UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **August 2, 2017**

ANTERO RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**001-36120**	**80-0162034**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1615 Wynkoop Street
Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(303) 357-7310**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.02 Results of Operations and Financial Condition.

On August 2, 2017, Antero Resources Corporation (the "Company") issued a press release, a copy of which is attached hereto as Exhibit 99.1 and incorporated by reference herein, announcing its financial and operational results for the quarter ended June 30, 2017. The press release contains certain non-GAAP financial information. The reconciliation of such information to GAAP financial measures is included in the release.

On August 2, 2017, the Company also issued a press release, a copy of which is attached hereto as Exhibit 99.2 and incorporated by reference herein, announcing the Company's total proved, probable and possible reserves as of June 30, 2017.

The information in this Current Report, including Exhibit 99.1 and Exhibit 99.2, is being furnished pursuant to Item 2.02 of Form 8-K and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

EXHIBIT	**DESCRIPTION**

99.1	Antero Resources Corporation press release dated August 2, 2017.
99.2	Antero Resources Corporation press release dated August 2, 2017.

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 hereunto duly authorized.

ANTERO RESOURCES CORPORATION

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

Dated: August 2, 2017

EXHIBIT INDEX

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99.1	Antero Resources Corporation press release dated August 2, 2017.
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Exhibit 99.1

Antero Resources Reports Second Quarter 2017 Financial and Operational Results and Increases 2017 Production Guidance

Denver, Colorado, August 2, 2017—Antero Resources Corporation (NYSE: AR) ("Antero" or the "Company") today released its second quarter 2017 financial and operational results. The relevant condensed consolidated financial statements are included in Antero's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, which has been filed with the Securities and Exchange Commission (the "SEC").

Highlights Include:

- **Net daily gas equivalent production averaged a record 2,200 MMcfe/d (28% liquids), a 25% increase over the prior year quarter**
- **Achieved record 102,766 Bbl/d of liquids production, a 37% increase over the prior year quarter**
- **Raising 2017 production guidance range to 2,250 to 2,300 MMcfe/d, a 3% increase from previous guidance range with no change to the drilling and completion capital budget**
- **Realized natural gas price of $3.15 per Mcf, a $0.03 differential to the average Nymex natural gas price before hedging**
- **Realized natural gas equivalent price of $3.41 per Mcfe including NGLs, oil and hedges**
- **GAAP net loss of $(5) million, or $(0.02) per share, compared to a net loss of $(596) million, or $(2.12) per share, in the prior year quarter**
- **Adjusted EBITDAX of $321 million, a 3% decrease compared to the prior year quarter**
- **Increased type curve for almost 600 proved undeveloped and probable Marcellus locations from 1.7 Bcf/1,000' to approximately 2.0 Bcf/1,000' of lateral with an average lateral length of 8,600 feet for mid-year reserves**
- **Increased mid-year 3P reserves by 14% to 53.0 Tcfe (29% liquids) from year-end 2016**
- **Pre-tax PV-10 of 3P reserves was $17.0 billion at 6/30/2017 strip pricing, including hedges**
- **Completed two laterals in the Marcellus averaging 13,700 feet of lateral length and drilled a 17,400 foot lateral in the Ohio Utica**

Recent Developments

Raising 2017 Guidance

The Company is raising its 2017 net production guidance from a range of 2,160 to 2,250 Bcfe/d to a range of 2,250 to 2,300 Bcfe/d. This represents a 3% increase from the previously announced guidance. The increase in production guidance is primarily a function of the improved recoveries Antero continues to achieve through its advanced completions. Antero's advanced completions have utilized 1,500 to 2,500 pounds of proppant per foot, averaging 2,045 pounds of proppant per foot year to date in 2017. These techniques have yielded encouraging results with initial wellhead EURs ranging from 1.9 to 2.7 Bcf per 1,000' of lateral as compared to the Company's historical 1.7 Bcf per 1,000' type curve.

While the net production guidance is being raied, there is no change to the Company's $1.3 billion drilling and completion budget for 2017 due to continued efficiency gains. Drilling efficiencies include a reduction in drilling days in the Marcellus from 15 days in 2016 to 12 days in the second quarter of 2017 despite drilling longer laterals. In the second quarter of 2017, Antero drilled an average of 5,200 lateral feet per day in the Marcellus and the Company's average completed lateral was 9,400 feet and 11,200 feet in the Marcellus and Ohio Utica, respectively. Further, the Company continues to increase pad sizes and is currently drilling both a 12-well and a 14-well pad in the Marcellus.

Year to date in 2017, Antero has placed 59 total wells to sales. Of the 54 wells Antero has completed in the Marcellus, 46, or 85%, have used greater than 1,750 pounds of proppant per foot and have generated aggregate production in excess of the Company's 2.0 Bcf/1,000' type curve target through 180 days.

The following table is a comparison of the original 2017 production guidance issued in January 2017 and the revised 2017 guidance.

	2017 — New		2017 — Previous	
Guidance	**Low**	**High**	**Low**	**High**
Production				
Net Daily Production (MMcfe/d)	2,250	2,300	2,160	2,250
Net Daily Residue Natural Gas Production (MMcf/d)	1,650	1,675	1,625	1,675
Net Daily Liquids Production (Bbl/d)	100,000	105,000	88,500	96,500
Net Daily C3+ NGL Production (Bbl/d)	68,000	71,000	65,000	70,000
Net Daily Ethane Production (Bbl/d)	26,000	27,000	18,000	20,000
Net Daily Oil Production (Bbl/d)	6,000	7,000	5,500	6,500
Capital Expenditures ($MM)				

Drilling and Completion Capital	$1,300	$1,300
Land	$200	$200

Mid-Year 2017 Proved and 3P Reserves

Antero announced today that internally estimated proved reserves at mid-year 2017 were 16.5 Tcfe, a 7% increase compared to estimated proved reserves at December 31, 2016. Assuming futures strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing, the pre-tax present value discounted at 10% ("pre-tax PV–10") of the June 30, 2017 estimated proved reserves was $10.1 billion, including $1.7 billion of hedge value. All-in finding and development cost for proved reserve additions was $0.48 per Mcfe. Drill bit only finding and development cost for proved reserve additions was $0.47 per Mcfe. Proved developed reserves increased by 20% from year-end 2016 to 8.3 Tcfe at June 30, 2017 and the percentage of proved reserves classified as proved developed increased to 50%. The Company's proved, probable and possible ("3P") reserves at mid-year 2017 totaled 53.0 Tcfe, which represents a 14% increase compared to year-end 2016. Assuming futures strip benchmark pricing and applying the same company-specific production weighting for Appalachian index pricing, the pre-tax PV–10 of the June 30, 2017 3P reserves was $17.0 billion, including hedges. The 3P reserve figures exclude virtually all of the Company's Upper Devonian and West Virginia Utica resource.

Included in the mid-year 2017 reserves are 199 proved undeveloped and 398 probable locations that were upgraded to an approximate 2.0 Bcf/1,000' type curve from a 1.7 Bcf/1,000' type curve at year-end 2016. There are now 294 proved undeveloped locations, or 83% of the total proved undeveloped locations in the Marcellus that are booked at an approximate 2.0 Bcf/1,000' type curve. The remaining 60 Marcellus proved undeveloped locations are booked at a 1.7 Bcf/1,000' type curve.

Commenting on the continued enhanced recoveries and the impact on production and reserves, Paul Rady, Chairman and CEO, said, "We continue to see outstanding results from our advanced completions in the Marcellus that we began implementing in early 2016. In recognition of these productivity gains, our reserve engineers have now upgraded nearly 600 proved and probable drilling locations in the Marcellus from our previous 1.7 Bcf/1,000' type curve to an approximate 2.0 Bcf/1,000' type curve. The enhanced productivity from these completions combined with continued operational efficiencies has resulted in a further reduction in per unit development costs and a further increase in capital efficiency. The enhanced completions program has also resulted in a 3% increase to our production guidance without raising capital spending guidance."

Asset Acquisition

In early June of 2017, Antero closed on a 10,300 net acre Marcellus acquisition primarily located in Doddridge and Wetzel Counties, West Virginia for approximately $130 million. The acquisition included approximately 17 MMcfe/d of net equivalent production, 15 drilled but uncompleted wells with an average lateral length of 8,200 feet and one undeveloped drilling pad. Antero estimates the undeveloped properties include 418 Bcfe and 958 Bcfe of unaudited Marcellus proved reserves and 3P reserves, respectively, which were included in Antero's mid-year reserve analysis. In total, the acquisition adds 89 undeveloped 3P locations and enhances 74 existing 3P locations with incremental working interests and/or increased lateral length. The lateral length of the new or enhanced 3P locations average 8,700 feet.

Second Quarter 2017 Financial and Operating Results

As of June 30, 2017, Antero owned a 58% limited partner interest in Antero Midstream Partners LP ("Antero Midstream"). Antero Midstream's results are consolidated with Antero's results.

For the three months ended June 30, 2017, the Company reported a net loss of $5 million, or $(0.02) per basic and diluted share, compared to a net loss of $596 million, or $(2.12) per basic and diluted share, in the second quarter of 2016. The net loss for the second quarter of 2017 included the following items:

- Non-cash gain on unsettled hedges of $55 million
- Non-cash equity-based compensation expense of $27 million
- Impairment of unproved properties of $15 million
- Income tax effect of these reconciling items of $5 million

Excluding the items detailed above, the Company's results for the second quarter of 2017 were as follows:

- Adjusted net loss of $13 million, or $(0.04) per basic and diluted share, a 132% decrease compared to adjusted net income of $41 million in the second quarter of 2016
- Adjusted EBITDAX of $321 million, a 3% decrease compared to the second quarter of 2016

For a description of adjusted net loss and adjusted EBITDAX and reconciliations to their nearest comparable GAAP measures, please read "Non-GAAP Financial Measures."

Antero's net daily production for the second quarter of 2017 averaged 2,200 MMcfe/d, including 102,766 Bbl/d of liquids (28% liquids). Second quarter 2017 production represents an organic production growth rate of 25% from the second quarter of 2016 and a 3% increase compared to the first quarter of 2017. Second quarter 2017 C3+ natural gas liquids ("NGLs") and oil production averaged 68,026 Bbl/d and 6,738 Bbl/d, respectively. Ethane (C2) production averaged 28,003 Bbl/d while leaving approximately 91,710 Bbl/d of ethane in the natural gas stream. Total liquids production of 102,766 Bbl/d for the second quarter of 2017 represents an organic production growth rate of 37% and 4% as compared to the second quarter of 2016 and first quarter of 2017, respectively.

Commenting on capital spending and cash flow levels, Glen Warren, President and CFO, said, "Our ability to grow production 25% year-over-year while essentially holding capital spending flat speaks to our material gains in capital efficiency, especially in the face of the commodity down cycle. These gains are driven by a combination of drilling efficiencies which we have continued to achieve and the operational momentum we have been able to sustain through the downturn due to our ability to lock in volumes and pricing through our hedge book and firm transportation portfolio. Looking ahead, we expect to continue to build off this momentum as we are targeting 20% to 22% production growth in 2018 while maintaining a D&C budget at or below 2017 levels. Furthermore, we are targeting drilling and completion capital to be within discretionary cash flow in 2018."

Antero's average natural gas price before hedging increased 63% from the prior year quarter to $3.15 per Mcf, a $0.03 differential to the average Nymex natural gas price for the period. Antero's average realized natural gas price after hedging for the second quarter of 2017 was $3.53 per Mcf, a $0.35 premium to the Nymex average natural gas price for the period, and an 18% decrease compared to the prior year quarter. During the quarter, Antero realized a cash settled natural gas hedge gain of $55 million, or $0.38 per Mcf compared to $283 million, or $2.38 per Mcf in the prior year quarter.

The Company's average realized C3+ NGL price before hedging for the second quarter of 2017 was $24.14 per barrel, or 50% of the average Nymex WTI oil price, which represents a 41% increase as compared to the prior year quarter. The improvement in C3+ NGL pricing is primarily due to an increase in Mont Belvieu pricing combined with an improvement in local differentials. Antero's average realized C3+ NGL price including hedges was $19.92 per barrel, a 5% increase compared to the second quarter of 2016. The Company's average realized ethane price before hedging for the second quarter of 2017 was $0.20 per gallon, or $8.40 per barrel. Antero's average realized ethane price including hedges for the second quarter of 2017 was $0.21 per gallon, or $8.61 per barrel. The average realized oil price before hedging was $43.24 per barrel, a $5.00 differential to Nymex WTI for the period and a 23% increase as compared to the second quarter of 2016. Antero's average realized oil price including hedges was $46.12 per barrel, a $2.12 differential to Nymex WTI for the period.

Antero's average natural gas-equivalent price including C2+ NGLs and oil, but excluding hedge settlements, increased from the prior year quarter by $1.13 to $3.26 per Mcfe. The Company's average natural gas-equivalent price, including C2+ NGLs, oil and hedge settlements, decreased by 14% to $3.41 per Mcfe compared to the prior year quarter. For the second quarter of 2017, Antero realized a total cash settled hedge gain on all products of $31 million, or $0.16 per Mcfe.

Total operating revenue for the second quarter of 2017 was $790 million as compared to a $249 million loss for the second quarter of 2016. Operating revenue for the second quarter of 2017 included a $55 million non-cash gain on unsettled hedges, while the second quarter of 2016 included a $977 million non-cash loss on unsettled hedges. Revenue excluding the unrealized hedge gain for the quarter was $736 million, which was in line with the second quarter of 2016. Liquids production contributed 30% of total product revenues before hedges in the second quarter of 2017. For a reconciliation of revenue excluding unrealized hedge (gains) losses to operating revenue, the most comparable GAAP measure, please read "Non-GAAP Financial Measures."

Marketing revenue for the second quarter of 2017 was $50 million. Antero's marketing revenue was primarily associated with the sale of third party gas purchased to utilize the Company's excess firm transportation capacity on the Tennessee, Columbia Gas and Rockies Express Pipelines. Marketing expense for the second quarter of 2017 was $77 million, including costs related to excess capacity and the cost of purchasing third party gas. Net marketing expense was $27 million, or $0.14 per Mcfe, for the second quarter of 2017, representing a 36% or $0.08 per Mcfe decrease from the second quarter of 2016. The reduction in net marketing expense was primarily driven by the decrease in unutilized excess firm transportation capacity, a portion of which was assumed by a third party beginning July 1, 2016.

Per unit cash production expense (lease operating, gathering, compression, processing, transportation, and production and ad valorem taxes) for the second quarter of 2017 was $1.52 per Mcfe, a 3% increase compared to $1.48 per Mcfe in the prior year quarter. The increase is primarily a result of an increase in fuel costs as compared to the prior year due to higher natural gas prices. The per unit cash production expense for the quarter included $0.08 per Mcfe for lease operating costs, $1.33 per Mcfe for gathering, compression, processing and transportation costs and $0.11 per Mcfe for production and ad valorem taxes. Per unit general and administrative expense for the second quarter of 2017, excluding non-cash equity-based compensation expense, was $0.19 per Mcfe, a 10% decrease from the second quarter of 2016, driven by a 25% increase in production. Per unit depreciation, depletion and amortization expense decreased 18% from the prior year quarter to $1.01 per Mcfe, primarily driven by increases in Antero's estimated recoverable reserves combined with decreases in its per unit development costs. For the Marcellus, per unit depreciation, depletion and amortization expense decreased 19% from the prior year quarter to $0.85 per Mcfe.

Adjusted EBITDAX of $321 million for the second quarter of 2017 represents a 3% decrease compared to the prior year quarter. Adjusted EBITDAX margin for the quarter was $1.60 per Mcfe, representing a 23% decrease from the prior year quarter, driven primarily by a reduction in gains on settled derivatives. For the second quarter of 2017, cash flow from operations was $254 million, a 6% increase from the prior year quarter. Cash flow from operations before changes in working capital was $251 million, a 7% decrease from the second quarter of 2016.

For a description of adjusted EBITDAX, adjusted EBITDAX margin, as well as cash flow from operations before changes in working capital and reconciliations to their nearest comparable GAAP measures, please read "Non-GAAP Financial Measures."

The following table details the components of average net production and average realized prices for the three months ended June 30, 2017:

	Three Months Ended June 30, 2017				
	Gas (MMcf/d)	Oil (Bbl/d)	C3+ NGLs (Bbl/d)	Ethane (Bbl/d)	Combined Gas Equivalent (MMcfe/d)
Average Net Production	1,583	6,738	68,026	28,003	2,200

	Gas ($/Mcf)	Oil ($/Bbl)	C3+ NGLs ($/Bbl)	Ethane ($/Bbl)	Combined Gas Equivalent ($/Mcfe)
Average Realized Prices					
Average realized price before settled derivatives	$ 3.15	$ 43.24	$ 24.14	$ 8.40	$ 3.26
Settled derivatives	0.38	2.88	(4.22)	0.21	0.15
Average realized price after settled derivatives	$ 3.53	$ 46.12	$ 19.92	$ 8.61	$ 3.41
Nymex average price	$ 3.18	$ 48.24			$ 3.18
Premium / (Differential) to Nymex	$ 0.35	$ (2.12)			$ 0.23

Marcellus Shale — Antero completed and placed on line 29 horizontal Marcellus wells during the second quarter of 2017 with an average lateral length of 9,380 feet. During the period, Antero drilled an average of 5,200 lateral feet per day, which represents a 50% increase compared to 2016.

Current average well costs are $0.9 million per 1,000 feet of lateral in the Marcellus assuming a 2,000 pounds of proppant per foot completion. Average drilling days from spud to final rig release was 12 days in the second quarter of 2017, a 4% reduction from 2016. Antero is currently operating four drilling rigs and three completion crews in the Marcellus Shale.

In late March 2017, Antero placed two wells to sales on a pad with average lateral lengths of 13,700 feet. The 13,700’ laterals each averaged 26 MMcfe/d of production in the first 30 days and have an average wellhead EUR of 2.1 Bcf/1000’ and a processed EUR of 2.5 Bcfe/1,000’. The two wells have an average EUR of approximately 34 Bcfe per well.

In mid-July of 2017, the Sherwood 8 processing plant (200 MMcf/d) was placed into service. The Sherwood 8 plant is the second Antero Midstream / MPLX joint venture (the “Joint Venture”) plant placed in service during the year and is already 100% utilized. The Joint Venture’s next plant, Sherwood 9 (200 MMcf/d), is expected to be in service in January of 2018.

Ohio Utica Shale — Antero completed and placed on line 5 horizontal Utica wells during the second quarter of 2017 with an average lateral length of 11,222 feet. During the period, Antero set a record for drilling its longest lateral to date at 17,380 feet. This lateral was drilled within a 7 foot target zone and was drilled in 12 days. The well is expected to be placed to sales in the third quarter of 2017.

Current average well costs are $1.0 million per 1,000 feet of lateral in the Utica. Antero is currently operating two drilling rigs and two completion crews in the Utica Shale.

Antero Midstream Financial Results

Antero Midstream results were released today and are available at www.anteromidstream.com.

Low pressure gathering volumes for the second quarter of 2017 averaged 1,683 MMcf/d, a 24% increase from the second quarter of 2016 and a 3% increase sequentially. Compression volumes for the second quarter of 2017 averaged 1,192 MMcf/d, an 81% increase from the second quarter of 2016 and a 17% increase sequentially. High pressure gathering volumes for the second quarter of 2017 averaged 1,734 MMcf/d, a 38% increase from the second quarter of 2016 and an 11% increase sequentially. The increase in gathering and compression volumes was driven by production growth from Antero Resources in Antero Midstream’s area of dedication. Joint Venture processing volumes for the second quarter of 2017 averaged 216 MMcf/d and fractionation volumes averaged 4,039 Bbl/d. Fresh water delivery volumes averaged 173 MBbl/d during the quarter, a 64% increase compared to the prior year quarter and an 18% increase sequentially.

For the three months ended June 30, 2017, Antero Midstream reported revenues of $194 million, comprised of $99 million from the Gathering and Processing segment and $95 million from the Water Handling and Treatment segment. Revenues increased 42% compared to the prior year quarter, driven by growth in throughput volumes and fresh water delivery volumes. Water Handling and Treatment segment revenues include $36 million from produced water handling and high rate water transfer services provided to Antero Resources, which is billed at cost plus 3%.

Direct operating expenses for the Gathering and Processing and Water Handling and Treatment segments were $10 million and $42 million, respectively, for a total of $52 million compared to $43 million in direct operating expenses in the prior year quarter. Water Handling and Treatment direct operating expenses include $35 million from produced water handling and high rate water transfer services. General and administrative expenses including equity-based compensation were $15 million, a $2 million increase compared to the second quarter of 2016. General and administrative expenses excluding equity-based compensation were $8 million during the second quarter of 2017, a $1 million increase compared to the second quarter of 2016. Total operating expenses were $101 million, including $30 million of depreciation and $4 million of accretion of contingent acquisition consideration. During the quarter, Antero Midstream continued construction on the Antero Clearwater Facility, which is expected to be placed into service in the fourth quarter of 2017 and have up to 60,000 Bbl/d of treating capacity.

Antero Midstream Distribution

Antero Midstream declared a cash distribution of $0.32 per unit ($1.28 per unit annualized) for the second quarter of 2017. The distribution represents a 28% increase compared to the prior year quarter and a 7% increase sequentially. The distribution is Antero Midstream's tenth consecutive quarterly distribution increase since its initial public offering in November 2014 and will be payable on August 16, 2017 to unitholders of record as of August 3, 2017.

Balance Sheet and Liquidity

As of June 30, 2017, Antero's consolidated net debt was $5.3 billion, of which $1.2 billion were borrowings outstanding under the Company's and Antero Midstream's revolving credit facilities. Total borrowing capacity under these two facilities is currently $5.5 billion. Reduced for $706 million in letters of credit outstanding, the company had $3.6 billion in available consolidated liquidity as of June 30, 2017. For a reconciliation of consolidated net debt to consolidated total debt, the most comparable GAAP measure, please read "Non-GAAP Financial Measures."

Second Quarter 2017 Capital Spending

Antero's drilling and completion costs for the three months ended June 30, 2017 were $322 million. In addition, the Company invested $74 million for land and $130 million for proved property acquisitions. Antero Midstream invested $88 million for gathering and compression systems and $58 million for water infrastructure projects, including $46 million on the Antero Clearwater Treatment Facility. Investments in unconsolidated affiliates for Antero Midstream's processing and fractionation joint venture were $31 million during the quarter.

Hedge Position

Antero currently has hedged 3.1 Tcfe of future natural gas equivalent production using fixed price swaps covering the period from July 1, 2017 through December 31, 2023 at an average index price of $3.62 per MMBtu. At June 30, 2017, the Company's estimated fair value of commodity derivative instruments was $2.0 billion.

The following table summarizes Antero's hedge position as of June 30, 2017:

Period	Natural Gas MMBtu/d		Average Index price ($/MMBtu)	Liquids Bbl/d		Average Index price
3Q 2017:						
Nymex Henry Hub	1,370,000	$	3.33	—		—
CGTLA	420,000	$	4.20	—		—
Chicago	70,000	$	4.45	—		—
Propane MB ($/Gal)	—		—	27,500	$	0.39
Ethane MB ($/Gal)	—		—	20,000	$	0.25
Nymex WTI ($/Bbl)	—		—	3,000	$	54.75
4Q 2017:						
Nymex Henry Hub	1,370,000	$	3.46	—		—
CGTLA	420,000	$	4.37	—		—
Chicago	70,000	$	4.68	—		—
Propane MB ($/Gal)	—		—	27,500	$	0.40
Ethane MB ($/Gal)	—		—	20,000	$	0.25
Nymex WTI ($/Bbl)	—		—	3,000	$	54.75
2017 Total	1,860,000	$	3.64	50,500		N/A (1)
2018:						
Nymex Henry Hub	2,002,500	$	3.91	—		—
Propane MB ($/Gal)	—		—	2,000	$	0.65
2019 Nymex Henry Hub	2,330,000	$	3.70	—		—
2020 Nymex Henry Hub	1,417,500	$	3.63	—		—
2021 Nymex Henry Hub	710,000	$	3.31	—		—
2022 Nymex Henry Hub	850,000	$	3.16	—		—
2023 Nymex Henry Hub	90,000	$	2.91	—		—

(1) *Average index price is not applicable as 2017 liquids hedges include propane, ethane and oil hedges.*

Conference Call

A conference call is scheduled on Thursday, August 3, 2017 at 9:00 am MT to discuss the quarterly results. A brief Q&A session for security analysts will immediately follow the discussion of the results for the quarter. To participate in the call, dial in at 888-347-8204 (U.S.), 855-669-9657 (Canada), or 412-902-4229 (International) and reference "Antero Resources". A telephone replay of the call will be available until Friday, August 11, 2017 at 9:00 am MT at 844-512-2921 (U.S.) or 412-317-6671 (International) using the passcode 10108841.

A simultaneous webcast of the call may be accessed over the internet at www.anteroresources.com. The webcast will be archived for replay on the Company's website until Friday, August 11, 2017 at 9:00 am MT.

Presentation

An updated presentation will be posted to the Company's website before the August 3, 2017 conference call. The presentation can be found at www.anteroresources.com on the homepage. Information on the Company's website does not constitute a portion of this press release.

Non-GAAP Financial Measures

Revenue excluding unrealized hedge (gains) losses as set forth in this release represents total operating revenue adjusted for non-cash (gains) losses on unsettled hedges. Antero believes that revenue excluding unrealized hedge (gains) losses is useful to investors in evaluating operational trends of the Company and its performance relative to other oil and gas producing companies. Revenue excluding unrealized hedge (gains) losses is not a measure of financial performance under GAAP and should not be considered in isolation or as a substitute for total operating revenue as an indicator of financial performance. The following table reconciles total operating revenue to revenue excluding unrealized hedge (gains) losses (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2016	2017	2016	2017
Total operating revenue	$ (249,198)	$ 790,389	$ 471,806	$ 1,985,968
Hedge (gains) losses	684,634	(85,641)	404,710	(524,416)
Cash receipts for settled hedges	292,500	31,064	616,847	75,913
Revenue excluding unrealized hedge (gains) losses	$ 727,936	$ 735,812	$ 1,493,363	$ 1,537,465

Adjusted net income (loss) as set forth in this release represents net income (loss), adjusted for certain items. Antero believes that adjusted net income (loss) is useful to investors in evaluating operational trends of the Company and its performance relative to other oil and gas producing companies. Adjusted net income (loss) is not a measure of financial performance under GAAP and should not be considered in isolation or as a substitute for net income (loss) as an indicator of financial performance. The following table reconciles net income (loss) to adjusted net income (loss) (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2016	2017	2016	2017
Net income (loss)	$ (596,244)	$ (5,132)	$ (601,299)	$ 263,264
Hedge (gains) losses	684,634	(85,641)	404,710	(524,416)
Cash receipts for settled hedges	292,500	31,064	616,847	75,913
Impairment of unproved properties	19,944	15,199	35,470	42,098
Equity-based compensation	25,816	26,975	49,286	52,478
Income tax effect of reconciling items	(385,928)	4,693	(417,401)	133,918
Adjusted net income (loss)	$ 40,722	$ (12,842)	$ 87,613	$ 43,255

Cash flow from operations before changes in working capital as presented in this release represents net cash provided by operating activities before changes in working capital items. Cash flow from operations before changes in working capital is widely accepted by the investment community as a financial indicator of an oil and gas company's ability to generate cash to internally fund exploration and development activities and to service debt. Cash flow from operations before changes in working capital is also useful because it is widely used by professional research analysts in valuing, comparing, rating and providing investment recommendations of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Cash flow from operations before changes in working capital is not a measure of financial performance under GAAP and should not be considered in isolation or as a substitute for cash flows from operating, investing, or financing activities, as an indicator of cash flows, or as a measure of liquidity.

The following table reconciles net cash provided by operating activities to cash flow from operations before changes in working capital as used in this release (in thousands):

	Three months ended June 30, 2016	Three months ended June 30, 2017	Six months ended June 30, 2016	Six months ended June 30, 2017
Net cash provided by operating activities	$ 238,538	$ 253,647	$ 578,706	$ 647,586
Net change in working capital	30,218	(2,853)	(18,612)	(100,190)
Cash flow from operations before changes in working capital	$ 268,756	$ 250,794	$ 560,094	$ 547,396

The following table reconciles consolidated total debt to consolidated net debt as used in this release (in thousands):

	December 31, 2016	June 30, 2017
Bank credit facilities	$ 650,000	$ 1,235,000
5.375% AR senior notes due 2021	1,000,000	1,000,000
5.125% AR senior notes due 2022	1,100,000	1,100,000
5.625% AR senior notes due 2023	750,000	750,000
5.375% AM senior notes due 2024	650,000	650,000
5.000% AR senior notes due 2025	600,000	600,000
Net unamortized premium	1,749	1,655
Net unamortized debt issuance costs	(47,776)	(44,682)
Consolidated total debt	$ 4,703,973	$ 5,291,973
Less: Cash and cash equivalents	31,610	40,190
Consolidated net debt	$ 4,672,363	$ 5,251,783

Adjusted EBITDAX is a non-GAAP financial measure that the Company defines as net income from continuing operations including noncontrolling interest after adjusting for those items shown in the table below. Adjusted EBITDAX, as used and defined by the Company, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income, cash flows from operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, Antero's management team believes adjusted EBITDAX is useful to an investor in evaluating the Company's financial performance because this measure:

- is widely used by investors in the oil and 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 Antero's operations from period to period by removing the effect of its capital structure from its operating structure; and

- is used by the Company's management team for various purposes, including as a measure of operating performance, in presentations to its Board of Directors, as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our Board of Directors as a performance measure in determining executive compensation. Adjusted EBITDAX, as defined by our credit facility, is used by our lenders pursuant to covenants under our revolving credit facility and the indentures governing the Company's senior notes.

There are significant limitations to using adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect Antero's net income, the lack of comparability of results of operations of different companies and the different methods of calculating adjusted EBITDAX reported by different companies. The following tables represent a reconciliation of the Company's net income (loss) from continuing operations including noncontrolling interest to adjusted EBITDAX, a reconciliation of adjusted EBITDAX to net cash provided by operating activities and a reconciliation of realized price before cash receipts for settled hedges to adjusted EBITDAX margin (in thousands except adjusted EBITDAX margin).

	Three months ended June 30, 2016	Three months ended June 30, 2017	Six months ended June 30, 2016	Six months ended June 30, 2017
Net Income (loss) including noncontrolling interest	$ (575,490)	$ 39,965	$ (564,840)	$ 345,523
Commodity derivative (gains) losses	684,634	(85,641)	404,710	(524,416)
Gains on settled derivative instruments	292,500	31,064	616,847	75,913
Interest expense	62,595	68,582	125,879	135,252
Income tax expense (benefit)	(376,494)	18,819	(371,679)	150,165
Depreciation, depletion, amortization, and accretion	197,982	201,831	390,162	405,197
Impairment of unproved properties	19,944	15,199	35,470	42,098
Exploration expense	1,109	1,804	2,123	3,911

Equity-based compensation expense	25,816	26,075	49,286	53,478
Equity in earnings of unconsolidated affiliate	(484)	(5,825)	(484)	(8,834)
Distributions from unconsolidated affiliates	—	5,820	—	5,820
State franchise taxes .	—	—	39	—
Total Adjusted EBITDAX	332,112	320,795	687,513	686,087
Interest expense	(62,595)	(68,582)	(125,879)	(135,252)
Exploration expense	(1,109)	(1,804)	(2,123)	(3,911)
Changes in current assets and liabilities	(30,218)	2,853	18,612	100,190
State franchise taxes	—	—	(39)	—
Other non-cash items	348	385	622	472
Net cash provided by operating activities	$ 238,538	$ 253,647	$ 578,706	$ 647,586

	Three months ended June 30, 2016	Three months ended June 30, 2017	Six months ended June 30, 2016	Six months ended June 30, 2017
Adjusted EBITDAX margin ($ per Mcfe):				
Realized price before cash receipts for settled hedges	$ 2.13	$ 3.26	$ 2.12	$ 3.41
Gathering, compression, water handling and treatment revenues	0.02	0.04	0.02	0.03
Lease operating expense	(0.08)	(0.08)	(0.07)	(0.08)
Gathering, compression, processing and transportation costs	(1.29)	(1.33)	(1.29)	(1.36)
Marketing, net	(0.22)	(0.14)	(0.23)	(0.13)
Production taxes	(0.11)	(0.11)	(0.11)	(0.12)
General and administrative(1)	(0.21)	(0.19)	(0.21)	(0.19)
Adjusted EBITDAX margin before settled hedges	0.24	1.45	0.23	1.56
Cash receipts for settled hedges	1.82	0.15	1.93	0.19
Adjusted EBITDAX margin ($ per Mcfe):	**$ 2.06**	**$ 1.60**	**$ 2.16**	**$ 1.75**

(1) Excludes equity-based stock compensation

Antero Resources is an independent natural gas and oil company engaged in the acquisition, development and production of unconventional liquids-rich natural gas properties located in the Appalachian Basin in West Virginia and Ohio. The Company's website is located at www.anteroresources.com.

This release includes "forward-looking statements". Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond Antero's control. All statements, except for statements of historical fact, made in this release regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future production targets, completion of natural gas or natural gas liquids transportation projects, future earnings, future capital spending plans, improved and/or increasing capital efficiency, continued utilization of existing infrastructure, gas marketability, estimated realized natural gas and natural gas liquids prices, acreage quality, access to multiple gas markets, expected drilling and development plans, future financial position, future technical improvements and future marketing opportunities, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All forward-looking statements speak only as of the date of this release. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

Antero cautions 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 the Company's 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 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 Antero's Annual Report on Form 10-K for the year ended December 31, 2016.

For more information, contact Michael Kennedy — SVP — Finance, at (303) 357-6782 or mkennedy@anteroresources.com.

Reserves Disclosure

In this release, Antero has provided a number of unaudited reserve metrics, which include all-in finding and development cost per unit and drill bit only finding and development cost per unit. These non-GAAP metrics are commonly used in the exploration and production industry by companies, investors and analysts in order to measure a company's ability of adding and developing reserves at a reasonable cost. The finding and development costs per unit are statistical indicators that have limitations, including their predictive and comparative value. In addition, because the finding and development costs per unit do not consider the cost or timing of future production of new reserves, such measures may not be adequate measures of value creation. These reserve metrics may not be comparable to similarly titled measurements used by other companies. The calculations for both all-in and drill bit only finding and development cost per unit do not include future development costs required for the development of proved undeveloped reserves.

Pre-tax PV—10 values and pre-tax PV-10 values including hedges are non-GAAP financial measures as defined by the SEC. Antero believes that the presentation of these pre-tax PV—10 values are relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves and hedges prior to taking into account corporate future income taxes and the Company's current tax structure. The Company further believes investors and creditors use pre-tax PV—10 values

as a basis for comparison of the relative size and value of its reserves and hedges as compared with other companies. Antero believes that PV—10 estimates using strip pricing and including hedges can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows in the current commodity price environment. PV—10 estimates using strip pricing are not adjusted for the likelihood that the pricing scenario will occur, and thus they may not be comparable to PV—10 value using SEC pricing.

The GAAP financial measure most directly comparable to pre-tax PV—10 is the standardized measure of discounted future net cash flows ("Standardized Measure"). With respect to PV-10 calculated as of an interim date, it is not practical to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

ANTERO RESOURCES CORPORATION
Condensed Consolidated Balance Sheets
December 31, 2016 and June 30, 2017
(unaudited)
(In thousands, except per share amounts)

	December 31, 2016	June 30, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 31,610	40,190
Accounts receivable, net of allowance for doubtful accounts of $1,195 in 2016 and 2017	29,682	16,494
Accrued revenue	261,960	218,621
Derivative instruments	73,022	452,005
Other current assets	6,313	8,573
Total current assets	402,587	735,883
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	2,331,173	2,309,839
Proved properties	9,549,671	10,493,932
Water handling and treatment systems	744,682	840,183
Gathering systems and facilities	1,723,768	1,884,712
Other property and equipment	41,231	48,537
	14,390,525	15,577,203
Less accumulated depletion, depreciation, and amortization	(2,363,778)	(2,767,358)
Property and equipment, net	12,026,747	12,809,845
Derivative instruments	1,731,063	1,600,165
Investments in unconsolidated affiliates	68,299	259,697
Other assets	26,854	36,631
Total assets	$ 14,255,550	15,442,221
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 38,627	51,567
Accrued liabilities	393,803	418,352
Revenue distributions payable	163,989	203,151
Derivative instruments	203,635	3,279
Other current liabilities	17,334	16,711
Total current liabilities	817,388	693,060
Long-term liabilities:		
Long-term debt	4,703,973	5,291,973
Deferred income tax liability	950,217	1,100,382
Derivative instruments	234	172
Other liabilities	55,160	53,772
Total liabilities	6,526,972	7,139,359
Commitments and contingencies		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000 shares; issued and outstanding		

314,877 shares and 315,448 shares, respectively	3,149	3,154
Additional paid-in capital	5,299,481	6,435,047
Accumulated earnings	959,995	1,223,259
Total stockholders' equity	6,262,625	7,661,460
Noncontrolling interests in consolidated subsidiary	1,465,953	641,402
Total equity	7,728,578	8,302,862
Total liabilities and equity	$ 14,255,550	15,442,221

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Operations and Comprehensive Loss
Three Months Ended June 30, 2016 and 2017
(unaudited)
(In thousands, except per share amounts)

	Three Months Ended June 30,	
	2016	**2017**
Revenue:		
Natural gas sales	$ 229,787	454,257
Natural gas liquids sales	94,713	170,819
Oil sales	16,740	26,512
Gathering, compression, water handling and treatment	3,294	3,192
Marketing	90,902	49,968
Commodity derivative fair value gains (losses)	(684,634)	85,641
Total revenue	(249,198)	790,389
Operating expenses:		
Lease operating	12,043	16,992
Gathering, compression, processing, and transportation	206,060	266,747
Production and ad valorem taxes	17,458	22,553
Marketing	125,977	77,421
Exploration	1,109	1,804
Impairment of unproved properties	19,944	15,199
Depletion, depreciation, and amortization	197,362	201,182
Accretion of asset retirement obligations	620	649
General and administrative (including equity-based compensation expense of $25,816 and $26,975 in 2016 and 2017, respectively)	60,102	64,099
Total operating expenses	640,675	666,646
Operating income (loss)	(889,873)	123,743
Other income (expenses):		
Equity in earnings of unconsolidated affiliates	484	3,623
Interest	(62,595)	(68,582)
Total other expenses	(62,111)	(64,959)
Income (loss) before income taxes	(951,984)	58,784
Provision for income tax (expense) benefit	376,494	(18,819)
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(575,490)	39,965
Net income and comprehensive income attributable to noncontrolling interests	20,754	45,097
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (596,244)	(5,132)
Loss per common share—basic	$ (2.12)	(0.02)
Loss per common share—assuming dilution	$ (2.12)	(0.02)
Weighted average number of shares outstanding:		
Basic	281,786	315,401
Diluted	281,786	315,401

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)
Six Months Ended June 30, 2016 and 2017
(unaudited)
(In thousands, except per share amounts)

	Six Months Ended June 30,	
	2016	**2017**
Revenue and other:		

Natural gas sales		484,563	920,921
Natural gas liquids sales		167,778	365,471
Oil sales		26,919	53,472
Gathering, compression, water handling and treatment		7,138	5,796
Marketing		190,118	115,892
Commodity derivative fair value gains (losses)		(404,710)	524,416
Total revenue and other		471,806	1,985,968
Operating expenses:			
Lease operating		23,336	32,543
Gathering, compression, processing, and transportation		414,798	533,576
Production and ad valorem taxes		36,742	47,346
Marketing		263,910	167,414
Exploration		2,123	3,911
Impairment of unproved properties		35,470	42,098
Depletion, depreciation, and amortization		388,944	403,911
Accretion of asset retirement obligations		1,218	1,286
General and administrative (including equity-based compensation expense of $49,286 and $52,478 in 2016 and 2017, respectively)		116,389	128,797
Total operating expenses		1,282,930	1,360,882
Operating income (loss)		(811,124)	625,086
Other income (expenses):			
Equity in earnings of unconsolidated affiliates		484	5,854
Interest		(125,879)	(135,252)
Total other expenses		(125,395)	(129,398)
Income (loss) before income taxes		(936,519)	495,688
Provision for income tax (expense) benefit		371,679	(150,165)
Net income (loss) and comprehensive income (loss) including noncontrolling interests		(564,840)	345,523
Net income and comprehensive income attributable to noncontrolling interests		36,459	82,259
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation		(601,299)	263,264
Earnings (loss) per common share—basic	$	(2.15)	0.84
Earnings (loss) per common share—assuming dilution	$	(2.15)	0.83
Weighted average number of shares outstanding:			
Basic		279,418	315,179
Diluted		279,418	315,927

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Cash Flows
Six Months Ended June 30, 2016 and 2017
(unaudited)
(In thousands)

		Six Months Ended June 30,	
		2016	**2017**
Cash flows from operating activities:			
Net income (loss) including noncontrolling interests	$	(564,840)	345,523
Adjustment to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion		390,162	405,197
Impairment of unproved properties		35,470	42,098
Derivative fair value (gains) losses		404,710	(524,416)
Gains on settled derivatives		616,848	75,913
Deferred income tax expense (benefit)		(371,679)	150,165
Equity-based compensation expense		49,286	52,478
Equity in earnings of unconsolidated affiliates		(484)	(5,854)
Distributions of earnings from unconsolidated affiliates		—	5,820
Other		621	472
Changes in current assets and liabilities:			
Accounts receivable		7,798	13,188
Accrued revenue		(5,237)	43,339
Other current assets		1,559	(2,385)
Accounts payable		13,223	2,072
Accrued liabilities		(3,362)	4,204
Revenue distributions payable		5,105	39,162
Other current liabilities		(474)	610
Net cash provided by operating activities			

	578,706	647,586
Cash flows used in investing activities:		
Additions to proved properties	—	(179,318)
Additions to unproved properties	(58,195)	(129,876)
Drilling and completion costs	(709,974)	(629,308)
Additions to water handling and treatment systems	(78,625)	(95,451)
Additions to gathering systems and facilities	(97,300)	(155,365)
Additions to other property and equipment	(1,296)	(6,564)
Investments in unconsolidated affiliates	(45,044)	(191,364)
Change in other assets	(47,925)	(12,452)
Other	—	2,156
Net cash used in investing activities	(1,038,359)	(1,397,542)
Cash flows from financing activities:		
Issuance of common stock	752,599	—
Issuance of common units by Antero Midstream Partners LP	—	246,585
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	178,000	—
Borrowings (repayments) on bank credit facilities, net	(427,000)	585,000
Payments of deferred financing costs	(96)	—
Distributions to noncontrolling interests in consolidated subsidiary	(31,681)	(61,869)
Employee tax withholding for settlement of equity compensation awards	(4,819)	(8,433)
Other	(2,572)	(2,747)
Net cash provided by financing activities	464,431	758,536
Net increase in cash and cash equivalents	4,778	8,580
Cash and cash equivalents, beginning of period	23,473	31,610
Cash and cash equivalents, end of period	$ 28,251	40,190
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ 121,128	125,284
Supplemental disclosure of noncash investing activities:		
Increase (decrease) in accounts payable and accrued liabilities for additions to property and equipment	$ (155,671)	31,182

ANTERO RESOURCES CORPORATION

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

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2017	Amount of Increase (Decrease)	Percent Change
Operating revenues and other:				
Natural gas sales	$ 229,787	$ 454,257	$ 224,470	98%
NGLs sales	94,713	170,819	76,106	80%
Oil sales	16,740	26,512	9,772	58%
Gathering, compression, water handling and treatment	3,294	3,192	(102)	(3)%
Marketing	90,902	49,968	(40,934)	(45)%
Commodity derivative fair value gains (losses)	(684,634)	85,641	770,275	*
Total operating revenues and other	(249,198)	790,389	1,039,587	*
Operating expenses:				
Lease operating	12,043	16,992	4,949	41%
Gathering, compression, processing, and transportation	206,060	266,747	60,687	29%
Production and ad valorem taxes	17,458	22,553	5,095	29%
Marketing	125,977	77,421	(48,556)	(39)%
Exploration	1,109	1,804	695	63%
Impairment of unproved properties	19,944	15,199	(4,745)	(24)%
Depletion, depreciation, and amortization	197,362	201,182	3,820	2%
Accretion of asset retirement obligations	620	649	29	5%
General and administrative (before equity-based compensation)	34,286	37,124	2,838	8%
Equity-based compensation	25,816	26,975	1,159	4%
Total operating expenses	640,675	666,646	25,971	4%
Operating income (loss)	(889,873)	123,743	1,013,616	*
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliate	484	3,623	3,139	649%
Interest expense	(62,595)	(68,582)	(5,987)	10%
Total other expenses	(62,111)	(64,959)	(2,848)	5%

Income (loss) before income taxes	(951,984)	58,784	1,010,768	*
Income tax (expense) benefit	376,494	(18,819)	(395,313)	*
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(575,490)	39,965	615,455	*
Net income and comprehensive income attributable to noncontrolling interest	20,754	45,097	24,343	117%
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (596,244)	$ (5,132)	$ 591,112	(99)%
Adjusted EBITDAX (1)	$ 332,112	$ 320,795	$ (11,317)	(3)%
Production data:				
Natural gas (Bcf)	119	144	25	21%
C2 Ethane (MBbl)	1,581	2,548	967	61%
C3+ NGLs (MBbl)	4,771	6,190	1,419	30%
Oil (MBbl)	477	613	136	29%
Combined (Bcfe)	160	200	40	25%
Daily combined production (MMcfe/d)	1,762	2,200	438	25%
Average prices before effects of derivative settlements:				
Natural gas (per Mcf)	$ 1.93	$ 3.15	$ 1.22	63%
C2 Ethane (per Bbl)	$ 8.36	$ 8.40	$ 0.04	*
C3+ NGLs (per Bbl)	$ 17.08	$ 24.14	$ 7.06	41%
Oil (per Bbl)	$ 35.08	$ 43.24	$ 8.16	23%
Combined (per Mcfe)	$ 2.13	$ 3.26	$ 1.13	53%
Average realized prices after effects of derivative settlements:				
Natural gas (per Mcf)	$ 4.31	$ 3.53	$ (0.78)	(18)%
C2 Ethane (per Bbl)	$ 8.36	$ 8.61	$ 0.25	3%
C3+ NGLs (per Bbl)	$ 18.98	$ 19.92	$ 0.94	5%
Oil (per Bbl)	$ 35.08	$ 46.12	$ 11.04	31%
Combined (per Mcfe)	$ 3.95	$ 3.41	$ (0.54)	(14)%
Average Costs (per Mcfe):				
Lease operating	$ 0.08	$ 0.08	$ —	*
Gathering, compression, processing, and transportation	$ 1.29	$ 1.33	$ 0.04	3%
Production and ad valorem taxes	$ 0.11	$ 0.11	$ —	*
Marketing expense, net	$ 0.22	$ 0.14	$ (0.08)	(36)%
Depletion, depreciation, amortization, and accretion	$ 1.23	$ 1.01	$ (0.22)	(18)%
General and administrative (before equity-based compensation)	$ 0.21	$ 0.19	$ (0.02)	(10)%

(1) *Please see "Non-GAAP Financial Measures" for a description of Adjusted EBITDAX*

**Not meaningful or applicable*

The following tables set forth selected operating data for the six months ended June 30, 2016 compared to the six months ended June 30, 2017:

(in thousands)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2017	Amount of Increase (Decrease)	Percent Change
Operating revenues and other:				
Natural gas sales	$ 484,563	$ 920,921	$ 436,358	90%
NGLs sales	167,778	365,471	197,693	118%
Oil sales	26,919	53,472	26,553	99%
Gathering, compression, water handling and treatment	7,138	5,796	(1,342)	(19)%
Marketing	190,118	115,892	(74,226)	(39)%
Commodity derivative fair value gains (losses)	(404,710)	524,416	929,126	*
Total operating revenues and other	471,806	1,985,968	1,514,162	321%
Operating expenses:				
Lease operating	23,336	32,543	9,207	39%
Gathering, compression, processing, and transportation	414,798	533,576	118,778	29%
Production and ad valorem taxes	36,742	47,346	10,604	29%
Marketing	263,910	167,414	(96,496)	(37)%
Exploration	2,123	3,911	1,788	84%
Impairment of unproved properties	35,470	42,098	6,628	19%
Depletion, depreciation, and amortization	388,944	403,911	14,967	4%
Accretion of asset retirement obligations	1,218	1,286	68	6%
General and administrative (before equity-based				

compensation)	67,103	76,319	9,216	14%
Equity-based compensation	49,286	52,478	3,192	6%
Total operating expenses	1,282,930	1,360,882	77,952	6%
Operating income (loss)	(811,124)	625,086	1,436,210	*
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliates	484	5,854	5,370	1,110%
Interest expense	(125,879)	(135,252)	(9,373)	7%
Total other expenses	(125,395)	(129,398)	(4,003)	3%
Income (loss) before income taxes	(936,519)	495,688	1,432,207	*
Income tax (expense) benefit	371,679	(150,165)	(521,844)	*
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(564,840)	345,523	910,363	*
Net income and comprehensive income attributable to noncontrolling interest	36,459	82,259	45,800	126%
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (601,299)	$ 263,264	$ 864,563	*
Adjusted EBITDAX (1)	$ 687,513	$ 686,087	$ (1,426)	*
Production data:				
Natural gas (Bcf)	242	284	42	17%
C2 Ethane (MBbl)	2,662	4,858	2,196	82%
C3+ NGLs (MBbl)	9,452	12,159	2,707	29%
Oil (MBbl)	949	1,256	307	32%
Combined (Bcfe)	320	393	73	23%
Daily combined production (MMcfe/d)	1,760	2,172	412	23%
Average prices before effects of derivative settlements:				
Natural gas (per Mcf)	$ 2.00	$ 3.25	$ 1.25	63%
C2 Ethane (per Bbl)	$ 7.68	$ 8.21	$ 0.53	7%
C3+ NGLs (per Bbl)	$ 15.59	$ 26.78	$ 11.19	72%
Oil (per Bbl)	$ 28.36	$ 42.58	$ 14.22	50%
Combined (per Mcfe)	$ 2.12	$ 3.41	$ 1.29	61%
Average realized prices after effects of derivative settlements:				
Natural gas (per Mcf)	$ 4.42	$ 3.71	$ (0.71)	(16)%
C2 Ethane (per Bbl)	$ 7.68	$ 8.67	$ 0.99	13%
C3+ NGLs (per Bbl)	$ 18.93	$ 21.92	$ 2.99	16%
Oil (per Bbl)	$ 28.36	$ 44.61	$ 16.25	57%
Combined (per Mcfe)	$ 4.05	$ 3.60	$ (0.45)	(11)%
Average Costs (per Mcfe):				
Lease operating	$ 0.07	$ 0.08	$ 0.01	14%
Gathering, compression, processing, and transportation	$ 1.29	$ 1.36	$ 0.07	5%
Production and ad valorem taxes	$ 0.11	$ 0.12	$ 0.01	9%
Marketing expense, net	$ 0.23	$ 0.13	$ (0.10)	(43)%
Depletion, depreciation, amortization, and accretion	$ 1.22	$ 1.03	$ (0.19)	(16)%
General and administrative (before equity-based compensation)	$ 0.21	$ 0.19	$ (0.02)	(10)%

(1) *Please see "Non-GAAP Financial Measures" for a description of Adjusted EBITDAX*

**Not meaningful or applicable*

Exhibit 99.2

Antero Resources Announces 14% Increase in Estimated Mid-Year 3P Reserves

Denver, CO, August 2, 2017 — Antero Resources (NYSE: AR) ("Antero" or the "Company") today announced estimated reserves as of June 30, 2017.

Highlights:

- **Increased Marcellus wellhead type curves for 199 proved undeveloped and 398 probable locations from 1.7 Bcf/1,000' to approximately 2.0 Bcf/1,000' of lateral**
- **Mid-year 2017 proved reserves increased by 7% to 16.5 Tcfe (41% liquids) from year-end 2016**
- **Pre-tax PV-10 of proved reserves at mid-year 2017 was $10.1 billion at 6/30/2017 strip pricing, including hedges**
- **$0.48 per Mcfe all-in finding and development cost for proved reserve additions for the first half of 2017**
- **3P reserves increased by 14% to 53.0 Tcfe (29% liquids)**
- **Pre-tax PV-10 of 3P reserves at mid-year 2017 was $17.0 billion at 6/30/2017 strip pricing, including hedges**

Antero's estimated proved reserves at June 30, 2017 were 16.5 Tcfe, a 7% increase compared to estimated proved reserves at December 31, 2016. Proved, probable and possible ("3P") reserves at mid-year 2017 totaled 53.0 Tcfe, which represents a 14% increase compared to year-end 2016. Proved and probable reserves comprise over 96% of the total 3P reserves.

Drill bit only finding and development cost, including revisions, was $0.47 per Mcfe for the first half of 2017. All-in finding and development cost for estimated proved reserve additions was $0.48 per Mcfe for mid-year 2017.

Paul Rady, Chairman and CEO, commented, "After announcing encouraging initial results for advanced completions in the Marcellus over the past year, our reserve engineers had the production history necessary to upgrade the type curve on almost 600 proved and probable undrilled locations from 1.7 previously to approximately 2.0 Bcf per 1,000' of lateral at mid-year 2017. Once processed, these rich gas locations deliver gas equivalent reserves of approximately 2.6 Bcfe per 1,000' of lateral assuming ethane rejection. As we expand our advanced completion footprint, we anticipate revising the type curve for a significant portion of our approximate 2,400 undeveloped locations that are still booked at 1.7 Bcf per 1,000' of lateral."

Antero's reserves at June 30, 2017 were prepared by the Company's internal reserve engineers and have not been reviewed or audited by its independent reserve engineers.

Estimated Proved Reserves

As of June 30, 2017, the Company's 16.5 Tcfe of estimated proved reserves were comprised of 59% natural gas, 40% NGLs and 1% oil. The Marcellus Shale accounted for 88% of estimated proved reserves and the Ohio Utica Shale accounted for 12%. For the first half of 2017, Antero added 1.3 Tcfe of estimated proved reserves through the drill bit, which is reflective of the continued productivity gains from the use of advanced completion techniques and longer laterals.

Included in the mid-year 2017 reserves are 294 proved undeveloped locations, or 83% of the total proved undeveloped locations in the Marcellus, booked at an approximate 2.0 Bcf/1,000' type curve. This includes an increase of 199 proved undeveloped locations that were previously booked at a 1.7 Bcf/1,000' type curve at year-end 2016 that have now been upgraded to an approximate 2.0 Bcf/1,000' type curve. The remaining 60 Marcellus proved undeveloped locations are booked at a 1.7 Bcf/1,000' type curve and are generally outside of areas where advanced completions have been applied.

Approximately 29% of Antero's combined 636,000 net acre leasehold position was classified as proved at June 30, 2017 which was in line with year-end 2016. Based on Antero's successful drilling results to date, as well as those of other operators in the vicinity of Antero's leasehold position, the Company believes that a substantial portion of its Marcellus and Ohio Utica Shale undeveloped acreage will be classified as proved over time as more wells are drilled. Virtually no West Virginia Upper Devonian or Utica locations were classified as 3P reserves at June 30, 2017, with the exception of four proved developed producing Upper Devonian locations and one proved developed producing Utica location, due to the early stage of drilling and production in the play.

Estimated proved developed reserves increased by 20% from year-end 2016 to 8.3 Tcfe at June 30, 2017. The Company added 76 Marcellus and 25 Ohio Utica wells to estimated proved developed reserves in the first half of 2017. The percentage of estimated proved reserves classified as proved developed increased to 50% at June 30, 2017 from 45% at year-end 2016. The average heating content of the Marcellus and Utica proved undeveloped locations is 1250 BTU and 1235 BTU, respectively, and the average lateral length is approximately 9,100 feet per location.

Under the Securities and Exchange Commission ("SEC") reporting rules, proved undeveloped reserves are limited to reserves that are planned to be developed within five years of initial booking. The Company reclassified 888 Bcfe of proved undeveloped reserves to the probable category in the first half of 2017 to comply with the SEC five-year development rule. The proved undeveloped locations were reclassified primarily as a result of fewer wells being needed to meet production growth targets due to the enhanced productivity from advanced completions. Antero's 8.2 Tcfe of estimated proved undeveloped reserves will require an estimated $3.3 billion of future development capital over the next five years, resulting in an estimated average future development cost for proved undeveloped reserves of $0.40 per Mcfe. The future development capital is based on a combination of current contracted rates and spot market rates based on today's market pricing.

Antero incurred estimated capital costs of approximately $939 million during the first half of 2017, including drilling and completion costs of $629 million, proved property acquisitions of $179 million and leasehold additions of $130 million. Assuming the $939 million of capital costs, mid-year 2017 all-in finding and development cost for proved reserve additions from all sources, including revisions, was $0.48 per Mcfe.

Summary of Changes in Estimated Proved Reserves (in Bcfe)	
Balance at December 31, 2016	**15,386**
Extensions, discoveries and additions	479
Purchases of estimated proved reserves	620
Revisions(1)	857
Partial ethane recovery	453
Reclassification to probable due to SEC 5-year development rule	(888)
Production	(393)
Balance at June 30, 2017	**16,514**

(1) Revisions include 742 Bcfe of performance revisions as a result of the Company's advanced completions program and 115 Bcfe of price revisions.

Costs Incurred ($ Millions)		
Proved leasehold acquisitions:	$	179
Leasehold additions		130
Drilling and completion		629
Total costs incurred	**$**	**939**

Finding and Development Costs ($/ Mcfe)		
All-in F&D cost for proved reserve additions(1)	$	0.48
Drill bit only F&D cost(2)	$	0.47

(1) Total costs incurred divided by the summation of 479 Bcfe for extensions, discoveries and additions, 620 Bcfe for purchases and 857 Bcfe for revisions.
(2) Drilling and completion costs divided by the summation of 479 Bcfe for extensions, discoveries and additions and 857 Bcfe for revisions.

The table below summarizes both SEC and strip pricing as of June 30, 2017 and the associated PV-10 for estimated proved reserves and hedge values:

	2017 Mid-Year						
		SEC Pricing		Strip Pricing(1)		Variance	% Variance
Benchmark Pricing:							
WTI Oil Price ($/Bbl)	$	48.85	$	52.06	$	3.21	7%
Appalachian Oil Price ($/Bbl)(2)	$	43.33	$	48.05	$	4.72	11%
Nymex Natural Gas Price ($/MMBtu)	$	3.07	$	3.00	$	(0.07)	(2)%
Appalachian Natural Gas Price ($/MMBtu) (2)	$	2.88	$	2.74	$	(0.14)	(5)%
C3+ Natural Gas Liquids ($/Bbl)	$	26.68	$	30.84	$	4.14	16%
C2+ Natural Gas Liquids ($/Bbl)(3)	$	16.40	$	18.77	$	2.37	14%
Pre-Tax PV-10 Values ($ Billions):							
Estimated proved reserves PV-10	$	8.0	$	8.4	$	0.4	5%
Hedge PV-10 (4)		1.3		1.7		0.4	31%
Total PV-10	$	9.3	$	10.1	$	0.8	9%

(1) Strip pricing as of June 30, 2017 for each of the first ten years and flat thereafter.
(2) Represents SEC and strip prices as of June 30, 2017 on a weighted average Appalachian index basis related to company-specific sales points.
(3) Represents realized NGL price including regional market differentials.

(4) Hedge PV-10 at strip pricing differs from mid-year 2017 mark-to-market value of $2.0 billion due to the application of a higher discount rate.

Assuming SEC prices, the pre-tax present value discounted at 10% ("pre-tax PV-10") of the June 30, 2017 estimated proved reserves was $8.0 billion, a 117% increase from year-end 2016. Including Antero's hedges as of June 30, 2017 and assuming SEC prices, the pre-tax PV-10 value of estimated proved reserves was $9.3 billion, which represents a 39% increase from year-end 2016 pre-tax PV-10 values. The GAAP standardized measure is based on SEC pricing, after tax, and does not include hedge values. For further discussion on pre-tax PV-10 values, please read "Non-GAAP Disclosure."

Assuming future strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing as of June 30, 2017, the pre-tax PV-10 value of the same mid-year 2017 estimated proved reserves was $8.4 billion. This represents a 5% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 value of estimated proved reserves was $10.1 billion assuming strip pricing, a 3% increase compared to year-end 2016.

Assuming SEC prices, the pre-tax PV-10 of the June 30, 2017 estimated proved developed reserves was $5.4 billion, which represents an 86% increase compared to year-end 2016.

Assuming future strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing as of June 30, 2017, the pre-tax PV-10 value of the estimated proved developed reserves was $5.5 billion, a 2% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges, and an 8% increase compared to year-end 2016.

Proved, Probable and Possible Reserves

Antero estimates that it had mid-year 2017 3P reserves of 53.0 Tcfe, a 14% increase from year-end 2016. The 14% increase in 3P reserves was driven by a combination of increased type curves in certain areas driven by continued productivity gains from advanced completions, first-half 2017 leasehold acquisitions and an increase in ethane recovery. Approximately 69 million and 954 million barrels of ethane are accounted for as natural gas rather than liquids in proved and 3P reserves as of June 30, 2017, respectively, as this ethane is assumed to remain in the natural gas stream until such time as pricing supports full ethane recovery. As of June 30, 2017, the Company's 53.0 Tcfe of 3P reserves were comprised of 71% natural gas, 28% NGLs and 1% oil. The Marcellus and Ohio Utica Shale comprised 45.7 Tcfe and 7.3 Tcfe of the 3P reserves, respectively.

Importantly, 44.0 Tcfe of Antero's 45.7 Tcfe, or 96% of estimated 3P reserves in the Marcellus were classified as proved and probable reserves ("2P"), reflecting the low risk and statistically repeatable nature of Antero's Marcellus drilling. The 44.0 Tcfe of 2P reserves includes 398 probable locations that were increased from the 1.7 Bcf/1,000' type curve to the approximate 2.0 Bcf/1,000' type curve. Further, 6.9 Tcfe of Antero's 7.2 Tcfe, or 96% of estimated 3P reserves in the Ohio Utica were classified as 2P.

The tables below summarize Antero's estimated 3P reserve volumes as of June 30, 2017 using SEC pricing, categorized by operating area as well as PV-10 values of Antero's 3P reserve volumes using both SEC and strip pricing:

	Marcellus Shale				Ohio Utica Shale			
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations
Proved	8,219	1,065	14,609	972	1,518	65	1,905	264
Probable	21,673	1,289	29,408	2,795	4,387	94	4,950	608
Possible	1,390	56	1,727	222	316	6	353	59
Total 3P	**31,282**	**2,410**	**45,744**	**3,989**	**6,221**	**165**	**7,208**	**931**
% Liquids(1)			32%				14%	

	Combined 3P Reserves			
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations
Proved(2)	9,737	1,130	16,514	1,236
Probable	26,059	1,383	34,358	3,403
Possible	1,706	62	2,080	281
Total 3P	**37,502**	**2,575**	**52,952**	**4,920**
% Liquids(1)			29%	

(1) Represents liquids volumes as a percentage of total volumes. Combined liquids comprised of 1,170 million barrels of ethane, 1,279 million barrels of C3+ NGLs and 126 million barrels of oil.
(2) 437 of the 1,236 proved locations were undeveloped locations.

	SEC Pricing	Strip Pricing(1)	Variance	% Variance
Pre-Tax 3P PV-10 Values ($ Billion):				
3P Reserves PV-10	$ 13.3	$ 15.3	$ 2.0	15%
Hedge PV-10 (2)	1.3	1.7	0.4	31%
Total PV-10	$ 14.6	$ 17.0	$ 2.4	16%

(1) Strip pricing as of June 30, 2017 for each of the first ten years and flat thereafter.
(2) Hedge PV-10 at strip pricing differs from mid-year 2017 mark-to-market value of $2.0 billion due to the application of a higher discount rate.

Assuming SEC prices, the pre-tax PV-10 of the June 30, 2017 3P reserves was $13.3 billion before hedges and $14.6 billion including hedges. Assuming mid-year 2017 future strip pricing, with adjustments similar to SEC pricing, the pre-tax PV-10 of the same year-end 2016 3P reserves was $15.3 billion which represents a 15% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 value of estimated 3P reserves was $17.0 billion assuming strip pricing, a 2% increase compared to year-end 2016. For further discussion on pre-tax PV-10 values, please read "Non-GAAP Disclosure."

Non-GAAP Disclosure

Certain selected financial information in this release is unaudited. Additional unaudited financial information will be provided in Antero's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, which the Company intends to file with the SEC on August 2, 2017. In this release, Antero has provided a number of unaudited metrics, which include all-in finding and development cost per unit and drill bit only finding and development cost per unit. These non-GAAP metrics are commonly used in the exploration and production industry by companies, investors and analysts in order to measure a company's ability of adding and developing reserves at a reasonable cost. The finding and development costs per unit are statistical indicators that have limitations, including their predictive and comparative value. In addition, because the finding and development costs per unit do not consider the cost or timing of future production of new reserves, such measures may not be adequate measures of value creation. These reserve metrics may not be comparable to similarly titled measurements used by other companies.

Calculations for all-in and drill bit only finding and development cost per unit are based on estimated and unaudited costs incurred in the first half of 2017 and can be found in the footnotes to the table on page two of this release. The calculations for both all-in and drill bit only finding and development cost per unit do not include future development costs required for the development of proved undeveloped reserves.

Pre-tax PV-10 values and pre-tax PV-10 values including hedges are non-GAAP financial measures as defined by the SEC. Antero believes that the presentation of these pre-tax PV-10 values are relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves and hedges prior to taking into account corporate future income taxes and the Company's current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves and hedges as compared with other companies. Antero believes that PV-10 estimates using strip pricing and including hedges can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows in the current commodity price environment. PV–10 estimates using strip pricing are not adjusted for the likelihood that the pricing scenario will occur, and thus they may not be comparable to PV-10 value using SEC pricing.

The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows ("Standardized Measure"). With respect to PV-10 calculated as of an interim date, it is not practical to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

Notwithstanding their use for comparative purposes, the Company's non-GAAP financial measures may not be comparable to similarly titled measure employed by other companies.

Antero Resources is an independent natural gas and oil company engaged in the acquisition, development and production of unconventional liquids-rich natural gas properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. The Company's website is located at www.anteroresources.com.

Cautionary Statements

This release includes "forward-looking statements". Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond Antero's control. All statements, except for statements of historical fact, made in this release regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future development costs, future capital spending plans, expected drilling and development plans, plans with respect to the rejection of ethane and the prices we will receive for future production as well as future production volumes are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All forward-looking statements speak only as of the date of this release. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

Antero cautions 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 the Company's 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 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 Antero's Annual Report on Form 10-K for the year ended December 31, 2016 and any subsequently filed Quarterly Report on Form 10-Q.

The SEC permits oil and gas companies to disclose probable and possible reserves in their filings with the SEC. Antero does not plan to *include probable and possible reserve estimates in its filings with the SEC. Antero has provided internally generated estimates that have not been audited by its third party reserve engineer in this release. Antero's estimate of proved, probable and possible reserves is provided in this release because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, the Company notes that the SEC prohibits companies from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.*

This release provides a summary of Antero's reserves as of June 30, 2017, assuming partial ethane "rejection" where sales demand for ethane is not available. Ethane rejection occurs when ethane is left in the wellhead natural gas stream when the natural gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the Btu content of the residue natural gas at the outlet of the processing plant is higher. Producers will generally elect to "reject" ethane at the processing plant when the price received for the ethane in the natural gas stream is greater than the price received for the ethane being sold as a liquid after fractionation, net of fractionation costs. When ethane is recovered in the processing plant, the Btu content of the residue natural gas is lower, but a producer is then able to recover the value of the ethane sold as a separate natural gas liquid product. In addition, natural gas processing plants can produce the other NGL products (propane, normal butane, isobutene and natural gasoline) while rejecting ethane.

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