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January 17, 2017

H. Roger Schwall
Assistant Director
United States Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, D.C. 20549-3561

Re: Antero Resources Corporation
Form 10-K for Fiscal Year Ended December 31, 2015
Filed February 24, 2016
File No. 1-36120

Ladies and Gentlemen:

Set forth below are the responses of Antero Resources Corporation (the "***Company***", "***we***," "***us***" or "***our***"), to comments received from the staff of the Division of Corporation Finance (the "***Staff***") of the Securities and Exchange Commission (the "***Commission***") by letter dated December 21, 2016, with respect to Form 10-K for Fiscal Year Ended December 31, 2015, File No. 1-36120, filed with the Commission on February 24, 2016 (the "***Form 10-K***").

For your convenience, each response is prefaced by the exact text of the Staff's corresponding comment in bold, italicized text. All references to page numbers and captions correspond to the Form 10-K for Fiscal Year Ended December 31, 2015 unless otherwise specified.

Form 10-K for the Fiscal Year Ended December 31, 2015

Business and Properties, page 1

Proved Undeveloped Reserves, page 6

1. The disclosure on page 6 explains that the negative revision of 2,332 Bcfe or approximately 26% of the prior estimate of proved undeveloped reserves at December 31, 2014 was due to the SEC 5-year development rule because the Company no longer expects certain locations in the eastern portion of the Marcellus acreage containing primarily dry gas to be developed within five years. We note similar disclosure provided in your Form 10-K for the fiscal year ending December 31, 2014 explaining the negative revision of 1,417 Bcfe or approximately 25% of the prior estimate of proved undeveloped reserves at December 31, 2013 was due to the reclassification of 191 dry gas wells to the probable category because they were no longer expected to be drilled within five years as your drilling plans were more focused on liquids-rich acreage.

Furthermore, disclosure provided in your Form 10-K for the fiscal year ending December 31, 2013 indicates that you reclassified 65 wells to the probable category because they are no longer expected to be drilled within five years of initial booking.

Given the successive nature of the revisions to your proved undeveloped reserves, please tell us how the reserves disclosed for the fiscal years ending December 31, 2013, 2014 and 2015 complied with the requirement of reasonable certainty pursuant to Rule 4¬10(a)(22) of Regulation S-X and the requirement

relating to an adopted development plan and schedule as set forth in the definition of undeveloped reserves under Rule 4-10(a)(31)(ii) of Regulation S-X.

RESPONSE:

We acknowledge the Staff's comment and respectfully advise the Staff that we believe the reserves disclosed for the fiscal years ended December 31, 2013, 2014 and 2015 complied with the requirements of reasonable certainty pursuant to Rule 4-10(a)(22) of Regulation S-X and the requirements relating to an adopted development plan and schedule as set forth in the definition of undeveloped reserves under Rule 4-10(a)(31)(ii) of Regulation S-X.

Compliance with Rule 4-10(a)(22)

The Marcellus Shale can be characterized as a statistical mature Resource Play as defined in the Society of Petroleum Evaluation Engineers Monograph 3. We believe the booking of our proved undeveloped ("PUD") reserves is supported by our interpretation of the Marcellus Shale across our acreage block as a consistent, predictable reservoir. We believe this conclusion is appropriate based upon our analysis of geosteering interpretations available for the 433 horizontal Marcellus Shale wells we completed within a three county area of West Virginia between 2009 and 2016, each of which produces in commercially viable quantities. We believe the information obtained while drilling these wells, some of which with lateral lengths in excess of 10,000 feet, confirms the low dips in the Marcellus Shale that exists across our acreage position (generally less than two degrees), the absence of faulting and the consistency of the reservoir thickness. We also believe that geologic control from 149 vertical Marcellus Share well logs, and production data from a number of non-operated horizontal wells near or adjacent to our acreage, significantly de-risked our undeveloped acreage.

Based on our analysis of geoscience and engineering data, we believe the proved undeveloped reserve estimates we reported for the years ended December 31, 2013, 2014 and 2015, which were audited by DeGolyer & McNaughton, independent petroleum engineers, were estimated with reasonable certainty to be economically producible in compliance with Rule 4-10(a)(22) of Regulation S-X.

Compliance with Rule 4- 10(a)(31)(ii)

Since 2011, we have added more than 353,000 gross acres with Btu content of at least 1,100 Btu per Mcf in the Marcellus and Utica Shale through organic leasing and acreage acquisitions. In the past four years, we have increasingly focused our land additions to richer gas

areas where well economics provide higher returns based on the relative prices of NGLs and oil to dry gas. As a result of these efforts, we have built a large inventory of undrilled Marcellus and Utica Shale locations, including 3,381 locations classified as PUD or probable as of December 31, 2015.

We maintain a 5-year drilling plan that supports our corporate production growth target. The drilling schedule is reviewed periodically to ensure capital is allocated to highest rate of return wells within our inventory of undrilled well locations. As our acreage position has grown and well economics have changed, we have reallocated 5-year capital away from lower rate of return areas. This has resulted in the reclassification of 404 Bcfe, 1,417 Bcfe, and 2,332 Bcfe of reserves from classification as PUD to probable during the years ended 2013, 2014, and 2015, respectively, due to the 5-year development rule. Based on our then-current acreage position, then-existing well economics and our development plans at the time these reserves were classified as proved, we believe the previous classification of the dry gas locations as PUDs was appropriate and supportable under Rule 10(a)(31)(ii) of Regulation S-X. There has been no change in our view of reasonable certainty of the undeveloped eastern drier wells. Rather, we have reallocated capital based on changing well economics and acreage positions to our rich gas locations where we have been more focused on land acquisitions. Therefore, we believe our reported proved reserves, by analysis of geoscience and engineering data, were estimated with reasonable certainty to be economically producible in compliance with Rule 4-10(a)(31)(ii) of Regulation S-X.

2. To the extent that you continue to disclose dry gas locations as proved undeveloped reserves as of December 31, 2015, please quantify for us and expand your disclosure to provide the total number of locations and net proved reserve amounts pursuant to FASB ASC 932-235-50-10. Also refer to refer to Rule 4-10(a)(31)

(ii) of Regulation S-X and to Question 131.04 in the Compliance and Disclosure Interpretations (C&DIs), issued October 26, 2009 and updated May 16, 2013, and affirm that all such locations are part of a development plan adopted by the Company's management including approval by the Board, if such approval is required. You may find the C&DIs on our website at the following address:

http://www.sec.gov/divisions/corpfin/guidance/oilandgas-interp.htm.

RESPONSE:

We acknowledge the Staff's comment and respectfully advise the Staff that as of December 31, 2015, we had only 20 Marcellus dry gas PUD locations, which we define as locations with less than 1,150 Btu per Mcf. These 20 PUD locations accounted for 181 Bcfe, or 1.4%, of our total proved reserve volumes at December 31, 2015. These 20 PUD locations were part of management's 5-year development plan at year-end 2015. Although we do not believe additional disclosure is required under FASB ASC 932-235-50-10 because of the immaterial reserves associated with these dry gas locations, if in the future reserves associated with dry gas locations are material, we will expand our disclosure to provide the total number of locations and net proved reserve amounts.

3. Your disclosure indicates that you have approximately $5.1 billion in future development costs to be incurred over the next five years relating to your proved undeveloped reserves which if calculated as a straight line five year average would represent expenditures of approximately $1.02 billion per year. However, the disclosure provided on page 6 and elsewhere on page 2 indicates that during 2015, you incurred approximately $577 million in capital expenditures to convert proved undeveloped reserves to proved developed reserves and that you plan to reduce the 2016 capital budget for drilling, completions and land for 2016 by 24% from your 2015 capital budget. You also disclose on page 2 that in conjunction with the reduction in capital expenditures during 2015, you deferred the completion of 50 wells.

Please expand the disclosure relating to conversion of your proved undeveloped reserves to explain your development plans sufficiently to understand how you have complied with the timeframe stipulated for development within Rule 4-10(a)(31)(ii) of Regulation S-X, and how you have formulated a reasonable expectation that any financing necessary to proceed with development will be available, as required by Rule 4-10(a)(26) of Regulation S-X, prior to reporting these reserves.

RESPONSE:

We acknowledge the Staff's comment and respectfully advise the Staff that the $577 million in capital expenditures used to convert PUDs to proved developed reserves related directly to drilling and completion of wells classified as PUDs at the end of 2014, which resulted in their classification as proved developed wells at the end of 2015. In addition to the estimated $577 million spent on those wells in 2015, we spent an additional $462 million on development costs related primarily to drilled and uncompleted wells and properties in the PUD classification at the end of 2014, resulting in total development spending of $1.039 billion, as disclosed on page F-37 of the Form 10-K. We believe this level of spending supports our 5-year development plan for PUDs. In addition to our development spending in 2015, we spent an additional $612 million for exploratory wells, as disclosed on page F-37 of the Form 10-K. For the year ended December 31, 2016, we planned to spend approximately $1.3 billion for development and exploratory costs, approximately $1.0 billion of which was spent during the nine months ended September 30, 2016. We have also realized operational efficiencies and cost reductions, which reduces the amount of capital required to develop our reserves. For 2017, we have budgeted an additional $1.3 billion for development and exploratory costs.

Historically, our primary sources of financing for our exploration and development activities have been through issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales and net cash provided by operating activities.

The borrowing base under our revolving credit facility is redetermined semi-annually and is based on estimated future cash flows from our proved reserves and our commodity hedge positions. As of September 30, 2016, our revolving credit facility had a borrowing base of $4.75 billion, lender commitments of $4.0 billion and outstanding borrowings and letters of credit of $1.3 billion. As we continue to spend on drilling and completion, we expect that our reserves

and resulting available borrowing base will continue to increase, which will further enhance our liquidity and ability to finance future development and exploration of our properties.

Our net cash provided by operating activities was approximately $1.0 billion for the year ended December 31, 2015 and $905 million for the nine months ended September 30, 2016. Our revenues are supported by a large gas hedge position, which provides price certainty supporting the planned future drilling program. Approximately 86% of targeted production is hedged through 2019 at $3.72/MMBtu, a $0.78 premium to current strip pricing.

We have a demonstrated ability to raise money in capital markets transactions and sales of non-core assets. During 2016, we raised approximately $1.0 billion through new issuances of our common stock, $178 million from our sale of common units representing limited partner interests in Antero Midstream Partners LP and $170 million from our sale of non-core Pennsylvania acreage. Additionally, in December 2016, we completed offering private placement of $600 million of 5.00% senior notes due in 2025 to refinance $525 million of outstanding 6.00% senior notes due in 2020.

We believe that cash provided by operating activities and availability under our revolving credit facilities will be sufficient to finance the future development costs related to our proved reserves in compliance with Rule 4-10 (a)(26) of Regulation S-X. To the extent these amounts are insufficient to finance our growing development and exploration activities, we believe we will have the ability to access the debt or equity capital markets in order to raise additional capital. In future filings, we will expand our disclosure to more thoroughly explain our development plans and reasonable expectation with respect to the availability of necessary financing.

4. ***Please provide us with your development schedule, indicating for each future annual period, the number of gross wells, the net quantities of proved reserves and estimated capital expenditures necessary to convert all of the proved undeveloped reserves disclosed as of December 31, 2015 to developed.***

RESPONSE:

We acknowledge the Staff's comment and have set forth below our development schedule by annual period and number of gross wells, net quantities of proved reserves and estimated capital expenditures to develop all of the proved undeveloped reserves disclosed as of December 31, 2015:

	2016	2017	2018	2019	2020	Total
Gross Wells	97	89	106	144	196	632
Bcfe	1,231	1,136	1,301	1,686	2,023	7,377
Capex, $MM	$ 1,017	$ 841	$ 755	$ 1,543	$ 937	$ 5,093

Undeveloped Acreage Expirations, page 9

5. ***We note the acreage scheduled to expire over the next three years represents approximately 23% and 61% of the total net undeveloped Marcellus and Utica acreage, respectively. Please tell us the extent to which you have assigned any proved undeveloped reserves to locations which are currently scheduled to be drilled after lease expiration. If there are material quantities of net proved undeveloped reserves relating to such locations, please expand your disclosure to identify the number of locations, the related net reserve quantities, and clarify your plans and the related expenditures necessary to extend the time to expiration of such leases.***

RESPONSE:

We acknowledge the Staff's comment and respectfully advise the Staff that we do not believe expiring acreage related to PUD development or the amounts required to retain such acreage are material.

At the end of 2015, we had 544 Marcellus PUD wells scheduled for drilling over the next 5 years across 74,783 acres. The Marcellus PUD acreage includes 20,764 separate leases. Most of the acreage, or 69,490 acres, is held by production or is scheduled to be drilled prior to lease expiration. However, an estimated 7%, or 5,293 acres, is subject to renewal prior to scheduled drilling. Some of these leases have contract renewal options and some will need to be renegotiated. Historically, we have had an approximately 90% success rate in renewing Appalachian leases. Therefore, we estimate the 10% risked PUD volume to be approximately 46 Bcfe, or less than 1%, of our total proved reserves at December 31, 2015. We estimate a potential cost of $8.2 million, or $1,550/acre, to renew 5,293 Marcellus acres based upon current leasing authorizations and option to extend payments.

At the end of 2015, we had 88 Utica PUD wells scheduled for drilling and completion over the next 5 years across 13,008 acres. The Utica PUD acreage includes 349 separate leases. An estimated 121 leases covering 1,688 net acres is subject to renewal prior to scheduled drilling. Some of these leases have contract renewal options and some will need to be renegotiated. Assuming a 90% lease renewal rate, we estimate the 10% risked PUD volume to be approximately 11 Bcfe, or less than 1.5%, of our total proved reserves at December 31, 2015. We estimate a cost of $8.1 million, or $4,773/acre, to renew 1,688 Utica acres based upon current leasing authorizations and option to extend payments.

*   *   *   *   *

Please direct any questions that you have with respect to the foregoing or if any additional supplemental information is required by the Staff, please contact W. Matthew Strock of Vinson & Elkins L.L.P. at (713) 758-3452.

Very truly yours,

ANTERO RESOURCES CORPORATION

By: /s/ Glen C. Warren, Jr.
Name: Glen C. Warren, Jr.
Title: President, Chief Financial Officer and Secretary
