. and GS Investment Strategies, LLC (collectively, "Goldman Sachs Asset Management") have a mailing address of 200 West Street, New York, New York 10282 and share voting and dispositive power with respect to all of our common units reported as beneficially owned.

(4) Tortoise Capital Advisors, L.L.C. ("TCA") has a mailing address of 11550 Ash Street, Suite 300, Leawood, Kansas 66211. TCA acts as an investment adviser to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners, under Rule 13d-3 of the Act, of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has investment power but no voting power with respect to certain other of these client accounts. TCA has reported that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right to acquire investment and voting power through termination of their agreements with TCA. TCA may be deemed the beneficial owner of the securities covered by this statement under Rule 13d-3 of the Act that are held by its clients.

(5) Neuberger Berman Group LLC has a mailing address of 1290 Avenue of the Americas, New York, New York 10104. Neuberger Berman Group LLC and its affiliates may be deemed to be beneficial owners of securities for purposes of Exchange Act Rule 13d-3 because they or certain affiliated persons have shared power to retain, dispose of or vote the securities of unrelated clients. Neuberger Berman Group LLC or its affiliated persons do not, however, have any economic interest in the securities of those

clients. The clients have the sole right to receive and the power to direct the receipt of dividends from or proceeds from the sale of such securities. No one client has an interest of more than 5% of the issuer.
(6) Has a mailing address of c/o Warburg Pincus LLC, 450 Lexington Avenue, New York, New York 10017.
(7) Has a mailing address of 410 Park Avenue, 19th Floor, New York, New York 10022.

The following table sets forth the number of common shares representing limited partner interests in AMGP owned by each of the Named Executive Officers and directors of our general partner and all directors and executive officers of our general partner as a group as of February 13, 2018:

Name of Beneficial Owner	Common Shares Beneficially Owned	Percentage of Common Shares Beneficially Owned
Richard W. Connor	—	—
Peter R. Kagan[(1)(2)]	55,114,464	29.6 %
W. Howard Keenan, Jr.[(3)(4)]	3,185	*
John C. Mollenkopf	—	—
David A. Peters	—	—
Paul M. Rady[(5)(6)]	22,396,619	12.0 %
Glen C. Warren, Jr.[(7)]	14,931,079	8.0 %
Kevin J. Kilstrom	1,067,548	*
Alvyn A. Schopp	1,394,146	*
Ward D. McNeilly	425,270	*
Michael N. Kennedy	27,774	*
All directors and executive officers as a group (11 persons)[(7)]	40,250,496	21.6 %

* Less than 1%.
(1) Has a mailing address of c/o Warburg Pincus LLC, 450 Lexington Avenue, New York, New York 10017.
(2) Includes 55,109,589 common shares held by the Warburg Pincus Entities (as defined below). Mr. Kagan is a Partner of Warburg Pincus & Co., a New York general partnership ("WP"), and a Member and Managing Director of Warburg Pincus LLC, a New York limited liability company ("WP LLC"). The Warburg Pincus funds are Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership ("WP VIII," and together with its two affiliated partnerships, Warburg Pincus Netherlands Private Equity VIII C.V. I, a company formed under the laws of the Netherlands ("WP VIII CV I"), and WP-WPVIII Investors, L.P., a Delaware limited partnership ("WP-WPVIII Investors"), collectively, the "WP VIII Funds"), Warburg Pincus Private Equity X O&G, L.P., a Delaware limited partnership ("WP X O&G"), and Warburg Pincus X Partners, L.P., a Delaware limited partnership ("WP X Partners," and together with WP X O&G, the "WP X O&G Funds"). WP-WPVIII Investors GP L.P., a Delaware limited partnership ("WP-WPVIII GP"), is the general partner of WP-WPVIII Investors. Warburg Pincus X, L.P., a Delaware limited partnership ("WP X GP"), is the general partner of each of the WP X O&G Funds. Warburg Pincus X GP L.P., a Delaware limited partnership ("WP X GP LP"), is the general partner of WP X GP. WPP GP LLC, a Delaware limited liability company ("WPP GP"), is the general partner of WP-WPVIII GP and WP X GP LP. Warburg Pincus Partners, L.P., a Delaware limited partnership ("WP Partners"), is (i) the managing member of WPP GP, and (ii) the general partner of WP VIII and WP VIII CV I. Warburg Pincus Partners GP LLC, a Delaware limited liability company ("WP Partners GP"), is the general partner of WP Partners. WP is the managing member of WP Partners GP. WP LLC is the manager of each of the WP VIII Funds and the WP X O&G Funds. Each of the WP VIII Funds, the WP X O&G Funds, WP-WPVIII GP, WP X GP, WP X GP LP, WPP GP, WP Partners, WP Partners GP, WP and WP LLC are collectively referred to herein as the "Warburg Pincus Entities." Mr. Kagan disclaims beneficial ownership of all shares of common stock attributable to the Warburg Pincus Entities except to the extent of his pecuniary interest therein.
(3) Has a mailing address of 410 Park Avenue, 19th Floor, New York, New York 10022.
(4) Mr. Keenan is a member and manager of the direct or indirect general partner of each of Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P., which own 1,875,802 common shares, 1,970,846 common shares, 4,596,064 common shares and 7,091,699 common shares, respectively. Mr. Keenan does not have sole or shared voting or investment power within the meaning of Rule 13d-3 under the Exchange Act with respect to the common shares held by such investment funds and disclaims beneficial ownership of such securities except to the extent of his pecuniary interest therein.
(5) Includes 19,180,821 common shares held by Mockingbird Investments LLC ("Mockingbird"). Mr. Rady owns a 3.68% limited liability company interest in Mockingbird, and a trust under his control owns the remaining 96.32%. Mr. Rady disclaims beneficial ownership of all common shares held by Mockingbird except to the extent of his pecuniary interest therein.
(6) Includes 2,400,000 common shares held by Schwab Charitable Fund ("Schwab"), over which Mr. Rady may be deemed to have shared voting and dispositive power. Mr. Rady disclaims beneficial ownership of all common shares held by Schwab except to the extent of his pecuniary interest therein.

(7) Includes 3,891,100 common shares held by Canton Investment Holdings LLC ("Canton"). Mr. Warren is the managing member and 50% owner of Canton. Mr. Warren disclaims beneficial ownership of all common shares held by Canton except to the extent of his pecuniary interest therein.
(8) Excludes 55,109,589 common shares held by the Warburg Pincus Entities (as defined in footnote 2), over which Mr. Kagan may be deemed to have indirect beneficial ownership.

The following table sets forth the number of shares of common stock of Antero Resources owned by each of the Named Executive Officers and directors of our general partner and all directors and executive officers of our general partner as a group as of February 13, 2018:

Name of Beneficial Owner	Shares Beneficially Owned	Percentage of Shares Beneficially Owned
Richard W. Connor(1)(2)	28,731	*
Peter R. Kagan(1)(3)(4)(5)	46,959,247	14.9 %
W. Howard Keenan, Jr.(1)(6)(7)	187,739	*
John C. Mollenkopf	—	—
David A. Peters	—	—
Paul M. Rady(8)(9)	16,433,900	5.4 %
Glen C. Warren, Jr.(10)(11)(12)	10,876,364	3.4 %
Kevin J. Kilstrom(13)	153,538	*
Alvyn A. Schopp(14)	1,146,145	*
Ward D. McNeilly(15)	278,340	*
Michael N. Kennedy(16)	259,634	*
All directors and executive officers as a group (11 persons)(17)	29,714,577	9.4 %

* Less than 1%.
(1) Includes options to purchase 1,477 shares of common stock that expire ten years from the date of grant, or October 10, 2023, and options to purchase 1,526 shares of common stock that expire ten years from the date of grant, or October 16, 2024.
(2) Mr. Connor indirectly owns 40 shares of common stock purchased by a family member, and these shares are included because of his relation to the purchaser. Mr. Connor disclaims beneficial ownership of all shares reported except to the extent of his pecuniary interest therein.
(3) Has a mailing address of c/o Warburg Pincus LLC, 450 Lexington Avenue, New York, New York 10017.
(4) Includes 46,609,061 shares of common stock held by the Warburg Pincus Entities (as defined below). Mr. Kagan is a Partner of Warburg Pincus & Co., a New York general partnership ("WP"), and a Member and Managing Director of Warburg Pincus LLC, a New York limited liability company ("WP LLC"). The Warburg Pincus funds are Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership ("WP VIII," and together with its two affiliated partnerships, Warburg Pincus Netherlands Private Equity VIII C.V. I, a company formed under the laws of the Netherlands ("WP VIII CV I"), and WP-WPVIII Investors, L.P., a Delaware limited partnership ("WP-WPVIII Investors"), collectively, the "WP VIII Funds"), Warburg Pincus Private Equity X, L.P., a Delaware limited partnership ("WP X"), Warburg Pincus X Partners, L.P., a Delaware limited partnership ("WP X Partners," and together with WP X, the "WP X Funds"), and Warburg Pincus Private Equity X O&G, L.P., a Delaware limited partnership ("WP X O&G"). WP-WPVIII Investors GP L.P., a Delaware limited partnership ("WP-WPVIII GP"), is the general partner of WP-WPVIII Investors. Warburg Pincus X, L.P., a Delaware limited partnership ("WP X GP"), is the general partner of each of the WP X Funds and WP X O&G. Warburg Pincus X GP L.P., a Delaware limited partnership ("WP X GP LP"), is the general partner of WP X GP. WPP GP LLC, a Delaware limited liability company ("WPP GP"), is the general partner of WP-WPVIII GP and WP X GP LP. Warburg Pincus Partners, L.P., a Delaware limited partnership ("WP Partners"), is (i) the managing member of WPP GP, and (ii) the general partner of WP VIII and WP VIII CV I. Warburg Pincus Partners GP LLC, a Delaware limited liability company ("WP Partners GP"), is the general partner of WP Partners. WP is the managing member of WP Partners GP. WP LLC is the manager of each of the WP VIII Funds, the WP X Funds and WP X O&G. Each of the WP VIII Funds, the WP X Funds, WP X O&G, WP-WPVIII GP, WP X GP, WP X GP LP, WPP GP, WP Partners, WP Partners GP, WP and WP LLC are collectively referred to herein as the "Warburg Pincus Entities." Mr. Kagan disclaims beneficial ownership of all shares of common stock attributable to the Warburg Pincus Entities except to the extent of his pecuniary interest therein.
(5) Includes 7,500 shares of common stock held by The 2017 Kagan Family Trust (the "Kagan Trust"), over which Mr. Kagan may be deemed to have shared voting and dispositive power. Mr. Kagan disclaims beneficial ownership of all shares held by the Kagan Trust except to the extent of his pecuniary interest therein.
(6) Has a mailing address of 410 Park Avenue, 19th Floor, New York, New York 10022.
(7) Mr. Keenan is a member and manager of the direct or indirect general partner of each of Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P., which own 235,380 shares of common stock, 215,319 shares of common stock, 3,104,317 shares of common stock and 10,425,078 shares of common stock, respectively. Mr. Keenan does not have sole or shared voting or investment power within the meaning of Rule

13d-3 under the Exchange Act with respect to the shares of common stock held by such investment funds and disclaims beneficial ownership of such securities except to the extent of his pecuniary interest therein.

(8) Includes 2,821,394 shares of common stock held by Salisbury Investment Holdings LLC ("Salisbury") and 2,461,712 shares of common stock held by Mockingbird Investments LLC ("Mockingbird"). Mr. Rady owns a 95% limited liability company interest in Salisbury and his spouse owns the remaining 5%. Mr. Rady owns a 3.68% limited liability company interest in Mockingbird, and a trust under his control owns the remaining 96.32%. Mr. Rady disclaims beneficial ownership of all shares held by Salisbury and Mockingbird except to the extent of his pecuniary interest therein.

(9) Includes 215,879 shares of common stock that remain subject to vesting and options to purchase 50,000 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(10) Mr. Warren indirectly owns 7 shares of common stock purchased by a family member, and these shares are included because of his relation to the purchaser. Mr. Warren disclaims beneficial ownership of all shares reported except to the extent of his pecuniary interest therein.

(11) Includes 3,847,839 shares of common stock held by Canton Investment Holdings LLC ("Canton") and 735,000 shares of common stock held by The Titus Foundation ("Titus"). Mr. Warren is the managing member and 50% owner of Canton and the President of Titus. Mr. Warren disclaims beneficial ownership of all shares held by Canton and Titus except to the extent of his pecuniary interest therein.

(12) Includes 143,920 shares of common stock that remain subject to vesting and options to purchase 33,332 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(13) Includes 113,672 shares of common stock that remain subject to vesting and options to purchase 12,500 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(14) Includes 151,172 shares of common stock that remain subject to vesting and options to purchase 12,500 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(15) Includes 104,175 shares of common stock that remain subject to vesting and options to purchase 11,250 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(16) Includes 105,032 shares of common stock that remain subject to vesting, options to purchase 60,000 shares of common stock that expire ten years from the date of grant, or October 10, 2023, and options to purchase 12,500 shares of common stock that expire ten years from the date of grant, or April 15, 2025.

(17) Excludes 46,609,061 shares of common stock held by the Warburg Pincus Entities (as defined in footnote 4), over which Mr. Kagan may be deemed to have indirect beneficial ownership.

Securities Authorized for Issuance Under Equity Compensation Plan

Please read the information under "Item 11. Executive Compensation – Compensation Discussion and Analysis – Equity Compensation Plan Information."

Item 13. Certain Relationships and Related Transactions and Director Independence

As of February 13, 2018, Antero Resources owned 98,870,335 common units representing an approximate 52.9% limited partner interest in us. AMGP owns and controls (and appoints all the directors of) our general partner, AMP GP, which owns a non-economic general partner interest in us. AMGP also controls IDR LLC, the holder of our incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the conversion, ongoing operation and any liquidation of us.

Conversion of Antero Resources Midstream LLC to Antero Midstream Partners LP

The aggregate consideration received by our general partner in connection with the conversion of its special membership interest pursuant to the limited liability company agreement of Antero Resources Midstream LLC	• the non-economic general partner interest; and • the incentive distribution rights.

The aggregate consideration received by Antero Resources in connection with the conversion of its common economic interest pursuant to the limited liability company agreement of Antero Resources Midstream LLC	• 35,940,957 common units; • 75,940,957 subordinated units; • a distribution of \$332.5 million to reimburse it for certain capital expenditures it incurred in connection with the Predecessor prior to Midstream Operating being contributed to us; • our assumption of \$510 million of indebtedness incurred in connection with the Predecessor prior to Midstream Operating being contributed to us; and • we will also undertake a public or private offering of common units in the future upon request by Antero Resources and use the proceeds thereof (net of underwriting or placement agency discounts and commissions, as applicable) to redeem an equal number of common units from Antero Resources as a distribution to reimburse Antero Resources for certain capital expenditures incurred in connection with the Predecessor prior to Midstream Operating being contributed to us.
Option units or proceeds from option units	In connection with the completion of the IPO, the underwriters exercised their option to purchase additional common units. We used the net proceeds resulting from the issuance of 6,000,000 common units upon such exercise to acquire an equivalent number of common units from Antero Resources, which common units were cancelled, to reimburse Antero Resources for capital expenditures incurred in connection with the Predecessor prior to Midstream Operating being contributed to us.

Operational Stage

Distributions of cash available for distribution to our general partner and its affiliates	We will generally make cash distributions 100% to our unitholders, including affiliates of our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our outstanding common units for four quarters, our general partner and its affiliates (including Antero Resources) would receive an annual distribution of approximately \$67.2 million on their units.

Payments to our general partner and its affiliates	Antero Resources provides customary management and general administrative services to us. Our general partner reimburses Antero Resources at cost for its direct expenses incurred on behalf of us and a proportionate amount of its indirect expenses incurred on behalf of us, including, but not limited to, compensation expenses. Our general partner does not receive a management fee or other compensation for its management of our partnership, but we reimburse our general partner and its affiliates for all direct and indirect expenses they incur and payments they make on our behalf, including payments made to Antero Resources for customary management and general administrative services. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read "The Partnership Agreement—Withdrawal or Removal of Our General Partner."
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Antero Resources

We have entered into certain agreements with Antero Resources, as described in more detail below.

Registration Rights Agreement

Pursuant to the registration rights agreement, we may be required to register the sale of Antero Resources' (i) common units issued (or issuable) to it pursuant to the contribution agreement and (ii) common units issued upon conversion of subordinated units pursuant to the terms of the partnership agreement (together, the "Registrable Securities") in certain circumstances.

Demand Registration Rights

Antero Resources has the right to require us by written notice to register the sale of a number of their Registrable Securities in an underwritten offering. We are required to provide notice of the request within 10 days following the receipt of such demand request to all additional holders of Registrable Securities, if any, who may, in certain circumstances, participate in the registration. We are not obligated to effect any demand registration in which the anticipated aggregate offering price included in such offering is less than $50,000,000. While we are eligible to effect a registration on Form S-3, any such demand registration may be for a shelf registration statement.

Piggy-back Registration Rights

If, at any time, we propose to register an offering of our securities (subject to certain exceptions) for our own account, then we must give to Antero Resources securities to allow it to include a specified number of Registrable Securities in that registration statement.

Redemptive Offerings

We may be required pursuant to the registration rights agreement to undertake a future public or private offering and use the proceeds (net of underwriting or placement agency discounts, fees and commissions, as applicable) to redeem an equal number of common units from Antero Resources.

Conditions and Limitations; Expenses

The registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of Registrable Securities to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective. The obligations to register Registrable Securities under the registration rights agreement will terminate when no Registrable Securities remain outstanding. Registrable Securities shall cease to be covered by the registration rights agreement when they have (i) been sold pursuant to an effective registration statement under the Securities Act, (ii) been sold in a transaction exempt from registration under the Securities Act (including transactions pursuant to Rule 144), (iii) ceased to be outstanding, (iv) been sold in a private transaction in which Antero Resources' rights under the registration rights agreement are not assigned to the transferee or (v) become eligible for resale pursuant to Rule 144(b) (or any similar rule then in effect under the Securities Act).

Services Agreement

Pursuant to the services agreement, Antero Resources has agreed to provide customary operational and management services for us in exchange for reimbursement of its direct expenses and an allocation of its indirect expenses attributable to the provision of such services to us. On September 23, 2015, Antero Resources, the Partnership and Midstream Management amended and restated the services agreement to remove provisions relating to operational services in support of our gathering and compression business which is now covered by a secondment agreement and to provide that Antero Resources will perform certain administrative services for us and our subsidiaries, and we will reimburse Antero Resources for expenditures incurred by Antero Resources in the performance of those administrative services.

Secondment Agreement

In connection with the Water Acquisition, on September 23, 2015, we entered into a secondment agreement with Antero Resources, Midstream Management, Midstream Operating, Antero Water and Antero Treatment, whereby Antero Resources has agreed to provide seconded employees to perform certain operational services with respect to our gathering and compression facilities and the Contributed Assets, and we have agreed to reimburse Antero Resources for expenditures incurred by Antero Resources in the performance of those operational services. The initial term of the secondment agreement is twenty years from November 10, 2014, and from year to year thereafter. For the year ended December 31, 2017, we reimbursed Antero Resources for approximately $31.2 million of its direct and allocated indirect expenses under the services and secondment agreement.

Gathering and Compression Agreement

Pursuant to our 20-year gas gathering and compression agreement with Antero Resources, Antero Resources has agreed to dedicate all of its current and future acreage in West Virginia, Ohio and Pennsylvania to us (other than the existing third-party commitments), so long as such production is not otherwise subject to a pre-existing dedication for third-party services. Antero Resources' production subject to a pre-existing dedication is also dedicated to us at the expiration of such pre-existing dedication. In addition, if Antero Resources acquires any gathering facilities, it is required to offer such gathering facilities to us at its cost.

Under the gathering and compression agreement, we receive a low pressure gathering fee of $0.30 per Mcf, a high pressure gathering fee of $0.18 per Mcf, and a compression fee of $0.18 per Mcf, in each case subject to CPI-based adjustments. For the year ended December 31, 2017, we generated revenues of approximately $396 million under the gathering and compression agreement with Antero Resources, and on February 13, 2018, we amended and restated the gathering and compression agreement to, among other things, make certain clarifying changes with respect to CPI and the associated adjustments to the fees we will receive from Antero Resources under the agreement.

If and to the extent Antero Resources requests that we construct new high pressure lines and compressor stations requested by Antero Resources, the gathering and compression agreement contains minimum volume commitments that require Antero Resources to utilize or pay for 75% and 70%, respectively, of the capacity of such new construction. Additional high pressure lines and compressor stations installed on our own initiative are not subject to such volume commitments. These minimum volume commitments on new infrastructure, as well as price adjustment mechanisms, are intended to support the stability of our cash flows.

We also have an option to gather and compress natural gas produced by Antero Resources on any acreage it acquires in the future outside of West Virginia, Ohio and Pennsylvania on the same terms and conditions. In the event that we do not exercise this option, Antero Resources will be entitled to obtain gathering and compression services and dedicate production from limited areas to such third-party agreements from third parties.

In return for Antero Resources' acreage dedication, we have agreed to gather, compress, dehydrate and redeliver all of Antero Resources' dedicated natural gas on a firm commitment, first-priority basis. We may perform all services under the gathering and compression agreement or we may perform such services through third parties. In the event that we do not perform our obligations under the gathering and compression agreement, Antero Resources will be entitled to certain rights and procedural remedies thereunder.

Pursuant to the gathering and compression agreement, we have also agreed to build to and connect all of Antero Resources' wells producing dedicated natural gas, subject to certain exceptions, upon 180 days' notice by Antero Resources. In the event of late connections, Antero Resources' natural gas will temporarily not be subject to the dedication. We are entitled to compensation under the gathering and compression agreement for capital costs incurred if a well does not commence production within 30 days following the target completion date for the well set forth in the notice from Antero Resources.

We have agreed to install compressor stations at Antero Resources' direction, but will not be responsible for inlet pressures or for pressuring natural gas to enter downstream facilities if Antero Resources has not directed us to install sufficient compression. Additionally, we will provide high pressure gathering pursuant to the gathering and compression agreement.

Under the gathering and compression agreement, Antero Resources may sell, transfer, convey, assign, grant, or otherwise dispose of dedicated properties free of the dedication, provided that the number of net acres of dedicated properties so disposed of, when added to the number of net acres of dedicated properties previously disposed of free of the dedication since the effective date of the agreement, does not exceed the aggregate number of net acres of dedicated properties acquired by Antero Resources since such effective date. Accordingly, under certain circumstances, Antero Resources may dispose of a significant number of net acres of dedicated properties free from dedication without our consent, and we have no control over the timing or extent of such dispositions.

Upon completion of the initial 20-year term, the gathering and compression agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either us or Antero Resources on or before the 180th day prior to the anniversary of such effective date.

Water Services Agreement

In connection with the Water Acquisition, on September 23, 2015, we entered in a 20-year Water Services Agreement with Antero Resources whereby we have agreed to provide certain water handling and treatment services to Antero Resources within an area of dedication in defined service areas in Ohio and West Virginia and Antero Resources agrees to pay monthly fees to us for all water handling and treatment services provided by us in accordance with the terms of the Water Services Agreement. The initial term of the Water Services Agreement is twenty years from the date thereof and from year to year thereafter. Under the agreement, Antero Resources will pay a fixed fee of $3.685 per barrel in West Virginia and $3.635 per barrel in Ohio and all other locations for fresh water deliveries by pipeline directly to the well site, subject to annual CPI adjustments. Antero Resources has committed to pay a fee on a minimum volume of fresh water deliveries in calendar years 2016 through 2019. Antero Resources is obligated to pay a minimum of 90,000 barrels per day in 2016, 100,000 barrels per day in 2017 and 120,000 barrels per day in 2018 and 2019. Antero Resources also agreed to pay us a fixed fee of $4.00 per barrel for wastewater treatment at the advanced wastewater treatment complex and a fee per barrel for wastewater collected in trucks owned by us, in each case subject to annual CPI-based adjustments. In addition, we contract with third party service providers to provide Antero Resources other fluid handling services including flow back and produced water services and Antero Resources will reimburse us third party out-of-pocket costs plus 3%. For the year ended December 31, 2017, we generated revenues of approximately $376 million under the Water Services Agreement with Antero Resources.

Under the Water Services Agreement, Antero Resources may sell, transfer, convey, assign, grant, or otherwise dispose of dedicated properties free of the dedication, provided that the number of net acres of dedicated properties so disposed of, when added to the number of net acres of dedicated properties previously disposed of free of the dedication since the effective date of the agreement, does not exceed the aggregate number of net acres of dedicated properties acquired by Antero Resources since such effective date. Accordingly, under certain circumstances, Antero Resources may dispose of a significant number of net acres of dedicated properties free from dedication without our consent, and we have no control over the timing or extent of such dispositions.

Upon completion of the initial 20-year term, the fresh water distribution agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either us or Antero Resources on or before the 180th day prior to the anniversary of such effective date.

Processing

Joint Venture

On February 6, 2017, we formed the Joint Venture to develop processing and fractionation assets in Appalachia with MarkWest. We and MarkWest each own a 50% interest in the Joint Venture and MarkWest operates the Joint Venture assets. The Joint Venture assets consist of processing plants in West Virginia, and a one-third interest in a recently commissioned MarkWest fractionator in Ohio.

Pursuant to a certain gas processing agreement between Antero Resources and MarkWest, MarkWest has agreed to process gas from acreage dedicated by Antero Resources for a fee. MarkWest has entered into a separate agreement with the Joint Venture whereby the Joint Venture has agreed to perform gas processing services with respect to certain volumes on behalf of MarkWest in exchange for the gas processing fees that MarkWest receives from Antero Resources in connection with such volumes (the "MW-JV Arrangement"). During the year ended December 31, 2017, the Joint Venture derived approximately $32 million of revenues under the MW-JV Arrangement, and approximately $10 million of our equity in earnings of unconsolidated affiliates for the year ended December 31, 2017 was attributable to our investment in the Joint Venture. In addition, on February 6, 2018, Antero Resources and MarkWest have entered into an agreement pursuant to which MarkWest has agreed to address certain regulatory matters related to expansions at one of MarkWest's processing sites, and if certain conditions are not met, Antero Resources has agreed to make reimbursement payments for such work directly to the Joint Venture.

Right-of-First-Offer Agreement

Prior to the Joint Venture, we did not have any processing or NGLs fractionation infrastructure; however we have a right-of-first-offer agreement with Antero Resources for gas processing services, pursuant to which Antero Resources has agreed, subject to certain exceptions, not to procure any gas processing or NGLs fractionation services with respect to its production (other than production subject to a pre-existing dedication) without first offering us the right to provide such services.

If Antero Resources requires any gas processing or NGLs fractionation services that we are not already providing, including any services to be provided through a facility that Antero Resources has acquired or proposes to be acquired, Antero Resources' request for offer will, among other things, describe the production that will be dedicated under the resulting agreement and the capacities of the facilities it desires and, if applicable, details of the facility Antero Resources has acquired or proposes to acquire. Antero Resources is permitted concurrently to seek offers from third parties for the same services on the same terms and conditions, but we have a right to match the fees offered by any third-party. Antero Resources will only be permitted to obtain these services from third parties if we either do not make an offer or do not match a competing third-party offer. The process could result in Antero Resources obtaining certain of the required services from us (for example, gas processing) and certain of such services (for example, NGLs fractionation and related services) from a third-party. Our right of first offer does not apply to production that is subject to a pre-existing dedication. The right of first offer agreement has an initial 20-year term from the date of our IPO, and is subject to automatic annual renewal after the initial term.

Pursuant to the procedures provided for in the right of first offer agreement, if our offer prevails, Antero Resources will enter into a gas processing agreement or other appropriate services agreement with us and, if such services are to be provided through a facility that Antero Resources has acquired or proposes to acquire, transfer such acquired facility to us for the price for which Antero Resources acquired it. Relevant production will be dedicated under such agreement. We will provide the relevant services for the offered fees, subject to price adjustments based on the consumer price index, or CPI, and Antero Resources will be obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. We may perform all services under the gas processing or other services agreement or may perform such services through third parties. In the event that we do not perform our obligations under the agreement, Antero Resources will be entitled to certain rights and procedural remedies thereunder.

If pursuant to the foregoing procedures Antero Resources enters into a gas processing agreement with us, we will agree to construct or cause to be constructed a processing plant to process the dedicated natural gas, except to the extent rendered unnecessary if Antero Resources is transferring an acquired facility to us. If Antero Resources requires additional capacity in the future at the plant at which we are providing the services, we will have the option to provide such additional capacity on the same terms and conditions. In the event that we do not exercise this option, Antero Resources will be entitled to obtain proposals from third parties to process such production.

Under the right of first offer agreement, Antero Resources may sell, transfer, convey, assign, grant, or otherwise dispose of dedicated properties free of the dedication, provided that the number of net acres of dedicated properties so disposed of, when added to the number of net acres of dedicated properties previously disposed of free of the dedication since the effective date of the agreement, does not exceed the aggregate number of net acres of dedicated properties acquired by Antero Resources since such effective date. Accordingly, under certain circumstances, Antero Resources may dispose of a significant number of net acres of dedicated properties free from dedication without our consent, and we have no control over the timing or extent of such dispositions.

On February 6, 2017, in connection with the formation of the Joint Venture, we and Antero Resources amended and restated the right of first offer agreement in order to, among other things, amend the list of conflicting dedications set forth in such agreement to include the gas processing arrangement between Antero Resources and MarkWest. On February 13, 2018, we further amended and restated the right of first offer agreement to make certain clarifying changes to reflect the original intent of the agreement.

License

Pursuant to a license agreement with Antero Resources, we have the right to use certain Antero Resources related names and trademarks in connection with our operation of the midstream business.

Other Agreements

From time to time, in the ordinary course of business, we participate in transactions with Antero Resources and other third parties in which Antero Resources may be deemed to have a direct or indirect material interest. These transactions include, among other things, agreements that address the provision of midstream services and receipt of contract operating services, the purchase of fuel for use in our operations, the release of midstream service dedications in connection with acquisitions, dispositions or exchanges of acreage, and the acquisition of assets and the assumption of liabilities by us, our subsidiaries and our unconsolidated affiliates. While certain of these transactions are not the result of arm's-length negotiations, we believe that the terms of each of the transactions are, and specifically intend the terms to be, generally no less favorable to either party than those that could have been negotiated with unaffiliated parties with respect to similar transactions. During the year ended December 31, 2017, we incurred approximately $11 million of costs in connection with such transactions.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

The board has determined that the audit committee will periodically review all related person transactions that the rules of the SEC require be disclosed in this Annual Report on Form 10-K, and make a determination regarding the initial authorization or ratification of any such transaction.

The audit committee is charged with reviewing the material facts of all related person transactions and either approving or disapproving of our participation in such transactions under our Related Persons Transaction Policy, as amended by the board ("RPT Policy") on October 17, 2017, which pre-approves certain related person transactions, including:

- any employment of an executive officer if his or her compensation is required to be reported in our Annual Reports on Form 10-K under Item 402;
- director compensation which is required to be reported in our Annual Reports on Form 10-K under Item 402;
- any transaction with an entity at which the related person's only relationship is as an employee (other than an executive officer), director or beneficial owner of less than 10% of the entity's equity, if the aggregate amount involved does not exceed $1 million;
- any charitable contribution, grant or endowment by us to a charitable organization, foundation or university at which a related person's only relationship is as an employee (other than an executive officer) or a director is pre-approved or ratified (as applicable) if the aggregate amount involved does not exceed $200,000;
- any transaction where the related person's interest arises solely from the ownership of our common units and all holders of our common units received the same benefit on a pro rata basis (e.g., distributions) is pre-approved or ratified (as applicable);
- any transaction involving a related person where the rates or charges involved are determined by competitive bids is pre-approved or ratified (as applicable);
- any transaction with a related person involving the rendering of services as a common or contract carrier, or public utility, at rates or charges fixed in conformity with law or governmental authority is pre-approved or ratified (as applicable); and
- any transaction with a related person involving services as a bank depositary of funds, transfer agent, registrar, trustee under a trust indenture or similar services is pre-approved or ratified (as applicable).

The audit committee chairman may approve any related person transaction in which the aggregate amount involved is expected to be less than $120,000. A summary of such approved transactions and each new related person transaction deemed pre-approved under the RPT Policy is provided to the audit committee for its review. The audit committee has the authority to modify the RPT Policy regarding pre-approved transactions or to impose conditions upon our ability to participate in any related person transaction.

There were no related person transactions during 2017 which were required to be reported in "Related Persons Transactions" where the procedures described above did not require review, approval or ratification or where these procedures were not followed.

Conflicts of Interest

The board has adopted a written code of business conduct and ethics, under which a director would be expected to bring to the attention of our chief executive officer or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the board of directors of our general partner in accordance with the provisions of our partnership agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by the conflicts committee.

Pursuant to our code of business conduct, our general partner's executive officers are required to avoid conflicts.

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its directors, officers, affiliates (including Antero Resources) and owners, on the one hand, and us and our limited partners, on the other hand. Conflicts may arise as a result of the duties of our general partner and its directors and officers to act for the benefit of its owners, which may conflict with our interests and the interests of our public unitholders. We are managed and operated by the board of directors and officers of our general partner, AMP GP, which is owned by AMGP. Certain of our officers and directors are also officers or directors of AMGP GP, AMGP's general partner, and Antero Resources. Similarly, all of the officers and a majority of the directors of our general partner are also officers or directors of Antero Resources. Affiliates of Warburg Pincus LLC ("Warburg"), Yorktown Partners LLC ("Yorktown"), Paul M. Rady and Glen C. Warren, Jr. serve as members of the board of directors of our general partner, the board of directors of AMGP GP and the board of directors of Antero Resources. Mr. Rady, Mr. Warren and certain investment funds affiliated with Warburg and Yorktown (collectively, the "Sponsors") also own the membership interests in AMGP GP, a majority of the common units and other interests in AMGP and a significant portion of the shares of common stock of Antero Resources. As a result of their investments in AMGP , AMGP GP, and its general partner and Antero Resources, the Sponsors may have conflicting interests with other holders of our common units.

Although our general partner has a contractual duty to manage us in a manner that it believes is not adverse to our interests, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to AMGP. Our general partner's directors and officers who are also directors and officers of Antero Resources have a fiduciary duty to manage Antero Resources in a manner that is beneficial to Antero Resources and its shareholders, and our directors and officers who are also directors and officers of AMGP GP have a fiduciary duty to manage AMGP GP in a manner that is beneficial to AMGP GP and its owners. Our partnership agreement specifically defines the remedies available to unitholders for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law. The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by the general partner to the limited partners and the partnership.

Whenever a conflict arises between our general partner or its owners and affiliates (including Antero Resources and AMGP), on the one hand, and us or our limited partners, on the other hand, the resolution or course of action in respect of such conflict of interest shall be permitted and deemed approved by us and all our limited partners and shall not constitute a breach of our partnership agreement, of any agreement contemplated thereby or of any duty, if the resolution or course of action in respect of such conflict of interest is:

- approved by the conflicts committee of our general partner, although our general partner is not obligated to seek such approval; or

- approved by the holders of a majority of the outstanding common units, excluding any such units owned by our general partner or any of its affiliates.

Our general partner may, but is not required to, seek the approval of such resolutions or courses of action from the conflicts committee of its board of directors or from the holders of a majority of the outstanding common units as described above. If our general partner does not seek approval from the conflicts committee or from holders of common units as described above and the board of directors of our general partner approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. Unless the resolution of a conflict is specifically provided for in our partnership agreement, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner may consider any factors they determine in good faith to consider when resolving a conflict. An independent third party is not required to evaluate the resolution. Under our partnership agreement, a determination, other action or failure to act by our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) will be deemed to be “in good faith” unless our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) believed such determination, other action or failure to act was adverse to the interest of the partnership. Please read “Management—Committees of the Board of Directors—Conflicts Committee” for information about the conflicts committee of our general partner’s board of directors.

Director Independence

Rather than adopting categorical standards, the Board assesses director independence on a case-by-case basis, in each case consistent with applicable legal requirements and the listing standards of the NYSE. After reviewing all relationships each director has with us, including the nature and extent of any business relationships between us and each director, as well as any significant charitable contributions we make to organizations where our directors serve as board members or executive officers, the Board has affirmatively determined that the following directors have no material relationships with us and are independent as defined by the current listing standards of the NYSE: Messrs. Kagan, Keenan, Mollenkopf, Connor and Peters. Neither Mr. Rady, the Chairman and Chief Executive Officer of our general partner, nor Mr. Warren, the President and Secretary of our general partner, is considered by the Board to be an independent director because of his employment with Antero Resources.

Item 14. Principal Accountant Fees and Services

The table below sets forth the aggregate fees and expenses billed by KPMG LLP, our independent registered public accounting firm, for the Partnership for the following periods:

(in thousands)	**For the Year Ended December 31,**	
Audit Fees:	**2016**	**2017**
Audit and Quarterly Reviews	$ 520	$ 540
Other Filings	400	433
	$ 920	$ 973

The charter of the Audit Committee and its pre-approval policy require that the Audit Committee review and pre-approve our independent registered public accounting firm's fees for audit, audit-related, tax and other services. The Chairman of the Audit Committee has the authority to grant pre-approvals, provided such approvals are within the pre-approval policy and are presented to the Audit Committee at a subsequent meeting. For the year ended December 31, 2017, the audit committee of our predecessor approved 100% of the services described above under the captions "Audit Fees."

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.

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 the Current Report on Form 8-K (Commission File No. 001-36719) filed on September 18, 2015).
3.1	Certificate of Conversion of Antero Resources Midstream LLC, dated November 5, 2014 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on November 7, 2014).
3.2	Amended and Restated Certificate of Limited Partnership of Antero Midstream Partners LP, dated April 11, 2017 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on April 11, 2017).
3.3	Agreement of Limited Partnership, dated as of November 10, 2014, by and between Antero Resources Midstream Management LLC, as the General Partner, and Antero Resources Corporation, as the Organizational Limited Partner (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
3.4	Amendment No. 1 to Agreement of Limited Partnership of Antero Midstream Partners LP, dated as of February 23, 2016 (incorporated by reference to Exhibit 3.4 to Annual Report on Form 10-K (Commission File No. 001-36719) filed on February 24, 2016).
3.5	Amendment No. 2 to Agreement of Limited Partnership of Antero Midstream Partners LP, dated as of December 20, 2017 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on December 26, 2017).
4.1	Indenture, dated as of September 13, 2016, by and among Antero Midstream Partners LP, Antero Midstream Finance Corporation, the subsidiary guarantors party thereto 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. 001-36719) filed on September 13, 2016).
4.2	Form of 5.375% Senior Note due 2024 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on September 13, 2016).
4.3	Registration Rights Agreement, dated as of September 13, 2016, by and among Antero Midstream Partners LP, Antero Midstream Finance 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. 001-36719) filed on September 13, 2016).
10.1	Common Unit Purchase Agreement, dated as of September 17, 2015, by and among Antero Midstream Partners LP and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-36719) filed on September 18, 2015).

10.2	Senior Note Purchase Agreement, dated as of September 8, 2016, by and among Antero Midstream Partners LP, Antero Midstream Finance Corporation and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on September 13, 2016).
10.3	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 the Current Report on Form 8-K (Commission File No. 001-36719) filed on September 24, 2015).
10.4	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 10.3 to the Current Report on Form 8-K (Commission File No. 001-36719) filed on September 24, 2015).
10.5†	Water Services Agreement, dated as of September 23, 2015, by and between Antero Resources Corporation and Antero Water LLC (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q (Commission File No. 001-36719) filed on October 28, 2015).
10.6	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 Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.7	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 Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.8	First Amended and Restated Right of First Offer Agreement, dated as of February 6, 2017, but effective as of January 1, 2017, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36719) filed on February 6, 2017).
10.9	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 Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.10	Registration Rights Agreement, dated as of November 10, 2014, by and among Antero Midstream Partners LP and Antero Resources Corporation (incorporated by reference to Exhibit 10.5 to Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.11	Amended and Restated Credit Agreement, dated as of October 26, 2017, among Antero Midstream Partners LP and certain of its subsidiaries, certain lenders party thereto, Wells Fargo Bank, National Association, as administrative agent, l/c issuer and swingline lender and the other parties thereto (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36719) filed on November 1, 2017).
10.12	Form of Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Amendment No. 4 to Antero Resources Midstream LLC's Registration Statement on Form S-1, filed on July 11, 2014, File No. 333-193798).
10.13	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.12 to Amendment No. 4 to Antero Resources Midstream LLC's Registration Statement on Form S-1, filed on July 11, 2014, File No. 333-193798).

10.14	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).
10.15	Form of Restricted Unit Grant Notice and Restricted Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.5 to Antero Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.16	Form of Bonus Unit Grant Notice and Bonus Unit Agreement (Form for Non-Employee Directors) under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 24, 2016).
10.17	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).
10.18	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).
10.19	Form of Bonus Stock Grant Notice and Bonus Stock Agreement (Form for Non-Employee Directors) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.36 to Antero Resources' Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 24, 2016).
10.20	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 Antero Resources' Current Report on Form 8-K (Commission File No. 001-36120) filed on February 12, 2016).
10.21	Global Grant Amendment to Grant Notices and Award Agreements Under the Antero Midstream Partners LP Long-Term Incentive Plan, effective as of October 24, 2016 (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 Midstream Partners LP.
23.1*	Consent of KPMG, LLP.
31.1*	Certification of the 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 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 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 Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
101*	The following financial information from this Form 10-K of Antero Midstream Partners LP for the year ended December 31, 2017, 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.

** Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted exhibit or schedule to the U.S. Securities and Exchange Commission upon request.
†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 MIDSTREAM PARTNERS LP

By: **ANTERO MIDSTREAM PARTNERS GP LLC, its general partner**

By: /s/ Michael N. Kennedy
Michael N. Kennedy
Chief Financial Officer

Date: February 13, 2018

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 (Position with Antero Midstream Partners GP LLC)	Date
/s/ Paul M. Rady Paul M. Rady	Chairman of the Board, Director and Chief Executive officer (principal executive officer)	February 13, 2018
/s/Michael N. Kennedy Michael N. Kennedy	Chief Financial Officer (principal financial officer)	February 13, 2018
/s/ K. Phil Yoo K. Phil Yoo	Vice President, Accounting and Chief Accounting Officer (principal accounting officer)	February 13, 2018
/s/ Glen C. Warren, Jr. Glen C. Warren, Jr.	President, Director, and Secretary	February 13, 2018
/s/ Richard W. Connor Richard W. Connor	Director	February 13, 2018
/s/ W. Howard Keenan, Jr. W. Howard Keenan, Jr.	Director	February 13, 2018
/s/ Peter R. Kagan Peter R. Kagan	Director	February 13, 2018
/s/ JOHN C. MOLLENKOPF John C. Mollenkopf	Director	February 13, 2018
/s/ David A. Peters David A. Peters	Director	February 13, 2018

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The unitholders of Antero Midstream Partners LP and
board of directors of Antero Midstream Partners GP LLC:

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

We have audited the accompanying consolidated balance sheets of Antero Midstream Partners LP (the "Partnership") as of December 31, 2016 and 2017, the related consolidated statements of operations and comprehensive income, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2016 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 2 to the consolidated financial statements of the Partnership, the consolidated statements of operations and comprehensive income, partners' capital, and cash flows for 2015 have been prepared on a combined basis of accounting.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ KPMG LLP

We have served as the Partnership's auditor since 2013.

Denver, Colorado
February 13, 2018

ANTERO MIDSTREAM PARTNERS LP

Consolidated Balance Sheets

December 31, 2016 and 2017

(In thousands)

		December 31,	
		2016	2017
Assets			
Current assets:			
Cash and cash equivalents	$	14,042	8,363
Accounts receivable–Antero Resources		64,139	110,182
Accounts receivable–third party		1,240	1,170
Prepaid expenses		529	670
Total current assets		79,950	120,385
Property and equipment, net		2,195,879	2,605,602
Investments in unconsolidated affiliates		68,299	303,302
Other assets, net		5,767	12,920
Total assets	$	2,349,895	3,042,209
Liabilities and Partners' Capital			
Current liabilities:			
Accounts payable–third party	$	16,979	8,642
Accounts payable–Antero Resources		3,193	6,459
Accrued liabilities		61,641	106,006
Other current liabilities		200	209
Total current liabilities		82,013	121,316
Long-term liabilities:			
Long-term debt		849,914	1,196,000
Contingent acquisition consideration		194,538	208,014
Other		620	410
Total liabilities		1,127,085	1,525,740
Partners' capital:			
Common unitholders - public (70,020 units and 88,059 units issued and outstanding at December 31, 2016 and 2017, respectively)		1,458,410	1,708,379
Common unitholder - Antero Resources (32,929 units and 98,870 units issued and outstanding at December 31, 2016 and 2017, respectively)		26,820	(215,682)
Subordinated unitholder - Antero Resources (75,941 issued and outstanding at December 31, 2016)		(269,963)	—
General partner		7,543	23,772
Total partners' capital		1,222,810	1,516,469
Total liabilities and partners' capital	$	2,349,895	3,042,209

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM PARTNERS LP

Consolidated Statements of Operations and Comprehensive Income

Years Ended December 31, 2015 (Combined), 2016, and 2017

(In thousands, except per unit amounts)

	Year Ended December 31,		
	2015	2016	2017
Revenue:			
Gathering and compression–Antero Resources	$ 230,210	303,250	396,202
Water handling and treatment–Antero Resources	155,954	282,267	376,031
Gathering and compression–third party	382	835	264
Water handling and treatment–third party	778	—	—
Gain on sale of assets	—	3,859	—
Total revenue	387,324	590,211	772,497
Operating expenses:			
Direct operating	78,852	161,587	232,538
General and administrative (including $22,470, $26,049 and $27,283 of equity-based compensation in 2015, 2016, and 2017, respectively)	51,206	54,163	58,812
Impairment of property and equipment	—	—	23,431
Depreciation	86,670	99,861	119,562
Accretion of contingent acquisition consideration	3,333	16,489	13,476
Total operating expenses	220,061	332,100	447,819
Operating income	167,263	258,111	324,678
Interest expense, net	(8,158)	(21,893)	(37,557)
Equity in earnings of unconsolidated affiliates	—	485	20,194
Net income and comprehensive income	159,105	236,703	307,315
Pre-Water Acquisition net income attributed to parent	(40,193)	—	—
Net income attributable to incentive distribution rights	(1,264)	(16,944)	(69,720)
Limited partners' interest in net income	$ 117,648	219,759	237,595
Net income per limited partner unit - basic and diluted	$ 0.74	1.24	1.28
Weighted average limited partner units outstanding - basic	158,479	176,647	185,630
Weighted average limited partner units outstanding - diluted	158,527	176,801	186,083

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM PARTNERS LP

Consolidated Statements of Partners' Capital

Years Ended December 31, 2015 (Combined), 2016, and 2017

(In thousands)

	Limited Partners					
	Common Unitholders Public	Common Unitholder Antero Resources	Subordinated Unitholder Antero Resources	General Partner	Parent Net Investment	Total Partners' Capital
Balance at December 31, 2014	$1,090,037	71,665	180,757	—	278,444	1,620,903
Net income and comprehensive income	37,368	25,053	55,227	1,264	40,193	159,105
Distributions to unitholders	(33,834)	(22,292)	(50,827)	(295)	—	(107,248)
Deemed distribution to Antero Resources, net	—	—	—	—	(52,669)	(52,669)
Equity-based compensation	4,577	7,363	7,086	—	3,444	22,470
Issuance of common units upon vesting of equity-based compensation awards, net of units withheld for income taxes	12,466	(17,272)	—	—	—	(4,806)
Issuance of common units, net of offering costs	240,703	—	—	—	—	240,703
Issuance of common units to Antero Resources in Water Acquisition	—	229,988	—	—	—	229,988
Purchase price in excess of net assets acquired in Water Acquisition	—	(264,319)	(491,970)	—	—	(756,289)
Carrying value of net assets acquired in Water Acquisition	—	—	—	—	(269,412)	(269,412)
Balance at December 31, 2015	$1,351,317	30,186	(299,727)	969	—	1,082,745
Net income and comprehensive income	82,424	42,817	94,518	16,944	—	236,703
Distributions to unitholders	(64,712)	(33,701)	(73,663)	(10,370)	—	(182,446)
Equity-based compensation	8,012	9,128	8,909	—	—	26,049
Issuance of common units upon vesting of equity-based compensation awards, net of units withheld for income taxes	9,555	(15,191)	—	—	—	(5,636)
Issuance of common units, net of offering costs	65,395	—	—	—		65,395
Sale of units held by Antero Resources to public	6,419	(6,419)	—	—	—	—
Balance at December 31, 2016	$1,458,410	26,820	(269,963)	7,543	—	1,222,810
Net income and comprehensive income	100,347	137,248	—	69,720	—	307,315
Distributions to unitholders	(98,861)	(131,598)	—	(53,491)	—	(283,950)
Conversion of subordinated units to common units	—	(269,963)	269,963	—	—	—
Equity-based compensation	9,776	17,507	—	—	—	27,283
Issuance of common units upon vesting of equity-based compensation awards, net of units withheld for income taxes	9,691	(15,636)	—	—	—	(5,945)
Sale of units held by Antero Resources to public	(19,940)	19,940	—	—	—	—
Issuance of common units, net of offering costs	248,956	—	—	—	—	248,956
Balance at December 31, 2017	$1,708,379	(215,682)	—	23,772	—	1,516,469

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM PARTNERS LP

Consolidated Statements of Cash Flows
Years Ended December 31, 2015 (Combined), 2016, and 2017
(In thousands)

	Year Ended December 31,		
	2015	2016	2017
Cash flows provided by operating activities:			
Net income	$ 159,105	236,703	307,315
Adjustment to reconcile net income to net cash provided by operating activities:			
Depreciation	86,670	99,861	119,562
Accretion of contingent acquisition consideration	3,333	16,489	13,476
Impairment of property and equipment	—	—	23,431
Equity-based compensation	22,470	26,049	27,283
Equity in earnings of unconsolidated affiliates	—	(485)	(20,194)
Distributions from unconsolidated affiliates	—	7,702	20,195
Amortization of deferred financing costs	1,144	1,814	2,888
Gain on sale of assets	—	(3,859)	—
Changes in assets and liabilities:			
Accounts receivable–Antero Resources	(35,148)	1,573	(41,043)
Accounts receivable–third party	2,867	1,467	70
Prepaid expenses	518	(529)	(141)
Accounts payable–third party	2,803	95	3,003
Accounts payable–Antero Resources	475	1,055	3,266
Accrued liabilities	15,441	(9,328)	16,685
Net cash provided by operating activities	259,678	378,607	475,796
Cash flows used in investing activities:			
Additions to gathering systems and facilities	(320,002)	(228,100)	(346,217)
Additions to water handling and treatment systems	(132,633)	(188,220)	(195,162)
Investments in unconsolidated affiliates	—	(75,516)	(235,004)
Proceeds from sale of assets	—	10,000	—
Change in other assets	7,180	3,673	(3,435)
Net cash used in investing activities	(445,455)	(478,163)	(779,818)
Cash flows provided by (used in) financing activities:			
Deemed distribution to Antero Resources, net	(52,669)	—	—
Distributions to Antero Resources	(620,997)	—	—
Distributions to unitholders	(107,248)	(182,446)	(283,950)
Issuance of senior notes	—	650,000	—
Borrowings (repayments) on bank credit facilities, net	505,000	(410,000)	345,000
Issuance of common units, net of offering costs	240,703	65,395	248,956
Payments of deferred financing costs	(2,059)	(10,435)	(5,520)
Employee tax withholding for settlement of equity compensation awards	—	(5,636)	(5,945)
Other	(262)	(163)	(198)
Net cash provided by (used in) financing activities	(37,532)	106,715	298,343
Net increase (decrease) in cash and cash equivalents	(223,309)	7,159	(5,679)
Cash and cash equivalents, beginning of period	230,192	6,883	14,042
Cash and cash equivalents, end of period	$ 6,883	14,042	8,363
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 7,765	13,494	46,666
Supplemental disclosure of noncash investing activities:			
Increase (decrease) in accrued capital expenditures and accounts payable for property and equipment	$ 4,552	(8,471)	16,338

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements

Years Ended December 31, 2015 (Combined), 2016, and 2017

(1) Business and Organization

Antero Midstream Partners LP (the "Partnership") is a growth-oriented master limited partnership formed by Antero Resources Corporation ("Antero Resources") to own, operate and develop midstream energy infrastructure primarily to service Antero Resources' increasing production and completion activity in the Appalachian Basin's Marcellus Shale and Utica Shale located in West Virginia and Ohio. The Partnership's assets consist of gathering pipelines, compressor stations, interests in processing and fractionation plants, and water handling and treatment assets, through which the Partnership and its affiliates provide midstream services to Antero Resources under long-term, fixed-fee contracts. The Partnership's consolidated financial statements as of December 31, 2017, include the accounts of the Partnership, Antero Midstream LLC ("Midstream Operating"), Antero Water LLC ("Antero Water"), Antero Treatment LLC ("Antero Treatment"), and Antero Midstream Finance Corporation ("Finance Corp"), all of which are entities under common control.

On September 23, 2015, Antero Resources contributed (the "Water Acquisition") (i) all of the outstanding limited liability company interests of Antero Water to the Partnership and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero Resources and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero Resources' advanced wastewater treatment complex in Doddridge County, West Virginia, to Antero Treatment (collectively, (i) and (ii) are referred to herein as the "Contributed Assets"). Our results for periods prior to September 23, 2015 have been recast to include the historical results of Antero Water because the transaction was between entities under common control. Antero Water's operations prior to the Water Acquisition consisted entirely of fresh water delivery operations.

References in these financial statements to "Predecessor," "we," "our," "us" or like terms, when referring to periods prior to November 10, 2014, refer to Antero Resources' gathering, compression and water assets, the Partnership's predecessor for accounting purposes. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods between November 10, 2014 and September 23, 2015 refer to the Partnership's gathering and compression assets and Antero Resources' water handling and treatment assets. References to "the Partnership," "we," "our," "us" or like terms, when referring to periods since September 23, 2015 or when used in the present tense or prospectively, refer to the Partnership.

The Partnership's gathering and compression assets consist of 8-, 12-, 16-, 20-, 24-, and 30-inch high and low pressure gathering pipelines, compressor stations, and processing and fractionation plants that collect and process natural gas, NGLs and oil from Antero Resources' wells in West Virginia and Ohio. The Partnership's water handling and treatment assets include two independent systems that deliver fresh water from sources including the Ohio River, local reservoirs as well as several regional waterways and other fluid handling assets which includes high rate transfer, wastewater transportation, disposal, and treatment.

The Partnership also has a 15% equity interest in the gathering system of Stonewall Gas Gathering LLC ("Stonewall") and a 50% equity interest in the Joint Venture to develop processing and fractionation assets with MarkWest. See Note 11 – Equity Method Investments.

The Partnership's financial statements are consolidated with the financial statements of Antero Resources (NYSE: AR), our primary beneficiary, for financial reporting purposes.

On April 6, 2017, in connection with its initial public offering, Antero Resources Midstream Management LLC ("ARMM") formed Antero Midstream Partners GP LLC ("AMP GP" or our "general partner"), a Delaware limited liability company, as a wholly owned subsidiary, and, on April 11, 2017, assigned to AMP GP the general partner interest in us. Concurrent with the assignment, AMP GP was admitted as the Partnership's sole general partner and ARMM ceased to be our general partner.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

On May 9, 2017, ARMM closed its initial public offering. In connection with the offering, ARMM was converted into a Delaware limited partnership, and changed its name to Antero Midstream GP LP ("AMGP").

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, these statements include all adjustments considered necessary for a fair presentation of the Partnership's financial position as of December 31, 2016 and 2017, and the results of our operations and our cash flows for the years ended December 31, 2015, 2016, and 2017. The combined consolidated statements of operations and comprehensive income, partners' capital, and cash flows for 2015 have been prepared on a combined basis of accounting. The Partnership has no items of other comprehensive income or loss; therefore, net income is identical to comprehensive income.

Certain costs of doing business incurred by Antero Resources on our behalf have been reflected in the accompanying consolidated financial statements. These costs include general and administrative expenses attributed to us by Antero Resources in exchange for:

- business services, such as payroll, accounts payable and facilities management;
- corporate services, such as finance and accounting, legal, human resources, investor relations and public and regulatory policy; and
- employee compensation, including equity-based compensation.

Transactions between us and Antero Resources have been identified in the consolidated financial statements (see Note 3 – Transactions with Affiliates).

As of the date these consolidated financial statements were filed with the SEC, we completed our evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified, except the declaration of a cash distribution to unitholders, as described in Note 7 – Partnership Equity and Distributions.

(b) Revenue Recognition

We provide gathering and compression and water handling and treatment services under fee-based contracts primarily based on throughput or at cost plus a margin. Under these arrangements, we receive fees for gathering oil and gas products, compression services, and water handling and treatment services. The revenue we earn from these arrangements is directly related to (1) in the case of natural gas gathering and compression, the volumes of metered natural gas that we gather, compress and deliver to natural gas compression sites or other transmission delivery points, (2) in the case of oil gathering, the volumes of metered oil that we gather and deliver to other transmission delivery points, (3) in the case of fresh water services, the quantities of fresh water delivered to our customers for use in their well completion operations, (4) in the case of wastewater treatment services, the quantities of wastewater treated for our customers, or (5) in the case of flowback and produced water, the third party out-of-pocket costs plus 3%. We recognize revenue when all of the following criteria are met: (1) persuasive evidence of an agreement exists, (2) services have been rendered, (3) prices are fixed or determinable and (4) collectability is reasonably assured.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

(c) Use of Estimates

The preparation of the consolidated financial statements and notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities. Items subject to estimates and assumptions include the useful lives of property and equipment and valuation of accrued liabilities, among others. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(d) Cash and Cash Equivalents

Prior to September 23, 2015 Antero Water was owned and funded by Antero Resources. Net amounts funded by Antero Resources are reflected as "Deemed distribution to Antero Resources, net" on the accompanying Statements of Consolidated Cash Flows.

We consider 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.

(e) Property and Equipment

Property and equipment primarily consists of gathering pipelines, compressor stations and fresh water delivery pipelines and facilities stated at historical cost less accumulated depreciation. We capitalize construction-related direct labor and material costs. We also capitalize interest on capital costs during the construction phase of the water treatment facility, currently undergoing testing and commissioning. We capitalized interest of $4 million and $12 million for the years ended December 31, 2016 and 2017, respectively. Maintenance and repair costs are expensed as incurred.

Depreciation is computed using the straight-line method over the estimated useful lives and salvage values of assets. The depreciation of fixed assets recorded under capital lease agreements is included in depreciation expense. Uncertainties that may impact these estimates of useful lives include, among others, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions, and supply and demand for our services in the areas in which we operate. When assets are placed into service, management makes estimates with respect to useful lives and salvage values that management believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts.

Our investment in property and equipment for the periods presented is as follows (in thousands):

	Estimated useful lives	December 31, 2016	December 31, 2017
Land	n/a	$ 11,338	15,382
Fresh water surface pipelines and equipment	5 years	39,562	46,139
Above ground storage tanks	10 years	4,301	4,301
Fresh water permanent buried pipelines and equipment	20 years	443,453	472,810
Gathering systems and facilities	20 years	1,551,771	1,781,386
Construction-in-progress	n/a	400,096	654,904
Total property and equipment		2,450,521	2,974,922
Less accumulated depreciation		(254,642)	(369,320)
Property and equipment, net		$ 2,195,879	2,605,602

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

(f) Impairment of Long-Lived Assets

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

During the year ended December 31, 2017, we recorded a $23.4 million impairment charge for the carrying value of property and equipment related to condensate gathering lines which Antero Resources no longer uses. These lines were part of our gathering and processing segment.

(g) Asset Retirement Obligations

We are under no legal obligations, neither contractually nor under the doctrine of promissory estoppel, to restore or dismantle our gathering pipelines, compressor stations, water delivery pipelines and water treatment facility upon abandonment. Our gathering pipelines, compressor stations and fresh water delivery pipelines and facilities have an indeterminate life, if properly maintained. Accordingly, we are not able to make a reasonable estimate of when future dismantlement and removal dates of our pipelines, compressor stations and facilities will occur. It has been determined by our operational management team that abandoning all other ancillary equipment, outside of the assets stated above, would require minimal costs. For the reasons stated above, we have not recorded asset retirement obligations at December 31, 2016 or 2017.

(h) Litigation and Other Contingencies

An accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. We regularly review contingencies to determine the adequacy of our accruals and related disclosures. The ultimate amount of losses, if any, may differ from these estimates.

We accrue losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time a remediation feasibility study, or an evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

As of December 31, 2016 and 2017, we have no recorded liabilities for litigation, environmental, or other contingencies.

(i) Equity-Based Compensation

Our consolidated financial statements reflect various equity-based compensation awards granted by Antero Resources, as well as compensation expense associated with our own plan. These awards include profits interests awards, restricted stock, stock options, restricted units, and phantom units. We recognized expense in each period for an amount allocated from Antero Resources, with the offset included in partners' capital. See Note 3—Transactions with Affiliates for additional information regarding Antero Resources' allocation of expenses to us.

In connection with our Initial Public Offering ("IPO"), the Antero Midstream Partners LP Long-Term Incentive Plan ("Midstream LTIP") was adopted, pursuant to which certain non-employee directors of our general partner and certain officers, employees and consultants of our general partner and its affiliates are eligible to receive awards representing equity interests in the Partnership. An aggregate of 10,000,000 common units may be delivered pursuant to awards under the Midstream LTIP, subject to customary adjustments. For accounting purposes, these units are treated as if they are distributed from us to Antero Resources. Antero Resources recognizes compensation expense for the units awarded to its employees and a portion of that expense is allocated to us. See Note 6—Equity-Based Compensation.

(j) Income Taxes

Our consolidated financial statements do not include a provision for income taxes as we are treated as a partnership for federal and state income tax purposes, with each partner being separately taxed on its distributive share of our items of income, gain, loss, or deduction.

(k) Fair Value Measures

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

The carrying values on our balance sheet of our cash and cash equivalents, accounts receivable—Antero Resources, accounts receivable—third party, prepaid expenses, other assets, accounts payable, accounts payable—Antero Resources, accrued liabilities, other current liabilities, other liabilities and the revolving credit facility approximate fair values due to their short-term maturities.

(l) Investments in Unconsolidated Entities

The Partnership uses the equity method to account for its investments in companies if the investment provides the Partnership with the ability to exercise significant influence over, but not control, the operating and financial policies of the investee. The Partnership's consolidated net income includes the Partnership's proportionate share of the net income or loss of such companies. The Partnership's judgment regarding the level of influence over each equity method investee includes considering key factors such as the Partnership's ownership interest, representation on the board of directors and participation in policy-making decisions of the investee and material intercompany transactions. See Note 11–Equity Method Investments.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

(m) Recently Adopted Accounting Pronouncement

On August 26, 2016, the FASB issued ASU No. 2016-15, Classification of Certain Cash Receipts and Cash Payments, which removes diversity in practice for how certain cash receipts and payments are presented and classified in the statement of cash flows, including the presentation of distributions received from equity method investees. We elected to early adopt the standard during 2017.

As permitted by this standard we made an accounting policy election to account for distributions received from equity method investees under the "nature of the distribution" approach. Under the nature of the distribution approach, distributions received from equity method investees are classified on the basis of the nature of the activity or activities of the investee that generated the distribution as either a return on investment (classified as cash inflows from operating activities) or a return of investment (classified as cash inflows from investing activities). No changes were necessary to our historical financial statements as a result of adopting ASU No. 2016-15.

(3) Transactions with Affiliates

(a) Revenues

All revenues earned, except revenues earned from third parties, were earned from Antero Resources, under various agreements for gathering and compression, water handling and treatment services and seconded employees.

(b) Accounts receivable—Antero Resources, and Accounts payable—Antero Resources

Accounts receivable—Antero Resources represents amounts due from Antero Resources, primarily related to gathering and compression services and water handling and treatment services. Accounts payable—Antero Resources represents amounts due to Antero Resources for general and administrative and other costs.

(c) Allocation of Costs

The employees supporting our operations are employees of Antero Resources. Direct operating expense includes allocated costs of $3.0 million, $4.0 million and $6.4 million during the years ended December 31, 2015, 2016, and 2017, respectively, related to labor charges for Antero Resources employees associated with the operation of our assets. General and administrative expense includes allocated costs of $44.2 million, $49.6 million and $54.1 million during the years ended December 31, 2015, 2016, and 2017, respectively. These costs relate to: (i) various business services, including payroll processing, accounts payable processing and facilities management, (ii) various corporate services, including legal, accounting, treasury, information technology and human resources and (iii) compensation, including equity-based compensation (see Note 6—Equity-Based Compensation for more information). These expenses are charged or allocated to us based on the nature of the expenses and are allocated based on a combination of our proportionate share of gross property and equipment, capital expenditures and labor costs, as applicable. We reimburse Antero Resources directly for all general and administrative costs allocated to us, with the exception of noncash equity compensation allocated to the Partnership for awards issued under the Antero Resources long-term incentive plan or the Midstream LTIP.

(4) Long-term Debt

Long-term debt was as follows at December 31, 2016 and 2017 (in thousands):

	December 31,	
	2016	2017
Credit Facility (a)	$ 210,000	555,000
5.375% senior notes due 2024 (b)	650,000	650,000
Net unamortized debt issuance costs	(10,086)	(9,000)
	$ 849,914	1,196,000

(a) Revolving Credit Facility

On October 26, 2017, we entered into a restated and amended senior revolving credit facility. The facility was amended to include a fall away covenants and lower interest rates that is triggered if and when we are assigned an investment grade credit rating by either Standard and Poor's or Moody's.

Lender commitments under our new facility remained at $1.5 billion. The maturity date of the facility was extended from November 2019 to October 26, 2022. At December 31, 2017, we had borrowings of $555 million and no letters of credit outstanding under the Credit Facility. Under the Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred and the Partnership is in pro forma compliance with the financial covenants under the Credit Facility, commences when the Partnership elects to give notice to the Administrative Agent that the Partnership has received at least one of either (i) a BBB- or better rating from Standard and Poor's or (ii) a Baa3 or better from Moody's (provided that the non-investment grade rating from the other rating agency is at least either Ba1 if Moody's or BB+ if Standard and Poor's (an "Investment Grade Rating")). An Investment Grade Period can end at the Partnership's election.

During a period that is not an Investment Grade Period, the Credit Facility is ratably secured by mortgages on substantially all of our properties, including the properties of our subsidiaries, and guarantees from our subsidiaries. During an Investment Grade Period, the liens securing the obligations thereunder shall be automatically released (subject to the provisions of the Credit Facility).

The revolving credit facility contains certain covenants including restrictions on indebtedness, and requirements with respect to leverage and interest coverage ratios; provided, however, that during an Investment Grade Period, such covenants become less restrictive on the Partnership. The revolving credit facility permits distributions to the holders of our equity interests in accordance with the cash distribution policy adopted by the board of directors of our general partner in connection with the Partnership's initial public offering, provided that no event of default exists or would be caused thereby, and only to the extent permitted by our organizational documents. The Partnership was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2016 and 2017.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly or, in the case of Eurodollar Rate Loans, at the end of the applicable interest period if shorter than six months. Interest is payable at a variable rate based on LIBOR or the base rate, determined by election at the time of borrowing. Interest at the time of borrowing is determined with reference to (i) during any period that is not an Investment Grade Period, the Partnership's then-current leverage ratio and (ii) during an Investment Grade Period, with reference to the rating given to the Partnership by Moody's or Standard and Poor's. During an Investment Grade Period, the applicable margin rates are reduced by 25 basis points. Commitment fees on the unused portion of the revolving credit facility are due quarterly at rates ranging from 0.25% to 0.375% based on the leverage ratio, during a period that is not an Investment Grade Period, and 0.175% to 0.375% based on the Partnership's rating during an Investment Grade Period.

At December 31, 2016 and 2017, we had borrowings under the Credit Facility of $210 million and $555 million, respectively, with a weighted average interest rate of 2.23% and 2.81%, respectively. No letters of credit were outstanding at December 31, 2016 or 2017 under the Credit Facility.

(b) 5.375% Senior Notes Due 2024

On September 13, 2016, the Partnership and its wholly-owned subsidiary, Finance Corp, as co-issuers, issued $650 million in aggregate principal amount of 5.375% senior notes due September 15, 2024 (the "2024 Notes") at par. The 2024 Notes are unsecured and effectively subordinated to the revolving credit facility to the extent of the value of the collateral securing the revolving credit facility. The 2024 Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by the Partnership's wholly-owned subsidiaries (other than Finance Corp) and certain of its future restricted subsidiaries. Interest on the 2024 Notes is payable on March 15 and September 15 of each year. The Partnership may redeem all or part of the 2024 Notes at any time on or after September 15, 2019 at redemption prices ranging from 104.031% on or after September 15, 2019 or 100.00% on or after September 15, 2022. In addition, prior to September 15, 2019, the Partnership may redeem up to 35% of the aggregate principal amount of the 2024 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 Notes, plus accrued and unpaid interest. At any time prior to September 15, 2019, the Partnership may also redeem the 2024 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Notes plus "make-whole" premium and accrued and unpaid interest. If the Partnership undergoes a change of control, the holders of the 2024 Notes will have the right to require the Partnership to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2024 Notes, plus accrued and unpaid interest.

(5) Accrued Liabilities

Accrued liabilities as of December 31, 2016 and 2017 consisted of the following items (in thousands):

	December 31,	
	2016	**2017**
Capital expenditures	$ 35,608	63,286
Operating expenses	14,582	29,905
Interest expense	10,613	10,508
Other	838	2,307
	$ 61,641	106,006

(6) Equity-Based Compensation

Our general and administrative expenses include equity-based compensation costs allocated to us by Antero Resources for grants made pursuant to Antero Resources' long-term incentive plan and the Midstream LTIP. Equity-based compensation expense allocated to us was $22.5 million, $26.0 million and $27.3 million for the years ended December 31, 2015, 2016 and 2017, respectively. These expenses were allocated to us based on our proportionate share of Antero Resources' labor costs. Antero Resources has unamortized expense totaling approximately $112.0 million as of December 31, 2017 related to its various equity-based compensation plans, which includes the Midstream LTIP. A portion of this will be allocated to us as it is amortized over the remaining service period of the related awards. The Partnership does not reimburse Antero Resources for noncash equity compensation allocated to it for awards issued under the Antero Resources long-term incentive plan or the Midstream LTIP.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

Midstream LTIP

Our general partner manages our operations and activities and Antero Resources employs the personnel who provide support to our operations. In connection with the IPO, our general partner adopted the Midstream LTIP, pursuant to which non-employee directors of our general partner and certain officers, employees and consultants of our general partner and its affiliates are eligible to receive awards representing ownership interests in the Partnership. An aggregate of 10,000,000 common units may be delivered pursuant to awards under the Midstream LTIP, subject to customary adjustments. A total of 7,864,621 common units are available for future grant under the Midstream LTIP as of December 31, 2017. Restricted units and phantom units granted under the Midstream LTIP vest subject to the satisfaction of service requirements, upon the completion of which common units in the Partnership are delivered to the holder of the restricted units or phantom units. Compensation related to each restricted unit and phantom unit award is recognized on a straight-line basis over the requisite service period of the entire award. The grant date fair values of these awards are determined based on the closing price of the Partnership's common units on the date of grant. These units are accounted for as if they are distributed by the Partnership to Antero Resources. Antero Resources recognizes compensation expense for the units awarded and a portion of that expense is allocated to the Partnership. Antero Resources allocates equity-based compensation expense to the Partnership based on our proportionate share of Antero Resources' labor costs. The Partnership's portion of the equity-based compensation expense is included in general and administrative expenses, and recorded as a credit to the applicable classes of partners' capital.

A summary of restricted unit and phantom unit awards activity during the year ended December 31, 2017 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2016	1,331,961	$ 27.31	$ 41,131
Granted	377,660	$ 32.52	
Vested	(558,525)	$ 28.00	
Forfeited	(108,133)	$ 28.63	
Total awarded and unvested—December 31, 2017	1,042,963	$ 28.69	$ 30,288

Intrinsic values are based on the closing price of the Partnership's common units on the referenced dates. Midstream LTIP unamortized expense of $25.0 million at December 31, 2017 is expected to be recognized over a weighted average period of approximately 2.0 years and our proportionate share will be allocated to us as it is recognized. We paid $5.9 million in minimum statutory tax withholdings for restricted and phantom units that vested during 2017, which is included in the "Issuance of common units upon vesting of equity-based compensation awards, net of units withheld for income taxes" line item in the Consolidated Statements of Partners' Capital.

(7) Partnership Equity and Distributions

Our Minimum Quarterly Distribution

Our partnership agreement provides for a minimum quarterly distribution of $0.17 per unit for each quarter, or $0.68 per unit on an annualized basis.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

If cash distributions to our unitholders exceed $0.1955 per common unit in any quarter, our unitholders and the holders of our incentive distribution rights (“IDRs”), will receive distributions according to the following percentage allocations:

	Marginal Percentage Interest in Distributions	
Total Quarterly Distribution Target Amount	**Unitholders**	**Holders of IDRs**
above $0.1955 up to $0.2125	85 %	15 %
above $0.2125 up to $0.2550	75 %	25 %
above $0.2550	50 %	50 %

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner is under common control with the holder of the IDRs and may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Upon payment of the February 8, 2017 distribution to unitholders, the requirements for the conversion of all subordinated units were satisfied under our partnership agreement. As a result, effective February 9, 2017, the 75,940,957 subordinated units owned by Antero Resources were converted into common units on a one-for-one basis and now participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of the cash distributions paid by the Partnership or the total units outstanding, as shown on the “Conversion of subordinated units to common units” line item on our consolidated Statement of Partners’ Capital.

Cash Distributions

The board of directors of our general partner has declared a cash distribution of $0.365 per unit for the quarter ended December 31, 2017. The distribution was paid on February 13, 2018 to unitholders of record as of February 1, 2018.

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

The following table details the amount of quarterly distributions the Partnership paid for each of its partnership interests, with respect to the quarter indicated (in thousands, except per unit data):

			Distributions				
			Limited Partners				
Quarter and Year	Record Date	Distribution Date	Common unitholders	Subordinated unitholders	Holder of IDRs	Total	Distributions per limited partner unit
Q4 2015	February 15, 2016	February 29, 2016	$ 22,048	16,708	969	39,725	$ 0.2200
Q1 2016	May 11, 2016	May 25, 2016	23,556	17,846	1,850	43,252	0.2350
Q2 2016	August 10, 2016	August 24, 2016	25,059	18,985	2,731	46,775	0.2500
Q3 2016	November 10, 2016	November 24, 2016	26,901	20,124	4,820	51,845	0.2650
*	November 12, 2016	November 18, 2016	849	—	—	849	*
	Total 2016		$ 98,413	73,663	10,370	182,446	
Q4 2016	February 1, 2017	February 8, 2017	$ 50,090	—	7,543	57,633	$ 0.2800
*	April 21, 2017	April 30, 2017	75	—	—	75	*
Q1 2017	May 3, 2017	May 10, 2017	55,753	—	11,553	67,306	0.3000
Q2 2017	August 3, 2017	August 16, 2017	59,695	—	15,328	75,023	0.3200
Q3 2017	November 1, 2017	November 16, 2017	63,454	—	19,067	82,521	0.3400
*	November 12, 2017	November 17, 2017	1,392	—	—	1,392	*
	Total 2017		$ 230,459	-	53,491	283,950	

* Distribution equivalent rights on limited partner common units that vested under the Midstream LTIP.

(8) Net Income Per Limited Partner Unit

The Partnership's net income is attributed to the general partner and limited partners in accordance with their respective ownership percentages, and when applicable, giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less general partner incentive distributions, by the weighted average number of outstanding limited partner units during the period.

We compute earnings per unit using the two-class method for master limited partnerships. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are attributed to the general partner and limited partners in accordance with the contractual terms of the partnership agreement under the two-class method.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted net income per limited partner unit reflects the potential dilution that could occur if agreements to issue common units, such as awards under long-term incentive

plans, were exercised, settled or converted into common units. When it is determined that potential common units resulting from an award should be included in the diluted net income per limited partner unit calculation, the impact is reflected by applying the treasury stock method. Earnings per common unit assuming dilution for the year ended December 31, 2017 was calculated based on the diluted weighted average number of units outstanding of 186,082,898, including 453,035 dilutive units attributable to non-vested restricted unit and phantom unit awards. For the year ended December 31, 2017, there were no non-vested phantom unit and restricted unit awards that were anti-dilutive and therefore excluded from the calculation of diluted earnings per unit.

The Partnership's calculation of net income per unit for the periods indicated is as follows (in thousands, except per unit data):

	Year Ended December 31,		
	2015	2016	2017
Net income	$ 159,105	236,703	307,315
Less:			
Pre-Water Acquisition net income attributed to parent	(40,193)	—	—
Net income attributable to incentive distribution rights	(1,264)	(16,944)	(69,720)
Limited partner interest in net income	$ 117,648	219,759	237,595
Net income per limited partner unit - basic and diluted	$ 0.74	1.24	1.28
Weighted average limited partner units outstanding - basic	158,479	176,647	185,630
Weighted average limited partner units outstanding - diluted	158,527	176,801	186,083

(9) Sale of Common Units

During the third quarter of 2016, the Partnership entered into an Equity Distribution Agreement (the "Distribution Agreement"), pursuant to which the Partnership may sell, from time to time through brokers acting as its sales agents, common units representing distribution limited partner interest having an aggregate offering price of up to $250 million. The program is registered with the Securities and Exchange Commission (the "SEC") on an effective registration statement on Form S-3. Sales of the common units may be 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 expected to be 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, 2017, the Partnership issued and sold 777,262 common units under the Distribution Agreement, resulting in net proceeds of $25.5 million, net of $0.6 million of compensation payable to the sales agents made during the period and $0.4 million of other offering costs. As of December 31, 2017, additional common units under the Distribution Agreement up to an aggregate sales price of $157.3 million were available for issuance.

In conjunction with the Joint Venture, on February 10, 2017 we issued 6,900,000 common units, including common units issued pursuant to the underwriters' option to purchase additional common units, resulting in net proceeds of approximately $223 million (the "Offering"). We used the proceeds from the Offering to repay outstanding borrowings under our Credit Facility incurred to fund the investment in the Joint Venture, and for general partnership purposes.

(10) Fair Value Measurement

In connection with the Water Acquisition, we have agreed to pay Antero Resources (a) $125 million in cash if the Partnership 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 the Partnership delivers 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. This contingent consideration liability is valued based on Level 3 inputs related to expected average volumes and weighted average cost of capital.

The following table provides a reconciliation of changes in Level 3 financial liabilities measured at fair value on a recurring basis for the periods shown below (in thousands):

Contingent acquisition consideration - December 31, 2015	$	178,049
Accretion		16,489
Contingent acquisition consideration - December 31, 2016	$	194,538
Accretion and change in fair value		13,476
Contingent acquisition consideration - December 31, 2017	$	208,014

We account for contingent consideration in accordance with applicable accounting guidance pertaining to business combinations. We are contractually obligated to pay Antero Resources contingent consideration in connection with the Water Acquisition, and therefore recorded this contingent consideration liability at the time of the Water Acquisition. We update our assumptions each reporting period based on new developments and adjust such amounts to fair value based on revised assumptions, if applicable, until such consideration is satisfied through payment upon achievement of the specified objectives or it is eliminated upon failure to achieve the specified objectives.

As of December 31, 2017, we expect to pay the entire amount of the contingent consideration amounts in 2019 and 2020. The fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 measurement within the fair value hierarchy. The fair value of the contingent consideration liability associated with future milestone payments was based on the risk adjusted present value of the contingent consideration payout.

The carrying values of accounts receivable and accounts payable at December 31, 2016 and 2017 approximated fair value because of their short-term nature. The carrying value of the amounts under the revolving credit facility at December 31, 2016 and 2017 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 Partnership’s 2024 Notes was approximately $669.5 million at December 31, 2017.

(11) Equity Method Investments

In the second quarter of 2016, the Partnership exercised its option to purchase a 15% equity interest in Stonewall, which operates the 67-mile Stonewall pipeline on which Antero is an anchor shipper.

On February 6, 2017, we formed the Joint Venture to develop processing and fractionation assets in Appalachia with MarkWest, a wholly owned subsidiary of MPLX. We and MarkWest each own a 50% equity

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

interest in the Joint Venture and MarkWest operates the Joint Venture assets. The Joint Venture assets consist of processing plants in West Virginia, and a one-third interest in a MarkWest fractionator in Ohio.

Our consolidated net income includes the Partnership's proportionate share of the net income of the Joint Venture and Stonewall. When the Partnership records its proportionate share of net income, it increases equity income in the consolidated statements of operations and comprehensive income and the carrying value of that investment on its balance sheet. When distributions on its proportionate share of net income are received, they are recorded as reductions to the carrying value of the investment on the balance sheet. The Partnership uses the equity method of accounting to account for its investments in Stonewall and the Joint Venture because the Partnership exercises significant influence, but not control, over the entities. Our judgment regarding the level of influence over our equity investments includes considering key factors such as the Partnership's ownership interest, representation on the board of directors and participation in policy-making decisions of Stonewall and the Joint Venture.

The following table is a reconciliation of our investments in these unconsolidated affiliates (in thousands):

	Stonewall	MarkWest Joint Venture	Total Investment in Unconsolidated Affiliates
Balance at December 31, 2015	$ —	—	—
Initial investment	45,044	—	45,044
Additional investments	30,472	—	30,472
Equity in net income of unconsolidated affiliates	485	—	485
Distributions from unconsolidated affiliates	(7,702)	—	(7,702)
Balance at December 31, 2016	68,299	—	68,299
Initial investment	—	153,770	153,770
Additional investments	—	81,234	81,234
Equity in net income of unconsolidated affiliates	10,304	9,890	20,194
Distributions from unconsolidated affiliates	(11,475)	(8,720)	(20,195)
Balance at December 31, 2017	$ 67,128	236,174	303,302

(12) Reporting Segments

The Partnership's operations are located in the United States and are organized into two reporting segments: (1) gathering and processing and (2) water handling and treatment.

Gathering and Processing

The gathering and processing segment includes a network of gathering pipelines and compressor stations that collect and process production from Antero Resources' wells in West Virginia and Ohio. The gathering and processing segment also includes income from processing and fractionation plants through our equity in the Joint Venture with MarkWest.

Water Handling and Treatment

The Partnership's water handling and treatment segment includes two independent systems that deliver fresh water from sources including the Ohio River, local reservoirs as well as several regional waterways. The segment also includes a wastewater treatment facility that is currently undergoing testing and commissioning. The water handling and treatment segment also includes other fluid handling services which includes, high rate transfer, wastewater transportation, disposal and treatment. See Note 2 – Summary of Significant Accounting Policies, Property and Equipment.

These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. We evaluate the performance of the Partnership's

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

business segments based on operating income. Interest expense is primarily managed and evaluated on a consolidated basis.

	Gathering and Processing	Water Handling and Treatment	Consolidated Total
Year ended December 31, 2015			
Revenues:			
Revenue - Antero Resources	$ 230,210	155,954	386,164
Revenue - third-party	382	778	1,160
Total revenues	$ 230,592	156,732	387,324
Operating expenses:			
Direct operating	25,783	53,069	78,852
General and administrative (before equity-based compensation)	22,608	6,128	28,736
Equity-based compensation	17,840	4,630	22,470
Depreciation	60,838	25,832	86,670
Accretion of contingent acquisition consideration	—	3,333	3,333
Total expenses	127,069	92,992	220,061
Operating income	$ 103,523	63,740	167,263
Total assets	$ 1,428,796	551,236	1,980,032
Additions to property and equipment	$ 320,002	132,633	452,635
Year ended December 31, 2016			
Revenues:			
Revenue - Antero Resources	$ 303,250	282,267	585,517
Revenue - third-party	835	—	835
Gain on sale of assets	3,859	—	3,859
Total revenues	307,944	282,267	590,211
Operating expenses:			
Direct operating	27,289	134,298	161,587
General and administrative (before equity-based compensation)	20,118	7,996	28,114
Equity-based compensation	19,714	6,335	26,049
Depreciation	69,962	29,899	99,861
Accretion of contingent acquisition consideration	—	16,489	16,489
Total expenses	137,083	195,017	332,100
Operating income	$ 170,861	87,250	258,111
Equity in earnings of unconsolidated affiliates	$ 485	—	485
Total assets	$ 1,734,208	615,687	2,349,895
Additions to property and equipment	$ 228,100	188,220	416,320

ANTERO MIDSTREAM PARTNERS LP

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2015, 2016, and 2017

	Gathering and Processing	Water Handling and Treatment	Consolidated Total
Year ended December 31, 2017			
Revenues:			
Revenue - Antero Resources	$ 396,202	376,031	772,233
Revenue - third-party	264	—	264
Total revenues	396,466	376,031	772,497
Operating expenses:			
Direct operating	39,251	193,287	232,538
General and administrative (before equity-based compensation)	20,607	10,922	31,529
Equity-based compensation	19,730	7,553	27,283
Impairment of property and equipment	23,431	—	23,431
Depreciation	86,372	33,190	119,562
Accretion of contingent acquisition consideration	—	13,476	13,476
Total expenses	189,391	258,428	447,819
Operating income	$ 207,075	117,603	324,678
Equity in earnings of unconsolidated affiliates	$ 20,194	—	20,194
Total assets	$ 2,237,913	804,296	3,042,209
Additions to property and equipment	$ 346,217	195,162	541,379

(13) Quarterly Financial Information (Unaudited)

Our quarterly financial information for the years ended December 31, 2016 and 2017 is as follows (in thousands, except per unit data):

	First quarter	Second quarter	Third quarter	Forth quarter
Year ended December 31, 2016				
Total operating revenues	$136,072	136,810	150,475	166,854
Total operating expenses	89,452	83,503	76,192	82,953
Operating income	46,620	53,307	74,283	83,901
Net income	42,916	49,912	70,524	73,351
Less: general partner's interest in net income	(1,850)	(2,731)	(4,806)	(7,557)
Net income attributable to limited partner units	$ 41,066	47,181	65,718	65,794
Net income per limited partner unit - basic and diluted	$ 0.23	0.27	0.37	0.37
Year ended December 31, 2017				
Total operating revenues	$174,770	193,766	193,629	210,332
Total operating expenses[(1)]	93,073	101,199	110,458	143,089
Operating income	81,697	92,567	83,171	67,243
Net income	75,092	87,175	80,893	64,155
Less: general partner's interest in net income	(11,553)	(15,328)	(19,067)	(23,772)
Net income attributable to limited partner units	$ 63,539	71,847	61,826	40,383
Net income per limited partner unit - basic and diluted	$ 0.35	0.39	0.33	0.22

(1) Operating expenses in the fourth quarter of 2017 include $23 million of impairment on certain condensate gathering lines that Antero Resources no longer uses.

Exhibit 12.1

ANTERO MIDSTREAM PARTNERS LP
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands)

	2013	2014	2015	2016	2017
Net income and comprehensive income	$ 2,015	127,875	159,105	236,703	307,315
Fixed Charges	164	6,183	8,478	24,140	37,557
Total adjusted earnings available for payment of fixed charges	$ 2,179	134,058	167,583	260,843	344,872
Fixed Charges					
Interest expense, including amortization of debt-related expenses	$ 164	6,183	8,158	$ 21,893	$ 37,557
Rental expense representative of interest factor	—	—	—	—	—
Total fixed charges	$ 164	6,183	8,158	21,893	37,557
Ratio of earnings to fixed charges	13.29 X	21.68 X	20.54 X	11.91 X	9.18 X

Exhibit 21.1

SUBSIDIARIES OF ANTERO MIDSTREAM PARTNERS LP

Name of Subsidiary	Jurisdiction of Organization
Antero Midstream LLC	Delaware
Antero Water LLC	Delaware
Antero Treatment LLC	Delaware
Antero Midstream Finance Corporation	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Antero Midstream Partners GP LLC and
Unitholders of Antero Midstream Partners LP:

We consent to the incorporation by reference in the registration statements (Nos. 333-210372, 333-212283, 333-215912, and 333-220359) on Form S-3 and (No. 333-200111) on Form S-8 of Antero Midstream Partners LP of our report dated February 13, 2018, with respect to the consolidated balance sheets of Antero Midstream Partners LP as of December 31, 2016 and 2017, and the related consolidated statements of operations and comprehensive income, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"), and the effectiveness of internal control over financial reporting as of December 31, 2017, which report appears in the December 31, 2017 annual report on Form 10-K of Antero Midstream Partners LP.

As discussed in note 2 to the consolidated financial statements of Antero Midstream Partners LP, the consolidated statements of operations and comprehensive income, partners' capital, and cash flows for 2015 have been prepared on a combined basis of accounting.

/s/ KPMG LLP

Denver, Colorado
February 13, 2018

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Paul M. Rady, Chairman and Chief Executive Officer of Antero Midstream Partners LP, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of Antero Midstream Partners LP (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2018

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 31.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Michael N. Kennedy, Chief Financial Officer of Antero Midstream Partners LP, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of Antero Midstream Partners LP (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 13, 2018

/s/ Michael N. Kennedy
Michael N. Kennedy
Chief Financial Officer

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF ANTERO MIDSTREAM PARTNERS LP
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Annual Report on Form 10-K of Antero Midstream Partners LP for the year ended December 31, 2017, I, Paul M. Rady, Chief Executive Officer of Antero Midstream Partners LP, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2017 fairly presents, in all material respects, the financial condition and results of operations of Antero Midstream Partners LP for the periods presented therein.

Date: February 13, 2018

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF ANTERO MIDSTREAM PARTNERS LP
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with this Annual Report on Form 10-K of Antero Midstream Partners LP for the year ended December 31, 2017, I, Michael N. Kennedy, Chief Financial Officer of Antero Midstream Partners LP, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2017 fairly presents, in all material respects, the financial condition and results of operations of Antero Midstream Partners LP for the periods presented therein.

Date: February 13, 2018

/s/ Michael N. Kennedy
Michael N. Kennedy
Chief Financial Officer