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, 2013

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** (I.R.S. Employer Identification No.)
1625 17th 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The registrant had 262,049,659 shares of common stock outstanding as of November 6, 2013.

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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 and Section 21E of 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 in this report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" included in this Quarterly Report on Form 10-Q. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized 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;
- 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 and conducting our gathering and other midstream operations;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Form 10-Q that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering, and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2012 (the "2012 Form 10-K") on file with the Securities and Exchange Commission (File No. 333-164876-06), under the heading "Risk Factors" in our Final Prospectus dated October 9, 2013 (the "IPO Prospectus") on file with the Securities and Exchange Commission (File No. 333-189284), and in "Item 1A. Risk Factors" of this Form 10-Q.

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Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing, and production activities 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 Form 10-Q.

Introductory Note

On October 16, 2013, the members of Antero Resources LLC exchanged their membership interests in Antero Resources LLC for identical membership interests in Antero Resources Investment LLC ("Antero Investment"), a wholly owned subsidiary of Antero Resources LLC. Following the exchange of membership interests, pursuant to the merger agreement by and among Antero Resources LLC, Antero Investment and Antero Resources Corporation (ARC) whereby, (a) Antero Resources LLC merged with and into ARC, with ARC surviving the merger, (b) all of the membership interests of Antero Resources LLC held by Antero Investment converted into all 224,375,000 shares of outstanding common stock of ARC, and (c) the membership interest in Antero Investment held by Antero Resources LLC was cancelled. On the same date, ARC completed a public offering of its common stock and issued 37,674,659 additional shares of its common stock to the public for proceeds of approximately $1.58 billion, net of commissions and expenses of the offering.

The current and historical consolidated financial statements of Antero Resources LLC presented herein are identical with respect to the underlying financial information of ARC, which subsequent to September 30, 2013, became the reporting company with the Securities and Exchange Commission as a result of the aforementioned merger and initial public offering.

Prior to the merger, Antero Resources LLC and Antero Resources Corporation filed separate federal and state income tax returns. Antero Resources LLC was not subject to income taxes because it was a pass-through entity for federal and state tax purposes. Antero Resources Corporation has provided for income taxes, in its financial statements and its income tax provisions and liabilities did not change as a result of the merger of Antero Resources LLC and Antero Resources Corporation.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

ANTERO RESOURCES LLC

Condensed Consolidated Balance Sheets

December 31, 2012 and September 30, 2013

(Unaudited)

(In thousands)

		2012	2013
Assets			
Current assets:			
Cash and cash equivalents	$	18,989	11,584
Accounts receivable		21,296	33,023
Notes receivable — current portion		4,555	3,111
Accrued revenue		46,669	86,122
Derivative instruments		160,579	204,857
Other		22,518	20,816

Total current assets	274,606	359,513
Property and equipment:		
Oil and natural gas properties, at cost (successful efforts method):		
Unproved properties	1,243,237	1,420,719
Proved properties	1,689,132	3,199,830
Gathering systems and facilities	168,930	455,818
Other property and equipment	9,517	12,741
	3,110,816	5,089,108
Less accumulated depletion, depreciation, and amortization	(173,343)	(331,993)
Property and equipment, net	2,937,473	4,757,115
Derivative instruments	371,436	503,666
Notes receivable — long-term portion	2,667	—
Other assets, net	32,611	51,914
Total assets	$ 3,618,793	5,672,208
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 181,478	311,092
Accrued liabilities and other	61,161	103,359
Derivative instruments	—	309
Revenue distributions payable	46,037	68,926
Current portion of long-term debt	25,000	25,000
Deferred income tax liability	62,620	78,199
Total current liabilities	376,296	586,885
Long-term liabilities:		
Long-term debt	1,444,058	2,970,455
Deferred income tax liability	91,692	202,708
Other long-term liabilities	33,010	34,333
Total liabilities	1,945,056	3,794,381
Equity:		
Members' equity	1,460,947	1,460,947
Accumulated earnings	212,790	416,880
Total equity	1,673,737	1,877,827
Total liabilities and equity	$ 3,618,793	5,672,208

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES LLC

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Three Months ended September 30, 2012 and 2013

(Unaudited)

(In thousands, except per share amounts)

	2012	**2013**
Revenue:		
Natural gas sales	$ 66,796	182,125
Natural gas liquids sales	—	31,956
Oil sales	285	8,473
Commodity derivative fair value gains (losses)	(159,004)	161,968
Loss on sale of assets	(115)	—
Total revenue	(92,038)	384,522
Operating expenses:		
Lease operating	1,513	2,697
Gathering, compression, processing, and transportation	25,291	58,383
Production taxes	3,621	11,851
Exploration	3,156	5,372
Impairment of unproved properties	2,438	3,205
Depletion, depreciation, and amortization	26,858	65,697
Accretion of asset retirement obligations	25	266
General and administrative	11,938	14,443
Total operating expenses	74,840	161,914

Operating income (loss)	(166,878)	232,608
Interest expense	(22,453)	(47,444)
Income (loss) from continuing operations before income taxes and discontinued operations	(189,331)	185,164
Income tax (expense) benefit	75,444	(67,370)
Income (loss) from continuing operations	(113,887)	117,794
Discontinued operations:		
Income (loss) from results of operations and sale of discontinued operations	(13,791)	3,100
Net income (loss) and comprehensive income (loss) attributable to Antero equity owners	$ (127,678)	120,894
Pro forma information:		
Pro forma earnings (loss) per share - basic:		
Continuing operations	$ (0.44)	$ 0.45
Discontinued operations	$ (0.05)	$ 0.01
Net income (loss)	$ (0.49)	$ 0.46
Pro forma earnings (loss) per share - diluted:		
Continuing operations	$ (0.44)	$ 0.45
Discontinued operations	$ (0.05)	$ 0.01
Net income (loss)	$ (0.49)	$ 0.46
Pro forma weighted average number of shares outstanding:		
Basic	262,050	262,050
Diluted	262,050	262,050

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES LLC

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Nine Months ended September 30, 2012 and 2013

(Unaudited)

(In thousands, except per share amounts)

	2012	2013
Revenue:		
Natural gas sales	$ 156,618	476,403
Natural gas liquids sales	—	59,772
Oil sales	610	11,435
Commodity derivative fair value gains	52,210	285,510
Gain on sale of gathering system	291,190	—
Total revenue	500,628	833,120
Operating expenses:		
Lease operating	4,072	5,222
Gathering, compression, processing, and transportation	56,945	148,023
Production taxes	10,734	30,578
Exploration	7,912	17,034
Impairment of unproved properties	4,019	9,564
Depletion, depreciation, and amortization	65,289	158,650
Accretion of asset retirement obligations	71	797
General and administrative	31,584	40,727
Total operating expenses	180,626	410,595
Operating income	320,002	422,525
Interest expense	(71,046)	(100,840)
Income from continuing operations before income taxes and discontinued operations	248,956	321,685
Income tax expense	(108,525)	(120,695)
Income from continuing operations	140,431	200,990
Discontinued operations:		
Income (loss) from results of operations and sale of discontinued operations	(418,465)	3,100
Net income (loss) and comprehensive income (loss) attributable to Antero equity owners	$ (278,034)	204,090
Pro forma information:		

Pro forma earnings (loss) per share - basic:		
Continuing operations	$ 0.54	$ 0.77
Discontinued operations	$ (1.60)	$ 0.01
Net income (loss)	$ (1.06)	$ 0.78
Pro forma earnings (loss) per share - diluted:		
Continuing operations	$ 0.54	$ 0.77
Discontinued operations	$ (1.60)	$ 0.01
Net income (loss)	$ (1.06)	$ 0.78
Pro forma weighted average number of shares outstanding:		
Basic	262,050	262,050
Diluted	262,050	262,050

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES LLC

Condensed Consolidated Statements of Cash Flows

Nine Months ended September 30, 2012 and 2013

(Unaudited)

(In thousands)

	2012	2013
Cash flows from operating activities:		
Net income (loss)	$ (278,034)	204,090
Adjustment to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	65,360	159,447
Impairment of unproved properties	4,019	9,564
Commodity derivative fair value gains	(52,210)	(285,510)
Cash receipts for settled derivatives	141,506	109,311
Gain on sale of assets	(291,190)	—
Loss (gain) on sale of discontinued operations	427,232	(5,000)
Deferred income tax expense	87,695	120,695
Depletion, depreciation, amortization, accretion, and impairment of unproved properties – discontinued operations	78,616	—
Commodity derivative fair value gains - discontinued operations	(46,358)	—
Cash receipts for settled derivatives - discontinued operations	79,736	—
Deferred income tax expense – discontinued operations	4,085	1,900
Other	(4,567)	3,911
Changes in current assets and liabilities:		
Accounts receivable	(16,811)	(11,727)
Accrued revenue	17,378	(39,453)
Other current assets	(3,112)	1,702
Accounts payable	(9,812)	(4,602)
Accrued liabilities	7,281	44,720
Revenue distributions payable	(414)	22,889
Other	15,000	—
Net cash provided by operating activities	225,400	331,937
Cash flows from investing activities:		
Additions to proved properties	(4,451)	—
Additions to unproved properties	(428,574)	(342,832)
Development costs	(619,344)	(1,267,086)
Additions to gathering systems and facilities	(58,748)	(240,119)
Additions to other property and equipment	(2,786)	(3,225)
Proceeds from asset sales	816,167	—
Changes in other assets	2,556	(11,622)
Net cash used in investing activities	(295,180)	(1,864,884)
Cash flows from financing activities:		
Issuance of senior notes	—	231,750
Borrowings on bank credit facility, net	82,000	1,295,500
Payments of deferred financing costs	—	(8,334)
Other	992	6,626
Net cash provided by financing activities	82,992	1,525,542

Net increase (decrease) in cash and cash equivalents		13,212	(7,405)
Cash and cash equivalents, beginning of period		3,343	18,989
Cash and cash equivalents, end of period	$	16,555	11,584
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$	(61,930)	(70,221)
Supplemental disclosure of noncash investing activities:			
Increase in accounts payable for additions to properties, gathering systems, and facilities	$	73,430	134,525

See accompanying notes to condensed consolidated financial statements.

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ANTERO RESOURCES LLC

Notes to Condensed Consolidated Financial Statements

December 31, 2012 and September 30, 2013

(Unaudited)

(1) Business and Organization

Antero Resources LLC, a limited liability company, and its consolidated operating subsidiaries (collectively referred to as the Company, we, or our) are engaged in the exploration for and the production of natural gas, natural gas liquids (NGLs), and oil onshore in the United States in unconventional reservoirs, which can generally be characterized as fractured shales. Our properties are located in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. During 2012 we sold our Arkoma Basin and Piceance Basin properties. We have certain midstream gathering and pipeline operations. Our corporate headquarters are in Denver, Colorado.

Our consolidated financial statements as of September 30, 2013 include the accounts of Antero Resources LLC and its directly and indirectly owned subsidiaries prior to the merger, as described below. The subsidiaries included in the consolidated financial statements are Antero Resources Corporation (ARC) (formerly Antero Resources Appalachian Corporation) and its wholly owned subsidiaries prior to the merger, Antero Resources Bluestone LLC and Antero Resources Finance Corporation (Antero Finance) (collectively referred to as the Antero Entities). Antero Resources LLC, the stand alone parent entity, had insignificant independent assets and no operations. In September 2013, we formed Antero Resources Midstream LLC (Antero Midstream). We intend to tranfer our midstream business to Antero Midstream.

On October 16, 2013, in connection with a corporate reorganization that was completed immediately prior to the closing of ARC’s initial public offering, the members of Antero Resources LLC exchanged their membership interests in Antero Resources LLC for identical membership interests in Antero Resources Investment LLC (“Antero Investment”), which was a wholly owned subsidiary of Antero Resources LLC. Following the exchange of membership interests, pursuant to the merger agreement by and among Antero Resources LLC, Antero Investment and ARC, (a) Antero Resources LLC merged with and into ARC, with ARC surviving the merger, (b) all of the membership interests of Antero Resources LLC held by Antero Investment converted into all 224,375,000 shares of outstanding common stock of ARC, and (c) the membership interest in Antero Investment held by Antero Resources LLC was cancelled. On the same date, ARC completed a public offering of its common stock and issued 37,674,659 additional shares of its common stock to the public for estimated proceeds of approximately $1.58 billion, net of commissions and expenses of the offering. As a result of this corporate reorganization, we expect to recognize non-cash stock compensation expense in the fourth quarter of 2013 of approximately $297.0 million. Approximately $217.0 million of additional stock compensation will be recognized over the remaining service period of the underlying equity compensation awards.

The current and historical consolidated financial statements of Antero Resources LLC presented herein are identical with respect to the underlying financial information of ARC, which subsequent to September 30, 2013, became the reporting company with the Securities and Exchange Commission as a result of the aforementioned merger and initial public offering. The accompanying Condensed Consolidated Statements of Operations and Comprehensive Income (Loss) contain pro forma earnings per share information based upon the 262,049,659 shares outstanding upon the public offering.

(2) Basis of Presentation and Significant Accounting Policies

(a) Basis of Presentation

These consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC) applicable to interim financial information and should be read in the context of the December 31, 2012 consolidated financial statements and notes thereto for a more complete understanding of the Company’s operations, financial position, and accounting policies. The December 31, 2012 consolidated financial statements have been filed with the SEC in the Company’s Annual Report on Form 10-K for the year ended December 31, 2012 and the IPO Prospectus.

The accompanying unaudited 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 consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of September 30, 2013, and the results of its operations for the three and nine months ended September 30, 2012 and 2013, and its cash flows for the nine months ended September 30, 2012 and 2013. We have no items of other comprehensive income or loss; therefore, our net income (loss) is identical to our comprehensive income (loss). All significant intercompany accounts and transactions have been eliminated. Operating results for the period ended September 30, 2013 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 and oil, natural production declines, the uncertainty of exploration and development drilling results, and other factors.

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 Securities and Exchange Commission, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified, except the public stock offering and a refinancing of the senior notes described in Note 11. See Note 1 for a description of the merger and public stock offering completed on October 16, 2013.

(b) Use of Estimates

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

The Company's financial statements are based on a number of significant judgments, assumptions, and estimates, including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion, and amortization, present value of future reserves, and impairment of oil and gas properties. Reserve estimates are, by their nature, inherently imprecise.

(c) Risks and Uncertainties

Historically, the market for natural gas has experienced significant price fluctuations. Prices for natural gas, NGLs, and oil are volatile; price fluctuations can result from variations in weather, levels of production in a given region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in prices received could have a significant impact on the Company's future results of operations.

(d) 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 investments.

(e) Derivative Financial Instruments

In order to manage its exposure to oil and gas price volatility, the Company enters into derivative transactions from time to time, which may include commodity swap agreements, collar agreements, and other similar agreements relating to oil and natural gas expected to be produced. From time to time, the Company may also enter into derivative contracts to mitigate the effects of interest rate fluctuations. To the extent legal right of offset with a counterparty exists, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The fair value of the Company's commodity derivative contracts of approximately $708 million at September 30, 2013 includes the following asset values by bank counterparty: Credit Suisse — $174 million; BNP Paribas — $156 million; Wells Fargo — $116 million; JP Morgan — $113 million; Barclays — $112 million; CitiBank - $23 million; Deutsche Bank — $11 million; Toronto Dominion Bank — $2 million; and Union Bank — $1 million. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at September, 2013 for each of the European and North American banks. We believe that all of these institutions currently are acceptable credit risks.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues.

(f) Fair Value Measurements

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

(g) Income Taxes

Prior to the merger described in Note 1, Antero Resources LLC and its subsidiaries filed separate federal and state income tax returns. Antero Resources LLC was a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC was borne by the individual members through the allocation of taxable income.

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

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties as income tax expense. The tax years 2009 through 2012 remain open to examination by the U.S. Internal Revenue Service. The Company files tax returns with various state taxing authorities which remain open to examination for tax years 2008 through 2012.

(h) Impairment of Unproved Properties

Unproved properties are assessed for impairment on a property-by-property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage.

Impairment of unproved properties during the three months ended September 30, 2012 and 2013 was $2 million and $3 million, respectively. Impairment of unproved properties during the nine months ended September 30, 2012 and 2013 was $5 million and $10 million, respectively.

(i) Industry Segment and Geographic Information

We have evaluated how the Company is organized and managed and have identified one operating segment — the exploration and production of oil, natural gas, and natural gas liquids. We consider our gathering, processing, and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States and all of our revenues are attributable to United States customers.

(j) Guarantees

In November 2009 and January 2010, an indirect wholly owned finance subsidiary of Antero Resources LLC, Antero Finance, issued $375 million and $150 million, respectively, of 9.375% senior notes due December 1, 2017. In August 2011, Antero Finance issued $400 million of 7.25% senior notes due August 1, 2019. In November 2012 and February 2013, Antero Finance issued $300 million and $225 million, respectively, of 6.00% senior notes due December 1, 2020. For purposes of this footnote, we collectively refer to the 2017 senior notes, the 2019 senior notes and the 2020 senior notes as the "senior notes."

Antero Resources LLC, as the parent company (for purposes of this footnote only, the Parent Company), has no independent assets or operations. Antero Finance is a 100% indirectly owned finance subsidiary of Parent Company. The senior notes are each guaranteed on a senior unsecured basis by Parent Company and all of Parent Company's wholly owned subsidiaries (other than Antero Finance) and certain of its future restricted subsidiaries. The guarantees are full and unconditional and joint and several. The guarantor subsidiaries may be released from those guarantees upon the occurrence of certain events, including (i) the designation of that subsidiary guarantor as an unrestricted subsidiary; (ii) the release or discharge of any guarantee or indebtedness that resulted in the creation of the guarantee of the senior notes by such subsidiary guarantor; or (iii) the sale or other disposition, including the sale of substantially all of the assets, of that subsidiary guarantor. There are no significant restrictions on Antero Finance's ability to obtain funds from the Parent Company or the subsidiary guarantors by dividend or loan, except those imposed by applicable law. However, the indentures governing the senior notes and the Credit Facility agreement contain significant restrictions on the ability of Antero Finance or the subsidiary guarantors to make distributions to the Parent Company. Finally, the Parent Company's wholly owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

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

On December 21, 2012, the Company completed the sale of its Piceance Basin assets. The $316 million of net proceeds from the sale represented the purchase price of $325 million, adjusted for expenses of the sale and estimated income, expenses, and capital costs related to the Piceance Basin properties from the October 1, 2012 effective date of the sale through December 21, 2012. The agreement to sell the properties is subject to post-closing adjustments for up to a one year period. The Company believes that post-closing adjustments, if any, will not have a material effect on the financial statements. The Company recognized a loss of $364 million on the sale of the Piceance Basin assets in the fourth quarter of 2012. The purchaser also assumed all of the Company's Rocky Mountain firm transportation obligations, which totaled approximately $100 million. In connection with the sale of the Piceance Basin assets, the Company also liquidated its hedge positions related to the Piceance Basin and realized additional proceeds of approximately $100 million.

On June 29, 2012, the Company completed its sale of its Arkoma Basin assets and associated the commodity hedges. Proceeds from the sale of $427 million represent the purchase price of $445 million adjusted for expenses of the sale and estimated income, expenses, and capital costs from the effective date of the sale through the closing date of June 29, 2012. The agreement to sell the properties is subject to post-closing adjustments for up to a two year period. The Company believes that post-closing adjustments, if any, will not have a material effect on the financial statements. The Company recognized a loss of $427 million on the sale of the Arkoma Basin assets in the second quarter of 2012.

During the three and nine months ended September 30, 2013, the Company recorded pre-tax income of $5 million, or $3,100 net of taxes, related to operations that were discontinued in 2012 for sales tax refunds received and reductions in estimated expenses related to discontinued operations. Results of operations for the three months and nine months ended September 30, 2012 for the Piceance Basin and Arkoma Basin assets are shown as discontinued operations on the accompanying Consolidated Statement of Operations and Comprehensive Income (Loss) and are comprised of the following (in thousands):

	Three months Ended September 30, 2012	Nine months ended September 30, 2012
Sales of oil, natural gas, and natural gas liquids	$ 22,690	105,096
Commodity derivative fair value gains (losses)	(18,880)	46,358
Total revenues	3,810	151,454
Lease operating expenses	2,430	16,395
Gathering, compression, and transportation	7,685	38,210
Production taxes	1,776	4,874
Exploration expenses	95	507
Impairment of unproved properties	(31)	962
Depletion, depreciation, and amortization	14,197	77,344
Accretion of asset retirement obligations	91	310
Loss on sale of discontinued operations	—	427,232
Total expenses	26,243	565,834
Loss from discontinued operations before income taxes	(22,433)	(414,380)
Income tax (expense) benefit	8,642	(4,085)
Net loss from discontinued operations attributable to Antero equity owners	$ (13,791)	(418,465)

(4) Long-term Debt

Long-term debt consists of the following at December 31, 2012 and September 30, 2013 (in thousands):

	December 31, 2012	September 30, 2013
Bank credit facility (a)	$ 217,000	1,512,500

9.375% senior notes due 2017 (b)	525,000	525,000
7.25% senior notes due 2019 (c)	400,000	400,000
6.00% senior notes due 2020 (d)	300,000	525,000
9.00% senior note (d)	25,000	25,000
Net premium	2,058	7,955
	1,469,058	2,995,455
Less amounts due within one year	25,000	25,000
Total	$ 1,444,058	2,970,455

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(a) Bank Credit Facility

The Company has a senior secured revolving bank credit facility (the Credit Facility) with a consortium of bank lenders. The maximum amount of the Credit Facility is $2.5 billion. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At September 30, 2013, the borrowing base is $2.0 billion and lender commitments were $1.75 billion. Lender commitments can be increased to the full amount of the borrowing base upon approval of the lenders. The next redetermination of the borrowing base is scheduled to occur in April 2014. The maturity date of the Credit Facility is May 12, 2016. Subsequent to September 30, 2013, lender commitments under the Credit Facility were reduced to $1.5 billion.

The Credit Facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. 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 based on the Company's election at the time of borrowing. The Company was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2012 and September 30, 2013.

As of September 30, 2013, the Company had an outstanding balance under the Credit Facility of $1.5 billion, with a weighted average interest rate of 2.3%, and outstanding letters of credit of approximately $32 million. As of December 31, 2012, the Company had an outstanding balance under the Credit Facility of $217 million, with a weighted average interest rate of 1.91%, and outstanding letters of credit of approximately $43 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused facility based on utilization.

(b) 9.375% Senior Notes Due 2017

On November 17, 2009 Antero Finance issued $375 million of 9.375% senior notes due December 1, 2017 at a discount of $2.6 million. In January 2010, the Company issued an additional $150 million of the same series of 9.375% senior notes at a premium of $6.0 million. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes are guaranteed on a full and unconditional basis and joint and severally by the Company, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2013 at redemption prices ranging from 104.688% on or after December 1, 2013 to 100% on or after December 1, 2015. At any time prior to December 1, 2013, Antero Finance may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If the Company undergoes a change of control, Antero Finance may be required to offer to purchase notes from the holders.

The 9.375% senior notes due 2017 will be redeemed with the proceeds of the issuance of the 5.375% notes issued subsequent to September 30, 2013. See Note 11.

(c) 7.25% Senior Notes Due 2019

On August 1, 2011, Antero Finance issued $400 million of 7.25% senior notes due August 1, 2019 at par. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 9.375% senior notes. The notes are guaranteed on a senior unsecured basis by the Company, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on August 1 and February 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after August 1, 2014 at redemption prices ranging from 105.438% on or after August 1, 2014 to 100% on or after August 1, 2017. In addition, on or before August 1, 2014, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 107.25% of the principal amount of the notes, plus accrued interest. At any time prior to August 1, 2014, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If the Company undergoes a change of control, the note holders will have the right to require Antero Finance to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

The Company will redeem 35% of the 7.25% senior notes due 2019 from the proceeds of the initial public offering. See Note 11.

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(d) 6.00% Senior Notes Due 2020

On November 19, 2012, Antero Finance issued $300 million of 6.00% senior notes due December 1, 2020 at par. In a subsequent transaction, on February 4, 2013 Antero Finance issued an additional $225 million of the 6.00% notes at 103% of par. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 9.375% and 7.25% senior notes. The notes are guaranteed on a senior unsecured basis by the Company, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100% on or after December 1, 2018. In addition, on or before December 1, 2015, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the notes, plus accrued interest. At any time prior to December 1, 2015, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If a change of control (as defined in the bond indenture) occurs at any time prior to January 1, 2014, Antero Finance may, at its option, redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes, plus accrued interest. If the Company undergoes a change of control, the note holders will have the right to require Antero Finance to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

(e) 9.00% Senior Note

The Company assumed a $25 million unsecured note payable in a business acquisition consummated on December 1, 2010. The note bears interest at 9% and is due December 1, 2013.

(f) Treasury Management Facility

The Company has a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25 million of cash management obligations in order to facilitate the Company's daily treasury management. Borrowings under the revolving note are secured by the collateral for the revolving credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2014. At December 31, 2012 and September 30, 2013, there were no outstanding borrowings under this facility.

(5) Ownership Structure

At December 31, 2012 and September 30, 2013, the outstanding units in Antero Resources LLC are summarized as follows:

	Units Authorized and issued
Class I units	107,281,058
Class A and B units	40,007,463
Class A and B profits units	19,726,873
	167,015,394

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None of the three classes of outstanding units are entitled to current cash distributions or are convertible into indebtedness. The Company has no obligation to repurchase these units at the election of the unitholders.

In the event of a distribution from Antero Resources LLC, amounts available for distribution are distributed according to a formula set forth in the Company's limited liability company agreement that takes into account the relative priority of the various classes of units outstanding. In the event of a distribution due to the disposition of an individual Antero Entity, a portion of the proceeds is allocated to the employees of the Company based on a requisite return financial threshold. In general, distributions are made first to holders of the Class I units until they have received their investment amount and an 8% special allocation and then, as a group, to the holders of all classes of units together. The Class I units participate on a pro rata basis with the other classes of units in funds available for distributions in excess of the Class I unit investment and special allocation amounts.

At December 31, 2012 and September 30, 2013, the Class I units had an aggregate liquidation priority, including the special allocation of 8% per annum, of $2.191 billion and $2.325 billion, respectively.

(6) Financial Instruments

The carrying values of trade receivables, trade payables, and the Credit Facility at December 31, 2012 and September 30, 2013 approximated market value. The carrying value of the Credit Facility at December 31, 2012 and September 30, 2013 approximated fair value because the variable interest rates are reflective of current market conditions. Based on Level 2 market data, the fair value of the Company's senior notes was approximately $1.3 billion and $1.5 billion at December 31, 2012 and September 30, 2013, respectively.

(7) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations, included in other long-term liabilities on the condensed consolidated balance sheets, for the nine months ended September 30, 2013 (in thousands):

Asset retirement obligations — beginning of period	$	10,552
Obligations incurred		69
Accretion expense		797
Asset retirement obligations — end of period	$	11,418

(8) Derivative Instruments and Risk Management Activities

(a) Commodity Derivatives

The Company periodically enters into natural gas and oil derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas 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 and oil recognized upon the ultimate sale of the natural gas and oil produced.

For the nine months ended September 30, 2012 and 2013, the Company was party to oil and natural gas fixed price swaps. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, the Company receives the difference from the counterparty. The Company's natural gas and oil swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently.

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The Company has no collateral from any counterparties. All but one of the Company's commodity derivative positions are with institutions that are lenders under our Credit Facility and are secured by the collateral pledged on the Credit Facility and cross default provisions between the Credit Facility and the derivative instruments. At September 30, 2013, there were no past due receivables from or payables to any of our counterparties.

As of September 30, 2013, the Company's positions in fixed price natural gas and oil swaps from October 1, 2013 through December 31, 2019 are summarized in the following table:

	MMbtu/day	Bbls/day	Price	
Three Months ending December 31, 2013:				
CGTAP-TCO	260,000		$	4.56
Dominion South	190,844			4.89
NYMEX-WTI	—	4,300		103.97
2013 Total	450,844	4,300		
Year ending December 31, 2014:				
CGLA	10,000		$	3.87
CGTAP-TCO	210,000			5.11
Dominion South	160,000			5.15
NYMEX	120,000			4.00
NYMEX-WTI	—	3,000		96.53
2014 Total	500,000	3,000		
Year ending December 31, 2015:				
CGLA	40,000		$	4.00
CGTAP-TCO	130,000			4.93
Dominion South	230,000			5.60
NYMEX	80,000			4.10
2015 Total	480,000			
Year ending December 31, 2016:				
CGLA	170,000		$	4.09
CGTAP-TCO	80,000			4.67
Dominion South	272,500			5.35
NYMEX	60,000			4.25
2016 Total	582,500			
Year ending December 31, 2017:				
CGLA	420,000		$	4.27
NYMEX	220,000			4.44

CGG	70,000		4.57
CGTAP-TCO	20,000		4.02
2017 Total	730,000		
Year ending December 31, 2018:			
NYMEX	530,000	$	4.73
Year ending December 31, 2019:			
NYMEX	87,500	$	4.75

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(b) Summary

The following is a summary of the fair values of our derivative instruments, which are not designated as hedges for accounting purposes and where such values are recorded in the consolidated balance sheets as of December 31, 2012 and September 30, 2013 (in thousands):

	December 31, 2012		September 30, 2013	
	Balance sheet location	**Fair value**	**Balance sheet location**	**Fair value**
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 160,579	Current assets	$ 204,857
Commodity contracts	Long-term assets	371,436	Long-term assets	503,666
Total asset derivatives		532,015		708,523
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	—	Current liabilities	309
Net asset fair value of derivatives		$ 532,015		$ 708,214

The following is a summary of realized and unrealized gains (losses) on derivative instruments and where such values are recorded in the consolidated statements of operations for the three months ended and nine months ended September 30, 2012 and 2013 (in thousands):

	Statement of operations location	Three months ended September 30,		Nine months ended September 30,	
		2012	**2013**	**2012**	**2013**
Commodity derivative fair value gains (losses)	Revenue	$ (159,004)	161,968	52,210	285,510
Commodity derivative fair value gains (losses)	Discontinued operations	(18,880)	—	46,358	—
Total gains (losses) on commodity contracts		$ (177,884)	161,968	98,568	285,510

The following table summarizes the valuation of investments and financial instruments by the fair value hierarchy described in note 1 at September 30, 2013 (in thousands):

	Fair value measurements using			
Description	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**	**Total**
Net derivatives asset:				
Fixed price commodity swaps	$ —	708,214	—	708,214

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The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value (in thousands):

December 31, 2012			September 30, 2013		
Gross amounts	**Gross amounts**	**Net amounts of assets**	**Gross amounts**	**Gross amounts**	**Net amounts of assets (liabilities)**

		of recognized assets	offset on balance sheet	on balance sheet	of recognized assets	offset on balance sheet	on balance sheet
Commodity derivative assets	$	597,359	(65,344)	532,015	715,960	(7,437)	708,523
Commodity derivative liabilities		—	—	—	—	(309)	(309)

(9) Sale of Appalachian Gathering Assets

On March 26, 2012, the Company closed the sale of a portion of its Marcellus Shale gathering system assets along with exclusive rights to gather the Company's gas for a 20-year period within an area of dedication (AOD) to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together Crestwood) for $375 million (subject to customary purchase price adjustments). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by the Company within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, the Company is committed to deliver minimum volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. The Company can earn up to an additional $40 million of sale proceeds over a period of three years from the date of the sale if it meets certain volume thresholds. Crestwood is obligated to incur all future capital costs to build out the gathering systems and compression facilities within the AOD to connect the Company's wells as it executes its drilling program and has assumed the various risks and rewards of the system build-out and operations. Because the Company has not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, a gain of approximately $291 million on the sale of the gathering system and rights was recognized during the first quarter of 2012.

(10) Contingencies

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

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(11) Subsequent Events

Initial Public Offering

On October 16, 2013, we completed our initial public offering of 41,083,750 shares of our common stock, including the exercise in full by the underwriters of their options to purchase an additional 3,409,091 shares of common stock from the selling stockholder and an additional 1,949,659 shares of common stock from us. Net proceeds received by us from the sale of 37,674,659 shares of common stock were approximately $1.58 billion, after deducting underwriting discounts. The proceeds from the offering were immediately used to paydown our Credit Facility, and ultimately will be used to redeem a portion of our outstanding senior notes and fund our development and production efforts. Antero Resources Corporation's stock is traded on the New York Stock Exchange under the symbol "AR".

Issuance of 5.375% Senior Notes

On November 5, 2013, Antero Finance issued $1 billion of 5.375% senior notes at par due November 1, 2021. Proceeds from the notes will be used to (i) finance the redemption of our 9.375% notes due 2017 and the repayment of the 9.0% senior note due December 1, 2013, (ii) repay the outstanding borrowings under the Credit Facility and (iii) fund our drilling and development program. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 7.25% and 6.00% senior notes. The notes are guaranteed on a senior unsecured basis by ARC and all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on May 1 and November 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100% on or after November 1, 2019. In addition, on or before November 1, 2016, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with 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 notes, plus accrued interest. At any time prior to November 1, 2016, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If a change of control (as defined in the bond indenture) occurs at any time prior to May 1, 2015, Antero Finance may, at its option, redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes, plus accrued interest. If ARC undergoes a change of control and there is a subsequent decline in ratings, the note holders will have the right to require Antero Finance to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

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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 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, NGL and oil prices, the timing of planned capital expenditures, 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, 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" included elsewhere in this report. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

In this section, references to "Antero," "Antero Resources," "we," "us," "our," and "operating entities" refer to the subsidiaries that conduct our operations, unless otherwise indicated or the context otherwise requires. For more information on our organizational structure, see note 1 to the consolidated financial statements included in elsewhere in this report..

Our Company

We are an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. We are focused on creating shareholder value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. As of September 30, 2013, we hold approximately 330,000 net acres in the southwestern core of the Marcellus Shale and approximately 103,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 170,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on 116,000 net acres of our Marcellus Shale acreage in West Virginia that we believe is prospective for the dry gas Utica Shale. As of June 30, 2013 (the date of our most recent audited reserves), our estimated proved, probable and possible reserves were 6.3 Tcfe, 14.0 Tcfe and 7.4 Tcfe, respectively, and our proved reserves were 23% proved developed and 91% natural gas, assuming ethane rejection. As of June 30, 2013, our drilling inventory consisted of 4,576 identified potential horizontal well locations, approximately 64% of which are liquids-rich drilling opportunities. Our corporate headquarters are in Denver, Colorado.

The statement of operations data for all periods presented in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" has been recast to present the results of operations from our Arkoma Basin and Piceance operations in discontinued operations.

We operate in one industry segment, which is the exploration, development and production of natural gas, NGLs, and oil, and all of our operations are conducted in the United States. Our gathering assets are dedicated to supporting the natural gas volumes we produce.

Recent Events and Highlights

Public Offering

On October 16, 2013, we completed our initial public offering of 41,083,750 shares of our common stock, including the exercise in full by the underwriters of their options to purchase an additional 3,409,091 shares of common stock from the selling stockholder and an additional 1,949,659 shares of common stock from us. Net proceeds received by us from the sale of 37,674,659 shares of common stock were approximately $1.58 billion, after deducting underwriting discounts. The proceeds from the offering were immediately used to paydown our Credit Facility, and ultimately will be used to redeem a portion of our outstanding senior notes and fund our development and production efforts. Antero Resources Corporation's stock is traded on the New York Stock Exchange under the symbol "AR".

In connection with a corporate reorganization that was completed immediately prior to the closing of Antero Resources Corporation's initial public offering, Antero Resources LLC merged with and into Antero Resources Corporation pursuant to a merger agreement by and among Antero Resources LLC, Antero Investment LLC and Antero Resources Corporation whereby, (a) Antero Resources LLC merged with and into Antero Resources Corporation, with Antero Resources Corporation surviving the merger, (b) all of the membership interests of Antero Resources LLC held by Antero Investment LLC converted into 224,375,000 shares of outstanding common stock of Antero Resources Corporation, and (c) the membership interest in Antero Investment LLC held by Antero Resources LLC was cancelled.

The Debt Offering

On November 5, 2013, Antero Finance closed its private placement of $1.0 billion aggregate principal amount of its 5.375% Senior Notes due 2021 to eligible purchasers. The notes are Antero Finance's senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and are senior to any future subordinated indebtedness. The notes are initially fully and unconditionally guaranteed on a senior unsecured basis by ARC and all of its subsidiaries (other than Antero Finance). The guarantees rank equally in right of payment with all of the other senior indebtedness of the guarantors. The notes and guarantees are effectively subordinated to any secured indebtedness, including borrowings and guarantees under our credit facility, to the extent of the value of the collateral securing such indebtedness. In addition, the notes are structurally subordinated to the liabilities (including trade payables) of any non-guarantor subsidiaries. The net proceeds from the Notes Offering were approximately $987.1 million, after deducting the initial purchasers' discounts and estimated expenses. We will use $549.6 million of the net proceeds of the Notes Offering to finance the redemption of our outstanding 9.375% senior notes due 2017. We will use the remaining net proceeds to (i) repay in full our 9.0% senior note due 2013, (ii) repay the outstanding borrowings under our Credit Facility and (iii) fund our drilling and development program. We will also use a portion of the net proceeds from our initial public offering to redeem 35% of our outstanding 7.25% senior notes due 2019.

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Financial Results and Production

For the three months ended September 30, 2013, we had net income from continuing operations of $118 million and EBITDAX from continuing operations of $183 million compared to a net loss from continuing operations for the three months ended September 30, 2012 of $114 million and EBITDAX from continuing operations of $71 million. Net income from continuing operations for the three months ended September 30, 2013 included $162 million of pre-tax commodity derivative fair value gains, which was net of $47 million of gains from cash settled derivatives; net income from continuing operations for the three months ended September 30, 2012 included $159 million of commodity derivative fair value losses, which was net of $45 million of gains from cash settled derivatives. Net income (loss) from continuing operations for the three months ended September 30, 2013 and 2012 included deferred income tax (expense) benefit of $(67) million and $75 million, respectively.

For the nine months ended September 30, 2013, we generated cash flow from operations of $332 million, net income from continuing operations of $201 million, and EBITDAX from continuing operations of $434 million. For the comparative nine month period ended September 30, 2012, we had cash flow from operations of $225 million, income from continuing operations of $140 million, and EBITDAX from continuing operations of $198 million. Net income from continuing operations for the nine months ended September 30, 2013 included $286 million of pre-tax commodity derivative fair value gains, which was net of $109 million of gains from cash settled derivatives; net loss from continuing operations for the nine months ended September 30, 2012 included $52 million of pre-tax commodity derivative fair value gains, which was net of $142 million of gains from cash settled derivatives. Net income (loss) from continuing operations for the nine months ended September 30, 2013 and 2012 included deferred income tax expense benefit of $121 million and $109 million, respectively. The net loss from continuing operations for the nine months ended September 30, 2012 also included a $291 million gain on the sale of assets and a $427 million loss from discontinued operations.

For the three months ended September 30, 2013, our production from the Appalachian Basin totaled approximately 52 Bcfe, or 566 MMcfe per day, compared to 23 Bcfe from continuing operations, or 248 MMcfe per day, for the three months ended September 30, 2012. The average price received for our production for the three months ended September 30, 2013 was $4.27 per Mcfe compared to $2.94 per Mcfe for the three months ended September 30, 2012. Average prices after giving effect to the settlement of commodity hedges were $5.18 per Mcfe for the three months ended September 30, 2013 compared to $4.90 for the three months ended September 30, 2012.

For the nine months ended September 30, 2013, our production from the Appalachian Basin totaled approximately 128 Bcfe, or 470 MMcfe per day, compared to 58 Bcfe from continuing operations, or 214 MMcfe per day, for the nine months ended September 30, 2012. The average price received for our production for the nine months ended September 30, 2013 was $4.27 per Mcfe before the effects of commodity hedges compared to $2.70 per Mcfe for the nine months ended September 30, 2012. Average prices after giving effect to the settlement of commodity hedges were $5.12 per Mcfe for both the nine months ended September 30, 2013 and 2012.

2013 Capital Budget

For the nine months ended September 30, 2013, our capital expenditures for development, leasehold, and gathering systems and facilities were approximately $1.9 billion. In November 2013, we increased our capital expenditure plan for 2013 by $200 million to $2.65 billion, including $1.55 billion for drilling and completion, $450 million for leasehold acquisitions, and $650 million for the construction of water handling infrastructure and gas gathering pipelines and facilities. The capital plan was increased to provide for increased drilling costs as a result of shorter stage length wells, additional land acquisition opportunities, and acceleration of compressor station expenditures.

Credit Facility Amendment

As a result of our increased liquidity from the public offering, on October 21, 2013 we entered into a Ninth Amendment to our Fourth Amended and Restated Credit Agreement (the “Credit Agreement”) to decrease the aggregate lender commitments thereunder from from $1.75 billion to $1.5 billion. The $2.0 billion borrowing base under the Credit Agreement was not modified in connection with the amendment. The borrowing base is redetermined semiannually and is based on the lenders’ judgment of the volume of our proved oil and gas reserves and the estimated future cash flows from these reserves and our hedge positions. The next scheduled redetermination will occur in April 2014.

At September 30, 2013, we had $1.55 billion of borrowings and letters of credit outstanding under the credit facility and $205 million of available borrowing capacity, based on $1.75 billion of lender commitments at that date. The Credit Facility matures in May 2016.

Hedge Position

As of September 30, 2013, we had entered into hedging contracts covering a total of approximately 1,131 Bcfe of natural gas and equivalent oil volumes from October 1, 2013 through December 31, 2019 at a weighted average index price of $4.73 per Mcfe. These hedging contracts include hedging contracts for the three month period ended December 31, 2013 of approximately 44 Bcfe of natural gas and equivalent oil volumes at a weighted average index price of $5.39 per Mcfe.

Principal Components of Our Cost Structure

- *Lease operating expenses.* These are the day-to-day operating costs incurred to maintain production of our natural gas, NGLs, and oil. Such costs include water recycling, pumping, maintenance, repairs, and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.

· *Gathering, compression, processing, and transportation.* These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low-pressure and high-pressure gathering and compression systems as well as fees paid to third parties who operate low-pressure and high-pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our products to market. We often enter into fixed-price long-term contracts that secure transportation and processing capacity that may include minimum volume commitments, the cost for which is included in these expenses.

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· *Production taxes*. Production taxes consist of severance and ad valorem taxes and are paid on produced natural gas, NGLs, and oil based on a percentage of market prices (not hedged prices) or at fixed per unit rates established by federal, state, or local taxing authorities.

· *Exploration expense*. These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes, and unsuccessful leasing efforts.

· *Impairment of unproved and proved properties.* These costs include unproved property impairment and costs associated with lease expirations. We could record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through September 30, 2013, we have not recorded any impairment for proved properties.

· *Depreciation, depletion, and amortization ("DD&A").* This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs, and oil. As a "successful efforts" company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.

· *General and administrative expense.* These costs include overhead, including payroll and benefits for our employees, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, and legal compliance expenses.

· *Interest expense*. We finance a portion of our working capital requirements and acquisitions and development costs with borrowings under our credit facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At September 30, 2013, we also had a fixed interest rate of 9.375% on senior notes having a principal balance of $525 million, a fixed interest rate of 7.25% on senior notes having a principal balance of $400 million, and a fixed interest rate of 6.00% on senior notes having a principal balance of $525 million. We expect to continue to incur significant interest expense as we grow. As further explained under Recent Events and Highlights, on November 5, 2013 we closed a private placement of $1.0 billion 5.375% senior notes due 2021. We will use approximately $550 million to finance the redemption of our 9.375% senior notes due 2017 and $25 million to repay our 9.0% senior note due 2013. We will also use approximately $150 million from the proceeds of the public offering to finance the redemption of 35% of our 7.25% senior notes due 2019.

· *Income tax expense.* Through December 31, 2011, each of our operating entities filed separate federal and state income tax returns; therefore, our provision for income taxes through that date consisted of the sum of our income tax provisions for each of the operating entities. In October 2012, we completed a reorganization of our legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were first converted to limited liability companies and then liquidated as part of the reorganization. As a result, for income tax purposes, the operations subsequent to the reorganizations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes. Our subsidiaries are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs and the deferral of unrealized commodity hedge gains for tax purposes until they are realized. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have generated net operating loss carryforwards that expire at various dates from 2024 through 2032. We have recognized the value of these net operating losses to the extent of our deferred tax liabilities. We recorded valuation allowances for deferred tax assets at December 31, 2012 of approximately $48 million primarily for capital loss and state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced.

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The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements included unrecognized benefits at December 31, 2012 and September 30, 2013 of $11 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. No impact to our 2013 or 2012 effective tax rate would result from the recognition of the tax benefits. As of September 30, 2013, we have accrued $0.6 million of interest expense on unrecognized tax benefits.

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Results of Operations

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2013

The following table sets forth selected operating data (as recast for discontinued operations) for the three months ended September 30, 2012 compared to the three months ended September 30, 2013:

	Three Months Ended September 30,		Amount of Increase	
	2012	2013	(Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				
Natural gas sales	$ 66,796	$ 182,125	$ 115,329	173%
NGL sales	—	31,956	31,956	*
Oil sales	285	8,473	8,188	2,873
Commodity derivative fair value gains (losses)	(159,004)	161,968	320,972	*
Loss on sale of assets	(115)	—	115	*
Total operating revenues	(92,038)	384,522	476,560	*
Operating expenses:				
Lease operating expense	1,513	2,697	1,184	78%
Gathering, compression, processing, and transportation	25,291	58,383	33,092	131%
Production taxes	3,621	11,851	8,230	227%
Exploration expenses	3,156	5,372	2,216	70%
Impairment of unproved properties	2,438	3,205	767	31%
Depletion, depreciation, and amortization	26,858	65,697	38,839	145%
Accretion of asset retirement obligations	25	266	241	964%
General and administrative	11,938	14,443	2,505	21%
Total operating expenses	74,840	161,914	87,074	116%
Operating income (loss)	(166,878)	222,608	389,486	*
Interest expense	(22,453)	(37,444)	(14,991)	67%
Income (loss) before income taxes	(189,331)	185,164	374,495	*
Income tax benefit (expense)	75,444	(67,370)	(142,814)	*
Income (loss) from continuing operations	(113,887)	117,794	231,681	*
Income (loss) from discontinued operations	(13,791)	3,100	16,891	*
Net income (loss) attributable to Antero members	$ (127,678)	$ 120,894	$ 248,572	*
EBITDAX from continuing operations (1)	$ 70,504	$ 182,834	$ 112,330	159%
Total EBITDAX (1)	$ 95,165	$ 182,834	$ 87,669	92%
Production data:				
Natural gas (Bcf)	23	48	25	109%
NGLs (MBbl)	—	637	637	*
Oil (MBbl)	4	87	83	2,393%
Combined (Bcfe)	23	52	29	128%
Daily combined production (MMcfe/d)	248	566	318	128%
Average prices before effects of hedges (2):				
Natural gas (per Mcf)	$ 2.93	$ 3.82	$ 0.89	30%
NGLs (per Bbl)	$ —	$ 50.13	$ 50.13	*
Oil (per Bbl)	$ 81.20	$ 97.10	$ 15.90	20%
Combined (per Mcfe)	$ 2.94	$ 4.27	$ 1.33	45%
Average realized prices after effects of hedges (2):				
Natural gas (per Mcf)	$ 4.89	$ 4.81	$ (0.08)	(2)%
NGls (per Bbl)	$ —	$ 50.13	$ 50.13	*
Oil (per Bbl)	$ 81.20	$ 94.71	$ 13.51	17%
Combined (per Mcfe)	$ 4.90	$ 5.18	$ 0.28	6%
Average costs (per Mcfe):				
Lease operating costs	$ 0.07	$ 0.05	$ (0.02)	(29)%
Gathering, compression, processing, and transportation	$ 1.11	$ 1.12	$ 0.01	1%
Production taxes	$ 0.16	$ 0.23	$ 0.07	44%
Depletion, depreciation, amortization, and accretion	$ 1.18	$ 1.27	$ 0.09	8%
General and administrative	$ 0.52	$ 0.28	$ (0.24)	(46)%

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(1) See "—Non-GAAP Financial Measure" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX from continuing and discontinued operations to net income (loss) from continuing and discontinued operations attributable to Antero members and to cash flow provided by operating activities.

(2) Average prices shown in the table reflect the sales prices we received before and after giving effect to our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges for accounting purposes. Oil and NGL 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

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $67 million from continuing operations for the three months ended September 30, 2012 to $223 million for the three months ended September 30, 2013, an increase of $156 million, or 233%. Our production increased by 128% over that same period, from 23 Bcfe from continuing operations for the three months ended September 30, 2012 to 52 Bcfe for the three months ended September 30, 2013. Net equivalent prices before the effects of realized hedge gains increased from $2.94 per Mcfe for the three months ended September 30, 2012 to $4.27 for the three months ended September 30, 2013, an increase of 45%. Increased production volumes accounted for an approximate $86 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $70 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of the ongoing Appalachian Basin drilling program. Additionally, natural gas prices were significantly higher than the depressed price levels during the previous year's quarter, increasing from an average of $2.93 during the three months ended September 30, 2012 to $3.82 during the three months ended September 30, 2013.

Commodity derivative fair value gains (losses). To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruements, are recognized in our results of operations.

For the three months ended September 30, 2012 and 2013, our hedges resulted in derivative fair value gains (losses) of $(159) million and $162 million, respectively. The derivative fair value gains (losses) included $45 million and $47 million of cash settlements received on derivatives for the three months ended September 30, 2012 and 2013, respectively. Cash settled derivatives resulted in an increase in realized equivalent prices of $1.96 and $0.91 per Mcfe during the three months ended September 30, 2012 and 2013, respectively.

Lease operating expenses. Lease operating expenses increased by 78% from the three months ended September 30, 2012 to the three months ended September 30, 2013 from $1.5 million to $2.7 million due primarily to increased production. On a per unit basis, lease operating expenses decreased by 29%, from $0.07 per Mcfe for the three months ended September 30, 2012 to $0.05 for the three months ended September 30, 2013 primarily because, during the early stages of production for Appalachian Basin wells, operating and maintenance expenses are low and initial production rates are higher than for wells that have been producing for longer periods of time.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $25 million for the three months ended September 30, 2012 to $58 million for the three months ended September 30, 2013, primarily due to an increase in production volumes, increased costs on firm transportation commitments and processing charges incurred in the 2013 period but not in the 2012 period. On a per unit basis, gathering, compression, processing, and transportation expense increased by $0.01 per Mcfe, or 1%, for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. We began processing natural gas in order to extract NGLs in October 2012 and this resulted in an increase in per unit costs. This increase was offset by a decrease in per unit gathering and transportation costs as a result of increased utilization of firm gathering and transportation capacity. Firm transportation charges increased by $4 million for the three months ended September 30, 2013 compared to the prior year period, but decreased on a per unit basis as total production increased from the prior year period. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

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Production taxes. Total production taxes increased by approximately $8 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012, primarily as a result of increased production and prices. On a per unit basis, production taxes increased from $0.16 to $0.23 per Mcfe. Production taxes as a percentage of natural gas, NGL, and oil revenues were 5.4% and 5.3% for the three months ended September 30, 2012 and 2013, respectively.

Exploration expense. Exploration expense increased from $3 million for the three months ended September 30, 2012 to $5 million for the three months ended September 30, 2013 primarily due to an increase in the cost of unsuccessful lease acquisition efforts as we increased the number of third-party lease brokers contracted in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $2 million for the three months ended September 30, 2012 compared to $3 million for the three months ended September 30, 2013. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be-expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks, expected well economics, or future plans to develop the acreage.

DD&A. DD&A increased from $27 million for the three months ended September 30, 2012 to $66 million for the three months ended September 30, 2013, primarily because of increased production. DD&A per Mcfe increased by 8% from $1.18 per Mcfe during the three months ended September 30, 2012 to $1.27 per Mcfe during the three months ended September 30, 2013 as a result of increased depreciation on gathering systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the three months ended September 30, 2012 or 2013 for proved properties.

General and administrative expense. General and administrative expense increased from $12 million for the three months ended September 30, 2012 to $14 million for the three months ended September 30, 2013, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in production levels and development activities. On a per unit basis, general and administrative expense decreased by 46%, from $0.52 per Mcfe during the three months ended September 30, 2012 to $0.28 per Mcfe during the three months ended September 30, 2013, primarily due to a 128% increase in production during that time. We had 143 employees as of September 30, 2012 and 204 employees as of September 30, 2013.

As a result of the corporate reorganization and the public stock offering discussed elsewhere in this report, we expect to recognize non-cash stock compensation expense in the fourth quarter of 2013 of approximately $297.0 million. Approximately $217.0 million of additional stock compensation will be recognized over the remaining service period of the underlying equity compensation awards.

Interest expense. Interest expense increased from $22 million for the three months ended September 30, 2012 to $37 million for the three months ended September 30, 2013, primarily due to the issuance of a total of $525 million of 6.00% senior notes due 2020 during the fourth quarter of 2012 and the first quarter of 2013. Interest expense includes approximately $2 million of non-cash amortization of deferred financing costs for both the three months ended September 30, 2012 and 2013.

Income tax benefit (expense). Income tax benefit (expense) changed from a deferred tax benefit of $75 million for the three months ended September 30, 2012 to a deferred tax expense of $67 million for the three months ended September 30, 2013. The deferred tax benefit in 2012 resulted primarily from unrealized commodity derivative losses. The deferred tax expense in 2013 resulted from pre-tax income of $185 million which included $115 million of unrealized commodity derivative gains.

At December 31, 2012, we had approximately $1.0 billion of U.S. federal net operating loss carryforwards ("NOLs") and approximately $1.3 billion of state NOLs, which expire starting in 2024 through 2032. From time to time, there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that any such legislation is enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. Our financial statements included unrecognized benefits at September 30, 2013 of $11 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. As of September 30, 2013, we had accrued approximately $0.6 million of interest on unrecognized tax benefits.

Income (loss) from discontinued operations. The loss from discontinued operations for the three months ended September 30, 2012 resulted from recasting the revenues and direct operating expenses attributable to the Piceance and Arkoma properties, which were sold during 2012, as discontinued operations. We did not reclassify any general and administrative expenses or interest expense from continuing operations to discontinued operations.

During the three months ended September 30, 2013, the Company recorded pre-tax income of $5 million related to operations that were discontinued in 2012 for sales tax refunds received and reductions in estimated expenses related to discontinued operations.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2013

The following table sets forth selected operating data (as recast for discontinued operations) for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2013:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Amount of Increase (Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				

Natural gas sales	$ 156,618	$ 476,403	$ 319,785	204%
NGL sales	—	59,772	59,772	*
Oil sales	610	11,435	10,825	1,775%
Commodity derivative fair value gains	52,210	285,510	233,300	447%
Gain on sale of gathering system	291,190	—	(291,190)	*
Total operating revenues	500,628	833,120	332,492	66%
Operating expenses:				
Lease operating expense	4,072	5,222	1,150	28%
Gathering, compression, processing, and transportation	56,945	148,023	91,078	160%
Production taxes	10,734	30,578	19,844	185%
Exploration expenses	7,912	17,034	9,122	115%
Impairment of unproved properties	4,019	9,564	5,545	138%
Depletion, depreciation, and amortization	65,289	158,650	93,361	143%
Accretion of asset retirement obligations	71	797	726	1,023%
General and administrative	31,584	40,727	9,143	29%
Total operating expenses	180,626	410,595	229,969	127%
Operating income	320,002	422,525	102,523	32%
Interest expense	(71,046)	(100,840)	(29,794)	42%
Income before income taxes	248,956	321,685	72,729	29%
Income tax expense	(108,525)	(120,695)	(12,170)	11%
Income from continuing operations	140,431	200,990	60,559	43%
Income (loss) from discontinued operations	(418,465)	3,100	421,565	*
Net income (loss) attributable to Antero members	$ (278,034)	$ 204,090	$ 482,124	*
EBITDAX from continuing operations (1)	$ 198,391	$ 434,191	$ 235,800	119%
Total EBITDAX (1)	$ 323,744	$ 434,191	$ 110,447	34%
Production data:				
Natural gas (Bcf)	58	120	62	106%
NGLs (MBbl)	—	1,197	1,197	*
Oil (MBbl)	8	122	114	1506%
Combined (Bcfe)	58	128	70	120%
Daily combined production (MMcfe/d)	214	470	256	120%
Average prices before effects of hedges (2):				
Natural gas (per Mcf)	$ 2.69	$ 3.96	$ 1.27	47%
NGLs (per Bbl)	$ —	$ 49.95	$ 49.95	*
Oil (per Bbl)	$ 80.58	$ 93.76	$ 13.18	16%
Combined (per Mcfe)	$ 2.70	$ 4.27	$ 1.57	58%
Average realized prices after effects of hedges (2):				
Natural gas (per Mcf)	$ 5.11	$ 4.87	$ (0.24)	(5)%
NGls (per Bbl)	$ —	$ 49.95	$ 49.95	*
Oil (per Bbl)	$ 80.58	$ 90.28	$ 9.70	12%
Combined (per Mcfe)	$ 5.12	$ 5.12	$ —	—%
Average costs (per Mcfe):				
Lease operating costs	$ 0.07	$ 0.04	$ (0.03)	(43)%
Gathering, compression, and transportation	$ 0.98	$ 1.15	$ 0.17	17%
Production taxes	$ 0.18	$ 0.24	$ 0.06	33%
Depletion, depreciation, amortization, and accretion	$ 1.12	$ 1.24	$ 0.12	11%
General and administrative	$ 0.54	$ 0.32	$ (0.22)	(41)%

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(1) See "—Non-GAAP Financial Measure" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX from continuing and discontinued operations to net income (loss) from continuing and discontinued operations attributable to Antero members and to cash flow provided by operating activities.

(2) Average prices shown in the table reflect the sales prices we received before and after giving effect to our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges for accounting purposes. Oil and NGL 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

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $157 million from continuing operations for the nine months ended September 30, 2012 to $548 million for the nine months ended September 30, 2013, an increase of $390 million, or 249%. Our production increased by 120% over that same period, from 58 Bcfe from continuing operations for the nine months ended September 30, 2012 to 128 Bcfe for the nine months ended September 30, 2013. Net equivalent prices before the effects of realized hedge gains increased from $2.70 per Mcfe for the nine months ended September 30, 2012 to $4.27 for the nine months ended September 30, 2013, an increase of 58%. Increased production volumes accounted for an approximate $189 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $201 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of the ongoing Appalachian Basin drilling program. Additionally, natural gas prices were significantly higher than the depressed price levels during the previous year period, increasing from an average of $2.69 during the nine months ended September 30, 2012 to $3.96 during the nine months ended September 30, 2013.

Commodity derivative fair value gains. For the nine months ended September 30, 2012 and 2013, our hedges resulted in derivative fair value gains of $52 million and $286 million, respectively. The derivative fair value gains included $142 million and $109 million of cash settlements received on derivatives for the nine months ended September 30, 2012 and 2013, respectively. Cash settled derivatives resulted in an increase in realized equivalent prices of $2.42 and $0.85 per Mcfe during the nine months ended September 30, 2012 and 2013, respectively.

Lease operating expenses. Lease operating expenses were approximately $4 million and $5 million during the nine months ended September 30, 2012 and 2013, respectively. On a per unit basis, lease operating expenses decreased by 43%, from $0.07 per Mcfe for the nine months ended September 30, 2012 to $0.04 for the nine months ended September 30, 2013, primarily because of a decrease in workover expenses and because, during the early stages of production for Appalachian Basin wells, operating and maintenance expenses are low and initial production rates are higher than for wells that have been producing for longer periods of time.

Gathering, compression, processing, and transportation expense. Gathering, compression, and transportation expense increased from $57 million for the nine months ended September 30, 2012 to $148 million for the nine months ended September 30, 2013, primarily due to an increase in production volumes, increased costs on firm transportation commitments, and processing charges incurred in the 2013 period but not in the 2012 period. On a per unit basis, gathering, compression, and transportation expense increased by $0.17 per Mcfe, or 17%, for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. In October 2012, we began processing gas in order to extract NGLs and the resulting processing charges resulted in an increase in per unit costs, which was partially offset by a decrease in per unit gathering and transportation costs as a result of increased utilization of firm gathering and transportation capacity. Firm transportation charges increased by $13 million for the nine months ended September 30, 2013 compared to the prior year period, but decreased on a per unit basis from the prior year period. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

Production taxes. Total production taxes increased by approximately $20 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, primarily as a result of increased production and prices. On a per unit basis, production taxes increased from $0.18 to $0.24 per Mcfe. Production taxes as a percentage of natural gas, NGL, and oil revenues were 6.8% and 5.6% for the nine months ended September 30, 2012 and 2013, respectively. Production taxes declined as a percent of production revenues because of increased production in Ohio, which has a lower production tax rate than West Virginia and higher per unit sales prices during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 and the impact of this increase in price on the West Virginia production tax expense..

Exploration expense. Exploration expense increased from $8 million for the nine months ended September 30, 2012 to $17 million for the nine months ended September 30, 2013 primarily due to an increase in the cost of unsuccessful lease acquisition efforts as we have increased the number of third-party lease brokers contracted in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $4 million for the nine months ended September 30, 2012 compared to $10 million for the nine months ended September 30, 2013. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be-expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks, expected well economics, or future plans to develop the acreage.

DD&A. DD&A increased from $65 million for the nine months ended September 30, 2012 to $159 million for the nine months ended September 30, 2013, primarily because of increased production. DD&A per Mcfe increased by 11% from $1.12 per Mcfe during the nine months ended September 30, 2012 to $1.24 per Mcfe during the nine months ended September 30, 2013 as a result of increased depreciation on gathering systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the nine months ended September 30, 2012 or 2013 for proved properties.

General and administrative expense. General and administrative expense increased from $32 million for the nine months ended September 30, 2012 to $41 million for the nine months ended September 30, 2013, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in production levels and development activities. On a per unit basis, general and administrative expense decreased by 41%, from $0.54 per Mcfe during the nine months ended September 30, 2012 to $0.32 per Mcfe during the nine months ended September 30, 2013, primarily due to a 120% increase in production during that time. We had 143 employees as of September 30, 2012 and 204 employees as of September 30, 2013.

As a result of the corporate reorganization and the public stock offering discussed elsewhere in this report, we expect to recognize non-cash stock compensation expense in the fourth quarter of 2013 of approximately $297.0 million. Approximately $217.0 million of additional stock compensation will be recognized over the remaining service period of the underlying equity compensation awards.

Interest expense. Interest expense increased from $71 million for the nine months ended September 30, 2012 to $101 million for the nine months ended September 30, 2013, primarily due to the issuance of a total of $525 million of 6.00% senior notes due 2020 during the fourth quarter of 2012 and the first quarter of 2013. Interest expense includes approximately $5 million of non-cash amortization of deferred financing costs for each of the nine months ended September 30, 2012 and 2013, respectively.

Income tax expense. Income tax expense of $109 million and $121 million for the nine months ended September 30, 2012 and 2013, respectively, relates to pre-tax income from continuing operations of $249 million and $322 million for the nine months ended September 30, 2012 and 2013, respectively. Pre-tax income includes unrealized commodity derivative gains (losses) of $(89) million and $176 million during the nine months ended September 30, 2012 and 2013, respectively, and a $291 million gain on the sale of assets in 2012.

At December 31, 2012, we had approximately $1.0 billion of U.S. federal net operating loss carryforwards ("NOLs") and approximately $1.3 billion of state NOLs, which expire starting in 2024 through 2032. From time to time, there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. Our financial statements included unrecognized benefits at September 30, 2013 of $11 million that, if recognized, would result in a reduction of other long-term liabilities and an increase in noncurrent deferred tax liabilities. As of September 30, 2013, we have accrued approximately $0.6 million of interest on unrecognized tax benefits.

Income (loss) from discontinued operations. The loss from discontinued operations for the nine months ended September 30, 2012 resulted from the recasting of the revenues and direct expenses from the Piceance and Arkoma properties, which were sold during 2012, as discontinued operations. The loss from discontinued operations of $418 million for the nine months ended September 30, 2012 includes a $427 million loss on the sale of the Arkoma properties. The agreement to sell the properties is subject to post-closing adjustments for up to a two year period. The Company believes that post-closing adjustments, if any, will not have a material effect on the financial statements. We did not reclassify any general and administrative expenses or interest expense from continuing operations to discontinued operations.

During the three months ended September 30, 2013, the Company recorded pre-tax income of $5 million related to operations that were discontinued in 2012 for sales tax refunds received and reductions in estimated expenses related to discontinued operations.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt securities, borrowings under the Credit Facility, asset sales, and net cash provided by operating activities. Additionally, in October 2013 we completed a public stock offering with net cash proceeds to the Company of approximately $1.58 billion after expenses. The proceeds were used to paydown the Credit Facility. Our Credit Facility, as amended on October 21, 2013, has a borrowing base of $2.0 billion and lender commitments of $1.5 billion. Our primary use of cash has been for the exploration, development, and acquisition of natural gas, NGLs, and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities, and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us.

In November 2013, we increased our capital budget for 2013 by $200 million to $2.65 billion, including $1.55 billion for drilling and completion, $450 million for leasehold acquisitions, and $650 million for the construction of water handling infrastructure and gas gathering pipelines and facilities. Our capital budget may be adjusted as business conditions warrant. The amount, timing, and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow, and other factors both within and outside our control.

We believe that funds from operating cash flows and available borrowings under our Credit Facility should 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.

The following table summarizes our cash flows for the nine months ended September 30, 2012 and 2013:

	Nine Months Ended September 30,	
	2012	2013
	(in thousands)	
Net cash provided by operating activities	$ 225,400	$ 331,937
Net cash used in investing activities	(295,180)	(1,864,884)
Net cash provided by (used in) financing activities	82,992	1,525,542
Net increase (decrease) in cash and cash equivalents	$ 13,212	$ (7,405)

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $225 million and $332 million for the nine months ended September 30, 2012 and 2013, respectively. The increase in cash flow from operations from the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 was primarily the result of increased production volumes and revenues (including derivative settlements), net of the increase in cash operating costs, interest expense, and changes in working capital levels.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas, NGL, and oil prices. Prices for these commodities are determined primarily by prevailing market conditions. Factors including regional and worldwide economic activity, weather, infrastructure, capacity to reach markets and other variables influence 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" below.

Cash Flow Used in Investing Activities

During the nine months ended September 30, 2013, we used cash totaling $1.9 billion in investing activities, including $343 million of undeveloped leasehold acquisitions, $1.3 billion of development costs (including $157 million for water handling infrastructure), and $240 million of expenditures for gathering systems and other facilities. Additionally, deposits on various equipment orders increased other assets by $12 million. During the nine months ended September 30, 2012, we had used cash for investing activities of $295 million as a result of $1.1 billion in land acquisitions, drilling and development, and gathering systems, partially offset by proceeds realized from the sale of certain Marcellus gathering systems and rights and the Arkoma Basin properties totaling $816 million.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2013 of $1.5 billion resulted from the issuance of $225 million of our 6.00% senior notes for net proceeds of approximately $232 million in February 2013 and $1.3 billion of net additional borrowings under our credit facility. Net cash provided by financing activities of $83 million during the nine months ended September 30, 2012 resulted primarily from credit facility borrowings.

Credit Facility. Our Credit Facility was amended as of October 21, 2013 to decrease the aggregate lender commitments thereunder from $1.75 billion to $1.5 billion. The $2.0 billion borrowing base under the Credit Agreement was not modified in connection with the amendment. The borrowing base is redetermined semiannually and the borrowing base depends on the amount of our proved oil and gas reserves and estimated cash flows from these reserves and our hedge positions. The next redetermination is scheduled to occur in April 2014. At September 30, 2013, we had $1.5 billion of borrowings and $32 million of letters of credit outstanding under the Credit Facility. At December 31, 2012, we had $217 million of borrowings and $43 million of letters of credit outstanding under the Credit Facility. The Credit Facility matures in May 2016.

The credit facility is secured by mortgages on substantially all of our properties and guarantees from our subsidiaries. Interest is payable at a variable rate based on LIBOR or the prime rate based on our election at the time of borrowing.

The Credit Facility contains certain covenants, including restrictions on indebtedness, asset sales, investments, liens, dividends, hedging, and certain other transactions without the prior consent of the lenders. We are required to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused commitment under the Credit Facility and excludes derivative assets) to our consolidated current liabilities of 1.0 to 1.0 at the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2012 and September 30, 2013.

Senior Notes. See Note 4 (b), (c), (d), and (e) to our condensed consolidated financial statements included elsewhere in this Form 10-Q for a description of the terms of the 9.375% senior notes due 2017 with a principal amount of $525 million, the 7.25% senior notes due 2019 with a principal amount of $400 million, the 6.00% senior notes due 2020 with a principal amount of $525 million, and the 9.00% senior note due 2013 with a principal amount of $25 million. See Note 11 to the condensed consolidated financial statements included elsewhere in this Form 10-Q for a description of the terms of the 5.375% senior notes due 2021 issued on November 5, 2013.

Treasury Management Facility. We have a stand-alone revolving note with a lender under the Credit Facility, which provides for up to $25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2014. We expect that the treasury management facility will be renewed for an additional one-year period when it expires. At December 31, 2012 and September 30, 2013, there were no outstanding borrowings under this facility.

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Non-GAAP Financial Measure

"EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense, interest income, derivative fair value gains or losses, excluding net cash receipts or payments on derivative instruments, taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, stock compensation, business acquisition expenses and gain or loss on sale of assets. "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. 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. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our Credit Facility and the indentures governing our senior notes.

There are significant limitations to using EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to EBITDAX from discontinued operations, and a reconciliation of our total EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

	Year Ended December 31,	Three Months Ended September 30,		Nine months Ended September 30,	
	2012	2012	2013	2012	2013
Net income (loss) from continuing operations	$ 225,276	$ (113,887)	$ 117,794	$ 140,431	$ 200,990
Commodity derivative fair value (gains) losses	(179,546)	159,004	(161,968)	(52,210)	(285,510)
Net cash receipts on settled derivative instruments	178.491	44,790	47,034	141,506	109,311
Loss (gain) on sale of assets	(291,190)	115	—	(291,190)	—
Interest expense and other	97,510	22,453	37,444	71,046	100,840
Provision (benefit) for income taxes	121,229	(75,444)	67,370	108,525	120,695
Depreciation, depletion, amortization, and accretion	102,127	26,883	65,963	65,360	159,447
Impairment of unproved properties	12,070	2,438	3,205	4,019	9,564
Exploration expense	14,675	3,156	5,372	7,912	17,034
Other	4,068	996	620	2,992	1,820
EBITDAX from continuing operations	284,710	70,504	182,834	198,391	434,191
Income (loss) from discontinued operations	(510,345)	(13,791)	3,100	(418,465)	3,100
Commodity derivative fair value (gains) losses	(46,358)	18,880	—	(46,358)	—
Net cash receipts on settled derivative instruments	92,166	13,862		79,736	
Loss (gain) on sale of assets	795,945	—	(5,000)	427,232	(5,000)
Provision (benefit) for income taxes	(272,553)	(8,642)	1,900	4,085	1,900
Depreciation, depletion, amortization, and accretion	89,124	14,288	—	77,654	—
Impairment of unproved properties	962	(31)	—	962	—
Exploration expense	664	95	—	507	—
EBITDAX from discontinued operations	149,605	24,661	—	125,353	—
Total EBITDAX	434,315	95,165	182,834	323,744	434,191
Interest expense and other	(97,510)	(22,453)	(37,444)	(71,046)	(100,840)
Exploration expense	(15,339)	(3,156)	(5,372)	(7,912)	(17,034)

Changes in current assets and current liabilities	9,887	5,470	1,194	9,510	13,529
Other	902	(10,610)	716	(28,986)	2,091
Net cash provided by operating activities	$ 332,255	$ 64,416	$ 139,540	$ 225,400	$ 331,937

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Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. 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. We provide an expanded discussion of our more significant accounting policies, estimates and judgments in our 2012 Form 10-K. We believe these accounting policies reflect our more significant estimates, and assumptions used in preparation of our condensed consolidated financial statements. Also, see note 2 of the notes to our audited consolidated financial statements, included in our 2012 Form 10-K, for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

There were no new accounting pronouncements issued during the three months ended September 30, 2013 that had or are expected to have a material effect on our financial statements.

Off-Balance Sheet Arrangements

As of September 30, 2013, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, frac services, firm transportation, and gas processing, gathering, and compression. See "—Contractual Obligations" for commitments under operating leases, drilling rig and frac service agreements, firm transportation agreements, and gas processing, gathering, compression service agreements.

Contractual Obligations

A summary of our contractual obligations as of September 30, 2013 is provided in the following table:

	Year						
(in millions)	**1**	**2**	**3**	**4**	**5**	**Thereafter**	**Total**
Credit Facility(1)	$ —	$ —	$ 1,513	$ —	$ —	$ —	$ 1,513
Senior notes—principal(2)	25	—	—	—	525	925	1,475
Senior notes—interest(2)	110	110	110	110	85	108	633
Drilling rig and frac service commitments(3)	168	88	23	1	—	—	280
Firm transportation (4)	92	139	144	142	142	944	1,603
Gas processing, gathering, and compression services (5)	147	158	165	161	158	641	1,430
Office and equipment leases	4	5	5	4	4	15	37
Asset retirement obligations (6)	—	—	—	—	—	11	11
Total	$ 546	$ 500	$ 1,960	$ 418	$ 914	$ 2,644	$ 6,982

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(1) Includes outstanding principal amount at September 30, 2013. This table does not include future commitment fees, interest expense, or other fees on the Credit Facility because they are floating-rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.

(2) Includes the 9.375% senior notes due 2017, the 7.25% senior notes due 2019, and the 6.00% senior notes issued in November 2012 and February 2013 and due 2020, and the $25 million note due 2013 assumed in the acquisition of Bluestone Energy Partners.

(3) At September 30, 2013, we had contracts for the services of 15 full service drilling rigs which expire at various dates from 2013 through 2016. We also had contracts for 5 shallow drilling rigs that we contract to drill wells to the depth of the horizontal "kickoff point". We also had two frac services contracts which expire in 2013 and 2014. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our

working interest.

(4) We have entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to liquid markets. These contracts commit us to transport minimum daily natural gas or NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5) Contractual commitments for gas processing, gathering, and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

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

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, NGL, and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

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

To mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our natural gas and oil production when management believes that favorable future prices can be secured. We hedge part of our production at a fixed price for natural gas at our sales points (New York Mercantile Exchange (“NYMEX”) less basis) to mitigate the risk of differentials to the sales point prices. Part of our production is also hedged at NYMEX prices.

Our financial hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price.

At September 30, 2013, we had in place natural gas and oil swaps covering portions of our projected production from 2013 through 2019. Our commodity hedge position as of September 30, 2013 is summarized in note 8 to our consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGL, and oil prices at targeted levels and to manage our exposure to price fluctuations. Our Credit Facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 80% for 13 to 24 months in the future, 75% for 25 to 36 months in the future, 70% for 37 to 48 months in the future, 65% for 49 to 60 months in the future, and 65% of production for 2019. Based on our annual production and our fixed price swap contracts in place during 2013, our income before taxes for the nine months ended September 30, 2013 would have decreased by approximately $1.0 million for each $0.10 decrease per MMBtu in natural gas prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception as mentioned above, are recorded at fair market value in accordance with U.S. GAAP and are included in the condensed consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk. Because we do not designate these hedges as accounting hedges, we do not receive accounting hedge treatment and all mark-to-market gains or losses as well as cash receipts or payments on settled derivative instruments are recognized in our results of operations as “Derivative fair value gains (losses).”

Mark-to-market adjustments of derivative instruments produce earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flow is only impacted when the underlying physical sales transaction takes place in the future and when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At September 30, 2013 and December 31, 2012, the estimated fair value of our commodity derivative instruments was a net asset of $708 million and $532 million, respectively, comprised of current and noncurrent assets and current and noncurrent liabilities. None of these commodity derivative instruments were entered into for trading or speculative purposes.

By removing price volatility from a portion of our expected production through December 2019, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility, which has a floating interest rate. The average annual interest rate incurred on this indebtedness for the nine months ended September 30, 2013 was approximately 2.1%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the nine months ended September 30, 2013 would have resulted in an estimated $4.4 million increase in interest expense for that period. We had no outstanding interest rate derivatives for hedging purposes at September 30, 2013.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($708 million at September 30, 2013) and the sale of our oil and gas production ($86 million at September 30, 2013), which we market to energy companies.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with eleven different counterparties, all but one of which is a lender under our Credit Facility. The fair value of our commodity derivative contracts of approximately $708 million at September 30, 2013 includes the following asset values by bank counterparty: Credit Suisse — $174 million; BNP Paribas — $156 million; Wells Fargo — $116 million; JP Morgan — $113 million; Barclays — $112 million; CitiBank - $23 million; Deutsche Bank — $11 million; Toronto Dominion Bank — $2 million; and Union Bank — $1 million. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available or, if not available, a discount rate based on the applicable Reuters bond rating) at September 30, 2013 for each of the European and North 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 contracts, nor are they required to provide credit support to us. As of September 30, 2013, we did not have past-due receivables from or payables to any of our counterparties.

We are also subject to credit risk due to concentration of our natural gas receivables from several significant customers. We 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.

Item 4.   Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this quarterly report. 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 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 disclosure 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, 2013 at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended September 30, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1.   Legal Proceedings

We are party to various legal proceedings and claims in the ordinary course of our business. We believe 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 condensed consolidated financial position, results of operations, or liquidity.

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 2012 Form 10-K. The risks described in our 2012 Form 10-K 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 2012 Form 10-K. 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 6. Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Form 10-Q and are incorporated herein by reference.

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 CORP

Date: November 6, 2013

By: /s/ Glen C. Warren, Jr.
Glen C. Warren, Jr.
President and Chief Financial Officer
(Duly Authorized Officer and Principal Financial Officer)

EXHIBIT INDEX

Exhibit Number	Description of Exhibits
3.1	Certificate of Formation of Antero Resources LLC (incorporated by reference to Exhibit 3.3 to Registration Statement on Form S-4 (Commission File No. 333-164876) filed on February 12, 2010).
3.2	Amended and Restated Limited Liability Company Agreement of Antero Resources LLC dated as of December 1, 2010 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 3, 2010).
3.3	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).
3.4	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).
3.5	Certificate of Incorporation of Antero Resources Finance Corporation (incorporated by reference to Exhibit 3.1 to Registration Statement on Form S-4 (Commission File No. 333-164876) filed on February 12, 2010).
3.6	Bylaws of Antero Resources Finance Corporation (incorporated by reference to Exhibit 3.2 to Registration Statement on Form S-4 (Commission File No. 333-164876) filed on February 12, 2010).
4.1	Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.2	Intercompany Credit Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).

10.3	Limited Liability Company Agreement of Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.4	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on September 24, 2013).
10.5	Agreement and Plan of Merger of Antero Resources LLC with and into Antero Resources Corporation (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 11, 2013).
10.6	Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-8 (Commission File No. 333-191693) filed on October 11, 2013).
10.7	Eighth Amendment to Fourth Amended and Restated Credit Agreement dated August 29, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.23 to Registration Statement on Form S-1/A (Commission File No. 333-189284) filed on August 30, 2013).
10.8	Ninth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 21, 2013, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2013).
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 Form 10-Q of Antero Resources Corporation for the quarter ended September 30, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to the Consolidated Financial Statements, tagged as blocks of text.

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Paul M. Rady, Chairman and Chief Executive Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 6, 2013

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Glen C. Warren, Jr., President and Chief Financial Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 6, 2013

/s/ Glen C. Warren, Jr.
Glen C. Warren, Jr.
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended September 30, 2013, I, Paul M. Rady, Chief Executive Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Quarterly Report on Form 10-Q for the quarter ended September 30, 2013 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2013 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: November 6, 2013

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended September 30, 2013, I, Glen C. Warren, Jr., Chief Financial Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Quarterly Report on Form 10-Q for the quarter ended September 30, 2013 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2013 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: November 6, 2013

/s/ Glen C. Warren, Jr.
Glen C. Warren, Jr.
Chief Financial Officer