This presentation includes "forward-looking statements." Such forward-looking statements are subject to a number of risks and uncertainties, many of which are not under AR's control. All statements, except for statements of historical fact, made in this presentation regarding activities, events or developments Antero expects, believes or anticipates will or may occur in the future, such as those regarding expected results, future commodity prices, future production targets, completion of natural gas or natural gas liquids transportation projects, future earnings, Adjusted EBITDAX leverage targets, future capital spending plans, improved and/or increasing capital efficiency, continued utilization of existing infrastructure, gas marketability, estimated realized natural gas, natural gas liquids and oil prices, acreage quality, access to multiple gas markets, expected drilling and development plans (including the number, type, lateral length and location of wells to be drilled, the number and type of drilling rigs and the number of wells per pad), projected well costs and cost savings initiatives, including with respect to potential incremental flowback and produced water services by AM, future financial position, the amount and timing of any litigation settlements or awards, future technical improvements, future marketing and asset monetization opportunities, and the amount and timing of any contingent payments 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 presentation. Although AR 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. Except as required by law, AR expressly disclaims any obligation to and does not intend to publicly update or revise any forward-looking statements.

AR cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil, most of which are difficult to predict and many of which are beyond AR's control. 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, impacts of world health events, including the COVID-19 pandemic, potential shut-ins of production due to lack of downstream demand or storage capacity, and the other risks described under the heading "Item 1A. Risk Factors" in AR's Annual Report on Form 10-K for the year ended December 31, 2019 and its Quarterly Report on Form 10-Q for the quarter ended March 31, 2020.

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). These measures include (i) Adjusted EBITDAX, (ii) Net Debt, (iii) F&D cost, (iv) leverage and (v) Free Cash Flow. Please see "Antero Non-GAAP Measures" for the definition of each of these measures as well as certain additional information regarding these measures, including the most comparable financial measures calculated in accordance with GAAP.
Antero Resources Executive Summary

- Natural Gas & NGL Macro
- Detailed Asset Overview
- Appendix
Antero Family at a Glance

- Exploration & Production
- Gathering & Compression
- Natural Gas Processing
- C3+ NGL Fractionation
- Water Delivery & Blending
Antero Resources at a Glance

Denver, CO
HEADQUARTERS

S&P 400
CONSTITUENT

5th Largest
U.S. GAS PRODUCER\(^{(1)}\)

2nd Largest
U.S. NGL PRODUCER\(^{(1)}\)

Own 40%
OF CORE LIQUIDS-RICH DRILLING LOCATIONS IN APPALACHIA\(^{(2)}\)

1,200
ADDITIONAL DRY GAS LOCATIONS IN DRILLING INVENTORY\(^{(2)}\)

~98% Hedged
ON NATURAL GAS THROUGH 2021
@ $2.83/MMBtu \(^{(3)}\)

100% Hedged
ON OIL AND PENTANES THROUGH 2020 @ $55.63/Bbl \(^{(4)}\)

Note: Hedge position as of 5/29/20. Rigs on map as of 6/5/20, per Rig data.
1) NGLs based on 2020E consensus as of 6/1/20. Natural gas based on 1Q20 reported production.
3) Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.310 Bcf/d in 2020 and flat production in 2021. Percentage of oil and pentanes hedges represents percent of expected oil and pentane production based on 2020 guidance.
On 6/12/2020 Antero Announced Closing of ORRI Transaction With Sixth Street Partners

- Antero has entered into an overriding royalty interest (ORRI) transaction with Sixth Street for proceeds of $402 MM (including up to $102 MM of contingent consideration)
- ORRI includes a 1.25% ORRI in wells producing as of 4/1/2020 and a 3.75% ORRI in existing undeveloped acreage that is developed over the next three years; no ORRI on wells completed after 3/31/2023 (1)
- Following a 13% IRR and a 1.5x cash-on-cash return to Sixth Street, Antero will have an 85% reversionary interest in the ORRI and Sixth Street’s interest will drop to 15%
- On a weighted average basis, the applicable overrides equate to an approximately 1.0% to 1.5% ORRI across Antero’s entire asset base on a perpetual basis (based on an acreage, reserve and present value analysis)

Proceeds

- $300 MM cash received at closing plus up to $102 MM of future payments over the next twelve months
  - $102 MM consists of two contingent payments of up to $51 MM each based on volume thresholds relating to expected cumulative production net to the ORRI through 9/30/2020 and 3/31/2021

Liquidity and Debt Maturities (6/12/2020)

- Antero has also repurchased $196 MM notional amount of its senior notes so far in 2Q 2020 at an aggregate price of $163 MM, reducing absolute debt by ~$33 MM ($540 MM of 2021 notes remain outstanding)
- Antero’s $2.85 B borrowing base or $2.64 B of lender commitments remain unchanged following the ORRI transaction
- Pro forma for the ORRI sale and the additional debt repurchases, Antero currently has $1.2 B of liquidity (2)

1) Assuming AR’s current 3-year development plan and strip pricing as of 5/29/2020.
2) Liquidity represents borrowing availability under AR’s credit facility based on $2.64 B of lender commitments, $730 MM of letters of credit and $882 MM of borrowings as of 03/31/2020. Pro forma for $300 MM in initial proceeds from ORRI sale and $163 MM in senior notes repurchases.
Pro Forma Liquidity and Use of ORRI Proceeds

With the close of the ORRI transaction, Antero Resources will have substantial capacity to address its November 2021 bond maturity.

AR Pro Forma 3/31/20 Liquidity Relative to Remaining 2021 Bond Maturity ($MM)

- 3/31/2020 Liquidity: $1,028
- 2Q 2020 Debt Repurchases: $163
- ORRI Initial Proceeds: $300 (Closed on 6/12/20)
- Pro Forma 3/31/20 Liquidity: $1,165
- Remaining 2021 Senior Notes: $540

Note: Liquidity represents borrowing availability under AR’s credit facility based on $2.64 B of lender commitments, $730 MM of letters of credit and $882 MM of borrowings as of 03/31/2020. Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.

1) $300 MM in ORRI proceeds excludes $51 MM contingent payment expected in 3Q 2020 and $51 MM contingent payment expected in 1Q 2021.
2) Market value based on bond pricing as of 6/12/2020 of $88.50 for the senior notes due in 2021.
Antero Resources Snapshot

Lowered 2020 Capital Budget to $750 MM
- Revised D&C capital budget of $750 MM in 2020, a 35% decrease from initial 2020 guidance and a 41% decrease from 2019 spending
- Revised 2020 production growth guidance of 7%, to reflect volumes net of the ORRI transaction, while forecasting ~$190 MM of Free Cash Flow

Completed Over 50% of 2020 Asset Sale Objective
- $502 MM of $750 MM to $1 B asset sale objective achieved
  - $402 MM ORRI transaction closed in June 2020
  - $100 MM AM share sale in December 2019
- More asset sales planned

Reduced Cost Structure
- 26% well cost reduction to $715/lateral foot in 2020 through efficiency improvements, water initiatives and service cost deflation
- Total of ~$602 MM in expected capital and operating cost savings expected in 2020 relative to 2019 initial budget

Repurchased Bonds at a Steep Discount
- Bought back ~$460 MM and $344 MM of 2021 and 2022 bonds, respectively, at a 19% weighted discount
  - Eliminated ~$153 MM of debt
- Borrowing base reset at $2.85 B in April 2020 with $2.64 B of lender commitments unchanged

Note: See appendix for more information regarding certain underlying assumptions.
1) Based on strip pricing as of 5/29/2020. See appendix for Free Cash Flow definition.
2) As of 6/12/2020.
Energy Industry Realities

Commodity prices are cyclical

Energy is a capital intensive business

Long-term planning & execution are critical

Commodity Price Risk

✓ AR is ~98% hedged on natural gas through 2021 at prices 20% above current strip pricing (1)
✓ AR firm transport substantially reduces basis risk
✓ Drive leverage lower & improve financial flexibility

Capital Intensity

✓ Develop highest rate of return locations across asset portfolio while living within cash flow
✓ Ongoing capital efficiency initiatives drive down capital and operating costs and improve capital efficiency

Planning & Execution

✓ Integrated upstream and midstream planning process to generate synergies, maximize utilization and minimize operational downtime
✓ Stress test commodity prices and evaluate multiple development plan scenarios
✓ Base compensation on plan execution and ESG performance

Leading Sustainability and ESG Metrics

**GHG Emissions**
- Antero has **zero flaring** of produced gas, one of the **lowest GHG intensity metrics** in the industry (upstream independents and majors) and a very low methane leak loss rate:

**Total Direct GHG Emissions and Intensity (CO₂e)**

<table>
<thead>
<tr>
<th>Year</th>
<th>CO₂e Tons</th>
<th>Tons/MBOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>469</td>
<td>3.5</td>
</tr>
<tr>
<td>2018</td>
<td>428</td>
<td>2.7</td>
</tr>
<tr>
<td>2019</td>
<td>422</td>
<td>2.3</td>
</tr>
</tbody>
</table>

*34% decrease*

**Methane Leak Loss Rate**

<table>
<thead>
<tr>
<th>Target</th>
<th>Intensity</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>OF Industry Target 2025</td>
<td>0.10%</td>
<td>AR 2019</td>
</tr>
<tr>
<td>Upstream Sector Target</td>
<td>0.28%</td>
<td>AR 2018 OF Upstream Sector Avg.</td>
</tr>
<tr>
<td>AR 2019</td>
<td>0.05%</td>
<td>Upstream Sector Avg.</td>
</tr>
</tbody>
</table>

**2019 Antero vs 2018 Industry GHG Emission Intensity(1)**

*For more information, please visit: [https://www.anteroresources.com/community-sustainability](https://www.anteroresources.com/community-sustainability)*

*OF stands for ONE Future*

Source: Data retrieved from 2018 and 2019 sustainability reports or calculated from 2018 sustainability and public disclosures. Antero Resources’ intensity is based on the total GHG emissions reported to the EPA under Subpart W of the Greenhouse Gas Reporting Rule Program (GHGRP). Previous years have been updated as of 4/2020.

*Company’s GHG intensity includes their midstream and/or downstream operations.

1) Comparisons for independents and majors who report include: BP, CHK, CNX, COP, CVX, DVN, ENI, EOG, EQR, FANG, HES, MPC, NBL, RRC, RDS, SWN and XEC.

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**Water Management**
- Fresh water pipeline network **eliminated 570,000 water truck trips** in 2019
- AR **recycles and reuses over 90%** of flowback and produced water (~50,000 Bbl/d currently)

**Safety**
- **Lost Time Incident Rate** in 2019 **outperformed** the industry benchmark by **160%**
- **Total Recordable Incident Rate** in 2019 **outperformed** the industry benchmark by **88%**

**Governance**
- Have established **ESG Committee** on AR and AM Boards for ESG oversight
- Both AR and AM are **C-corps** and have a **majority** of independent directors
- **Management compensation** is tied to Free Cash Flow (AR), ROIC (AM) and safety and environmental performance metrics
Natural Gas and NGL Macro Momentum

- Natural gas and NGL prices should strengthen over the coming quarters as global demand remains resilient while supply declines materially (assuming current oil price strip)
  - For oil and the resulting transportation fuels, some of the demand destruction from the pandemic may be permanent while supply is abundant

### U.S. Natural Gas

**Supply**
- Near-term potential 6 to 7 Bcf/d decrease due to oil shut-ins and natural gas well shut-ins
- Longer-term 5.5 Bcf/d reduction by YE 2020 and 8.5 Bcf/d aggregate reduction by YE 2021 due to decline in associated gas (Permian, Eagle Ford, SCOOP/STACK)
- Flat production from gas producers who will stick to capital discipline

**Demand**
- Near and medium-term 3 to 4 Bcf/d decline due to pandemic
- 3 to 4 Bcf/d reduction in LNG exports over summer of 2020 due to cargo cancellations

### U.S. NGLs

**Supply**
- U.S. NGL production is projected to decline by ~400 MBbl/d through 2022, driven by reduced drilling activity in shale oil basins
- International NGL production “associated” with OPEC oil production decreasing due to OPEC+ supply cut
- Lower global refinery utilization results in a decline in NGL supply as a byproduct of refining

**Demand**
- Resilient domestic and international demand from petrochem and residential/commercial sectors
- Rising living standards in developing countries, particularly in Asia, create an inelastic demand pull for LPG and NGL derivative products
- Asian economies have recovered from Covid-19 pandemic and Chinese tariffs on LPG were lifted in early 2020

### Outlook for Natural Gas
- Significant U.S. associated gas production decline both medium and long-term with limited medium-term demand destruction

### Outlook for NGLs
- The impact of a decline in shale oil activity on “associated NGL” production is expected to be even more pronounced than the impact on associated gas production while global NGL demand remains stable
- Increasing U.S. export capacity expected to tighten Mont Belvieu pricing to international pricing

Sources: April EIA Short Term Energy Outlook and S&P Global Platts estimates. LPG is comprised of NGL components propane and butane.
Significant Reduction in Drilling Rigs

- Since March 6th, the total U.S. rig count has declined by 502 rigs, or ~66%
  - NGL production “associated” with shale oil activity represents 66% of total U.S. NGL production and is expected to decline due to the recent collapse in oil prices and rig count

<table>
<thead>
<tr>
<th>Oil Focused</th>
<th>3/6/2020</th>
<th>6/12/2020</th>
<th>Change Since 3/6/20</th>
<th>Current Dry Gas Production</th>
<th>Current NGL Production</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rigs</td>
<td>%</td>
<td>Bcf/d (1)</td>
<td>MBbls/d (2)</td>
<td></td>
</tr>
<tr>
<td>Permian</td>
<td>429</td>
<td>150</td>
<td>(279) (65%)</td>
<td>10.7</td>
<td>1,618</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>79</td>
<td>11</td>
<td>(68) (86%)</td>
<td>4.4</td>
<td>598</td>
</tr>
<tr>
<td>Bakken</td>
<td>52</td>
<td>10</td>
<td>(42) (81%)</td>
<td>1.5</td>
<td>401</td>
</tr>
<tr>
<td>SCOOP/STACK</td>
<td>41</td>
<td>9</td>
<td>(32) (78%)</td>
<td>3.2</td>
<td>337</td>
</tr>
<tr>
<td>DJ Niobrara</td>
<td>28</td>
<td>8</td>
<td>(20) (71%)</td>
<td>2.1</td>
<td>431</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>629</strong></td>
<td><strong>188</strong></td>
<td><strong>(441) (70%)</strong></td>
<td><strong>22.0</strong></td>
<td><strong>3,386</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rigs</td>
<td>%</td>
<td>Bcf/d (1)</td>
<td>MBbls/d (2)</td>
<td></td>
</tr>
<tr>
<td>Marcellus</td>
<td>32</td>
<td>25</td>
<td>(7) (22%)</td>
<td>25.1</td>
<td>826</td>
</tr>
<tr>
<td>Haynesville</td>
<td>41</td>
<td>32</td>
<td>(9) (22%)</td>
<td>12.4</td>
<td>48</td>
</tr>
<tr>
<td>Utica</td>
<td>14</td>
<td>11</td>
<td>(3) -21%</td>
<td>6.0</td>
<td>145</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>87</strong></td>
<td><strong>68</strong></td>
<td><strong>(19) (22%)</strong></td>
<td><strong>43.5</strong></td>
<td><strong>1,019</strong></td>
</tr>
</tbody>
</table>

| Other                   | 50       | 8         | (42) (84%)          | 21.5                      | 762                   |
| **Total U.S.**          | **766**  | **264**   | **(502) (66%)**     | **86.9**                  | **5,167**             |

Source: Baker Hughes and S&P Global Platts.

2) NGL production per Platts monthly average C2+ NGL estimate for May 2020 as of 6/5/2020. Assumes ~2.7 MMBbl/d of ethane, or 46% of total C2+ NGL forecast.
Since March 6th, U.S. completion crew count has declined by 244 crews, or 77%
Material Impact to NGL Production in the U.S.

The oil price decline is expected to have an even more pronounced impact on NGL supply where two-thirds of the supply comes from shale oil plays.

U.S. NGL Production Forecast (MBbl/d)

Note: Represents Platts Analytics data as of June 1, 2020.

LPG Export Capacity

Gulf Coast export capacity is now plentiful, which should tighten Mont Belvieu LPG pricing to international pricing.

Note: Represents Platts Analytics data as of June 1, 2020.
Domestic and international LPG prices are improving on a relative basis to crude oil, driven by inelastic global demand from petrochemicals and res/comm.

**Mont Belvieu C3+ NGL Prices & % of WTI (1)**

- Historical % of WTI Avg: ~60%
- C3+ Price as % of WTI: 95%
- MB C3+ NGL ($/Bbl)

**FEI Propane Prices & % of Brent**

- FEI Propane Price as % of Brent: 81%
- FEI Propane ($/Bbl)

Source: ICE data Mont Belvieu strip pricing as of 5/29/2020

1) Based on Antero C3+ NGL component barrel consists of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+).
The Impact of the U.S. Shale Revolution

The Shale Revolution dramatically changed the NGL landscape, turning the U.S. into a **net exporter** after decades of **importing** NGL products.

### U.S. NGL Production (MBbl/d) (1)

- **Driven primarily by shale oil development with high oil prices**
- **144% from 2010-2020**

### U.S. NGL Exports / (Imports) (MBbl/d)

- **Net exporter of NGLs**

---

1) Includes recovered ethane volumes and natural gasoline (CS).
US exports surpassed the entire Middle East region combined in 2019

LPG Exports: US versus Middle East

US is the incremental supplier for growing world demand.

Supply from Middle East nations flat, OPEC policies limit growth potential

Source: Platts.
Notes: Propane and Butane exports only based on cFlow ship tracking data. US Exports do not include exports via land to Canada and Mexico. 2020 represents year-to-date data through March 1, 2020.
Future U.S. NGL Supply Challenged by Oil Price Decline

- U.S. shale plays were previously forecast (December 2019) to grow C3+ NGL supply through 2022 by almost 500,000 Bbl/d
- Now, with a $35 to $45/Bbl oil strip, U.S. C3+ NGL supply is expected to decline by 416,000 Bbl/d through 2022

Note: Bubbles reflect growth over the next three years (2019-2022). Supply includes field production, but excludes imports and refinery production. Source: U.S. Energy Information Administration and S&P Global Platts, as of 12/31/2019 and 6/5/20, respectively. Volumes have been adjusted by Antero to remove ethane.
Antero Resources Executive Summary

Natural Gas & NGL Macro

Detailed Asset Overview

Appendix
AR Business Strategy

Antero Resources Principles

Build Scale with Natural Gas & Liquids Diversification

Maintain Strong Balance Sheet and Financial Flexibility

Mitigate Commodity Price Risk With Hedges and Firm Transportation

Priorities

1. Balance cash flow with capital spending
2. Maintain liquidity & strengthen balance sheet with leverage target of mid 2-times
3. Develop highest rate of return locations across asset portfolio
4. Hedge commodities to protect cash flow and balance sheet

Denotes management & employee compensation plan metrics

Note: Leverage is a non-GAAP financial measure. Please see the appendix for more information.
Drilling and completion efficiencies and midstream cost savings result in approximately $602 million of savings in 2020 compared to AR’s 2019 initial budget.

**Cost Savings Update**

**Well Cost Reduction Progress**

- $750 MM revised D&C capital budget for 2020, a ~$400 MM reduction from the initial budget and 41% below 2019, with no change to production guidance.
- D&C of $715/lateral foot, a 26% reduction from $970/ft at the beginning of 2019.

**Water Savings Driving LOE Lower**

- 1Q20 represented a 33% reduction from 2019.
- Expect to save $90 MM in 2020 as a result of increased blending operations combined with reduced trucking costs.

**GP&T and Net Marketing Expense Reduction**

- $68 MM of midstream fee reductions in 2020 with Antero Midstream and other third party midstream providers.
- Targeting $100 MM reduction in 2020 net marketing expense (1).

**G&A Cost Reduction**

- 18% reduction by mid-2020 due to headcount reductions in 2019, natural employee attrition and a reduction across the board in expenses.

**2020 Savings (1)**

- $320 MM
  - (($970/ft - $715/ft) x 12,000’) = $3.05 MM
  - $3.05 MM per well x 105 wells = $320 MM

- $90 MM
  - ~54% reduction from 2019

- $168 MM

- $24 MM

**Grand Total Cost Reset for 2020**

= ~$602 MM

*Note: Cost reductions are based on updated 2020 guidance vs original 2019 guidance.*

1) Based on midpoint updated 2020 guidance.
Through drilling and completion efficiencies, midstream cost savings, service cost deflation and deferral of completions Antero has reduced its D&C capex budget by 41% year-over-year.

### Antero D&C Capex ($MM)

- **2018 Actual**: $1,490
- **2019 Actual**: $1,270
- **Original Budget (Feb 2020)**: $1,150
- **Revised Budget (Mar 2020)**: $1,000
- **Current Budget (Apr 2020)**: $750
- **2021 Maintenance Capital**: $600
- **Well Completions**: 63
- **D&C Capital**: 163
- **Maintenance Capital**: 131
- **Well Completions**: 125
- **Well Completions**: 125
- **Well Completions**: 105

1) Assumes $715/ft well cost and 12,000 laterals.
Maintenance Capital Calculation

- The average AR rich Marcellus well produces 3.27 Bcfe net in the calendar year when brought online mid-year
- Assume new wells average ½ year of production

Production can be held flat with ~63 wells

\[
\frac{205 \text{ Bcfe}}{3.27 \text{ Bcfe per well}} = 62.6 \text{ wells}
\]

Maintenance D&C Capital

63 wells $9.3 MM per well = $586 MM

Field and Operating Capital

- Roads
- Working interest optimization
- Pad construction costs

Maintenance Field Capital:

~$14 MM

Antero Average Development Well

- Avg. Lateral Length per Well: 13,000'
- Bcfe/1,000': 2.71
- Wellhead Gas BTU: 1265
- Well Cost ($715/ft): $9.3 MM
- Net F&D Cost: $0.325/Mcfe
- C2 Recovery \(^{(1)}\): 35% to 40%
- Well Spacing: 830'

First Year Recovery Volumes

- Gross (Bcfe): 6.42
- Net (Bcfe) \(^{(2)}\): 5.16

Net Production Rate: 3.45 Bcfe/d

Replacement Volume ~205 Bcfe

~16% of 2020 Volume

28% Base Decline (2021)

Note: Maintenance capital is net of ORRI transaction. Net F&D cost assumes 81% net revenue interest.

1) Reflects increased ethane volume with start up of Shell Cracker in 2021. Ethane sold at a premium to natural gas price.
2) Post ORRI transaction.

$600 MM Maintenance D&C Capital
Antero continues to achieve material improvements to drilling and completion efficiencies which reduce well costs

### Average Drilled Lateral Feet per Well

- **2014**: 11,062
- **2015**: 11,693
- **2016**: 11,693 (New Company Marcellus Record)
- **2017**: 16,320
- **2018**: 16,320
- **1Q 2020**: 16,320

### Lateral Feet Drilled per Day

- **2014**: 5,934
- **2015**: 6,395
- **2016**: 10,453
- **2017**: 10,453
- **2018**: 10,453
- **2019**: 10,453
- **1Q 2020**: 10,453

### Days to Drill a Well – Spud to Spud

- **2014**: 35.0
- **2015**: 30.0
- **2016**: 20.0
- **2017**: 11.4
- **2018**: 10.7
- **1Q 2020**: 8.0

### Completion Stages per Day

- **2014**: 5.0
- **2015**: 4.0
- **2016**: 6.0
- **2017**: 8.0
- **2018**: 10.0
- **2019**: 12.0
- **1Q 2020**: 14.0

**Note**: Percentage increase and decrease arrows represent change in Marcellus data from 2014 through 1Q 2020.
• **Significant Reduction in Well Costs already “in-hand”**
  - Reduced well costs by ~26% ($3.05 million per well)

**Marcellus Well Cost per Lateral Foot (January 2019 AFE to Current 2020)**

- $11.6 per lateral foot (2019 Budget)
- $9.7 per lateral foot (2019 Achievements)
- $1.59 per lateral foot (Initial 2020 AFE)
- $1.13 per lateral foot (Achieved)
- $8.6 per lateral foot (Current 2020 AFE)

Recent Cost Reductions:
- Further drilling & completion efficiencies
- Expanded produced water services via AM pipeline system
- Further service cost deflation

Cost reductions already achieved:
- Service cost deflation
- Sand sourcing logistics
- Completion efficiencies
- Drier completions (100% of wells)
- Water blending by AM
- Trucking savings
- Enhanced drillout methodology

Assumes 12,000 foot lateral
Materially Reducing LOE
- Targeting reduced LOE by 45% in 2020 (~$90 MM+)

Antero Lease Operating Expense Reductions (2020 Target)

- $194.0 ($0.15/Mcfe)
  - $42.0 ($0.03/Mcfe) reduction driven by $6/Bbl savings related to wells already on sales
  - $32.0 ($0.03/Mcfe) reduction driven by $6/Bbl savings related to new wells in 2020
  - $16.0 ($0.01/Mcfe) reduction driven by trucking performance, service cost deflation and efficiencies

- 45% Reduction ($90 MM+)
- 2020E LOE Pre-Water Savings Initiatives
- Existing Wells Produced Water (after 90 days, 70% of total)
- New 2020 Completions Produced Water (after 90 days, 30% of total)
- Contined Water Initiative + Efficiencies
- 2020E LOE Target

- $104.0 ($0.08/Mcfe)
Cost structure reset results in enhanced Free Cash Flow profile. The 2020 capital plan will remain flexible, targeting $190 MM in Free Cash Flow.

AR Free Cash Flow ($ MM)

Transitioning From Outspend to Free Cash Flow

Targeting $190 MM in Free Cash Flow in 2020

Note: Free Cash Flow is a non-GAAP financial measure. Please see the appendix for more information. Based on strip pricing as of 5/29/2020. Free Cash Flow is net of impact from ORRI transaction.
AR has additional assets that can be monetized in 2020 to further reduce debt.

**Asset Monetization Opportunity Set**

**Targeting $750 MM to $1 B**

**E&P Assets**
- Land / PDP
  - 536,000 net acres in Appalachia (1)
  - 84% NRI pre-ORRI sale
  - 19 Tcfe of Proved Reserves at 12/31/19
  - 3.4 Bcfe/d of net production (1Q20)
  - Potential for VPPs

**Minerals**
- ~5,000 net mineral acres
  - Completed $402 MM ORRI transaction (3)

**Hedge Portfolio**
- ~1.8 Tcfe of natural gas hedges with a current hedge value of ~$825 MM (2)
- 8.3 MMBbls of crude oil hedges with a current value of ~$240 MM (2)
- 14.8 MMBbls of propane & pentane hedges with a current value of ~$30 MM (2)

**Financial / Midstream Assets**
- Current market value of $735 MM (4)
- Divested $100 MM in December 2019
- AM had ~$150 MM remaining under its share repurchase program as of 3/31/2020

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2) Based on hedge position and strip pricing as of 3/31/2020.
3) Includes $51 MM contingent payment expected in 3Q 2020 and $51 MM contingent payment expected in 1Q 2021. See slide 6 for more information.
4) Based on AM share price of $5.28/share as of 6/12/2020.
Affirmation of the bank borrowing base above $2.64 B in lender commitments plus the execution of the $402 MM asset sale positions Antero to address upcoming bond maturities

AR 2020 Liquidity Outlook Relative to 2021 + 2022 Remaining Bond Maturities ($MM)

Note: Liquidity represents borrowing availability under AR’s credit facility based on $2.64 B of lender commitments, less $730 MM of letters of credit and less $882 MM of borrowings as of 03/31/2020. Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.

1) $402 MM in ORRI proceeds includes $51 MM contingent payment expected in 3Q 2020 and $51 MM contingent payment expected in 1Q 2021. Pro forma liquidity includes $402 MM total proceeds from ORRI.

2) Forecasted year-end 2020 liquidity assumes no change in bank credit facility. Includes full impact from ORRI sale including 1Q 2021 contingent payment and all 2020 debt repurchases to date. See slide 6 for more information.

3) Market value based on bond pricing as of 6/12/2020 of $88.50 for the senior notes due in 2021 and $73.50 for the senior notes due in 2022.
Develop Highest ROR Locations - Large Delineated Drilling Inventory

AR Resource Overview

Large Drilling Inventory
- Diverse set of locations
- AR holds ~1,400 liquids-rich locations, or 40% of the core undrilled liquids-rich locations in Appalachia
- ~1,200 dry gas locations

Contiguous Acreage Position Delivers Efficient Development
- Long-laterals average 12,100’ in Marcellus rich-gas drilling inventory
- Efficient gathering, compression and processing utilization, and water re-use opportunities generates synergies and capital savings

High Working Interest and Net Revenue Interest
- 925 horizontal Marcellus producing wells are 100% operated and have 99% average working interest
- AR has 83% average PDP NRI in the Marcellus, 81% development NRI for the next three years and 84% thereafter

AR Marcellus Asset Map

1) Net of ORRI transaction. Assumes Antero achieves production thresholds under ORRI agreement generating contingent payments as described on slide 6.
Diversified exposure to both international and domestic markets results in Antero realizing a premium to Mont Belvieu on its C3+ NGL pricing.

Antero 2020 C3+ NGL Pricing Outlook

<table>
<thead>
<tr>
<th>Sales Point</th>
<th>Domestic</th>
<th>International</th>
<th>Combined</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hopedale</td>
<td>50%</td>
<td>50%</td>
<td>100%</td>
</tr>
<tr>
<td>Marcus Hook</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Expected Premium / (Discount) to Mont Belvieu ($/Gal)**

$0.00 - $0.05

1) Based on Antero C3+ NGL component barrel consisting of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+).
Mariner East
Producer Advantaged & Unconstrained:
Antero Resources in Appalachia

Producer Disadvantaged:
E&Ps in Permian, Rockies, Mid-Con & Bakken

AR is the largest C3+ producer with the most international exposure in Appalachia
Anchor shipper on ME2

Who Captures the Arb at the Gulf Coast?
Answer: Midstream & LPG off-takers (not E&P’s)
- No direct E&P access to international markets (i.e. producers only receive Mont Belvieu linked pricing)
- No local fractionation to sell marketable purity products in-basin

Results in “Mont Belvieu Minus” pricing “before the dock”

Who Captures the Arb at Marcus Hook?
Answer: AR and other Appalachian E&P’s
- Direct sales to most attractive international (ARA & FEI) & domestic markets
- Fixed terminal rates
- Local fractionation & marketing to sell purity products in-basin for local demand

Results in “Mont Belvieu plus” pricing netbacks captured “at the dock” by AR

Develop Highest ROR Locations - Premium NGL Price Realizations
NGL prices have risen on an absolute basis and relative to WTI since March/April lows.

AR Monthly Realized C3+ NGL Price

Source: Bloomberg actuals through December 2019. Forecasted C3+ pricing based ICE pricing and on Antero C3+ NGL component barrel consisting of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+). Assum es blended sales of 50% domestic and 50% international.
Post ORRI transaction, Antero’s average half cycle rate of return for its 2020 and 2021 development program is 41%.

Develop Highest ROR Locations – Attractive Well Economics

**Antero Half Cycle Well Economics by BTU Regime (2020 + 2021 Drilling Program)**

| Pre-tax Rate of Return (ROR) | 0% | 5% | 10% | 15% | 20% | 25% | 30% | 35% | 40% | 45% | 50% |
|-----------------------------|--|--|--|--|--|--|--|--|--|--|--|--|
| Marcellus - Highly Rich Gas 1250 BTU | | | | | | | | | | 43% |   |
| Marcellus - Dry Gas 1050 BTU | | | | | | | | | | 42% |   |
| Marcellus - Highly Rich Gas 1225 BTU | | | | | | | | | | 41% |   |
| Marcellus - High Rich Gas 1275 BTU | | | | | | | | | | 40% |   |
| Utica - Dry Gas 1050 BTU | | | | | | | | | | 40% |   |
| Marcellus - Highly Rich Gas 1215 BTU | | | | | | | | | | 37% |   |

Note: Assumes 5/29/2020 strip pricing. Half cycle burdened with 71% of AM fee, variable FT costs and no charge for G&A or land. Assumes 12,000' lateral lengths, 180 days spud to 1st sales and 2,000 lb/ft completions.
AR continued its consistent hedging program during 1Q20, adding 688 MMBtu/d to its 2022 hedge position (previously unhedged) at a price of $2.48/MMBtu.
AR has hedged ~100% of expected oil and “oil-equivalent” pentane production in 2020 at $55.63/Bbl and 10% of oil and oil equivalent production in 2021 at $55.16/Bbl.

Antero has hedged pentanes as a percent of WTI and then hedged the corresponding WTI price, effectively converting its pentane production into “oil-equivalent” production.

Note: Percentage hedged represents percent of expected oil production hedged based on 2020 production guidance and flat production in 2021.

1) Based on hedge position and strip pricing as of 3/31/2020.

~$240 MM Forecasted Hedge Value (1)
### 2020 Credit Enhancement Momentum

Reduced capital budget and operating cost structure improves Free Cash Flow profile while asset sales, hedge position and scale support debt profile.

<table>
<thead>
<tr>
<th></th>
<th>2019A</th>
<th>2020E</th>
<th>Potential Credit Enhancement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>D&amp;C Capex Budget</strong></td>
<td>$1.275 B</td>
<td>$750 B</td>
<td>($0.525) B</td>
</tr>
<tr>
<td><strong>F&amp;D Costs ($/Mcfe)</strong></td>
<td>$0.44$^{(2)}</td>
<td>$0.30$^{(3)}</td>
<td>($0.14)</td>
</tr>
<tr>
<td><strong>Cost Structure ($/Mcfe)</strong></td>
<td>$2.48</td>
<td>$2.35</td>
<td>($0.13)</td>
</tr>
<tr>
<td><strong>Free Cash Flow ($MM)</strong></td>
<td>($310)</td>
<td>$190</td>
<td>$500</td>
</tr>
<tr>
<td><strong>Asset Sales (YE)</strong></td>
<td>$100 MM</td>
<td>$775 MM$^{(4)}</td>
<td>$675 MM</td>
</tr>
<tr>
<td><strong>Total Debt (YE)</strong></td>
<td>$3.8 B</td>
<td>$2.8 B$^{(4)}</td>
<td>($1.0) B</td>
</tr>
<tr>
<td><strong>Leverage (YE)</strong></td>
<td>3.0x</td>
<td>3.0x$^{(4)}</td>
<td>Neutral</td>
</tr>
<tr>
<td><strong>Gas Hedge Position</strong></td>
<td>75% @ $2.50</td>
<td>96% @ $2.87</td>
<td>21% / $0.37</td>
</tr>
<tr>
<td><strong>Net Production</strong>$^{(1)}</td>
<td>3.2 Bcfe/d</td>
<td>3.45 Bcfe/d</td>
<td>0.25 Bcfe/d</td>
</tr>
<tr>
<td><strong>Liquids</strong>$^{(1)}</td>
<td>161 MBbl/d</td>
<td>189 MBbl/d</td>
<td>28 MBbl/d</td>
</tr>
<tr>
<td><strong>PDP Reserves (YE)</strong>$^{(2)}</td>
<td>10.4 Tcfe$^{(2)}</td>
<td>11.7 Tcfe</td>
<td>1.3 Tcfe</td>
</tr>
</tbody>
</table>

Note: F&D cost and leverage are non-GAAP measures. See appendix for more information.

$^{(1)}$ Represents 2019 actuals and updated 2020 guidance.

$^{(2)}$ Based on 2018 audited financials and reserves.

$^{(3)}$ Based on 2019 audited financials and reserves. 2020E F&D cost assumes YE 2019 F&D cost less 18% based on reduction of well cost AFE from $868/ft. at YE 2019 to current $715/ft.

$^{(4)}$ Total debt and leverage as of 12/31/2019. 2020E debt and leverage assumes midpoint of asset sale target of $875 MM and includes 2020E Free Cash Flow of $190 MM. See appendix for more information on Free Cash Flow.
Producer resiliency is a key attribute for a sustainable development plan:

- **Cost Reduction Initiatives**
  - AR has budgeted ~$602 MM in reductions to 2020 capital and operating expenses

- **Asset Sale Initiatives**
  - $502 MM (1) of the $750 MM to $1 B asset sale target met; substantial remaining asset monetization optionality

- **World Class Hedge Book**
  - ~96% and ~100% of projected natural gas production hedged in 2020 and 2021 at $2.87 and $2.80/MMBtu, respectively (2)

- **Free Cash Flow**
  - 2020 D&C capital budget of $750 MM with $190 MM in projected Free Cash Flow (3)

- **Robust Liquidity**
  - Building liquidity to address the remaining 2021 and 2022 bond maturities

The AR business model delivers multiple ways to “Win”

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(1) Includes $51 MM contingent payment expected in 3Q 2020 and $51 MM contingent payment expected in 1Q 2021. See slide 6 for more information.

(2) Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.310 Bcf/d in 2020 and flat production in 2021.

(3) Based on strip pricing as of 5/29/2020. See appendix for Free Cash Flow definition.
Antero Resources Executive Summary

Natural Gas & NGL Macro

Detailed Asset Overview

Appendix
Antero Non-GAAP Measures

**Adjusted EBITDAX**: Adjusted EBITDAX as defined by the Company represents income or loss, including noncontrolling interests, before interest expense, interest income, gains or losses from commodity derivatives and marketing derivatives, but including net cash receipts or payments on derivative instruments included in derivative gains or losses other than proceeds from derivative monetizations, income taxes, impairment, depletion, depreciation, amortization, and accretion, exploration expense, equity-based compensation, contract termination and rig stacking costs, simplification transaction fees, and gain or loss on sale of assets. Adjusted EBITDAX also includes distributions received with respect to limited partner interests in Antero Midstream Partners common units prior to the closing of the simplification transaction on March 12, 2019.

The GAAP financial measure nearest to Adjusted EBITDAX is net income or loss including noncontrolling interest that will be reported in Antero’s condensed consolidated financial statements. While there are limitations associated with the use of Adjusted EBITDAX described below, management believes that this measure is useful to an investor in evaluating the Company’s financial performance because it:

- is widely used by investors in the oil and natural gas industry to measure operating performance without regard to items excluded from the calculation of such term, which may vary substantially from company to company depending upon accounting methods and the book value of assets, capital structure, and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of Antero’s operations from period to period by removing the effect of its capital and legal structure from its consolidated operating structure; and
- is used by management for various purposes, including as a measure of Antero’s operating performance, in presentations to the Company’s board of directors, and as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by the board of directors as a performance measure in determining executive compensation.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effects of certain recurring and non-recurring items that materially affect the Company’s net income or loss, the lack of comparability of results of operations of different companies, and the different methods of calculating Adjusted EBITDAX reported by different companies. In addition, Adjusted EBITDAX provides no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position.

The Company has not provided projected net income or a reconciliation of projected Adjusted EBITDAX to projected net income, the most comparable financial measure calculated in accordance with GAAP, because the Company does not provide guidance with respect to income tax expense, depletion and depreciation expense or the revenue impact of changes in the projected fair value of derivative instruments prior to settlement. Therefore, projected net income and a reconciliation of projected Adjusted EBITDAX to projected net income, are not available without unreasonable effort.

**Net Debt**: Net Debt is calculated as total debt less cash and cash equivalents. Management uses Net Debt to evaluate its financial position, including its ability to service its debt obligations.

**Leverage**: Leverage is calculated as LTM Adjusted EBITDAX divided by net debt.

**F&D Cost**: Proved undeveloped F&D costs is a non-GAAP metric 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. F&D costs is a statistical indicator that has limitations, including its predictive and comparative value. This reserve metric may not be comparable to similarly titled measurements used by other companies. There are no directly comparable financial measures presented in accordance with GAAP for PUD F&D costs, and therefore a reconciliation to GAAP is not practicable.

The calculation for F&D cost is based on future development costs required for the development of reserves, divided by total reserves.
Free Cash Flow:

Free Cash Flow is a measure of financial performance not calculated under GAAP and should not be considered in isolation or as a substitute for cash flow from operating, investing, or financing activities, as an indicator of cash flow, or as a measure of liquidity. The Company defines Free Cash Flow as Cash Flow from Operations, less drilling and completion capital and leasehold capital and earnout payments.

The Company has not provided projected Cash Flow from Operations or reconciliations of Free Cash Flow to projected Cash Flow from Operations, the most comparable financial measure calculated in accordance with GAAP. The Company is unable to project Cash Flow from Operations for any future period because this metric includes the impact of changes in operating assets and liabilities related to the timing of cash receipts and disbursements that may not relate to the period in which the operating activities occurred. The Company is unable to project these timing differences with any reasonable degree of accuracy without unreasonable efforts. However, the Company is able to forecast 2020 drilling and completion capital of $750 million and leasehold capital of $45 million. Targeted 2020 Free Cash Flow also includes the $125 million earnout payment received from Antero Midstream in January 2020 associated with the water drop down transaction that occurred in 2015. Targeted 2020 Free Cash Flow is based on current strip pricing, updated production guidance that reflects the ORRI transaction, and assumes that dividends from Antero Midstream remain flat for the year for aggregate annual dividends from Antero Midstream of $171 million in 2020. May 2020, Antero Midstream announced that in light of the uncertain market conditions impacting the energy industry, Antero Midstream will continue to evaluate its capital budget as well as the appropriate amount of capital that is returned to shareholders through dividends and share repurchases in order to maintain its financial profile.

Free Cash Flow is a useful indicator of the Company's ability to internally fund its activities and to service or incur additional debt. There are significant limitations to using Free Cash Flow as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the Company’s net income, the lack of comparability of results of operations of different companies and the different methods of calculating Free Cash Flow reported by different companies. Free Cash Flow does not represent funds available for discretionary use because those funds may be required for debt service, land acquisitions and lease renewals, other capital expenditures, working capital, income taxes, exploration expenses, and other commitments and obligations.
## Reconciliation of net loss to Adjusted EBITDAX:

| Net loss and comprehensive loss attributable to Antero Resources Corporation | 2019 | 2020 |
|——|——|——|
| $ (1,657,702) | 878,233 | 1,308,420 |
| Depletion, depreciation, amortization, and accretion | 952,500 | 761,337 |
| Impairment of oil and gas properties | 923,041 | 750,000 |
| Impairment of midstream assets | 600,000 | 600,000 |
| Commodity derivative fair gains | 791 | 600 |
| Gains on settled commodity derivatives | (1,107,173) | 438,924 |
| Equity-based compensation expense | 7,800 | 17,985 |
| Provision for income tax benefit | (472,805) | (116,980) |
| Gain on early extinguishment of debt | 285,352 | 1,078,222 |
| Equity in loss of unconsolidated affiliates | (125,000) | 188,107 |
| Impairment of equity investment | 108,745 | 920 |
| Distributions/dividends from unconsolidated affiliates | 209,263 | 968 |
| Loss on sale of equity investments | 5,666 | 1,048,945 |
| Water earnout | 19,464 | (16,433) |
| Net unamortized premium | (19,464) | (16,433) |
| Total debt | $ 3,758,868 | 3,707,787 |
| Net debt | $ 3,758,868 | 3,707,787 |

## Twelve months ended

**March 31, 2020**
## Antero Resources 2019 LTM EBITDAX Reconciliation

<table>
<thead>
<tr>
<th>Description</th>
<th>December 31, 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net loss and comprehensive loss attributable to Antero Resources Corporation</td>
<td>$(340,129)</td>
</tr>
<tr>
<td>Net income and comprehensive income attributable to noncontrolling interests</td>
<td>$46,993</td>
</tr>
<tr>
<td>Commodity derivative fair value gains</td>
<td>$(463,972)</td>
</tr>
<tr>
<td>Losses on settled commodity derivatives</td>
<td>$325,090</td>
</tr>
<tr>
<td>Loss on sale of assets</td>
<td>$951</td>
</tr>
<tr>
<td>Gain on deconsolidation of Antero Midstream</td>
<td>$(1,406,042)</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>$228,111</td>
</tr>
<tr>
<td>Gain on early extinguishment of debt</td>
<td>$(36,419)</td>
</tr>
<tr>
<td>Provision for income tax benefit</td>
<td>$(74,110)</td>
</tr>
<tr>
<td>Depletion, depreciation, amortization, and accretion</td>
<td>$918,629</td>
</tr>
<tr>
<td>Impairment of oil and gas properties</td>
<td>$1,300,444</td>
</tr>
<tr>
<td>Impairment of midstream assets</td>
<td>$14,782</td>
</tr>
<tr>
<td>Impairment of equity investments</td>
<td>$467,590</td>
</tr>
<tr>
<td>Exploration expense</td>
<td>$884</td>
</tr>
<tr>
<td>Equity-based compensation expense</td>
<td>$23,559</td>
</tr>
<tr>
<td>Equity in loss of unconsolidated affiliate - AMC</td>
<td>$143,216</td>
</tr>
<tr>
<td>Distributions from unconsolidated affiliates</td>
<td>$157,956</td>
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<tr>
<td>Contract termination and rig stacking</td>
<td>$14,026</td>
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<tr>
<td>Loss on sale of equity investment shares</td>
<td>$108,745</td>
</tr>
<tr>
<td>Water earnout</td>
<td>$(125,000)</td>
</tr>
<tr>
<td>Simplification transaction fees</td>
<td>$15,482</td>
</tr>
</tbody>
</table>

### Antero Midstream Related Adjustments

<table>
<thead>
<tr>
<th>Description</th>
<th>December 31, 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income and comprehensive income attributable to noncontrolling interests</td>
<td>$(46,993)</td>
</tr>
<tr>
<td>Antero Midstream interest expense, net</td>
<td>$(16,815)</td>
</tr>
<tr>
<td>Antero Midstream loss on extinguishment of debt</td>
<td>$(21,770)</td>
</tr>
<tr>
<td>Antero Midstream depreciation, accretion of ARO and accretion of contingent consideration</td>
<td>$(6,982)</td>
</tr>
<tr>
<td>Antero Midstream impairment</td>
<td>$(2,477)</td>
</tr>
<tr>
<td>Antero Midstream equity-based compensation expense</td>
<td>$12,264</td>
</tr>
<tr>
<td>Antero Midstream gain on sale</td>
<td>$(61,319)</td>
</tr>
<tr>
<td>Antero Midstream equity in earnings of unconsolidated affiliates</td>
<td>$(15,021)</td>
</tr>
<tr>
<td>Antero Midstream distributions from unconsolidated affiliates</td>
<td>$95,183</td>
</tr>
<tr>
<td>Equity in earnings of Antero Midstream</td>
<td>—</td>
</tr>
<tr>
<td>Distributions from Antero Midstream</td>
<td>—</td>
</tr>
<tr>
<td>Antero Midstream simplification transaction fees</td>
<td>$(9,185)</td>
</tr>
</tbody>
</table>

**Adjusted EBITDAX**

$1,247,671