ANTERO RESOURCES Corp
Form 10-Q
November 01, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2017

OR

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

For the transition period from to

Commission file number: 001-36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

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

(303) 357-7310

(Registrant's telephone number, including area code)

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 Web site, 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 check mark if the registrant has elected not 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 Exchange Act) Yes No

The registrant had 315,632,497 shares of common stock outstanding as of October 26, 2017.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward-looki statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2016 (our “2016 Form 10-K”) on file with the Securities and Exchange Commission (the “SEC”) and in “Item 1A. Risk Factors” of our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity, and capital required for our development program;
- natural gas, natural gas liquids (“NGLs”), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to meet our minimum volume commitments and to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;

- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- operations of Antero Midstream, including the operations of its unconsolidated affiliates;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations, and intentions.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering, processing, transportation, and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price

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volatility and low commodity prices, inflation, availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading “Item 1A. Risk Factors” in our 2016 Form 10-K on file with the SEC and in “Item 1A. Risk Factors” of our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017.

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

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

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

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

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PART I—FINANCIAL INFORMATION

ANTERO RESOURCES CORPORATION

Condensed Consolidated Balance Sheets

December 31, 2016 and September 30, 2017

(Unaudited)

(In thousands, except per share amounts)

	December 31, 2016	September 30, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 31,610	23,694
Accounts receivable, net of allowance for doubtful accounts of $1,195 and $1,320 at December 31, 2016 and September 30, 2017, respectively	29,682	43,854
Accrued revenue	261,960	233,585
Derivative instruments	73,022	299,796
Other current assets	6,313	10,024
Total current assets	402,587	610,953
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	2,331,173	2,305,749
Proved properties	9,549,671	10,779,043
Water handling and treatment systems	744,682	891,869
Gathering systems and facilities	1,723,768	1,977,510
Other property and equipment	41,231	54,571
	14,390,525	16,008,742
Less accumulated depletion, depreciation, and amortization	(2,363,778)	(2,973,544)
Property and equipment, net	12,026,747	13,035,198
Derivative instruments	1,731,063	876,293
Investments in unconsolidated affiliates	68,299	287,842
Other assets	26,854	38,928
Total assets	$ 14,255,550	14,849,214
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 38,627	47,457
Accrued liabilities	393,803	429,696
Revenue distributions payable	163,989	220,971
Derivative instruments	203,635	4,285
Other current liabilities	17,334	15,267
Total current liabilities	817,388	717,676
Long-term liabilities:		
Long-term debt	4,703,973	4,510,521

Deferred income tax liability	950,217	1,180,564
Derivative instruments	234	427
Other liabilities	55,160	52,764
Total liabilities	6,526,972	6,461,952
Commitments and contingencies (notes 10 and 13)		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000 shares; 314,877 shares and 315,470 shares issued and outstanding at December 31, 2016 and September 30, 2017, respectively	3,149	3,155
Additional paid-in capital	5,299,481	6,564,320
Accumulated earnings	959,995	1,088,196
Total stockholders' equity	6,262,625	7,655,671
Noncontrolling interests in consolidated subsidiary	1,465,953	731,591
Total equity	7,728,578	8,387,262
Total liabilities and equity	$ 14,255,550	14,849,214

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Three Months Ended September 30, 2016 and 2017

(Unaudited)

(In thousands, except per share amounts)

	Three Months Ended September 30, 2016	2017
Revenue:		
Natural gas sales	$ 364,373	409,141
Natural gas liquids sales	106,958	224,533
Oil sales	14,793	26,527
Gathering, compression, water handling and treatment	2,969	2,869
Marketing	97,076	50,767
Commodity derivative fair value gains (losses)	530,334	(65,957)
Total revenue	1,116,503	647,880
Operating expenses:		
Lease operating	13,854	23,491
Gathering, compression, processing, and transportation	234,915	282,134
Production and ad valorem taxes	15,554	22,995
Marketing	114,611	78,884
Exploration	1,166	1,599
Impairment of unproved properties	11,753	41,000
Depletion, depreciation, and amortization	199,113	206,968
Accretion of asset retirement obligations	628	658
General and administrative (including equity-based compensation expense of $26,381 and $26,447 in 2016 and 2017, respectively)	57,577	62,203
Total operating expenses	649,171	719,932
Operating income (loss)	467,332	(72,052)
Other income (expenses):		
Equity in earnings of unconsolidated affiliates	1,543	7,033
Interest	(59,755)	(70,059)
Total other expenses	(58,212)	(63,026)
Income (loss) before income taxes	409,120	(135,078)
Provision for income tax (expense) benefit	(140,924)	45,078
Net income (loss) and comprehensive income (loss) including noncontrolling interests	268,196	(90,000)
Net income and comprehensive income attributable to noncontrolling interests	29,941	45,063
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 238,255	(135,063)
Earnings (loss) per common share—basic	$ 0.78	(0.43)

Earnings (loss) per common share—assuming dilution	$ 0.77	(0.43)
Weighted average number of shares outstanding:		
Basic	306,785	315,463
Diluted	308,657	315,463

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Nine Months Ended September 30, 2016 and 2017

(Unaudited)

(In thousands, except per share amounts)

	Nine Months Ended September 30, 2016	2017
Revenue and other:		
Natural gas sales	$ 848,936	1,330,062
Natural gas liquids sales	274,736	590,004
Oil sales	41,712	79,999
Gathering, compression, water handling and treatment	10,107	8,665
Marketing	287,194	166,659
Commodity derivative fair value gains	125,624	458,459
Total revenue and other	1,588,309	2,633,848
Operating expenses:		
Lease operating	37,190	56,034
Gathering, compression, processing, and transportation	649,713	815,710
Production and ad valorem taxes	52,296	70,341
Marketing	378,521	246,298
Exploration	3,289	5,510
Impairment of unproved properties	47,223	83,098
Depletion, depreciation, and amortization	588,057	610,879
Accretion of asset retirement obligations	1,846	1,944
General and administrative (including equity-based compensation expense of $75,667 and $78,925 in 2016 and 2017, respectively)	173,966	191,000
Total operating expenses	1,932,101	2,080,814
Operating income (loss)	(343,792)	553,034
Other income (expenses):		
Equity in earnings of unconsolidated affiliates	2,027	12,887
Interest	(185,634)	(205,311)
Total other expenses	(183,607)	(192,424)
Income (loss) before income taxes	(527,399)	360,610
Provision for income tax (expense) benefit	230,755	(105,087)
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(296,644)	255,523
Net income and comprehensive income attributable to noncontrolling interests	66,400	127,322
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (363,044)	128,201
Earnings (loss) per common share—basic	$ (1.26)	0.41

Earnings (loss) per common share—assuming dilution	$ (1.26)	0.41
Weighted average number of shares outstanding:		
Basic	288,607	315,275
Diluted	288,607	316,140

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Equity

Nine Months Ended September 30, 2017

(Unaudited)

(In thousands)

	Common Stock Shares	Amount	Additional paid-in capital	Accumulated earnings	Noncontrolling interests	Total equity
Balances, December 31, 2016	314,877	$ 3,149	5,299,481	959,995	1,465,953	7,728,578
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	593	6	(7,574)	—	—	(7,568)
Issuance of common units by Antero Midstream Partners LP, net of underwriter discounts and offering costs	—	—	—	—	248,949	248,949
Issuance of common units in Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(1,559)	—	627	(932)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of tax	—	—	205,780	—	(19,940)	185,840
Equity-based compensation	—	—	71,786	—	7,139	78,925
Net income and comprehensive income	—	—	—	128,201	127,322	255,523

Effects of changes in ownership interests in consolidated subsidiaries	—	—	996,406	—	(996,406)	—
Distributions to noncontrolling interests	—	—	—	—	(102,053)	(102,053)
Balances, September 30, 2017	315,470	$ 3,155	6,564,320	1,088,196	731,591	8,387,262

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Cash Flows

Nine Months Ended September 30, 2016 and 2017

(Unaudited)

(In thousands)

	Nine Months Ended September 30,	
	2016	2017
Cash flows from operating activities:		
Net income (loss) including noncontrolling interests	$ (296,644)	255,523
Adjustment to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	589,903	612,823
Impairment of unproved properties	47,223	83,098
Derivative fair value gains	(125,624)	(458,459)
Gains on settled derivatives	813,559	137,392
Proceeds from derivative monetizations	—	749,906
Deferred income tax expense (benefit)	(230,755)	105,087
Equity-based compensation expense	75,667	78,925
Equity in earnings of unconsolidated affiliates	(2,027)	(12,887)
Distributions of earnings from unconsolidated affiliates	—	10,120
Other	(1,544)	1,191
Changes in current assets and liabilities:		
Accounts receivable	10,077	1,771
Accrued revenue	(68,248)	28,375
Other current assets	4,685	(3,836)
Accounts payable	5,683	4,731
Accrued liabilities	41,386	43,043
Revenue distributions payable	42,253	56,982
Other current liabilities	103	(977)
Net cash provided by operating activities	905,697	1,692,808
Cash flows used in investing activities:		
Additions to proved properties	(64,789)	(179,318)
Additions to unproved properties	(559,572)	(182,207)
Drilling and completion costs	(1,009,851)	(946,508)
Additions to water handling and treatment systems	(137,355)	(143,470)
Additions to gathering systems and facilities	(154,136)	(254,619)
Additions to other property and equipment	(1,747)	(11,417)
Investments in unconsolidated affiliates	(45,044)	(216,776)
Change in other assets	(2,173)	(16,148)
Other	—	2,156
Net cash used in investing activities	(1,974,667)	(1,948,307)
Cash flows from financing activities:		

Issuance of common stock	837,414	—
Issuance of common units by Antero Midstream Partners LP	19,605	248,949
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	178,000	311,100
Issuance of senior notes	650,000	—
Repayments on bank credit facilities, net	(552,000)	(198,000)
Payments of deferred financing costs	(9,029)	—
Distributions to noncontrolling interests in consolidated subsidiary	(51,238)	(102,053)
Employee tax withholding for settlement of equity compensation awards	(4,876)	(8,500)
Other	(3,867)	(3,913)
Net cash provided by financing activities	1,064,009	247,583
Net decrease in cash and cash equivalents	(4,961)	(7,916)
Cash and cash equivalents, beginning of period	23,473	31,610
Cash and cash equivalents, end of period	$ 18,512	23,694
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ 132,928	174,324
Supplemental disclosure of noncash investing activities:		
Decrease in accounts payable and accrued liabilities for additions to property and equipment	$ (189,234)	(3,084)

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

(1)Organization

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

(2)Summary of Significant Accounting Policies

(a)Basis of Presentation

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC applicable to interim financial information and should be read in the context of the December 31, 2016 consolidated financial statements and notes thereto for a more complete understanding of the Company's operations, financial position, and accounting policies. The December 31, 2016 consolidated financial statements have been filed with the Securities and Exchange Commission ("SEC") in the Company's 2016 Form 10-K.

The accompanying unaudited condensed consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information, and, accordingly, do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, the accompanying unaudited condensed consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2016 and September 30, 2017, the results of its operations for the three and nine months ended September 30, 2016 and 2017, and its cash flows for the nine months ended September 30, 2016 and 2017. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss. Operating results for the period ended September 30, 2017 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas, NGLs, and oil, natural production declines, the uncertainty of exploration and development drilling results, fluctuations in the fair value of derivative instruments, and other factors. The Company's statement of cash flows for the nine months ended September 30, 2016 includes reclassifications within current liabilities that were made to conform to the nine months ended September 30, 2017 presentation.

The Company's exploration and production activities are accounted for under the successful efforts method.

As of the date these financial statements were filed with the SEC, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified except for the amended and restated credit facilities entered into by Antero and Antero Midstream in October 2017. See note 5 for descriptions of the amended and restated facilies.

(b)Principles of Consolidation

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

We have determined that Antero Midstream is a VIE for which Antero is the primary beneficiary. Therefore, Antero Midstream's accounts are included in the Company's condensed consolidated financial statements. Antero is the primary beneficiary of Antero Midstream based on its power to direct the activities that most significantly impact Antero Midstream's economic performance, and its obligation to absorb losses or right to receive benefits of Antero Midstream that could be significant to Antero Midstream.

Antero Midstream was formed to own, operate, and develop midstream energy assets to service Antero's production under long-term service contracts. Antero owned 53.0% of the outstanding limited partner interests in Antero Midstream at September 30, 2017. Antero Midstream GP LP ("AMGP") indirectly controls the general partnership interest in Antero Midstream as well as Antero IDR

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Holdings LLC ("IDR LLC"), which owns the incentive distribution rights in Antero Midstream. AMGP has not provided, and is not expected to provide, financial support to Antero Midstream. Antero's officers and management group also act as management of Antero Midstream and AMGP.

Antero and Antero Midstream have contracts with 20-year initial terms and automatic renewal provisions, whereby Antero has dedicated the rights for gathering and compression, and water delivery and handling, services to Antero Midstream on a fixed-fee basis. Such dedications cover a substantial portion of Antero's current acreage and future acquired acreage, in each case, except for acreage that was already dedicated to other parties prior to entering into the service contracts or that was acquired subject to a pre-existing dedication. The contracts call for Antero to present, in advance, its drilling and completion plans in order for Antero Midstream to develop gathering and compression and water delivery and handling assets to service Antero's operations. Consequently, the drilling and completion capital investment decisions made by Antero control the development and operation of all of Antero Midstream's assets. Because of these contractual obligations and the capital requirements related to these obligations, Antero Midstream has and, for the foreseeable future, will devote substantially all of its resources to servicing Antero's operations. Additionally, revenues from Antero provide substantially all of Antero Midstream's financial support and, therefore, its ability to finance its operations. As a result of the long-term contractual commitment to support Antero's substantial growth plans, Antero Midstream will be practically and physically constrained from providing any substantive amount of services to third-parties. Therefore, Antero controls the activities that most significantly impact Antero Midstream's economic performance. Antero does not control AMGP and does not have any investment in AMGP.

All significant intercompany accounts and transactions have been eliminated in the Company's condensed consolidated financial statements. Noncontrolling interest in the Company's condensed consolidated financial statements represents the interests in Antero Midstream which are owned by the public and the holder of Antero Midstream's incentive distribution rights. Noncontrolling interests in consolidated subsidiaries is included as a component of equity in the Company's condensed consolidated balance sheets.

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

(c)Use of Estimates

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

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

(d)Risks and Uncertainties

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

(e)Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, which may include commodity swap agreements, basis swap agreements, collar agreements, and other similar

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agreements related to the price risk associated with the Company's production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent that the counterparty is unable to satisfy its settlement obligations. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

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

(f)Industry Segments and Geographic Information

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

All of the Company's assets are located in the United States and substantially all of its production revenues are attributable to customers located in the United States.

(g)Earnings (Loss) per Common Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2017	2016	2017
Basic weighted average number of shares outstanding	306,785	315,463	288,607	315,275
Add: Dilutive effect of non-vested restricted stock units	1,835	—	—	828
Add: Dilutive effect of outstanding stock options	—	—	—	—
Add: Dilutive effect of performance stock units	37	—	—	37
Diluted weighted average number of shares outstanding	308,657	315,463	288,607	316,140
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share(1):				
Non-vested restricted stock and restricted stock units	1,251	5,054	6,899	2,293
Outstanding stock options	693	674	706	679
Performance stock units	660	1,293	577	1,002

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

(h)Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments. From time to time, the Company may be in the position of a “book overdraft” in which outstanding checks exceed cash and cash equivalents.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

The Company classifies book overdrafts within accounts payable within its condensed consolidated balance sheets, and classifies the change in accounts payable associated with book overdrafts as an operating activity within its condensed consolidated statements of cash flows.

(i)Income Taxes

For the three and nine months ended September 30, 2016 and 2017, respectively, the Company's overall effective tax rate was different than the statutory rate of 35% primarily due to the effects of noncontrolling interest income, state tax rates, and permanent differences on vested equity compensation awards.

(3)Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream to own, operate, and develop midstream energy assets that service Antero's production. Antero Midstream's assets consist of gathering systems and facilities, water handling and treatment facilities, and interests in processing and fractionation plants, through which it provides services to Antero under long-term, fixed-fee contracts. AMGP indirectly owns the general partnership interest in Antero Midstream and directly owns capital interests in IDR LLC, which owns the incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero's senior secured revolving bank credit facility (the "Credit Facility"). As an unrestricted subsidiary, Antero Midstream and its subsidiaries are not guarantors of Antero's obligations, and Antero is not a guarantor of Antero Midstream's obligations (see Note 12).

In connection with Antero's contribution of its water handling and treatment assets to Antero Midstream in September 2015, Antero Midstream agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 176,295,000 barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if Antero Midstream delivers 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020.

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

During the nine months ended September 30, 2017, Antero Midstream issued and sold 777,262 common units under the Distribution Agreement, resulting in net proceeds of $25.5 million after deducting commissions and other offering costs. As of September 30, 2017, Antero Midstream had the capacity to issue additional common units under the Distribution Agreement up to an aggregate sales price of $157.3 million.

On May 26, 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. This investment is accounted for under the equity method, and had a carrying amount of $67.5 million at September 30, 2017. Antero Midstream's equity share of the pipeline's earnings was $7.7 million during the nine months ended September 30, 2017.

On February 6, 2017, Antero Midstream formed a joint venture (the "Joint Venture") to develop processing assets in Appalachia with MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, L.P. Antero Midstream and MarkWest each own a 50% equity 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. The Joint Venture is accounted for under the equity method, and had a carrying amount of $220.3 million at September 30, 2017. Antero Midstream's equity share of the Joint Venture's earnings was $5.2 million during the nine months ended September 30, 2017.

In conjunction with the formation of the Joint Venture, on February 10, 2017, Antero Midstream issued 6,900,000 common units, including common units issued pursuant to the underwriters' option to purchase additional common units, generating net proceeds of approximately $223 million. Antero Midstream used the net proceeds to fund the initial contribution to the Joint Venture, repay outstanding borrowings under its credit facility, dated as of November 10, 2014 (the "Prior Midstream Facility"), and for general partnership purposes.

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On September 11, 2017, Antero sold 10,000,000 common units representing limited partnership interests in Antero Midstream for approximately $311 million. The sale of the units is reflected in stockholders' equity as additional paid-in capital, net of taxes. Proceeds from the sale were used to pay down amounts outstanding under Antero' credit facility, dated as of November 4, 2010 (the "Prior Credit Facility").

Antero owned approximately 60.9% and 53.0% of the limited partner interests of Antero Midstream at December 31, 2016 and September 30, 2017, respectively.

(4)Accrued Liabilities

Accrued liabilities as of December 31, 2016 and September 30, 2017 consisted of the following items (in thousands):

	December 31, 2016	September 30, 2017
Capital expenditures	$ 159,811	162,116
Gathering, compression, processing, and transportation expenses	75,223	84,388
Marketing expenses	52,822	32,455
Interest expense	35,533	66,398
Other	70,414	84,339
	$ 393,803	429,696

(5)Long-Term Debt

Long-term debt was as follows at December 31, 2016 and September 30, 2017 (in thousands):

	December 31, 2016	September 30, 2017
Antero:		

Prior Credit Facility(a)	$ 440,000	25,000
5.375% senior notes due 2021(b)	1,000,000	1,000,000
5.125% senior notes due 2022(c)	1,100,000	1,100,000
5.625% senior notes due 2023(d)	750,000	750,000
5.00% senior notes due 2025(e)	600,000	600,000
Net unamortized premium	1,749	1,588
Net unamortized debt issuance costs	(37,690)	(33,789)
Antero Midstream:		
Prior Midstream Facility(g)	210,000	427,000
5.375% senior notes due 2024(h)	650,000	650,000
Net unamortized debt issuance costs	(10,086)	(9,278)
	$ 4,703,973	4,510,521

Antero Resources Corporation

(a)Senior Secured Revolving Credit Facility

Antero's Credit Facility (as defined below) is with a consortium of bank lenders. On November 4, 2010, Antero entered into a credit facility with a consortium of bank lenders (the "Prior Credit Facility"). On October 26, 2017, Antero entered into an amendment and restatement of the Prior Credit Facility (the "Credit Facility"). Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero's assets and are subject to regular annual redeterminations. At September 30, 2017, the borrowing base under the Prior Credit Facility was $4.75 billion and lender commitments were $4.0 billion. As of October 26, 2017, the Credit Facility had a maximum facility amount of $4.75 billion, aggregate commitments were $2.5 billion, and the facility was subject to a $4.5 billion borrowing base. The next redetermination of the borrowing base under the Credit Facility is scheduled to occur in March 2018. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the maturity of any series of Antero's senior notes, unless such series of notes is refinanced.

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

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

Antero was in compliance with all of the financial covenants under the Prior Credit Facility as of December 31, 2016 and September 30, 2017.

As of September 30, 2017, Antero had a total outstanding balance under the Prior Credit Facility of $25 million, with a weighted average interest rate of 4.75%, and outstanding letters of credit of $700 million. As of December 31, 2016, Antero had an outstanding balance under the Prior Credit Facility of $440 million, with a weighted average interest rate of 2.44%, and outstanding letters of credit of $710 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from (i) 0.300% to 0.375% (during any period that is not an Investment Grade Period) of the unused portion based on utilization and (ii) 0.150% to 0.300% (during an Investment Grade Period) of the unused portion based on Antero's credit rating.

(b)5.375% Senior Notes Due 2021

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

(c)5.125% Senior Notes Due 2022

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

(d)5.625% Senior Notes Due 2023

On March 17, 2015, Antero issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 notes") at par. The 2023 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit

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

(e) 5.00% Senior Notes Due 2025

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

(f)Treasury Management Facility

Antero has a stand-alone revolving note with a lender which provides for up to $25 million of cash management obligations in order to facilitate Antero's daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the revolving note bear interest at the lender's prime rate plus 1.0%. The note matures on May 1, 2018. At December 31, 2016 and September 30, 2017, there were no outstanding borrowings under this note.

Antero Midstream Partners LP

(g)Senior Secured Revolving Credit Facility – Antero Midstream

Antero Midstream has a secured revolving credit facility (the "Midstream Facility") with a syndicate of bank lenders. The Midstream Facility is an amendment and restatement of the Prior Midstream Facility, and provides for lender commitments of $1.5 billion. The maturity date of the Midstream Facility is October 26, 2022.

During any period that is not an Investment Grade Period (as such term is defined in the Midstream Facility), the Midstream Facility is ratably secured by mortgages on substantially all of the properties of Antero Midstream and guarantees from its restricted subsidiaries, as applicable. During an Investment Grade Period under the Midstream Facility, the liens securing the Midstream Facility are automatically released (subject to the provisions of the Midstream Facility). The Midstream Facility contains certain covenants, including restrictions on indebtedness and certain distributions to owners, and requirements with respect to leverage and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by election at the time of borrowing. Interest at the time of borrowing is determined with reference to (i) during any period that is not an Investment Grade Period, the Antero Midstream'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. Antero Midstream was in compliance with all of the financial covenants under the Prior Midstream Facility as of December 31, 2016 and September 30, 2017.

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As of September 30, 2017, Antero Midstream had an outstanding balance under the Prior Midstream Facility of $427 million with a weighted average interest rate of 2.82%. As of December 31, 2016, Antero Midstream had a total outstanding balance under the Prior Midstream Facility of $210 million with a weighted average interest rate of 2.23%. Commitment fees on the unused portion of the Midstream Facility are due quarterly at rates ranging from (i) 0.25% to 0.375% of the unused portion (during an period that is not an Investment Grade Period) based on the leverage ratio and (ii) 0.175% to 0.375% of the unused portion (during an Investment Grade Period) based on Antero Midstream's credit rating.

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

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

(6)Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2017 (in thousands):

Asset retirement obligations—December 31, 2016	$ 32,736
Obligations settled	(21)

Obligations incurred for wells drilled and producing properties acquired	3,399
Accretion expense	1,944
Asset retirement obligations—September 30, 2017	$ 38,058

Asset retirement obligations are included in Other liabilities on the Company's condensed consolidated balance sheets.

(7)Equity-Based Compensation

Antero is authorized to grant up to 16,906,500 shares of common stock to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the "Plan"). The Plan allows equity-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero's Board of Directors. A total of 7,724,613 shares were available for future grant under the Plan as of September 30, 2017.

Antero Midstream is authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream under the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream Plan") to non-employee directors of its general partner and certain officers, employees, and consultants of Antero Midstream and its affiliates (which include Antero). A total of 7,656,134 common units were available for future grant under the Midstream Plan as of September 30, 2017.

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The Company's equity-based compensation expense, by type of award, was as follows for the three and nine months ended September 30, 2016 and 2017 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2017	2016	2017
Restricted stock unit awards	$ 18,618	17,910	54,231	54,816
Stock options	638	614	1,939	1,850
Performance share unit awards	2,668	3,014	6,017	7,897
Antero Midstream phantom unit awards	3,977	4,420	11,978	12,906
Equity awards issued to directors	480	489	1,502	1,456
Total expense	$ 26,381	26,447	75,667	78,925

Restricted Stock Unit Awards

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

A summary of restricted stock unit awards activity for the nine months ended September 30, 2017 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2016	5,353,447	$ 31.77	$ 126,609
Granted	828,753	$ 22.21	
Vested	(834,796)	$ 43.46	
Forfeited	(353,152)	$ 27.10	
Total awarded and unvested—September 30, 2017	4,994,252	$ 28.56	$ 99,386

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. As of September 30, 2017, there was $85.3 million of unamortized equity-based compensation expense related to unvested restricted stock units. That expense is expected to be recognized over a weighted average period of approximately 1.8 years.

Stock Options

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

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A summary of stock option activity for the nine months ended September 30, 2017 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2016	687,929	$ 50.46	8.12	$ —
Granted	—	$ —		
Exercised	—	$ —		
Forfeited	(16,542)	$ 50.00		
Expired	—	$ —		
Outstanding at September 30, 2017	671,387	$ 50.47	7.32	$ —
Vested or expected to vest as of September 30, 2017	671,387	$ 50.47	7.32	$ —
Exercisable at September 30, 2017	363,605	$ 50.70	7.20	$ —

Intrinsic values are based on the exercise price of the options and the closing price of the Company's stock on the referenced dates. As of September 30, 2017, there was $3.3 million of unamortized equity-based compensation expense related to unvested stock options. That expense is expected to be recognized over a weighted average period of approximately 1.5 years.

Performance Share Unit Awards

Performance Share Unit Awards Based on Price Targets

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

Performance Share Unit Awards Based on Total Shareholder Return

In 2016 and 2017, the Company also granted PSUs to certain of its employees and executive officers which vest based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR of a peer group of companies over a three-year performance period. The number of performance shares which may ultimately be earned ranges from zero to 200% of the PSUs granted. Expense related to these PSUs is recognized on a straight-line basis over three years.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the nine months ended September 30, 2017 is as follows:

	Number of units	Weighted average grant date fair value
Total awarded and unvested—December 31, 2016	785,301	$ 29.75
Granted	558,021	$ 26.21
Vested	(41,666)	$ 27.38
Forfeited	(8,623)	$ 29.86
Total awarded and unvested—September 30, 2017	1,293,033	$ 28.30

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The following table presents information regarding the weighted average fair value for PSUs granted during the nine months ended September 30, 2017 and the assumptions used to determine the fair values.

	Nine Months Ended September 30, 2017	
Dividend yield	—	%
Volatility	42	%
Risk-free interest rate	1.40	%
Weighted average fair value of awards granted	$ 26.21	

As of September 30, 2017, there was $21.1 million of unamortized equity-based compensation expense related to unvested PSUs. That expense is expected to be recognized over a weighted average period of approximately 2.1 years.

Antero Midstream Partners Phantom Unit Awards

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

A summary of phantom unit awards activity for the nine months ended September 30, 2017 is as follows:

	Number of units	Weighted average	Aggregate intrinsic value

		grant date fair value	(in thousands)
Total awarded and unvested—December 31, 2016	1,331,961	$ 27.31	$ 41,131
Granted	377,660	$ 32.52	
Vested	(73,080)	$ 21.34	
Forfeited	(78,584)	$ 28.76	
Total awarded and unvested—September 30, 2017	1,557,957	$ 28.78	$ 49,122

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. As of September 30, 2017, there was $30.4 million of unamortized equity-based compensation expense related to unvested phantom unit awards. That expense is expected to be recognized over a weighted average period of approximately 2.2 years.

(8)Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2016 and September 30, 2017 approximated market values because of their short-term nature. The carrying values of the amounts outstanding under the Prior Credit Facility and Prior Midstream Facility at December 31, 2016 and September 30, 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 Antero's senior notes was approximately $3.5 billion at December 31, 2016 and September 30, 2017. Based on Level 2 market data inputs, the fair value of Antero Midstream's senior notes was approximately $657 million at December 31, 2016 and $676 million at September 30, 2017.

See Note 9 for information regarding the fair value of derivative financial instruments.

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(9)Derivative Instruments

(a)Commodity Derivative Positions

The Company periodically enters into natural gas, NGLs, and oil derivative contracts with counterparties to hedge the price risk associated with its production. These derivatives are entered into for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs, and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs, and oil recognized upon the ultimate sale of the Company's production.

The Company was party to various fixed price commodity swap contracts that settled during the nine months ended September 30, 2016 and 2017. The Company enters into these swap contracts when management believes that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices upon settlement exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices upon settlement are less than the contractually provided fixed price, the Company receives the difference from the counterparty. In addition to fixed price swap contracts, the Company has entered into basis swap contracts in order to hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price at which the Company sells a portion of its natural gas production.

The Company's derivative swap contracts have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's statements of operations.

As of September 30, 2017, the Company's fixed price natural gas, NGLs, and oil swap positions from October 1, 2017 through December 31, 2023 were as follows (abbreviations in the table refer to the index to which the swap position is tied, as follows: NYMEX=Henry Hub; CGTLA=Columbia Gas Louisiana Onshore; CCG=Chicago City Gate; Mont Belvieu-Ethane=Mont Belvieu Purity Ethane; Mont Belvieu-Propane=Mont Belvieu Propane; NYMEX-WTI=West Texas Intermediate):

	Natural gas MMbtu/day	Oil Bbls/day	Natural Gas Liquids Bbls/day	Weighted average index

				price
Three months ending December 31, 2017:				
NYMEX ($/MMBtu)	1,370,000	—	—	$ 3.46
CGTLA ($/MMBtu)	420,000	—	—	$ 4.37
CCG ($/MMBtu)	70,000	—	—	$ 4.68
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 54.75
Mont Belvieu-Ethane ($/Gallon)	—	—	20,000	$ 0.25
Mont Belvieu-Propane ($/Gallon)	—	—	27,500	$ 0.40
Total	1,860,000	3,000	47,500	
Year ending December 31, 2018:				
NYMEX ($/MMBtu)	2,002,500	—	—	$ 3.50
NYMEX-WTI ($/Bbl)	—	1,000	—	$ 49.96
Mont Belvieu-Propane ($/Gallon)	—	—	3,000	$ 0.67
Total	2,002,500	1,000	3,000	
Year ending December 31, 2019:				
NYMEX ($/MMBtu)	2,330,000			$ 3.50
Year ending December 31, 2020:				
NYMEX ($/MMBtu)	1,417,500			$ 3.25
Year ending December 31, 2021:				
NYMEX ($/MMBtu)	710,000			$ 3.00
Year ending December 31, 2022:				
NYMEX ($/MMBtu)	850,000			$ 3.00
Year ending December 31, 2023:				
NYMEX ($/MMBtu)	90,000			$ 2.91

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As of September 30, 2017, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of TCO to the NYMEX Henry Hub natural gas price, were as follows:

	Natural gas MMbtu/day	Hedged Differential ($/MMBtu)
Three months ending December 31, 2017:	125,000	$ (0.51)

As of September 30, 2017, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of NYMEX Henry Hub to the TCO natural gas price, were as follows:

	Natural gas MMbtu/day	Hedged Differential ($/MMBtu)
Three months ending December 31, 2017:	125,000	$ 0.39

(b)Commodity Derivative Fair Values

The following table presents a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets as of December 31, 2016 and September 30, 2017. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2016 Balance sheet location	Fair value (In thousands)	September 30, 2017 Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 73,022	Current assets	299,796
Commodity contracts	Long-term assets	1,731,063	Long-term assets	876,293

Total asset derivatives		1,804,085		1,176,089
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	203,635	Current liabilities	4,285
Commodity contracts	Long-term liabilities	234	Long-term liabilities	427
Total liability derivatives		203,869		4,712
Net derivatives		$ 1,600,216		1,171,377

The following table presents the gross values of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets as of the dates presented, all at fair value (in thousands):

	December 31, 2016			September 30, 2017		
	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet
Commodity derivative assets	$ 1,914,245	(110,160)	1,804,085	$ 1,326,727	(150,638)	1,176,089
Commodity derivative liabilities	$ (324,667)	120,798	(203,869)	$ (4,823)	111	(4,712)

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The following is a summary of derivative fair value gains and where such values are recorded in the condensed consolidated statements of operations for the three and nine months ended September 30, 2016 and 2017 (in thousands):

	Statement of operations location	Three months ended September 30,		Nine months ended September 30,	
		2016	2017	2016	2017
Commodity derivative fair value gains (losses)	Revenue	$ 530,334	(65,957)	$ 125,624	458,459

Commodity derivative fair value gains (losses) for the three and nine months ended September 30, 2017 include gains of $750 million related to certain natural gas derivatives that were monetized prior to their settlement dates. Proceeds received from the monetizations are classified as operating cash flows on the Company's condensed consolidated statement of cash flows for the nine months ended September 30, 2017. The monetizations were effected by reducing the average fixed index prices on certain natural gas swap contracts maturing from 2018 through 2022 while maintaining the total volumes hedged. The Company's commodity derivative position presented in note 9(a) reflects the adjusted fixed price indices after the monetization. Proceeds from the monetization were used to pay down amounts outstanding under the Prior Credit Facility.

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

(10)Contingencies

SJGC

The Company is the plaintiff in a lawsuit against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, "SJGC") pending in United States District Court in Colorado. In March 2015, the Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC had short paid, and continued to short pay, the Company in connection with two nearly identical long term gas contracts. Under those contracts, SJGC are long term purchasers of 80,000 MMBtu/day of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the term of the contracts continues through October 2019. The price for gas was based on specified indices in the contracts. Beginning in October 2014, SJGC began short paying the Company based on price indices unilaterally selected by SJGC and not the applicable index specified in the contracts.

SJGC claimed that the index price specified in the contracts, and the index at which SJGC paid for deliveries from 2011 through September 2014, was no longer appropriate under the contracts because a market disruption event (as defined by the contract) had occurred and, as a result, a new index price was required to be determined by the parties. The Company rejected SJGC's contention that a market disruption event occurred. SJGC's actions constituted a breach of the contracts by failing to pay the Company based on the express price terms of the contracts and paying the Company based on unilaterally selected price indices in violation of the contracts' remedial provisions. On May 8, 2017, a jury in the United States District Court in Colorado returned a unanimous verdict finding in favor of Antero's positions in the lawsuit against SJGC. On July 21, 2017, final judgment on the jury's unanimous verdict was entered by the court. On August 18, 2017, SJGC filed post-judgment motions with the court, which are currently pending. If the court denies those motions, SJGC will have 30 days from the court's decision on these post-judgment motions to file an appeal. SJGC continues to short pay the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. Through September 30, 2017, the Company estimates that it is owed approximately $70 million (gross damages, including interest) more than SJGC has paid using the indices unilaterally selected by them. Substantially all of this amount has not been accrued in the Company's financial statements. The Company will vigorously seek recovery from SJGC of all underpayments and damages, including interest, based on the contracted price.

WGL

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") were involved in a pricing dispute involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. From January 2016 through July 2017, the aggregate daily gas volumes contracted for under the Contracts was 500,000 MMBtu/day, with the aggregate daily contracted volumes having increased to 600,000 MMBtu/day during the months of August and September 2017. The Company invoiced WGL based on the natural gas index price specified in the Contracts and WGL paid the Company based on that invoice price. However, WGL asserted that the index price was no longer appropriate under the Contracts and claimed that an undefined alternative index was more appropriate for the delivery point of the gas. In July 2016, the matter was referred to arbitration by the Colorado district court. In January 2017, after hearing a week of testimony and evidence, the arbitration panel ruled in the Company's favor. As a result, the index price has remained as specified in the Contracts and there will be no

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adjustments to the invoices that have been paid by WGL, nor will future invoices to WGL be adjusted based on the same claim rejected by the arbitration panel. The arbitration panel's award was confirmed by the Colorado district court on April 14, 2017.

In March of 2017, WGL filed a second lawsuit against the Company in Colorado district court alleging breach of contract and seeking damages of more than $30 million. In this lawsuit, WGL claimed that the Company breached its contractual obligations under the Contracts by failing to deliver "TCO pool" gas. In subsequent filings, WGL explained that its claims were based on an alleged obligation that the Company must deliver gas to the Columbia IPP Pool ("IPP Pool"). WGL asserted this exact same claim in the arbitration and it was rejected by the arbitration panel. The arbitration panel specifically found that the Delivery Point under the Contracts was at a specific point in Braxton, West Virginia, not the IPP Pool. On August 24, 2017, the Colorado district court dismissed with prejudice WGL's claims against the Company in its second lawsuit and found that the Company had not breached its Contracts with WGL by allegedly failing to deliver to the IPP Pool. The Court also reaffirmed the arbitration panel's finding that the delivery point under the Contracts was not the IPP Pool. WGL has appealed this decision to the Colorado Court of Appeals decision and that appeal remains pending.

The Company is also actively engaged in pursuing cover damages against WGL based on WGL's failure to take receipt of all of the agreed quantities of gas required under the Contracts. WGL's failure to take the gas volumes specified in the Contracts is directly related to WGL's lack of primary firm transportation rights at the Delivery Point. The failures by WGL to take the gas began in April 2017 and have continued each month since in varying quantities. In defense of its conduct, WGL has asserted to the Company that their failure to receive gas is excused by (1) the Company's failure to deliver gas to the IPP Pool or (2) alleged instances of Force Majeure under the Contracts. However, as stated above, the alleged obligation that the Company must deliver gas to the IPP Pool was rejected by the arbitration panel and the Colorado district court. Further, the Contracts expressly prohibit a Force Majeure claim in circumstances in which the gas purchaser does not have primary firm transportation agreements in place to transport the purchased gas. In each instance that WGL has failed to receive the quantity of gas required under the Contracts, the Company has resold the quantities not taken and invoiced WGL for cover damages pursuant to the terms of the Contracts. WGL has refused to pay for the invoiced cover damages as required by the Contracts and has also short paid the Company for certain amounts of gas received by WGL. Through September 30, 2017, these damages amounted to approximately $65 million (gross damages, including interest). This amount has not been accrued in the Company's financial statements. The Company is currently pursuing its cover damages in a lawsuit filed in Colorado district court on October 24, 2017. WGL's failure to take receipt of all quantities of gas and resulting cover damages remains ongoing. The Company will continue to vigorously seek recovery of its cover damages and other unpaid amounts, including interest, as part of its claims against WGL.

Other

The Company is party to various other legal proceedings and claims in the ordinary course of its business. The Company believes that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

(11)Segment Information

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

Operating segments are evaluated based on their contribution to consolidated results, which is primarily determined by the respective operating income of each segment. General and administrative expenses are allocated to the gathering and processing and water handling and treatment segments based on the nature of the expenses and on a combination of the segments' proportionate share of the Company's consolidated property and equipment, capital expenditures, and labor costs, as applicable. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes, and interest expense are primarily managed and evaluated on a consolidated basis. Intersegment sales are transacted at prices which approximate market. Accounting policies for each segment are the same as the Company's accounting policies described in Note 2 to the condensed consolidated financial statements.

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The operating results and assets of the Company's reportable segments were as follows for the three months ended September 30, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2016:						
Sales and revenues:						
Third-party	$ 1,016,458	2,745	224	97,076	—	1,116,503
Intersegment	3,990	75,319	72,187	—	(151,496)	—
Total	$ 1,020,448	78,064	72,411	97,076	(151,496)	1,116,503
Operating expenses:						
Lease operating	$ 13,710	—	28,978	—	(28,834)	13,854
Gathering, compression, processing, and transportation	303,753	6,400	—	—	(75,238)	234,915
Depletion, depreciation, and amortization	172,735	18,540	7,838	—	—	199,113
General and administrative	44,637	10,282	3,033	—	(375)	57,577
Other	31,266	(1,708)	3,070	114,611	(3,527)	143,712
Total	566,101	33,514	42,919	114,611	(107,974)	649,171
Operating income (loss)	$ 454,347	44,550	29,492	(17,535)	(43,522)	467,332
Equity in earnings of unconsolidated affiliates	$ —	1,543	—	—	—	1,543
Segment assets	$ 12,966,493	1,669,667	562,995	33,114	(603,016)	14,629,253
Capital expenditures for segment assets	$ 909,837	56,836	58,730	—	(43,343)	982,060

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2017:						
Sales and revenues:						
Third-party	$ 594,244	2,609	260	50,767	—	647,880
Intersegment	3,070	97,909	92,851	—	(193,830)	—
Total	$ 597,314	100,518	93,111	50,767	(193,830)	647,880
Operating expenses:						
Lease operating	$ 24,060	—	51,569	—	(52,138)	23,491
Gathering, compression, processing, and transportation	369,538	10,468	—	—	(97,872)	282,134
Depletion, depreciation, and amortization	176,188	22,027	8,753	—	—	206,968
General and administrative	48,289	9,336	4,980	—	(402)	62,203
Other	65,259	92	3,457	78,884	(2,556)	145,136
Total	683,334	41,923	68,759	78,884	(152,968)	719,932
Operating income (loss)	$ (86,020)	58,595	24,352	(28,117)	(40,862)	(72,052)
Equity in earnings of unconsolidated affiliates	$ —	7,033	—	—	—	7,033
Segment assets	$ 12,751,606	2,158,107	752,982	15,807	(829,288)	14,849,214
Capital expenditures for segment assets	$ 415,088	99,254	48,019	—	(40,704)	521,657

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The operating results and assets of the Company's reportable segments were as follows for the nine months ended September 30, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2016:						
Sales and revenues:						
Third-party	$ 1,291,008	9,463	644	287,194	—	1,588,309
Intersegment	11,714	210,144	203,106	—	(424,964)	—
Total	$ 1,302,722	219,607	203,750	287,194	(424,964)	1,588,309
Operating expenses:						
Lease operating	$ 37,299	—	104,009	—	(104,118)	37,190
Gathering, compression, processing, and transportation	838,936	20,567	—	—	(209,790)	649,713
Depletion, depreciation, and amortization	513,302	52,780	21,975	—	—	588,057
General and administrative	135,356	29,755	9,957	—	(1,102)	173,966
Other	104,279	(809)	11,568	378,521	(10,384)	483,175
Total	1,629,172	102,293	147,509	378,521	(325,394)	1,932,101
Operating income (loss)	$ (326,450)	117,314	56,241	(91,327)	(99,570)	(343,792)
Equity in earnings of unconsolidated affiliates	$ —	2,027	—	—	—	2,027
Segment assets	$ 12,966,493	1,669,667	562,995	33,114	(603,016)	14,629,253
Capital expenditures for segment assets	$ 1,734,914	154,136	137,355	—	(98,955)	1,927,450

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2017:						
Sales and revenues:						
Third-party	$ 2,458,524	7,472	1,193	166,659	—	2,633,848
Intersegment	11,421	283,467	270,033	—	(564,921)	—
Total	$ 2,469,945	290,939	271,226	166,659	(564,921)	2,633,848
Operating expenses:						
Lease operating	$ 56,991	—	131,635	—	(132,592)	56,034
Gathering, compression, processing, and transportation	1,070,522	28,492	—	—	(283,304)	815,710
Depletion, depreciation, and amortization	521,603	64,445	24,831	—	—	610,879
General and administrative	148,876	30,179	13,383	—	(1,438)	191,000
Other	158,128	104	12,333	246,298	(9,672)	407,191
Total	1,956,120	123,220	182,182	246,298	(427,006)	2,080,814
Operating income (loss)	$ 513,825	167,719	89,044	(79,639)	(137,915)	553,034
Equity in earnings of unconsolidated affiliates	$ —	12,887	—	—	—	12,887
Segment assets	$ 12,751,606	2,158,107	752,982	15,807	(829,288)	14,849,214
Capital expenditures for segment assets	$ 1,456,870	254,619	143,470	—	(137,420)	1,717,539

(12)Subsidiary Guarantors

Each of Antero's wholly-owned subsidiaries has fully and unconditionally guaranteed Antero's senior notes. Antero Midstream and its subsidiaries have been designated as unrestricted subsidiaries under the Credit Facility and the indentures governing Antero's senior notes, and do not guarantee any of Antero's obligations (see Note 5). In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a "Subsidiary" of the Company (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease))

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and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person which is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

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

The following Condensed Consolidating Balance Sheets at December 31, 2016 and September 30, 2017, and the related Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and nine months ended September 30, 2016 and 2017 and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2016 and 2017 present financial information for Antero on a stand-alone basis (carrying its investment in subsidiaries using the equity method), financial information for the subsidiary guarantors, financial information for the non-guarantor subsidiaries, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. Antero's wholly-owned subsidiaries are not restricted from making distributions to the Parent.

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Condensed Consolidating Balance Sheet

December 31, 2016

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 17,568	—	14,042	—	31,610
Accounts receivable, net	28,442	—	1,240	—	29,682
Intercompany receivables	3,193	—	64,139	(67,332)	—
Accrued revenue	261,960	—	—	—	261,960
Derivative instruments	73,022	—	—	—	73,022
Other current assets	5,784	—	529	—	6,313
Total current assets	389,969	—	79,950	(67,332)	402,587
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,331,173	—	—	—	2,331,173
Proved properties	9,726,957	—	—	(177,286)	9,549,671
Water handling and treatment systems	—	—	744,682	—	744,682
Gathering systems and facilities	17,929	—	1,705,839	—	1,723,768
Other property and equipment	41,231	—	—	—	41,231
	12,117,290	—	2,450,521	(177,286)	14,390,525
Less accumulated depletion, depreciation, and amortization	(2,109,136)	—	(254,642)	—	(2,363,778)
Property and equipment, net	10,008,154	—	2,195,879	(177,286)	12,026,747
Derivative instruments	1,731,063	—	—	—	1,731,063
Investments in subsidiaries	(420,429)	—	—	420,429	—
Contingent acquisition consideration	194,538	—	—	(194,538)	—
Investments in unconsolidated affiliates	—	—	68,299	—	68,299
Other assets, net	21,087	—	5,767	—	26,854
Total assets	$ 11,924,382	—	2,349,895	(18,727)	14,255,550
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 21,648	—	16,979	—	38,627
Intercompany payable	64,139	—	3,193	(67,332)	—

Accrued liabilities	332,162	—	61,641	—	393,803
Revenue distributions payable	163,989	—	—	—	163,989
Derivative instruments	203,635	—	—	—	203,635
Other current liabilities	17,134	—	200	—	17,334
Total current liabilities	802,707	—	82,013	(67,332)	817,388
Long-term liabilities:					
Long-term debt	3,854,059	—	849,914	—	4,703,973
Deferred income tax liability	950,217	—	—	—	950,217
Contingent acquisition consideration	—	—	194,538	(194,538)	—
Derivative instruments	234	—	—	—	234
Other liabilities	54,540	—	620	—	55,160
Total liabilities	5,661,757	—	1,127,085	(261,870)	6,526,972
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,222,810	(1,222,810)	—
Common stock	3,149	—	—	—	3,149
Additional paid-in capital	5,299,481	—	—	—	5,299,481
Accumulated earnings	959,995	—	—	—	959,995
Total stockholders' equity	6,262,625	—	1,222,810	(1,222,810)	6,262,625
Noncontrolling interest in consolidated subsidiary	—	—	—	1,465,953	1,465,953
Total equity	6,262,625	—	1,222,810	243,143	7,728,578
Total liabilities and equity	$ 11,924,382	—	2,349,895	(18,727)	14,255,550

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Condensed Consolidating Balance Sheet

September 30, 2017

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 21,199	—	2,495	—	23,694
Accounts receivable, net	42,689	—	1,165	—	43,854
Intercompany receivables	4,050	—	84,124	(88,174)	—
Accrued revenue	233,585	—	—	—	233,585
Derivative instruments	299,796	—	—	—	299,796
Other current assets	9,011	—	1,013	—	10,024
Total current assets	610,330	—	88,797	(88,174)	610,953
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,305,749	—	—	—	2,305,749
Proved properties	11,093,749	—	—	(314,706)	10,779,043
Water handling and treatment systems	—	—	891,869	—	891,869
Gathering systems and facilities	17,929	—	1,959,581	—	1,977,510
Other property and equipment	54,571	—	—	—	54,571
	13,471,998	—	2,851,450	(314,706)	16,008,742
Less accumulated depletion, depreciation, and amortization	(2,630,298)	—	(343,246)	—	(2,973,544)
Property and equipment, net	10,841,700	—	2,508,204	(314,706)	13,035,198
Derivative instruments	876,293	—	—	—	876,293
Investments in subsidiaries	488,089	—	—	(488,089)	—
Contingent acquisition consideration	204,210	—	—	(204,210)	—
Investments in unconsolidated affiliates	—	—	287,842	—	287,842
Other assets, net	28,380	—	10,548	—	38,928
Total assets	$ 13,049,002	—	2,895,391	(1,095,179)	14,849,214
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 33,637	—	13,820	—	47,457
Intercompany payable	84,124	—	4,050	(88,174)	—

Accrued liabilities	359,164	—	70,532	—	429,696
Revenue distributions payable	220,971	—	—	—	220,971
Derivative instruments	4,285	—	—	—	4,285
Other current liabilities	15,061	—	206	—	15,267
Total current liabilities	717,242	—	88,608	(88,174)	717,676
Long-term liabilities:					
Long-term debt	3,442,799	—	1,067,722	—	4,510,521
Deferred income tax liability	1,180,564	—	—	—	1,180,564
Contingent acquisition consideration	—	—	204,210	(204,210)	—
Derivative instruments	427	—	—	—	427
Other liabilities	52,299	—	465	—	52,764
Total liabilities	5,393,331	—	1,361,005	(292,384)	6,461,952
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,534,386	(1,534,386)	—
Common stock	3,155	—	—	—	3,155
Additional paid-in capital	6,564,320	—	—	—	6,564,320
Accumulated earnings	1,088,196	—	—	—	1,088,196
Total stockholders' equity	7,655,671	—	1,534,386	(1,534,386)	7,655,671
Noncontrolling interests in consolidated subsidiary	—	—	—	731,591	731,591
Total equity	7,655,671	—	1,534,386	(802,795)	8,387,262
Total liabilities and equity	$ 13,049,002	—	2,895,391	(1,095,179)	14,849,214

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)

Three Months Ended September 30, 2016

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 364,373	—	—	—	364,373
Natural gas liquids sales	106,958	—	—	—	106,958
Oil sales	14,793	—	—	—	14,793
Gathering, compression, water handling and treatment	—	—	150,475	(147,506)	2,969
Marketing	97,076	—	—	—	97,076
Commodity derivative fair value gains	530,334	—	—	—	530,334
Other income	3,990	—	—	(3,990)	—
Total revenue	1,117,524	—	150,475	(151,496)	1,116,503
Operating expenses:					
Lease operating	13,710	—	28,978	(28,834)	13,854
Gathering, compression, processing, and transportation	303,753	—	6,400	(75,238)	234,915
Production and ad valorem taxes	17,719	—	(2,165)	—	15,554
Marketing	114,611	—	—	—	114,611
Exploration	1,166	—	—	—	1,166
Impairment of unproved properties	11,753	—	—	—	11,753
Depletion, depreciation, and amortization	172,976	—	26,137	—	199,113
Accretion of asset retirement obligations	628	—	—	—	628
General and administrative	44,637	—	13,315	(375)	57,577
Accretion of contingent acquisition consideration	—	—	3,527	(3,527)	—
Total operating expenses	680,953	—	76,192	(107,974)	649,171
Operating income	436,571	—	74,283	(43,522)	467,332
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	1,543	—	1,543
Interest	(54,631)	—	(5,303)	179	(59,755)
Equity in net income of subsidiaries	(2,761)	—	—	2,761	—
Total other expenses	(57,392)	—	(3,760)	2,940	(58,212)
Income before income taxes	379,179	—	70,523	(40,582)	409,120
Provision for income tax expense	(140,924)	—	—	—	(140,924)
	238,255	—	70,523	(40,582)	268,196

Net income and comprehensive income including noncontrolling interests					
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	29,941	29,941
Net income and comprehensive income attributable to Antero Resources Corporation	$ 238,255	—	70,523	(70,523)	238,255

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)

Three Months Ended September 30, 2017

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 409,141	—	—	—	409,141
Natural gas liquids sales	224,533	—	—	—	224,533
Oil sales	26,527	—	—	—	26,527
Gathering, compression, water handling and treatment	—	—	193,629	(190,760)	2,869
Marketing	50,767	—	—	—	50,767
Commodity derivative fair value losses	(65,957)	—	—	—	(65,957)
Other income	3,070	—	—	(3,070)	—
Total revenue	648,081	—	193,629	(193,830)	647,880
Operating expenses:					
Lease operating	24,060	—	51,569	(52,138)	23,491
Gathering, compression, processing, and transportation	369,538	—	10,468	(97,872)	282,134
Production and ad valorem taxes	22,002	—	993	—	22,995
Marketing	78,884	—	—	—	78,884
Exploration	1,599	—	—	—	1,599
Impairment of unproved properties	41,000	—	—	—	41,000
Depletion, depreciation, and amortization	176,412	—	30,556	—	206,968
Accretion of asset retirement obligations	658	—	—	—	658
General and administrative	48,289	—	14,316	(402)	62,203
Accretion of contingent acquisition consideration	—	—	2,556	(2,556)	—
Total operating expenses	762,442	—	110,458	(152,968)	719,932
Operating income (loss)	(114,361)	—	83,171	(40,862)	(72,052)
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	7,033	—	7,033
Interest	(60,906)	—	(9,311)	158	(70,059)
Equity in net income (loss) of subsidiaries	(4,874)	—	—	4,874	—
Total other expenses	(65,780)	—	(2,278)	5,032	(63,026)
Income (loss) before income taxes	(180,141)	—	80,893	(35,830)	(135,078)
Provision for income tax benefit	45,078	—	—	—	45,078
	(135,063)	—	80,893	(35,830)	(90,000)

Net income (loss) and comprehensive income (loss) including noncontrolling interests					
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	45,063	45,063
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (135,063)	—	80,893	(80,893)	(135,063)

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)

Nine Months Ended September 30, 2016

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 848,936	—	—	—	848,936
Natural gas liquids sales	274,736	—	—	—	274,736
Oil sales	41,712	—	—	—	41,712
Gathering, compression, water handling and treatment	—	—	423,357	(413,250)	10,107
Marketing	287,194	—	—	—	287,194
Commodity derivative fair value gains	125,624	—	—	—	125,624
Other income	11,714	—	—	(11,714)	—
Total revenue and other	1,589,916	—	423,357	(424,964)	1,588,309
Operating expenses:					
Lease operating	37,299	—	104,009	(104,118)	37,190
Gathering, compression, processing, and transportation	838,936	—	20,567	(209,790)	649,713
Production and ad valorem taxes	51,921	—	375	—	52,296
Marketing	378,521	—	—	—	378,521
Exploration	3,289	—	—	—	3,289
Impairment of unproved properties	47,223	—	—	—	47,223
Depletion, depreciation, and amortization	513,957	—	74,100	—	588,057
Accretion of asset retirement obligations	1,846	—	—	—	1,846
General and administrative	135,356	—	39,712	(1,102)	173,966
Accretion of contingent acquisition consideration	—	—	10,384	(10,384)	—
Total operating expenses	2,008,348	—	249,147	(325,394)	1,932,101
Operating income (loss)	(418,432)	—	174,210	(99,570)	(343,792)
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	2,027	—	2,027
Interest	(173,364)	—	(12,885)	615	(185,634)
Equity in net income of subsidiaries	(2,003)	—	—	2,003	—
Total other expenses	(175,367)	—	(10,858)	2,618	(183,607)
Income (loss) before income taxes	(593,799)	—	163,352	(96,952)	(527,399)
Provision for income tax benefit	230,755	—	—	—	230,755
	(363,044)	—	163,352	(96,952)	(296,644)

Net income (loss) and comprehensive income (loss) including noncontrolling interests					
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	66,400	66,400
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (363,044)	—	163,352	(163,352)	(363,044)

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Operations and Comprehensive Income

Nine Months Ended September 30, 2017

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,330,062	—	—	—	1,330,062
Natural gas liquids sales	590,004	—	—	—	590,004
Oil sales	79,999	—	—	—	79,999
Gathering, compression, water handling and treatment	—	—	562,165	(553,500)	8,665
Marketing	166,659	—	—	—	166,659
Commodity derivative fair value gains	458,459	—	—	—	458,459
Other income	11,421	—	—	(11,421)	—
Total revenue and other	2,636,604	—	562,165	(564,921)	2,633,848
Operating expenses:					
Lease operating	56,991	—	131,635	(132,592)	56,034
Gathering, compression, processing, and transportation	1,070,522	—	28,492	(283,304)	815,710
Production and ad valorem taxes	67,576	—	2,765	—	70,341
Marketing	246,298	—	—	—	246,298
Exploration	5,510	—	—	—	5,510
Impairment of unproved properties	83,098	—	—	—	83,098
Depletion, depreciation, and amortization	522,275	—	88,604	—	610,879
Accretion of asset retirement obligations	1,944	—	—	—	1,944
General and administrative	148,876	—	43,562	(1,438)	191,000
Accretion of contingent acquisition consideration	—	—	9,672	(9,672)	—
Total operating expenses	2,203,090	—	304,730	(427,006)	2,080,814
Operating income	433,514	—	257,435	(137,915)	553,034
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	12,887	—	12,887
Interest	(178,644)	—	(27,162)	495	(205,311)
Equity in net income of subsidiaries	(21,582)	—	—	21,582	—
Total other expenses	(200,226)	—	(14,275)	22,077	(192,424)
Income before income taxes	233,288	—	243,160	(115,838)	360,610
Provision for income tax expense	(105,087)	—	—	—	(105,087)
	128,201	—	243,160	(115,838)	255,523

Net income and comprehensive income including noncontrolling interests					
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	127,322	127,322
Net income and comprehensive income attributable to Antero Resources Corporation	$ 128,201	—	243,160	(243,160)	128,201

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2016

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 745,517	—	259,135	(98,955)	905,697
Cash flows used in investing activities:					
Additions to proved properties	(64,789)	—	—	—	(64,789)
Additions to unproved properties	(559,572)	—	—	—	(559,572)
Drilling and completion costs	(1,108,806)	—	—	98,955	(1,009,851)
Additions to water handling and treatment systems	—	—	(137,355)	—	(137,355)
Additions to gathering systems and facilities	(1,367)	—	(152,769)	—	(154,136)
Additions to other property and equipment	(1,747)	—	—	—	(1,747)
Investments in unconsolidated affiliates	—	—	(45,044)	—	(45,044)
Change in other assets	236	—	(2,409)	—	(2,173)
Distributions from non-guarantor subsidiary	78,514	—	—	(78,514)	—
Net cash used in investing activities	(1,657,531)	—	(337,577)	20,441	(1,974,667)
Cash flows provided by financing activities:					
Issuance of common stock	837,414	—	—	—	837,414
Issuance of common units by Antero Midstream Partners LP	—	—	19,605	—	19,605
Sale of common units in Antero Midstream Partners LP by Antero Resources Corporation	178,000	—	—	—	178,000
Issuance of senior notes	—	—	650,000	—	650,000
Repayments on bank credit facility, net	(102,000)	—	(450,000)	—	(552,000)
Payments of deferred financing costs	(89)	—	(8,940)	—	(9,029)
Distributions	—	—	(129,752)	78,514	(51,238)
Employee tax withholding for settlement of equity compensation awards	(4,859)	—	(17)	—	(4,876)
Other	(3,751)	—	(116)	—	(3,867)
	904,715	—	80,780	78,514	1,064,009

Net cash provided by financing activities					
Net increase (decrease) in cash and cash equivalents	(7,299)	—	2,338	—	(4,961)
Cash and cash equivalents, beginning of period	16,590	—	6,883	—	23,473
Cash and cash equivalents, end of period	$ 9,291	—	9,221	—	18,512

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2016 and September 30, 2017

Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2017

(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 1,485,961	—	344,267	(137,420)	1,692,808
Cash flows used in investing activities:					
Additions to proved properties	(179,318)	—	—	—	(179,318)
Additions to unproved properties	(182,207)	—	—	—	(182,207)
Drilling and completion costs	(1,083,928)	—	—	137,420	(946,508)
Additions to water handling and treatment systems	—	—	(143,470)	—	(143,470)
Additions to gathering systems and facilities	—	—	(254,619)	—	(254,619)
Additions to other property and equipment	(11,417)	—	—	—	(11,417)
Investments in unconsolidated affiliates	—	—	(216,776)	—	(216,776)
Change in other assets	(10,271)	—	(5,877)	—	(16,148)
Net distributions from subsidiaries	97,984	—	—	(97,984)	—
Other	2,156	—	—	—	2,156
Net cash used in investing activities	(1,367,001)	—	(620,742)	39,436	(1,948,307)
Cash flows provided by (used in) financing activities:					
Issuance of common units by Antero Midstream Partners LP	—	—	248,949	—	248,949
Sale of common units in Antero Midstream Partners LP by Antero Resources Corporation	311,100	—	—	—	311,100
Borrowings (repayments) on bank credit facility, net	(415,000)	—	217,000	—	(198,000)
Distributions	—	—	(200,037)	97,984	(102,053)
Employee tax withholding for settlement of equity compensation awards	(7,568)	—	(932)	—	(8,500)
Other	(3,861)	—	(52)	—	(3,913)
Net cash provided by (used in) financing activities	(115,329)	—	264,928	97,984	247,583

Net increase (decrease) in cash and cash equivalents	3,631	—	(11,547)	—	(7,916)
Cash and cash equivalents, beginning of period	17,568	—	14,042	—	31,610
Cash and cash equivalents, end of period	$ 21,199	—	2,495	—	23,694

(13)Commitments

The table below is a schedule of future minimum payments for firm transportation, drilling rig and completion services, processing, gathering and compression, and office and equipment agreements, as well as leases that have remaining lease terms in excess of one year as of September 30, 2017 (in millions).

	Firm transportation (a)	Processing, gathering and compression (b)	Drilling rigs and completion services (c)	Office and equipment (d)	Total
Remainder of 2017	$ 135	109	28	4	276
2018	886	401	80	13	1,380
2019	1,107	340	41	11	1,499
2020	1,127	337	—	9	1,473
2021	1,106	321	—	8	1,435
2022	1,053	317	—	8	1,378
Thereafter	9,635	1,502	—	17	11,154
Total	$ 15,049	3,327	149	70	18,595

(a) Firm Transportation

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

(b) Processing, Gathering, and Compression Service Commitments

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

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

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest. The values in the table also include minimum processing fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest, and Antero Midstream's commitments for the construction of its advanced wastewater treatment complex. The table does not include intracompany commitments. Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

(c) Drilling Rig Service Commitments

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

(d) Office and Equipment Leases

The Company leases various office space and equipment under capital and operating lease arrangements.

(14) Related Parties

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

Antero Midstream's operations comprise substantially all of the operations of our gathering and processing segment and our water handling and treatment segment. Substantially all of the revenues for those segments in the three and nine months ended September 30, 2016 and 2017 were derived from transactions with Antero. Please see Note 11 for the operating results of the Company's reportable segments.

Item 2. 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 condensed consolidated financial statements and related notes included elsewhere in this report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results, and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGLs, and oil prices, the timing of planned capital expenditures, our ability to fund our development programs, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors." We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law. For more information, please refer to the Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 28, 2017, the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, filed with the SEC on May 8, 2017, and the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, filed with the SEC on August 2, 2017.

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

Our Company

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

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. As of September 30, 2017, we held approximately 630,000 net acres of rich gas and dry gas properties located in the Appalachian Basin in West Virginia and Ohio. Our corporate headquarters are in Denver, Colorado.

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

Address, Internet Website and Availability of Public Filings

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

We furnish or file with the SEC our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. We make these documents available free of charge on our website under the “Investors Relations” link as soon as reasonably practicable after they are filed or furnished with the SEC.

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

2017 Developments and Highlights

Energy Industry Environment

In late 2014, global energy commodity prices declined precipitously as a result of several factors, including an increase in worldwide commodity supplies, a stronger U.S. dollar, relatively mild weather in large portions of the U.S., and strong competition among oil producing countries for market share. Depressed commodity prices continued into 2015 and 2016, although a modest recovery occurred in late 2016 and has continued through 2017. The following chart depicts quarterly percentage changes in natural gas (Henry Hub), propane (Mont Belvieu), and oil (West Texas Intermediate) spot prices since June 30, 2014.

In response to these market conditions and concerns about access to capital markets, many U.S. exploration and production companies significantly reduced their capital spending plans in recent years. Our 2017 capital budget includes $1.5 billion for drilling, completions, and land. Excluding acquisitions, this is consistent with our 2016 capital expenditures. Our 2017 capital budget includes plans to operate an average of seven drilling rigs over the course of 2017, which is consistent with 2016; completion of 170 horizontal wells in the Marcellus and Utica Shales in 2017 as compared to 140 in 2016; and deferring the completion of 30 wells until 2018. Although commodity prices have decreased in recent years, we have also realized reductions in drilling and development costs as a result of decreased demand for oilfield services and increased efficiencies from improved drilling and completion technologies and procedures.

We believe that our 2017 capital budget will be fully funded through operating cash flows, available borrowing capacity under Antero's senior secured revolving bank credit facility (the "Credit Facility"), and potential capital market transactions. We continually monitor commodity prices and may revise the capital budget if conditions warrant. Additionally, given the current commodity price environment, we have evaluated the carrying value of our proved properties. See "—Critical Accounting Policies and Estimates" for a discussion of such evaluation.

Production and Financial Results

For the three months ended September 30, 2017, we generated consolidated cash flows from operations of $1.0 billion, a consolidated net loss of $135 million, and consolidated Adjusted EBITDAX of $336 million. This compares to consolidated cash flows from operations of $327 million, consolidated net income of $238 million, and consolidated Adjusted EBITDAX of $373 million for the three months ended September 30, 2016. The consolidated net loss of $135 million for the three months ended September 30, 2017 included (i) commodity derivative fair value losses of $66 million, comprising gains on settled derivatives of $61 million, cash proceeds from hedge monetizations of $750 million (see "—Deleveraging Activities" below), and a non-cash loss of $877 million on changes in the fair value of unsettled commodity derivatives, (ii) a non-cash charge of $26 million for equity-based compensation, (iii) a non-cash charge of $41 million for impairments of unproved properties, and (iv) a non-cash deferred tax benefit

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of $45 million. See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income. The impact of hedge monetizations is excluded from our Adjusted EBITDAX and per-unit calculations presented herein. See "—Deleveraging Activities" for further discussion.

For the three months ended September 30, 2017, our net production totaled 213 Bcfe, or 2,317 MMcfe per day, a 24% increase compared to 172 Bcfe, or 1,875 MMcfe per day, for the three months ended September 30, 2016. Our average price received for production, before the effects of gains on settled derivatives, for the three months ended September 30, 2017 was $3.10 per Mcfe compared to $2.82 per Mcfe for the three months ended September 30, 2016. Our average realized price after the effects of gains on settled derivatives was $3.39 per Mcfe for the three months ended September 30, 2017 compared to $3.96 per Mcfe for the three months ended September 30, 2016.

For the nine months ended September 30, 2017, we generated consolidated cash flows from operations of $1.7 billion, consolidated net income of $128 million, and Adjusted EBITDAX of $1.0 billion. This compares to consolidated cash flows from operations of $906 million, a consolidated net loss of $363 million, and consolidated Adjusted EBITDAX of $1.1 billion for the nine months ended September 30, 2016. Consolidated net income of $128 million for the nine months ended September 30, 2017 included (i) commodity derivative fair value gains of $458 million, comprising gains on settled derivatives of $137 million, cash proceeds from hedge monetizations of $750 million, and a non-cash loss of $429 million on changes in the fair value of unsettled commodity derivatives, (ii) a non-cash charge of $79 million for equity-based compensation, (iii) a non-cash charge of $83 million for impairments of unproved properties, and (iv) a non-cash deferred tax expense of $105 million. See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income. The impact of hedge monetizations is excluded from our Adjusted EBITDAX and per-unit calculations presented herein. See "—Deleveraging Activities" for further discussion.

For the nine months ended September 30, 2017, our net production totaled 606 Bcfe, or 2,221 MMcfe per day, a 23% increase compared to 493 Bcfe, or 1,799 MMcfe per day, for the nine months ended September 30, 2016. Our average price received for production, before the effects of gains on settled derivatives, for the nine months ended September 30, 2017 was $3.30 per Mcfe compared to $2.36 per Mcfe for the nine months ended September 30, 2016. Our average realized price after the effects of gains on settled derivatives was $3.53 per Mcfe for the nine months ended September 30, 2017 compared to $4.02 per Mcfe for the nine months ended September 30, 2016.

Deleveraging Activities

During the three months ended September 30, 2017, we monetized over $1 billion of our non-exploration and production assets and used the proceeds to repay outstanding borrowings under our revolving credit facility. Proceeds from these activities are not expected to result in cash taxes payable due to the utilization of a portion of our net operating loss ("NOL") carryforwards. These deleveraging activities consisted of the following transactions:

- On September 11, 2017, we completed a public sale of 10,000,000 common units representing limited partner interests in Antero Midstream which were held by Antero. We received total net proceeds from the transaction of $311 million.
- In September 2017, we monetized portions of our hedge portfolio by reducing the average fixed index prices on certain of our natural gas hedges that settle from 2018 through 2022 while maintaining the total volumes hedged. We received total proceeds of approximately $750 million from the monetization of the natural gas hedges.

2017 Capital Budget and Capital Spending

Our consolidated capital budget for 2017 is $2.3 billion and includes: $1.3 billion for drilling and completion, $200 million for core leasehold acreage additions and extensions, and $800 million for capital expenditures by Antero Midstream, which includes investments in unconsolidated gathering and processing entities. We do not budget for acquisitions. Approximately 70% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 30% is allocated to the Ohio Utica Shale. Over the course of 2017, we plan to operate an average of four drilling rigs in the Marcellus Shale and three drilling rigs in the Ohio Utica Shale. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

For the nine months ended September 30, 2017, our consolidated capital expenditures were approximately $1.7 billion, including drilling and completion costs of $947 million, leasehold additions of $182 million, acquisitions of $179 million, gathering and compression expenditures of $255 million, water handling and treatment expenditures of $143 million, and other capital expenditures

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of $11 million. Antero Midstream also invested $217 million in a joint venture with MarkWest Energy Partners L.P. (the “Joint Venture”).

Hedge Position (after effects of hedge monetization)

As of September 30, 2017, we had entered into hedging contracts for approximately 2.9 Tcf of our projected natural gas production at a weighted average index price of $3.36 per MMbtu for the period from October 1, 2017 through December 31, 2023, 152 million gallons of propane at a weighted average price of $0.48 per gallon for the period from October 1, 2017 through December 31, 2018, 77 million gallons of ethane at a weighted average price of $0.25 per gallon for the period from October 1, 2017 through December 31, 2017, and 641 MBbls of oil at a weighted average price of $52.02 per Bbl for the period from October 1, 2017 through December 31, 2018. These hedging contracts include contracts for the remainder of 2017 of approximately 171 Bcf of natural gas at a weighted average index price of $3.71 per Mcf, 106 million gallons of propane at a weighted average price of $0.40 per gallon, 77 million gallons of ethane at a weighted average price of $0.25 per gallon, and 276 MBbls of oil at a weighted average price of $54.75 per Bbl.

Credit Facilities

On November 4, 2010, Antero entered into a credit facility with a consortium of bank lenders (the “Prior Credit Facility”). On October 26, 2017, Antero entered into an amendment and restatement of the Prior Credit Facility (the “Credit Facility”). As of September 30, 2017, our borrowing base under the Prior Credit Facility was $4.75 billion and lender commitments were $4.0 billion. Under the Credit Facility, the maximum facility amount is $4.75 billion, the borrowing base is $4.5 billion, and lender commitments are $2.5 billion. Our borrowing base under the Credit Facility is redetermined annually and is based on the estimated future cash flows from our proved oil and gas reserves and our commodity hedge positions. The next redetermination is scheduled to occur in March 2018. At September 30, 2017, we had $25 million of borrowings and $700 million of letters of credit outstanding under the Prior Credit Facility. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the maturity of any series of Antero’s senior notes, unless such series of senior notes is refinanced. See “—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility” for a description of the Credit Facility.

On November 10, 2014, Antero Midstream entered into a credit facility with a consortium of bank lenders that provides for lender commitments of $1.5 billion (the “Prior Midstream Facility”). On October 26, 2017, Antero Midstream entered into an amendment and restatement of the Prior Midstream Facility (the “Midstream Facility”) that also provides for lender commitments of $1.5 billion. At September 30, 2017, Antero Midstream had $427 million of borrowings outstanding under the Prior Midstream Facility. The Midstream Facility will mature on October 26, 2022. See “—Debt Agreements and Contractual Obligations—Midstream Credit Facility” for a description of the Midstream

Facility.

Antero Midstream Equity Distribution Agreement

During the nine months ended September 30, 2017, Antero Midstream issued and sold 777,262 common units under the Distribution Agreement, resulting in net proceeds of $25.5 million after deducting commissions and other offering costs. As of September 30, 2017, Antero Midstream had the capacity to issue additional common units under the Distribution Agreement up to an aggregate sales price of $157.3 million.

Results of Operations

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2017

The Company has four operating segments: (1) the exploration, development and production of natural gas, NGLs, and oil; (2) gathering and processing; (3) water handling and treatment; and (4) marketing of excess firm transportation capacity. Revenues from the gathering and processing and water handling and treatment operations are primarily derived from intersegment transactions for services provided to our exploration and production operations by Antero Midstream. Intersegment transactions that are eliminated include revenues from water handling and treatment services provided by Antero Midstream which are capitalized as proved property development costs by Antero. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties.

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The operating results of the Company's reportable segments were as follows for the three months ended September 30, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2016:						
Sales and revenues:						
Third-party	$ 1,016,458	2,745	224	97,076	—	1,116,503
Intersegment	3,990	75,319	72,187	—	(151,496)	—
Total	$ 1,020,448	78,064	72,411	97,076	(151,496)	1,116,503
Operating expenses:						
Lease operating	$ 13,710	—	28,978	—	(28,834)	13,854
Gathering, compression, processing, and transportation	303,753	6,400	—	—	(75,238)	234,915
Depletion, depreciation, and amortization	172,735	18,540	7,838	—	—	199,113
General and administrative (before equity-based compensation)	24,856	5,068	1,647	—	(375)	31,196
Equity-based compensation	19,781	5,214	1,386	—	—	26,381
Other	31,266	(1,708)	3,070	114,611	(3,527)	143,712
Total	566,101	33,514	42,919	114,611	(107,974)	649,171
Operating income (loss)	$ 454,347	44,550	29,492	(17,535)	(43,522)	467,332
Equity in earnings of unconsolidated affiliates	$ —	1,543	—	—	—	1,543
Segment Adjusted EBITDAX (1)	$ 323,261	68,304	42,243	(17,535)	(43,522)	372,751

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2017:						

Sales and revenues:						
Third-party	$ 594,244	2,609	260	50,767	—	647,880
Intersegment	3,070	97,909	92,851	—	(193,830)	—
Total	$ 597,314	100,518	93,111	50,767	(193,830)	647,880
Operating expenses:						
Lease operating	$ 24,060	—	51,569	—	(52,138)	23,491
Gathering, compression, processing, and transportation	369,538	10,468	—	—	(97,872)	282,134
Depletion, depreciation, and amortization	176,188	22,027	8,753	—	—	206,968
General and administrative (before equity-based compensation)	29,041	4,225	2,892	—	(402)	35,756
Equity-based compensation	19,248	5,111	2,088	—	—	26,447
Other	65,259	92	3,457	78,884	(2,556)	145,136
Total	683,334	41,923	68,759	78,884	(152,968)	719,932
Operating income (loss)	$ (86,020)	58,595	24,352	(28,117)	(40,862)	(72,052)
Equity in earnings of unconsolidated affiliates	$ —	7,033	—	—	—	7,033
Segment Adjusted EBITDAX (1)	$ 277,553	90,033	37,749	(28,117)	(40,862)	336,356

(1) See "—Non-GAAP Financial Measures" for a definition of Segment Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Segment Adjusted EBITDAX to operating income.

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The following tables set forth selected consolidated operating data for the three months ended September 30, 2016 compared to the three months ended September 30, 2017:

(in thousands)	Three Months Ended September 30, 2016	2017	Amount of Increase (Decrease)	Percent Change	
Operating revenues and other:					
Natural gas sales	$ 364,373	$ 409,141	$ 44,768	12	%
NGLs sales	106,958	224,533	117,575	110	%
Oil sales	14,793	26,527	11,734	79	%
Gathering, compression, water handling and treatment	2,969	2,869	(100)	(3)	%
Marketing	97,076	50,767	(46,309)	(48)	%
Commodity derivative fair value gains (losses)	530,334	(65,957)	(596,291)	*	
Total operating revenues and other	1,116,503	647,880	(468,623)	(42)	%
Operating expenses:					
Lease operating	13,854	23,491	9,637	70	%
Gathering, compression, processing, and transportation	234,915	282,134	47,219	20	%
Production and ad valorem taxes	15,554	22,995	7,441	48	%
Marketing	114,611	78,884	(35,727)	(31)	%
Exploration	1,166	1,599	433	37	%
Impairment of unproved properties	11,753	41,000	29,247	249	%
Depletion, depreciation, and amortization	199,113	206,968	7,855	4	%
Accretion of asset retirement obligations	628	658	30	5	%
General and administrative (before equity-based compensation)	31,196	35,756	4,560	15	%
Equity-based compensation	26,381	26,447	66	—	%
Total operating expenses	649,171	719,932	70,761	11	%
Operating income (loss)	467,332	(72,052)	(539,384)	*	
Other earnings (expenses):					
Equity in earnings of unconsolidated affiliate	1,543	7,033	5,490	356	%
Interest expense	(59,755)	(70,059)	(10,304)	17	%
Total other expenses	(58,212)	(63,026)	(4,814)	8	%
Income (loss) before income taxes	409,120	(135,078)	(544,198)	*	
Income tax (expense) benefit	(140,924)	45,078	186,002	*	
Net income (loss) and comprehensive income (loss) including noncontrolling interest	268,196	(90,000)	(358,196)	*	
Net income and comprehensive income attributable to noncontrolling interest	29,941	45,063	15,122	51	%
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 238,255	$ (135,063)	$ (373,318)	*	
Adjusted EBITDAX (1)	$ 372,751	$ 336,356	$ (36,395)	(10)	%

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	Three Months Ended September 30, 2016	2017	Amount of Increase (Decrease)	Percent Change	
Production data:					
Natural gas (Bcf)	128	151	23	18	%
C2 Ethane (MBbl)	1,801	2,789	988	55	%
C3+ NGLs (MBbl)	5,270	6,927	1,657	31	%
Oil (MBbl)	423	624	201	47	%
Combined (Bcfe)	172	213	41	24	%
Daily combined production (MMcfe/d)	1,875	2,317	442	24	%
Average prices before effects of derivative settlements(2):					
Natural gas (per Mcf)	$ 2.86	$ 2.71	$ (0.15)	(5)	%
C2 Ethane (per Bbl)	$ 8.00	$ 8.68	$ 0.68	9	%
C3+ NGLs (per Bbl)	$ 17.56	$ 28.92	$ 11.36	65	%
Oil (per Bbl)	$ 34.93	$ 42.50	$ 7.57	22	%
Combined (per Mcfe)	$ 2.82	$ 3.10	$ 0.28	10	%
Average realized prices after effects of derivative settlements(2):					
Natural gas (per Mcf)	$ 4.30	$ 3.37	$ (0.93)	(22)	%
C2 Ethane (per Bbl)	$ 8.00	$ 8.53	$ 0.53	7	%
C3+ NGLs (per Bbl)	$ 19.96	$ 23.15	$ 3.19	16	%
Oil (per Bbl)	$ 34.93	$ 45.40	$ 10.47	30	%
Combined (per Mcfe)	$ 3.96	$ 3.39	$ (0.57)	(14)	%
Average Costs (per Mcfe):					
Lease operating	$ 0.08	$ 0.11	$ 0.03	38	%
Gathering, compression, processing, and transportation	$ 1.36	$ 1.32	$ (0.04)	(3)	%
Production and ad valorem taxes	$ 0.09	$ 0.11	$ 0.02	22	%
Marketing expense, net	$ 0.10	$ 0.13	$ 0.03	30	%
Depletion, depreciation, amortization, and accretion	$ 1.16	$ 0.97	$ (0.19)	(16)	%
General and administrative (before equity-based compensation)	$ 0.18	$ 0.17	$ (0.01)	(6)	%

(1) See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) including noncontrolling interest and net cash provided by operating activities.

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

*Not meaningful or applicable.

Discussion of Consolidated Exploration and Production Results for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2017

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $486 million for the three months ended September 30, 2016 to $660 million for the three months ended September 30, 2017, an increase of $174 million, or 36%. Our production increased by 24% over that same period, from 172 Bcfe, or 1,875 MMcfe per day, for the three months ended September 30, 2016 to 213 Bcfe, or 2,317 MMcfe per day, for the three months ended September 30, 2017. Net equivalent prices before the effects of settled derivative gains increased from $2.82 per Mcfe for the three months ended September 30, 2016 to $3.10 for the three months ended September 30, 2017, an increase of 10%. Average prices for ethane, C3+ NGLs, and oil all increased from 2016 levels, whereas average prices for natural gas declined from 2016 levels. Net equivalent prices after the effects of gains on settled derivatives (excluding hedge monetizations) decreased from $3.96 for the three months ended September 30, 2016 to $3.39 for the three months ended September 30, 2017, due to lower average hedged prices in the three months ended September 30, 2017.

Increased production volumes accounted for an approximate $115 million increase in year-over-year product revenues (calculated as the combined change in year-to-year volumes times the prior year average price), and increases in our equivalent prices, excluding the effects of derivative settlements, accounted for an approximate $59 million increase in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our drilling and completion program.

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During the three months ended September 30, 2016 and 2017, our natural gas revenues were negatively affected by contractual issues with certain of our customers. For more information on these disputes, please see Note 10 to the condensed consolidated financial statements or "Item 1. Legal Proceedings" included elsewhere in this Quarterly Report on Form 10-Q.

Commodity derivative fair value gains (losses). To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into fixed for variable price swap contracts when management believes that favorable future sales prices for our production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment. Consequently, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the three months ended September 30, 2016 and 2017, our hedges resulted in derivative fair value gains (losses) of $530 million and $(66) million, respectively. The derivative fair value gains and losses included $197 million and $61 million of gains on cash settled derivatives for the three months ended September 30, 2016 and 2017, respectively. Commodity derivative fair value gains (losses) for the three months ended September 30, 2017 also include gains of $750 million related to derivatives which were partially monetized prior to their settlement dates. See "—Deleveraging Activities" for further discussion.

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

Gathering, compression, water handling and treatment revenues. Gathering, compression, water handling and treatment revenues remained consistent at $3 million for the three months ended September 30, 2016 and 2017. Fees for gathering, compression, water handling and treatment services provided to us by Antero Midstream are eliminated in consolidation. The amounts that are not eliminated represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for services provided by Antero Midstream.

Lease operating expense. Lease operating expense increased from $14 million for the three months ended September 30, 2016 to $23 million for the three months ended September 30, 2017, an increase of 70%. This increase is primarily the result of an increase in production and the number of producing wells. On a per unit basis, lease operating expenses increased from $0.08 per Mcfe for the three months ended September 30, 2016 to $0.11 per Mcfe for the three months ended September 30, 2017. The increase in lease operating expenses on a per Mcfe basis is due to an increase in produced water on new well pads, which is attributable to an increase in the amount of water used in our advanced well completions. In addition, lease operating expenses are expected to gradually increase on a per-unit basis as maturing properties make up a larger proportion of our production base and average production per existing well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $235 million for the three months ended September 30, 2016 to $282 million for the three months ended September 30, 2017. The increase in these expenses is a result of the increase in production and the related firm transportation, gathering, compression, and processing expenses. On a per Mcfe basis, consolidated gathering, compression, processing and transportation expenses decreased from $1.36 per Mcfe for the three months ended September 30, 2016 to $1.32 per Mcfe for the three months ended September 30, 2017, primarily as a result of decreases in fuel costs as compared to the prior year due to lower natural gas prices.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $16 million for the three months ended September 30, 2016 to $23 million for the three months ended September 30, 2017 as a result of an increase in production revenues. On a per Mcfe basis, production and ad valorem taxes increased from $0.09 per Mcfe for the three months ended September 30, 2016 to $0.11 per Mcfe for the three months ended September 30, 2017 as a result of higher realized prices. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging increased from 3.2% for the three months ended September 30, 2016 to 3.5% for the three months ended September 30, 2017. As production in West Virginia increased at a higher rate than Ohio, severance taxes as a percentage of revenue increased due to higher severance tax rates in West Virginia as compared to Ohio.

Exploration expense. Exploration expense increased from $1 million for the three months ended September 30, 2016 to $2 million for the three months ended September 30, 2017. These amounts represent expenses incurred for unsuccessful lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties increased from $12 million for the three months ended September 30, 2016 to $41 million for the three months ended September 30, 2017, primarily due to the expiration of certain Utica leases which we elected not to retain and develop. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, or future plans to develop the acreage.

Depletion, depreciation, and amortization expense. Depletion, depreciation, and amortization ("DD&A") increased from $199 million for the three months ended September 30, 2016 to $207 million for the three months ended September 30, 2017, primarily because of increased production. DD&A per Mcfe decreased by 16%, from $1.16 per Mcfe during the three months ended September 30, 2016 to $0.97 per Mcfe during the three months ended September 30, 2017. This decrease was due to increases in our estimated recoverable reserves, due to improved well performance, and decreases in our per-unit development costs, which is due to well cost reductions and drilling and completion efficiencies that we have achieved over the last year.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. At September 30, 2017, we compared the carrying values of our proved properties to estimated future net cash flows. As estimated future net cash flows were higher than the carrying values of our proved properties at September 30, 2017, we did not further evaluate our proved properties for impairment.

General and administrative expense. General and administrative expense (before equity-based compensation expense) increased from $31 million for the three months ended September 30, 2016 to $36 million for the three months ended September 30, 2017, primarily due to increases in employee compensation and benefits expenses. On a per-unit basis, general and administrative expense before equity-based compensation decreased by 6%, from $0.18 per Mcfe during the three months ended September 30, 2016 to $0.17 per Mcfe during the three months ended September 30, 2017, primarily due to our 24% increase in production. We had 516 employees as of September 30, 2016 and 583 employees as of September 30, 2017.

Equity-based compensation expense. Non-cash equity-based compensation expense remained consistent at $26 million for the three months ended September 30, 2016 and 2017. See Note 7 to the condensed consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Interest expense. Interest expense increased from $60 million for the three months ended September 30, 2016 to $70 million for the three months ended September 30, 2017, primarily due to Antero Midstream's issuance of its 5.375%

senior notes due 2024 in September 2016 and increased average balances outstanding under our revolving credit facilities. Interest expense includes approximately $2.9 million and $3.0 million of non-cash amortization of deferred financing costs for the three months ended September 30, 2016 and 2017, respectively

Income tax (expense) benefit. Income tax (expense) benefit changed from a deferred tax expense of $141 million for the three months ended September 30, 2016 to a deferred tax benefit of $45 million for the three months ended September 30, 2017. The deferred tax expense for the three months ended September 30, 2016 was due to pre-tax income generated for financial reporting purposes, whereas we incurred a pre-tax loss for financial reporting purposes for the three months ended September 30, 2017.

At December 31, 2016, we had approximately $1.6 billion of NOLs for U.S. federal income tax purposes that expire at various dates from 2024 through 2036 and approximately $1.4 billion of state NOLs that expire at various dates from 2017 through 2036. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies, such as deductions for intangible drilling costs. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expenses, may also change the taxation of oil and gas companies. If passed, such legislation could significantly affect our future taxable position. The impact of any such change would be recorded in the period in which such legislation is enacted.

Adjusted EBITDAX. Adjusted EBITDAX decreased by 10%, from $373 million for the three months ended September 30, 2016 to $336 million for the three months ended September 30, 2017. The decrease in Adjusted EBITDAX was primarily due to decreases in our average realized price for natural gas after gains on settled derivatives, partially offset by increased production. Adjusted EBITDAX does not include $750 million of realized gains from the partial monetization of certain natural gas hedges. See "—Deleveraging Activities" for further discussion of the hedge monetizations. See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) including noncontrolling interest and net cash provided by operating activities.

Discussion of Segment Results for the Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2017

Our previous discussion of the consolidated exploration and production results includes the consolidated results from our gathering and processing, water handling and treatment, and marketing segments, whose revenues are almost entirely derived from services provided to the exploration and production segment. Our gathering and processing and water handling and treatment operations are almost entirely conducted by Antero Midstream, a master limited partnership. Antero owns 53% of Antero Midstream's issued and outstanding common units. Antero Midstream's distributable cash is paid to its common unitholders subsequent to the end of each quarter. Following is a summary level discussion of the various segment results which should be read in conjunction with our detailed discussion of our consolidated exploration and production results:

Exploration and production.   Revenues from the exploration and production segment decreased from $1.0 billion for the three months ended September 30, 2016 to $597 million for the three months ended September 30, 2017, primarily because of the decrease in commodity derivative fair value gains and losses of $596 million, partially offset by an increase in production revenues of $174 million from increases in production and realized prices. Total operating expenses increased from $566 million for the three months ended September 30, 2016 to $683 million for the three months ended September 30, 2017, primarily because of a 24% increase in production. Gathering, compression, processing, and transportation expenses increased by $66 million, lease operating expenses increased by $10 million, DD&A expenses increased by $3 million, impairment expense for unproved properties increased by $29 million and other items increased by $9 million.

On a per Mcfe basis, total gathering, compression, processing and transportation expenses for the exploration and production segment decreased from $1.76 per Mcfe for the three months ended September 30, 2016 to $1.73 per Mcfe for the three months ended September 30, 2017, primarily as a result of decreases in fuel costs.

Gathering and Processing. Revenue for the gathering and processing segment increased from $78 million for the three months ended September 30, 2016 to $101 million for the three months ended September 30, 2017, an increase of $23 million, or 29%. Gathering revenues increased by $15 million from the prior year period and compression revenues increased by $8 million as additional wells on production increased throughput volumes. Total operating expenses related to the gathering and processing segment increased from $34 million for the three months ended September 30, 2016 to $42 million for the three months ended September 30, 2017 primarily as a result of increases in direct operating and depreciation expenses due to a larger base of gathering and compression assets.

In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. In February 2017, Antero Midstream formed the Joint Venture with MarkWest, which provides natural gas processing and fractionation services. Equity in earnings of unconsolidated affiliates of $1.5 million and $7.0 million for the three months ended September 30, 2016 and 2017, respectively, represents the portion of the net income from these investments which is allocated to Antero Midstream based on its equity interests. The increase was primarily attributable to the commencement of operations of the Joint Venture in February 2017.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $72 million for the three months ended September 30, 2016 to $93 million for the three months ended September 30, 2017, an increase of $21 million, or 29%. The increase was primarily due to an increase in the volume of water used per well in our advanced completions during the three months ended September 30, 2017 as compared to the three months ended September 30, 2016, as well as an increase in other fluid handling services. The volume of water delivered through the systems increased from 12.9 MMBbls for the three months ended September 30, 2016 to 13.0 MMBbls for the three months ended September 30, 2017. Operating expenses for the water handling and treatment segment increased from $43 million for the three months ended September 30, 2016 to $69 million for the three months ended September 30, 2017, primarily due to the increase in other fluid handling services.

Marketing. Where permitted, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets. Marketing revenues of $97 million and $51 million and expenses of $115 million and $79 million for the three months ended September 30, 2016 and 2017, respectively, relate to these activities. Net losses on our marketing activities were $18 million and $28 million for the three months ended September 30, 2016 and 2017, respectively. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-

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party purchased gas and NGLs. This includes firm transportation costs of $24 million and $27 million for the three months ended September 30, 2016 and 2017, respectively, related to unutilized excess capacity which increased due to decreased utilization of a pipeline which has higher per-unit commitment fees than the average of our transportation portfolio.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2017

The Company has four operating segments: (1) the exploration, development and production of natural gas, NGLs, and oil; (2) gathering and processing; (3) water handling and treatment; and (4) marketing of excess firm transportation capacity. Revenues from the gathering and processing and water handling and treatment operations are primarily derived from intersegment transactions for services provided to our exploration and production operations by Antero Midstream. Intersegment transactions that are eliminated include revenues from water handling and treatment services provided by Antero Midstream which are capitalized as proved property development costs by Antero. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties.

The operating results of the Company's reportable segments were as follows for the nine months ended September 30, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2016:						
Sales and revenues:						
Third-party	$ 1,291,008	9,463	644	287,194	—	1,588,309
Intersegment	11,714	210,144	203,106	—	(424,964)	—
Total	$ 1,302,722	219,607	203,750	287,194	(424,964)	1,588,309
Operating expenses:						
Lease operating	$ 37,299	—	104,009	—	(104,118)	37,190
Gathering, compression, processing, and transportation	838,936	20,567	—	—	(209,790)	649,713
Depletion, depreciation, and amortization	513,302	52,780	21,975	—	—	588,057
General and administrative (before equity-based	79,055	14,853	5,493	—	(1,102)	98,299

compensation)						
Equity-based compensation	56,301	14,902	4,464	—	—	75,667
Other	104,279	(809)	11,568	378,521	(10,384)	483,175
Total	1,629,172	102,293	147,509	378,521	(325,394)	1,932,101
Operating income (loss)	$ (326,450)	117,314	56,241	(91,327)	(99,570)	(343,792)
Equity in earnings of unconsolidated affiliates	$ —	2,027	—	—	—	2,027
Segment Adjusted EBITDAX (1)	$ 973,101	184,996	93,064	(91,327)	(99,570)	1,060,264

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	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2017:						
Sales and revenues:						
Third-party	$ 2,458,524	7,472	1,193	166,659	—	2,633,848
Intersegment	11,421	283,467	270,033	—	(564,921)	—
Total	$ 2,469,945	290,939	271,226	166,659	(564,921)	2,633,848
Operating expenses:						
Lease operating	$ 56,991	—	131,635	—	(132,592)	56,034
Gathering, compression, processing, and transportation	1,070,522	28,492	—	—	(283,304)	815,710
Depletion, depreciation, and amortization	521,603	64,445	24,831	—	—	610,879
General and administrative (before equity-based compensation)	90,387	15,242	7,884	—	(1,438)	112,075
Equity-based compensation	58,489	14,937	5,499	—	—	78,925
Other	158,128	104	12,333	246,298	(9,672)	407,191
Total	1,956,120	123,220	182,182	246,298	(427,006)	2,080,814
Operating income (loss)	$ 513,825	167,719	89,044	(79,639)	(137,915)	553,034
Equity in earnings of unconsolidated affiliates	$ —	12,887	—	—	—	12,887
Segment Adjusted EBITDAX (1)	$ 853,730	257,221	129,046	(79,639)	(137,915)	1,022,443

(1) See "—Non-GAAP Financial Measures" for a definition of Segment Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Segment Adjusted EBITDAX to operating income.

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The following tables set forth selected consolidated operating data for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2017:

(in thousands)	Nine Months Ended September 30, 2016	2017	Amount of Increase (Decrease)	Percent Change
Operating revenues and other:				
Natural gas sales	$ 848,936	$ 1,330,062	$ 481,126	57 %
NGLs sales	274,736	590,004	315,268	115 %
Oil sales	41,712	79,999	38,287	92 %
Gathering, compression, water handling and treatment	10,107	8,665	(1,442)	(14) %
Marketing	287,194	166,659	(120,535)	(42) %
Commodity derivative fair value gains	125,624	458,459	332,835	265 %
Total operating revenues and other	1,588,309	2,633,848	1,045,539	66 %
Operating expenses:				
Lease operating	37,190	56,034	18,844	51 %
Gathering, compression, processing, and transportation	649,713	815,710	165,997	26 %
Production and ad valorem taxes	52,296	70,341	18,045	35 %
Marketing	378,521	246,298	(132,223)	(35) %
Exploration	3,289	5,510	2,221	68 %
Impairment of unproved properties	47,223	83,098	35,875	76 %
Depletion, depreciation, and amortization	588,057	610,879	22,822	4 %
Accretion of asset retirement obligations	1,846	1,944	98	5 %
General and administrative (before equity-based compensation)	98,299	112,075	13,776	14 %
Equity-based compensation	75,667	78,925	3,258	4 %
Total operating expenses	1,932,101	2,080,814	148,713	8 %
Operating income (loss)	(343,792)	553,034	896,826	*
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliates	2,027	12,887	10,860	536 %
Interest expense	(185,634)	(205,311)	(19,677)	11 %
Total other expenses	(183,607)	(192,424)	(8,817)	5 %
Income (loss) before income taxes	(527,399)	360,610	888,009	*
Income tax (expense) benefit	230,755	(105,087)	(335,842)	*
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(296,644)	255,523	552,167	*
Net income and comprehensive income attributable to noncontrolling interest	66,400	127,322	60,922	92 %
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (363,044)	$ 128,201	$ 491,245	*
Adjusted EBITDAX (1)	$ 1,060,264	$ 1,022,443	$ (37,821)	(4) %

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	Nine Months Ended September 30, 2016	2017	Amount of Increase (Decrease)	Percent Change	
Production data:					
Natural gas (Bcf)	369	435	66	18	%
C2 Ethane (MBbl)	4,463	7,648	3,185	71	%
C3+ NGLs (MBbl)	14,722	19,085	4,363	30	%
Oil (MBbl)	1,373	1,880	507	37	%
Combined (Bcfe)	493	606	113	23	%
Daily combined production (MMcfe/d)	1,799	2,221	422	23	%
Average prices before effects of derivative settlements(2):					
Natural gas (per Mcf)	$ 2.30	$ 3.06	$ 0.76	33	%
C2 Ethane (per Bbl)	$ 7.81	$ 8.38	$ 0.57	7	%
C3+ NGLs (per Bbl)	$ 16.29	$ 27.56	$ 11.27	69	%
Oil (per Bbl)	$ 30.38	$ 42.56	$ 12.18	40	%
Combined (per Mcfe)	$ 2.36	$ 3.30	$ 0.94	40	%
Average realized prices after effects of derivative settlements(2):					
Natural gas (per Mcf)	$ 4.38	$ 3.59	$ (0.79)	(18)	%
C2 Ethane (per Bbl)	$ 7.81	$ 8.62	$ 0.81	10	%
C3+ NGLs (per Bbl)	$ 19.30	$ 22.37	$ 3.07	16	%
Oil (per Bbl)	$ 30.38	$ 44.87	$ 14.49	48	%
Combined (per Mcfe)	$ 4.02	$ 3.53	$ (0.49)	(12)	%
Average Costs (per Mcfe):					
Lease operating	$ 0.08	$ 0.09	$ 0.01	13	%
Gathering, compression, processing, and transportation	$ 1.32	$ 1.35	$ 0.03	2	%
Production and ad valorem taxes	$ 0.11	$ 0.12	$ 0.01	9	%
Marketing expense, net	$ 0.19	$ 0.13	$ (0.06)	(32)	%
Depletion, depreciation, amortization, and accretion	$ 1.20	$ 1.01	$ (0.19)	(16)	%
General and administrative (before equity-based compensation)	$ 0.20	$ 0.18	$ (0.02)	(10)	%

(1) See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) including noncontrolling interest and net cash provided by operating activities.

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

*Not meaningful or applicable.

Discussion of Consolidated Exploration and Production Results for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2017

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $1.2 billion for the nine months ended September 30, 2016 to $2.0 billion for the nine months ended September 30, 2017, an increase of $835 million, or 72%. Our production increased by 23% over that same period, from 493 Bcfe, or 1,799 MMcfe per day, for the nine months ended September 30, 2016 to 606 Bcfe, or 2,221 MMcfe per day, for the nine months ended September 30, 2017. Net equivalent prices before the effects of settled derivative gains increased from $2.36 per Mcfe for the nine months ended September 30, 2016 to $3.30 for the nine months ended September 30, 2017, an increase of 40%. Average prices for natural gas, ethane, C3+ NGLs, and oil all increased from 2016 levels. Net equivalent prices after the effects of gains on settled derivatives (excluding hedge monetizations) decreased from $4.02 for the nine months ended September 30, 2016 to $3.53 for the nine months ended September 30, 2017, due to lower average hedged prices in the nine months ended September 30, 2017.

Increased production volumes accounted for an approximate $268 million increase in year-over-year product revenues (calculated as the combined change in year-to-year volumes times the prior year average price), and increases in our equivalent prices, excluding the effects of derivative settlements, accounted for an approximate $567 million increase in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our drilling and completion program.

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During the nine months ended September 30, 2016 and 2017, our natural gas revenues were negatively affected by contractual issues with certain of our customers. For more information on these disputes, please see Note 10 to the condensed consolidated financial statements or "Item 1. Legal Proceedings" included elsewhere in this Quarterly Report on Form 10-Q.

Commodity derivative fair value gains. To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into fixed for variable price swap contracts when management believes that favorable future sales prices for our production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment. Consequently, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the nine months ended September 30, 2016 and 2017, our hedges resulted in derivative fair value gains of $126 million and $458 million, respectively. The derivative fair value gains included $814 million and $137 million of gains on cash settled derivatives for the nine months ended September 30, 2016 and 2017, respectively. Commodity derivative fair value gains for the nine months ended September 30, 2017 includes gains of $750 million related to derivatives which were partially monetized prior to their settlement dates. See "—Deleveraging Activities" for further discussion.

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

Gathering, compression, water handling and treatment revenues. Gathering, compression, water handling and treatment revenues decreased from $10 million for the nine months ended September 30, 2016 to $9 million for the nine months ended September 30, 2017, primarily attributable to the provision of such services to wells in which we hold a higher working interest than the wells to which such services were provided in 2016. Fees for gathering, compression, water handling and treatment services provided to us by Antero Midstream are eliminated in consolidation. The amounts that are not eliminated represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for services provided by Antero Midstream.

Lease operating expense. Lease operating expense increased from $37 million for the nine months ended September 30, 2016 to $56 million for the nine months ended September 30, 2017, an increase of 51%. This increase is primarily the result of an increase in production and the number of producing wells. On a per unit basis, lease operating expenses increased from $0.08 per Mcfe for the nine months ended September 30, 2016 to $0.09 for the nine months ended September 30, 2017. The increase in lease operating expenses on a per Mcfe basis is due to an increase in produced water on new well pads, which is attributable to an increase in the amount of water used in our advanced well completions. Lease operating expenses are expected to gradually increase on a per-unit basis as maturing properties make up a larger proportion of our production base and average production per existing well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $650 million for the nine months ended September 30, 2016 to $816 million for the nine months ended September 30, 2017. The increase in these expenses is a result of the increase in production and the related firm transportation, gathering, compression, and processing expenses. On a per Mcfe basis, consolidated gathering, compression, processing and transportation expenses increased from $1.32 per Mcfe for the nine months ended September 30, 2016 to $1.35 per Mcfe for the nine months ended September 30, 2017, primarily due to increased utilization of a pipeline, in the first half of 2017, which has higher per-unit transportation costs than the average of our transportation portfolio.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $52 million for the nine months ended September 30, 2016 to $70 million for the nine months ended September 30, 2017 as a result of an increase in production revenues. On a per Mcfe basis, production and ad valorem taxes increased from $0.11 per Mcfe for the nine months ended September 30, 2016 to $0.12 per Mcfe for the nine months ended September 30, 2017 as a result of increases in per-unit production revenues. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging decreased from 4.5% for the nine months ended September 30, 2016 to 3.5% for the nine months ended September 30, 2017, primarily attributable to the July 1, 2016 termination of a West Virginia production tax surcharge for workers' compensation funding.

Exploration expense. Exploration expense increased from $3 million for the nine months ended September 30, 2016 to $6 million for the nine months ended September 30, 2017. These amounts represent expenses incurred for unsuccessful lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties increased from $47 million for the nine months ended September 30, 2016 to $83 million for the nine months ended September 30, 2017, primarily due to the expiration of certain Utica leases, in the third quarter of 2017, which we elected not to retain and develop. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, or future plans to develop the acreage.

Depletion, depreciation, and amortization expense. DD&A increased from $588 million for the nine months ended September 30, 2016 to $611 million for the nine months ended September 30, 2017, primarily because of increased production. DD&A per Mcfe decreased by 16%, from $1.20 per Mcfe during the nine months ended September 30, 2016 to $1.01 per Mcfe during the nine months ended September 30, 2017. This decrease was due to increases in our estimated recoverable reserves, due to improved well performance, and decreases in our per-unit development costs, which is due to well cost reductions and drilling and completion efficiencies that we have achieved over the last year.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. At September 30, 2017, we compared the carrying values of our proved properties to estimated future net cash flows. As estimated future net cash flows were higher than the carrying values of our proved properties at September 30, 2017, we did not further evaluate our proved properties for impairment.

General and administrative expense. General and administrative expense (before equity-based compensation expense) increased from $98 million for the nine months ended September 30, 2016 to $112 million for the nine months ended September 30, 2017, primarily due to increases in employee compensation and benefits expenses. On a per-unit basis, general and administrative expense before equity-based compensation decreased by 10%, from $0.20 per Mcfe during the nine months ended September 30, 2016 to $0.18 per Mcfe during the nine months ended September 30, 2017, primarily due to our 23% increase in production. We had 516 employees as of September 30, 2016 and 583 employees as of September 30, 2017.

Equity-based compensation expense. Non-cash equity-based compensation expense increased from $76 million for the nine months ended September 30, 2016 to $79 million for the nine months ended September 30, 2017 as a result of an increase in outstanding equity awards. See Note 7 to the condensed consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Interest expense. Interest expense increased from $186 million for the nine months ended September 30, 2016 to $205 million for the nine months ended September 30, 2017, primarily due to Antero Midstream's issuance of its 5.375% senior notes due 2024 in September 2016. Interest expense includes approximately $8.5 million and $8.8 million of non-cash amortization of deferred financing costs for the nine months ended September 30, 2016 and 2017, respectively

Income tax (expense) benefit. Income tax (expense) benefit changed from a deferred tax benefit of $231 million for the nine months ended September 30, 2016 to a deferred tax expense of $105 million for the nine months ended September 30, 2017. The deferred tax benefit for the nine months ended September 30, 2016 was due to a pre-tax loss incurred for financial reporting purposes, whereas we generated pre-tax income for financial reporting purposes for the nine months ended September 30, 2017.

At December 31, 2016, we had approximately $1.6 billion of NOLs for U.S. federal income tax purposes that expire at various dates from 2024 through 2036 and approximately $1.4 billion of state NOLs that expire at various dates from 2017 through 2036. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies, such as deductions for intangible drilling costs. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expenses, may also change the taxation of oil and gas companies. If passed, such legislation could significantly affect our future taxable position. The impact of any such change would be recorded in the period in which such legislation is enacted.

Adjusted EBITDAX. Adjusted EBITDAX decreased from $1.1 billion for the nine months ended September 30, 2016 to $1.0 billion for the nine months ended September 30, 2017. The decrease in Adjusted EBITDAX was primarily due to decreases in our average realized price for natural gas after gains on settled derivatives, partially offset by increased production. Adjusted EBITDAX does not include $750 million of realized gains from the partial monetization of certain natural gas hedges. See "—Deleveraging Activities" for further discussion of the hedge monetizations. See "—Non-GAAP Financial Measures" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) including noncontrolling interest and net cash provided by operating activities.

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Discussion of Segment Results for the Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2017

Our previous discussion of the consolidated exploration and production results includes the consolidated results from our gathering and processing, water handling and treatment, and marketing segments, whose revenues are almost entirely derived from services provided to the exploration and production segment. Our gathering and processing and water handling and treatment operations are almost entirely conducted by Antero Midstream, a master limited partnership. Antero owns 53% of Antero Midstream's issued and outstanding common units. Antero Midstream's distributable cash is paid to its common unitholders subsequent to the end of each quarter. Following is a summary level discussion of the various segment results which should be read in conjunction with our detailed discussion of our consolidated exploration and production results:

Exploration and production. Revenues from the exploration and production segment increased from $1.3 billion for the nine months ended September 30, 2016 to $2.5 million for the nine months ended September 30, 2017, primarily because of an increase in production revenues of $835 million from increases in production and realized prices, as well as an increase in commodity derivative fair value gains and losses of $333 million. Total operating expenses increased from $1.6 billion for the nine months ended September 30, 2016 to $2.0 billion for the nine months ended September 30, 2017, primarily because of a 23% increase in production. Gathering, compression, processing, and transportation expenses increased by $232 million, lease operating expenses increased by $20 million, DD&A expenses increased by $8 million, impairment expense for unproved properties increased by $36 million and other items increased by $31 million.

On a per Mcfe basis, total gathering, compression, processing and transportation expenses for the exploration and production segment increased from $1.70 per Mcfe for the nine months ended September 30, 2016 to $1.76 per Mcfe for the nine months ended September 30, 2017 as a result of increased utilization of a pipeline, in the first half of 2017, which has higher per-unit transportation costs than the average of our transportation portfolio, as well as an increase in the proportion of gathering and compression expenses provided to us by Antero Midstream. Such expenses are eliminated in consolidation.

Gathering and Processing. Revenue for the gathering and processing segment increased from $220 million for the nine months ended September 30, 2016 to $291 million for the nine months ended September 30, 2017, an increase of $71 million, or 32%. Gathering revenues increased by $47 million from the prior year period and compression revenues increased by $24 million as additional wells on production increased throughput volumes. Total operating expenses related to the gathering and processing segment increased from $102 million for the nine months ended September 30, 2016 to $123 million for the nine months ended September 30, 2017 primarily as a result of increases in direct operating and depreciation expenses due to a larger base of gathering and compression assets.

In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. In February 2017, Antero Midstream formed the Joint Venture with MarkWest, which provides natural gas processing and fractionation services. Equity in earnings of unconsolidated affiliates of $2 million and $13 million for the nine months ended September 30, 2016 and 2017, respectively, represents the portion of the net income from these investments which is allocated to Antero Midstream based on its equity interests. The increase was due to a full nine months of investment income in the regional gathering pipeline during the nine months ended September 30 2017, as opposed to five months during the nine months ended September 30, 2016, and the commencement of operations of the Joint Venture in February 2017.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $204 million for the nine months ended September 30, 2016 to $271 million for the nine months ended September 30, 2017, an increase of $67 million, or 33%. The increase was due to an increase in the volume of water used per well in our advanced completions during the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016, as well as an increase in other fluid handling services The volume of water delivered through the systems increased from 31.3 MMBbls for the nine months ended September 30, 2016 to 42.1 MMBbls for the nine months ended September 30, 2017. Operating expenses for the water handling and treatment segment increased from $148 million for the nine months ended September 30, 2016 to $182 million for the nine months ended September 30, 2017, primarily due to the increase in other fluid handling services.

Marketing. Where permitted, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets. Marketing revenues of $287 million and $167 million and expenses of $379 million and $246 million for the nine months ended September 30, 2016 and 2017, respectively, relate to these activities. Net losses on our marketing activities were $92 million and $79 million for the nine months ended September 30, 2016 and 2017, respectively. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of $96 million and $74 million for the nine months ended September 30, 2016 and 2017, respectively, related to unutilized excess capacity which decreased due to the assumption of certain unutilized firm transportation capacity by a third party beginning July 1, 2016.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt and equity securities, borrowings under the Prior Credit Facility and Prior Midstream Facility, asset sales, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development, and acquisition of natural gas, NGLs, and oil properties, as well as for development of gathering systems and facilities, and fresh water handling and wastewater treatment infrastructure. As we pursue the development of our reserves, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities, and liquidity requirements. Our future success in growing our proved reserves and production will be highly dependent on the capital resources available to us.

We believe that funds from operating cash flows and available borrowings under the Credit Facility and Midstream Facility, or capital market transactions, will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see Note 5 to the condensed consolidated financial statements included in this Quarterly Report on Form 10-Q.

The following table summarizes our cash flows for the nine months ended September 30, 2016 and 2017:

	Nine Months Ended September 30,	
(in thousands)	2016	2017
Net cash provided by operating activities	$ 905,697	1,692,808
Net cash used in investing activities	(1,974,667)	(1,948,307)
Net cash provided by financing activities	1,064,009	247,583
Net decrease in cash and cash equivalents	$ (4,961)	(7,916)

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $906 million and $1.7 billion for the nine months ended September 30, 2016 and 2017, respectively. The increase in cash flows from operations from the nine months ended September 30, 2016 to the nine months ended September 30, 2017 was primarily due to $750 million of proceeds from the partial monetization of certain of our natural gas hedges. See "—Deleveraging Activities" for further discussion.

Our net operating cash flow is sensitive to many variables, the most significant of which is the volatility of natural gas, NGLs, and oil prices, as well as volatility in the cash flows attributable to settlement of our commodity derivatives. Prices for natural gas, NGLs, and oil are primarily determined by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables influence the market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk."

Cash Flow Used in Investing Activities

Cash flows used in investing activities decreased from $2.0 billion for the nine months ended September 30, 2016 to $1.9 billion for the nine months ended September 30, 2017, primarily due to decreases in acquisitions and drilling and completion costs, partially offset by increases Antero Midstream's investments in the Joint Venture and gathering and compression assets during the nine months ended September 30, 2017. During the nine months ended September 30, 2017, our cash flows used in investing activities included $947 million for drilling and completion costs, $182 million for undeveloped leasehold additions, $179 million for acquisitions, $143 million for water handling and treatment systems, $255 million for gathering and compression systems, $217 million for investments in the Joint Venture, and $11 million for other property and equipment. During the nine months ended September 30, 2016, our cash flows used in investing activities included $1.0 billion for drilling and completion costs, $106 million for undeveloped leasehold additions, $519 million for acquisitions, $137 million for water handling and treatment systems, $154 million for gathering and compression systems, $45 million for a 15% equity interest in a regional gathering pipeline, and $2 million for other property and equipment.

Our capital budget for 2017 is $1.5 billion, which does not include the capital budget of $800 million for Antero Midstream, our consolidated subsidiary. Our capital budget may be adjusted as business conditions warrant as the amount, timing, and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels, or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity, and to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in commodity prices, availability of financing, drilling and acquisition costs, industry conditions, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows, and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash flows provided by financing activities decreased from $1.1 billion for the nine months ended September 30, 2016 to $248 million for the nine months ended September 30, 2017, primarily due to issuances of common stock by Antero during the nine months ended September 30, 2016 to fund property acquisitions, as well as repayments on Antero's Prior Credit Facility during the nine months ended September 30, 2017 using proceeds from the hedge monetizations and sale of Antero Midstream common units owned by Antero described under "—Deleveraging Activities." During the nine months ended September 30, 2017, our cash flows provided by financing activities included proceeds of $311 million from the sale of Antero Midstream common units owned by Antero and net proceeds from the issuance of common units in Antero Midstream of $249 million (including $26 million issued under the Distribution Agreement), partially offset by net repayments on our revolving credit facilities of $198 million, distributions of $102 million to noncontrolling interest owners in Antero Midstream and other items totaling $12 million. During the nine months ended September 30, 2016, our cash flows provided by financing activities included proceeds of $837 million from the issuance of common stock, proceeds of $178 million from the sale of Antero Midstream common units owned by Antero, proceeds of $650 million from Antero Midstream's issuance of its 5.375% senior notes due 2024, and proceeds of $20 million from the sale of common units by Antero Midstream under the Distribution Agreement, partially offset by net repayments on our revolving credit facilities of $552 million, distributions of $51 million to noncontrolling interest owners in Antero Midstream, and other items totaling $18 million.

As a result of the aforementioned deleveraging activities, the balance outstanding under Antero's Prior Credit Facility had a net decrease from $930 million at June 30, 2017 to $25 million at September 30, 2017. The balance outstanding under the Prior Midstream Facility increased from $305 million at June 30, 2017 to $427 million at September 30, 2017.

Debt Agreements and Contractual Obligations

Antero Resources Senior Secured Revolving Credit Facility. Antero's Credit Facility is with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our assets and are subject to regular semiannual redeterminations. At September 30, 2017, under the Prior Credit Facility, the borrowing base was $4.75 billion and lender commitments were $4.0 billion. The next redetermination of the borrowing base is scheduled to occur in March 2018. At September 30, 2017, we had $25 million of borrowings and $700 million of letters of credit outstanding under the Prior Credit Facility, with a weighted average interest rate of 4.75%. At December 31, 2016, we had $440 million of borrowings and $710 million of letters of credit outstanding under the Prior Credit Facility, with a weighted average interest rate of 2.44%. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the maturity of any series of Antero's senior notes, unless such series of senior notes is refinanced.

Under the Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred, commences when Antero elects to give notice to the Administrative Agent that Antero has received at lease one of (i) a BBB- or better rating from Standard and Poor's and (ii) a Baa3 or better rating from Moody's (an "Investment Grade Rating"). An Investment Grade Period can end at Antero's election. During any period that is not an Investment Grade Period, the Credit Facility requires Antero and its restricted subsidiaries to maintain the following two financial ratios as of the end of each fiscal quarter:

· a current ratio, which is the ratio of our current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our current liabilities (excluding derivative liabilities), of not less than 1.0 to 1.0; and

· an interest coverage ratio, which is the ratio of EBITDAX (as defined by the credit facility agreement) to interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

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

· a current ratio, which is the ratio of our current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our current liabilities (excluding derivative liabilities), of not less than 1.0 to 1.0;

· a ratio of total Indebtedness (as defined by the credit facility agreement) to EBITDAX (as defined by the credit facility agreement) of not more than 4.25 to 1.00; and

· a ratio of PV-9 reflected in the most recently delivered reserve report to its total Indebtedness of not less than 1.50 to 1.00, but only if Antero does not have both (i) an unsecured rating from Moody's of Baa3 or better and (ii) an unsecured rating from S&P of BBB- or better.

We were in compliance with such covenants and ratios as determined by the Prior Credit Facility as of December 31, 2016 and September 30, 2017. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At September 30, 2017, our current ratio was 5.73 to 1.0 (based on the $4.5 billion borrowing base under the Credit Facility) and our interest coverage ratio was 9.01 to 1.0.

Midstream Credit Facility. Antero Midstream has a secured revolving credit facility among Antero Midstream, certain lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, and swing line lender. The Midstream Facility provides for lender commitments of $1.5 billion and for a letter of credit sublimit of $150 million. At September 30, 2017, Antero Midstream had a total outstanding balance under the Prior Midstream Facility of $427 million, with a weighted average interest rate of 2.82%. At December 31, 2016, Antero Midstream had a total outstanding balance under the Prior Midstream Facility of $210 million, with a weighted average interest rate of 2.23%. The Midstream Facility matures on October 26, 2022.

Senior Notes. Please refer to Note 5 to the condensed consolidated financial statements included in this Quarterly Report on Form 10-Q and to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on Form 10-K for the year ended December 31, 2016 for information on our senior notes.

We may, from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions, or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, and other factors. The amounts involved could be material.

For more information on the terms, conditions, and restrictions under the Prior Credit Facility, the Prior Midstream Facility, and senior unsecured notes, please refer to our Annual Report on Form 10-K for the year ended December 31, 2016 on file with the SEC.

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Contractual Obligations. A summary of our contractual obligations as of September 30, 2017 is provided in the table below. Contractual obligations listed exclude minimum fees that we will pay to Antero Midstream, our consolidated subsidiary, under gathering and compression, and water services agreements. Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

	Remainder	Year Ended December 31,						
(in millions)	of 2017	2018	2019	2020	2021	2022	Thereafter	Total
Antero Credit Facility(1)	$ —	—	—	—	25	—	—	25
Antero Midstream Facility(1)	—	—	—	—	—	427	—	427
Antero senior notes—principal(2)	—	—	—	—	1,000	1,100	1,350	3,450
Antero senior notes—interest(2)	77	182	182	182	155	129	111	1,018
Antero Midstream senior notes—principal(2)	—	—	—	—	—	—	650	650
Antero Midstream senior notes—interest(2)	—	35	35	35	35	35	70	245
Drilling rig and completion service commitments(3)	28	80	41	—	—	—	—	149
Firm transportation (4)	135	886	1,107	1,127	1,106	1,053	9,635	15,049
Processing, gathering, and compression services (5)	109	401	340	337	321	317	1,502	3,327
Office and equipment leases	4	13	11	9	8	8	17	70
Asset retirement obligations(6)	—	—	—	—	—	—	38	38
Total	$ 353	1,597	1,716	1,690	2,650	3,069	13,373	24,448

(1) Includes outstanding principal amounts at September 30, 2017. This table does not include future commitment fees, interest expense, or other fees on our Credit Facility or the Midstream Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged. The maturity date of Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the maturity of any series of Antero's senior notes, unless such series of notes is refinanced. The maturity date of the Midstream Facility is October 26, 2022

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

(3) Includes contracts for services provided by drilling rigs and completion fleets which expire at various dates from March 2018 through February 2020. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests.

(4) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of our production to market. These contracts commit us to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table reflect our minimum daily volumes at the reservation fee rates. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests.

(5) Contractual commitments for processing, gathering, and compression services agreements represent minimum commitments under long-term agreements. This includes fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest, as well as Antero Midstream's commitments for the construction of its advanced wastewater treatment complex. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. The table does not include intracompany commitments.

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

Non-GAAP Financial Measures

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income or loss, including noncontrolling interests, before interest expense, interest income, derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), taxes, impairment, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, and gain or loss on sale of assets. Adjusted EBITDAX also includes distributions from unconsolidated affiliates and excludes equity in earnings or losses of unconsolidated affiliates.

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

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

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

· is used by our management team for various purposes, including as a measure of operating performance, in presentations to our Board, and as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our Board as a performance measure in determining executive compensation. Adjusted EBITDAX, as defined under the Credit Facility, is used by our lenders pursuant to covenants under the Credit Facility and the indentures governing our senior notes.

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

"Segment Adjusted EBITDAX" is also used by our management team for various purposes, including as a measure of operating performance of our segments and as a basis for strategic planning and forecasting. Segment Adjusted EBITDAX is a non-GAAP financial measure that we define as operating income or loss before derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), impairment, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, gain or loss on sale of assets, and gain or loss on changes in the fair value of contingent acquisition consideration. Segment Adjusted EBITDAX also includes distributions received from unconsolidated affiliates. Operating income or loss represents net income or loss, including noncontrolling interests, before interest expense and interest income, income taxes, and equity in earnings of unconsolidated affiliates. Operating income is the most directly comparable GAAP financial measure to Segment Adjusted EBITDAX because we do not account for income tax expense or interest expense on a segment basis.

The following tables represent a reconciliation of our operating income (loss) to Segment Adjusted EBITDAX for the three and nine months ended September 30, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2016:						
Operating income (loss)	$ 454,347	44,550	29,492	(17,535)	(43,522)	467,332
Commodity derivative fair value gains	(530,334)	—	—	—	—	(530,334)
Gains on settled derivatives	196,712	—	—	—	—	196,712
Depletion, depreciation, amortization, and accretion	173,363	18,540	7,838	—	—	199,741
Impairment of unproved properties	11,753	—	—	—	—	11,753
Exploration expense	1,166	—	—	—	—	1,166
Loss (gain) on change in fair value of contingent acquisition consideration	(3,527)	—	3,527	—	—	—
Equity-based compensation expense	19,781	5,214	1,386	—	—	26,381
Segment and consolidated Adjusted EBITDAX	$ 323,261	68,304	42,243	(17,535)	(43,522)	372,751

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	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended September 30, 2017:						
Operating income (loss)	$ (86,020)	58,595	24,352	(28,117)	(40,862)	(72,052)
Commodity derivative fair value losses	65,957	—	—	—	—	65,957
Gains on settled derivatives (1)	61,479	—	—	—	—	61,479
Depletion, depreciation, amortization, and accretion	176,846	22,027	8,753	—	—	207,626
Impairment of unproved properties	41,000	—	—	—	—	41,000
Exploration expense	1,599	—	—	—	—	1,599
Loss (gain) on change in fair value of contingent acquisition consideration	(2,556)	—	2,556	—	—	—
Equity-based compensation expense	19,248	5,111	2,088	—	—	26,447
Distributions from unconsolidated affiliates	—	4,300	—	—	—	4,300
Segment and consolidated Adjusted EBITDAX	$ 277,553	90,033	37,749	(28,117)	(40,862)	336,356

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2016:						
Operating income (loss)	$ (326,450)	117,314	56,241	(91,327)	(99,570)	(343,792)
Commodity derivative fair value gains	(125,624)	—	—	—	—	(125,624)
Gains on settled derivatives	813,559	—	—	—	—	813,559
Depletion, depreciation, amortization, and accretion	515,148	52,780	21,975	—	—	589,903
Impairment of unproved properties	47,223	—	—	—	—	47,223
Exploration expense	3,289	—	—	—	—	3,289

Loss (gain) on change in fair value of contingent acquisition consideration	(10,384)	—	10,384	—	—	—
Equity-based compensation expense	56,301	14,902	4,464	—	—	75,667
State franchise taxes	39	—	—	—	—	39
Segment and consolidated Adjusted EBITDAX	$ 973,101	184,996	93,064	(91,327)	(99,570)	1,060,264

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Nine months ended September 30, 2017:						
Operating income (loss)	$ 513,825	167,719	89,044	(79,639)	(137,915)	553,034
Commodity derivative fair value gains	(458,459)	—	—	—	—	(458,459)
Gains on settled derivatives (1)	137,392	—	—	—	—	137,392
Depletion, depreciation, amortization, and accretion	523,547	64,445	24,831	—	—	612,823
Impairment of unproved properties	83,098	—	—	—	—	83,098
Exploration expense	5,510	—	—	—	—	5,510
Loss (gain) on change in fair value of contingent acquisition consideration	(9,672)	—	9,672	—	—	—
Equity-based compensation expense	58,489	14,937	5,499	—	—	78,925
Distributions from unconsolidated affiliates	—	10,120	—	—	—	10,120
Segment and consolidated Adjusted EBITDAX	$ 853,730	257,221	129,046	(79,639)	(137,915)	1,022,443

(1) Gains on settled derivatives for the three and nine months ended September 30, 2017 do not include proceeds of $750 million related to derivatives which were partially monetized prior to their settlement dates. See "—Deleveraging Activities" for further discussion.

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The following table represents a reconciliation of our net income, including noncontrolling interest, to consolidated Adjusted EBITDAX and a reconciliation of consolidated Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows for the three and nine months ended September 30, 2016 and 2017:

(in thousands)	Three months ended September 30, 2016	2017	Nine months ended September 30, 2016	2017
Net income (loss) including noncontrolling interest	$ 268,196	(90,000)	(296,644)	255,523
Commodity derivative fair value (gains) losses(1)	(530,334)	65,957	(125,624)	(458,459)
Gains on settled derivatives(1)(2)	196,712	61,479	813,559	137,392
Interest expense	59,755	70,059	185,634	205,311
Income tax expense (benefit)	140,924	(45,078)	(230,755)	105,087
Depletion, depreciation, amortization, and accretion	199,741	207,626	589,903	612,823
Impairment of unproved properties	11,753	41,000	47,223	83,098
Exploration expense	1,166	1,599	3,289	5,510
Equity-based compensation expense	26,381	26,447	75,667	78,925
Equity in earnings of unconsolidated affiliates	(1,543)	(7,033)	(2,027)	(12,887)
Distributions from unconsolidated affiliates	—	4,300	—	10,120
State franchise taxes	—	—	39	—
Consolidated Adjusted EBITDAX	372,751	336,356	1,060,264	1,022,443
Interest expense	(59,755)	(70,059)	(185,634)	(205,311)
Exploration expense	(1,166)	(1,599)	(3,289)	(5,510)
Changes in current assets and liabilities	17,327	29,899	35,939	130,089
State franchise taxes	—	—	(39)	—
Proceeds from derivative monetizations	—	749,906	—	749,906
Other non-cash items	(2,166)	719	(1,544)	1,191
Net cash provided by operating activities	$ 326,991	1,045,222	905,697	1,692,808

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

(2) Gains on settled derivatives for the three and nine months ended September 30, 2017 do not include proceeds of $750 million related to derivatives which were partially monetized prior to their settlement dates. See "—Deleveraging Activities" for further discussion.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Our more significant accounting policies and estimates include the successful efforts method of accounting for our production activities, estimates of natural gas, NGLs, and oil reserve quantities and standardized measures of future cash flows, and impairment of proved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments in our 2016 Form 10-K. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated financial statements. Also, see Note 2 of the notes to our audited consolidated financial statements, included in our 2016 Form 10-K, for a discussion of additional accounting policies and estimates made by management.

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

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September 30, 2017, we compared estimated undiscounted future net cash flows using futures pricing for our Utica and Marcellus Shale properties to the carrying values of those properties. Estimated undiscounted future net cash flows exceeded the carrying values at September 30, 2017 and thus, no further evaluation of the proved properties for impairment is required under GAAP. As a result, we have not recorded any impairment expenses associated with our Utica and Marcellus Basin proved properties during the three and nine months ended September 30, 2017. Additionally, we did not record any impairment expenses for proved properties during the years ended December 31, 2014, 2015, and 2016. Based on present futures commodity pricing, we currently do not anticipate having to record any impairment charges for our proved properties in the near future. We are unable, however, to predict commodity prices with any greater precision than the futures market.

New Accounting Pronouncements

On May 28, 2014, the Financial Accounting Standards Board ("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 will replace most existing revenue recognition guidance in GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method. The Company has not yet selected a transition method, but expects that it will elect the cumulative effect method. To the extent applicable, upon adoption, we will 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 transaction prices to performance obligations.

During the third quarter of 2017, the Company substantially completed its analysis of the impact of the standard on its contract types, and we do not believe that the adoption of ASU 2014-09 will have a material impact on its financial results. Currently, the Company is evaluating its disclosures to determine additional qualitative disclosures to provide under the standard. We continue to monitor relevant industry guidance regarding the implementation of ASU 2014-09 and will adjust our implementation strategies as necessary. We do not believe that adoption of the standard will impact our operational strategies, growth prospects, or cash flows.

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

Off-Balance Sheet Arrangements

As of September 30, 2017, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rig and completion services, firm transportation, gas processing and fractionation, gathering, and compression services. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for our commitments under these agreements.

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Item 3.Quantitative and Qualitative Disclosures About Market Risk.

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

Commodity Hedging Activities

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

To mitigate some of the potential negative impact on our cash flows caused by changes in commodity prices, we enter into derivative financial instruments to receive fixed prices for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured. These contracts may include commodity price swaps whereby we will receive a fixed price and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. These contracts are financial instruments, and do not require or allow for physical delivery of the hedged commodity. At September 30, 2017, the majority of our natural gas hedges were fixed price swaps at NYMEX pricing. The Company was not party to any collars as of or during the nine months ended September 30, 2017.

At September 30, 2017, we had in place natural gas, NGLs, and oil swaps covering portions of our projected production from 2017 through 2023. Our commodity hedge position as of September 30, 2017 is summarized in Note 9(a) to our condensed consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. Under the Credit Facility, we are permitted to hedge up to 75% of our projected production for the next 60 months. We may enter into hedge contracts with a term greater than 60 months, and for no longer than 72 months, for up to 65% of our estimated production. Based on our production and our fixed price swap contracts which settled during the nine months ended September 30, 2017, our revenues would have decreased by approximately $7.5 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices, excluding the effects of changes in the fair value of our derivative positions which remain open at September 30, 2017.

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

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. At September 30, 2017, the estimated fair value of our commodity derivative instruments was a net asset of $1.2 billion comprising current and noncurrent assets and liabilities. At December 31, 2016, the estimated fair value of our commodity derivative instruments was a net asset of $1.6 billion comprising current and noncurrent assets and liabilities.

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

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Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from the following: commodity derivative contracts ($1.2 billion at September 30, 2017); the sale and marketing of our oil and gas production ($234 million at September 30, 2017) which we market to energy companies, end users, and refineries; and joint interest receivables ($10 million at September 30, 2017).

By using derivative instruments that are not traded on an exchange to hedge our exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of a derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions which management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with fourteen different counterparties, twelve of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $1.2 billion at September 30, 2017 included the following derivative assets by bank counterparty: JP Morgan - $286 million; Morgan Stanley - $248 million; Citigroup - $184 million; Scotiabank - $157 million; Wells Fargo - $148 million; Canadian Imperial Bank of Commerce - $48 million; Toronto Dominion - $36 million; BNP Paribas - $24 million; Bank of Montreal - $16 million; Fifth Third - $13 million; SunTrust - $8 million; Capital One - $4 million; and Natixis - $1 million. The credit ratings of certain of these banks were downgraded several years ago because of their exposure to the sovereign debt crisis in Europe or various other economic factors. The estimated fair value of our commodity derivative assets has been risk-adjusted using a discount rate based upon the counterparties' respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at September 30, 2017 for each of the European and American banks. We believe that all of these institutions, currently, are acceptable credit risks. Other than as provided by the Credit Facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of September 30, 2017, we did not have any past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

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

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

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility and the Midstream Facility of our consolidated subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annualized interest rate incurred on the Prior Credit Facility and the Prior Midstream Facility during the nine months ended September 30, 2017 was approximately 3.17%. We estimate that a 1.0% increase in each of the applicable average interest rates for the nine months ended September 30, 2017 would have resulted in a $7.0 million increase in interest expense.

Item 4.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 Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures and is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2017 at a level of reasonable assurance.

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Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1.Legal Proceedings.

Environmental

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

SJGC

The Company is the plaintiff in a lawsuit against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, “SJGC”) pending in United States District Court in Colorado. In March 2015, the Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC had short paid, and continued to short pay, the Company in connection with two nearly identical long term gas contracts. Under those contracts, SJGC are long term purchasers of 80,000 MMBtu/day of the Company’s natural gas production. Deliveries under the contracts began in October 2011 and the term of the contracts continues through October 2019. The price for gas was based on specified indices in the contracts. Beginning in October 2014, SJGC began short paying the Company based on price indices unilaterally selected by SJGC and not the applicable index specified in the contracts. SJGC claimed that the index price specified in the contracts, and the index at which SJGC paid for deliveries from 2011 through September 2014, was no longer appropriate under the contracts because a market disruption event (as defined by the contract) had occurred and, as a result, a new index price was required to be determined by the parties. The Company rejected SJGC’s contention that a market disruption event occurred. SJGC’s actions constituted a breach of the contracts by failing to pay the Company based on the express price terms of the contracts and paying the Company based on unilaterally selected price indices in violation of the contracts’ remedial provisions. On May 8, 2017, a jury in the United States District Court in Colorado returned a unanimous verdict finding in favor of Antero’s positions in the lawsuit against SJGC. On July 21, 2017, final judgment on the jury’s unanimous verdict was entered by the court. On August 18, 2017, SJGC filed post-judgment motions with the court, which are currently pending. If the court denies those motions, SJGC will have 30 days from the court's decision on these post-judgment motions to file an appeal. SJGC continues to short pay the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. Through September 30, 2017, the Company estimates that it is owed approximately $70 million (gross damages, including interest) more than SJGC has paid using the indices unilaterally selected by them. Substantially all of this amount has not been accrued in the Company's financial statements. The Company will vigorously seek recovery from SJGC of all underpayments and damages, including interest, based on the contracted price.

WGL

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") were involved in a pricing dispute involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. From January 2016 through July 2017, the aggregate daily gas volumes contracted for under the Contracts was 500,000 MMBtu/day, with the aggregate daily contracted volumes having increased to 600,000 MMBtu/day during the months of August and September 2017. The Company invoiced WGL based on the natural gas index price specified in the Contracts and WGL paid the Company based on that invoice price. However, WGL asserted that the index price was no longer appropriate under the Contracts and claimed that an undefined alternative index was more appropriate for the delivery point of the gas. In July 2016, the matter was referred to arbitration by the Colorado district court. In January 2017, after hearing a week of testimony and evidence, the arbitration panel ruled in the Company's favor. As a result, the index price has remained as specified in the Contracts and there will be no adjustments to the invoices that have been paid by WGL, nor will future invoices to WGL be adjusted based on the same claim rejected by the arbitration panel. The arbitration panel's award was confirmed by the Colorado district court on April 14, 2017.

In March of 2017, WGL filed a second lawsuit against the Company in Colorado district court alleging breach of contract and seeking damages of more than $30 million. In this lawsuit, WGL claimed that the Company breached its contractual obligations under the Contracts by failing to deliver "TCO pool" gas. In subsequent filings, WGL explained that its claims were based on an alleged

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obligation that the Company must deliver gas to the Columbia IPP Pool ("IPP Pool"). WGL asserted this exact same claim in the arbitration and it was rejected by the arbitration panel. The arbitration panel specifically found that the Delivery Point under the Contracts was at a specific point in Braxton, West Virginia, not the IPP Pool. On August 24, 2017, the Colorado district court dismissed with prejudice WGL's claims against the Company in its second lawsuit and found that the Company had not breached its Contracts with WGL by allegedly failing to deliver to the IPP Pool. The Court also reaffirmed the arbitration panel's finding that the delivery point under the Contracts was not the IPP Pool. WGL has appealed this decision to the Colorado Court of Appeals decision and that appeal remains pending.

The Company is also actively engaged in pursuing cover damages against WGL based on WGL's failure to take receipt of all of the agreed quantities of gas required under the Contracts. WGL's failure to take the gas volumes specified in the Contracts is directly related to WGL's lack of primary firm transportation rights at the Delivery Point. The failures by WGL to take the gas began in April 2017 and have continued each month since in varying quantities. In defense of its conduct, WGL has asserted to the Company that their failure to receive gas is excused by (1) the Company's failure to deliver gas to the IPP Pool or (2) alleged instances of Force Majeure under the Contracts. However, as stated above, the alleged obligation that the Company must deliver gas to the IPP Pool was rejected by the arbitration panel and the Colorado district court. Further, the Contracts expressly prohibit a Force Majeure claim in circumstances in which the gas purchaser does not have primary firm transportation agreements in place to transport the purchased gas. In each instance that WGL has failed to receive the quantity of gas required under the Contracts, the Company has resold the quantities not taken and invoiced WGL for cover damages pursuant to the terms of the Contracts. WGL has refused to pay for the invoiced cover damages as required by the Contracts and has also short paid the Company for certain amounts of gas received by WGL. Through September 30, 2017, these damages amounted to approximately $65 million (gross damages, including interest). This amount has not been accrued in the Company's financial statements. The Company is currently pursuing its cover damages in a lawsuit filed in Colorado district court on October 24, 2017. WGL's failure to take receipt of all quantities of gas and resulting cover damages remains ongoing. The Company will continue to vigorously seek recovery of its cover damages and other unpaid amounts, including interest, as part of its claims against WGL.

Other

We are party to various other legal proceedings and claims in the ordinary course of our business. We believe that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. For a discussion of these risks, see "Item 1A. Risk Factors" in our 2016 Form 10-K and in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017. The risks described in our 2016 Form 10-K and in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017 could materially and adversely affect our business, financial condition, cash flows, and results of operations. There have been no material changes to the risks described in our 2016 Form 10-K and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet be Purchased Under the Plan
July 1, 2017 - July 31, 2017	3,017	$ 21.98	—	N/A
August 1, 2017 - August 31, 2017	—	$ —	—	N/A
September 1, 2017 - September 30, 2017	—	$ —	—	N/A

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Shares purchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of Antero equity awards held by our employees.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5.Other Information.

Amended and Restated Credit Facility

On October 26, 2017, we entered into an amendment and restatement of the Prior Credit Facility. See "—Debt Agreements—Revolving Credit Facility" for a description of the Credit Facility. The description of the Credit Facility is a summary and is qualified in its entirety by the terms of the Credit Facility. A copy of the Credit Facility is filed as Exhibit 10.1 hereto, and is incorporated herein by reference.

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

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Antero Resources Corporation, may be required to disclose in our annual and quarterly reports to the Securities and Exchange Commission (the "SEC"), whether we or any of our "affiliates" knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United State ("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 (“Warburg”), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and/or are members of our 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 us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by SAMIH and its affiliates. The disclosure does not relate to any activities conducted by us or by Warburg and does not involve our or Warburg’s management. Neither we nor Warburg has had any involvement in or control over the disclosed activities, and neither we nor Warburg has independently verified or participated in the preparation of the disclosure. Neither we nor Warburg is representing as to the accuracy or completeness of the disclosure nor do we or Warburg 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 US under the Specially Designated Global Terrorist (“SDGT”) sanctions program. Revenues and profits generated by Santander UK on these accounts in the first nine month period ended September 30, 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 nine month period ended September 30, 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 nine month period ended September 30, 2017.

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Item 6.Exhibits.

Exhibit Number	Description of Exhibit
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.1*	Amended and Restated Credit Agreement, dated as of October 26, 2017, by and among Antero Resources Corporation, the lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
101*	The following financial information from this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended September 30, 2017 formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Condensed Consolidated Statements of Equity, (iv) Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ANTERO RESOURCES CORPORATION

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

Date: November 1, 2017