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 AR 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, 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, future financial position, the amount and timing of any litigation settlements or awards, future technical improvements, future marketing and asset monetization opportunities, the amount and timing of any contingent payments, and the result of any tender offer, 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 the 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 June 30, 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 Corporation is denoted as “AR” in the presentation and Antero Midstream Corporation is denoted as “AM”, which are their respective New York Stock Exchange ticker symbols.
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

3rd Largest
U.S. GAS PRODUCER(1)

2nd Largest
U.S. NGL PRODUCER(1)

Own 40%
OF CORE LIQUIDS-RICH UNDRILLED LOCATIONS IN APPALACHIA(2)

1,200
ADDITIONAL DRY GAS LOCATIONS IN DRILLING INVENTORY(2)

~93% Hedged
ON NATURAL GAS THROUGH 2021
@ $2.82/MMBtu (3)

29% Midstream
AM VALUE HELD BY AR > $1B

Note: Hedge position as of 6/30/20, pro forma for hedge monetization and VPP transaction. Rigs on map as of 8/7/20, per Rig data. AM value based on 8/24/20 share price.
1) NGLs based on 2020E consensus as of 8/7/20. Natural gas based on 2Q20 reported production.
2) AR drilling inventory as of 6/30/2020. Industry locations based on Antero analysis of undeveloped acreage in the core of the Marcellus and Ohio Utica Shales.
3) Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.375 Bcf/d in 2020 and flat production in 2021.
Antero has closed $751 MM in asset sales and $250 MM in refinancing to date to address debt maturities and deleverage.

Announced Asset Sale Program with AM share sale (December 2019)
- $100 MM AM share sale

ORRI Transaction with Sixth Street Partners (June 2020)
- $402 MM in proceeds (1)

Hedge Monetization (July 2020)
- $29 MM monetization

VPP with J.P. Morgan (August 2020)
- $220 MM VPP sale to an affiliate of JPM

Convertible Senior Notes Offering (August 2020)
- $250 MM in proceeds

Senior Note Repurchases (4Q19 – 3Q20)
- $898 MM in 2021, 2022, 2023 and 2025 Senior Note open market repurchases

Senior Note Tender Offer (August 2020)
- $367 MM in 2021, 2022 and 2023 repurchases through cash tender offer

$1.3 B in senior notes repurchased since 4Q 2019 ~$210 MM reduction in total debt (2)

$750 MM - $1 B Asset Sale Target Range

1) Inclusive of $102 MM of contingent payments expected to be received in 4Q 2020 and 2Q 2021 if certain volume thresholds are met.
2) Includes $183 MM of 2021 bonds tendered and repurchased @ $98, $88 MM of 2022 bonds tendered and repurchased @ $86 and $96 MM of 2023 bonds tendered @78.
Pro Forma Liquidity Post VPP, Convert and Debt Tenders

Through a combination of asset sales, discounted senior note repurchases and the recent unsecured convertible note offering, Antero has plenty of liquidity to repay the November 2021 maturity.

AR Pro Forma 6/30/20 Liquidity Relative to Remaining 2021 Bond Maturity ($MM)

1) Liquidity represents borrowing availability under AR’s credit facility based on $2.64 B of lender commitments, $730 MM of letters of credit and $926 MM of borrowings as of 6/30/2020. Liquidity is pro forma for $29 MM in hedge proceeds, and $41 MM of debt repurchased in July 2020.
2) Tender offer repurchases as of Dutch Auction Early Tender Deadline on 8/24/20.
Unsecured Debt Maturity Summary:

- Repurchased ~$1.3 B of senior notes including the $367 MM tender offer, resulting in $985 MM of senior note par value due through December 2022
  - $1.1 B of pro forma liquidity as of June 30, 2020 under $2.64 B credit facility
  - Eliminated $210 MM of total debt and reduced annual interest expense by ~$33 MM

### AR Pro Forma 6/30/2020 Senior Note Maturity Schedule ($MM) (1)

<table>
<thead>
<tr>
<th>AR Senior Notes (Par Value)</th>
<th>AR Senior Notes (Market Value) (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$317</td>
<td>$308 MM 5.375% Nov 2021</td>
</tr>
<tr>
<td>$668</td>
<td>$554 MM 5.125% Dec 2022</td>
</tr>
<tr>
<td>$610</td>
<td>$457 MM 5.625% Jun 2023</td>
</tr>
<tr>
<td>$590</td>
<td>$395 MM 5.000% Mar 2025</td>
</tr>
<tr>
<td>$250</td>
<td>$250 4.250% Sep 2026</td>
</tr>
</tbody>
</table>

1) Represents 6/30/2020 debt maturity schedule pro forma for $29 MM in July hedge proceeds, $40 MM in July debt repurchases, $220 MM in VPP proceeds $367 MM of tender offer repurchase and $242 MM of net convertible offer proceeds. Includes $183 MM of 2021 bonds tendered and repurchased @ $98, $88 MM of 2022 bonds tendered and repurchased @ $86 and $96 MM of 2023 bonds tendered and repurchased @ 78.

2) Remaining market value of senior notes reflects bond pricing as of 8/24/2020.
Impressive Operational Momentum

**Lowered 2020 Capital Budget to $750 MM**
- Revised D&C capital budget to $750 MM in 2020, a 35% decrease from initial 2020 guidance and a 41% decrease from 2019 spending
- 2020 production growth guidance of 8% while forecasting ~$175 MM of 2H 2020 Free Cash Flow \(^{(1)}\)
- $580 MM D&C capital expected for 2021 to maintain 2020 production level

**Reduced Cost Structure**
- 30% well cost reduction from January 2019 budget to $675/lateral foot expected in 2H 2020
- Total of ~$616 MM in capital and operating cost savings expected in 2020 relative to 2019 initial budget

---

\(^{(1)}\) Free Cash Flow is a non-GAAP measure. See appendix for more information.
The improvement in NGL pricing, combined with a significant reduction in capital and operating costs, is expected to result in $175 MM in Free Cash Flow in 2H 2020.

**2H 2020 Pricing & Production**
- Fully hedged on natural gas at $2.83 / MMBtu
- C3+ NGL strip prices up 25%+ compared to 1H 2020 (~$5+/Bbl)
- 3.5 Bcfe/d 2H 2020 production (based on annual guidance)

**2H 2020 Capital**
- $280 MM Capital in 2H 2020 ($260 MM D&C and $20 MM Land)
- $230 MM reduction in capital from 1H 2020

**$175 MM 2H 2020 Free Cash Flow**

---

1) Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.
As one of the largest natural gas and NGL producers in the U.S., Antero has significant cash flow upside in a rising commodity price environment.

**Top 5 U.S. Natural Gas Producers (MMcf/d)**

- **EQT**: 3,576 MMcf/d
- **XOM**: 2,642 MMcf/d
- **AR**: 2,364 MMcf/d (3rd largest U.S. Natural Gas producer)
- **COG**: 2,229 MMcf/d
- **SWN + MR**: 2,198 MMcf/d

**Top 5 U.S. NGL Producers (MBbls/d)**

- **OXY**: 230 MBbls/d
- **AR**: 182 MBbls/d (2nd largest NGL producer)
- **RRC**: 107 MBbls/d
- **EOG**: 101 MBbls/d
- **COP**: 93 MBbls/d

**AR Leverage to Natural Gas Prices ($MM)**

- Every $0.10 per MMBtu move in natural gas prices results in an $86 MM unhedged annual revenue impact. (1)

**AR Leverage to C3+ NGL Prices ($MM)**

- Every $2 per Bbl move in C3+ NGL prices results in a $96 MM unhedged annual revenue impact. (2)

Note:
1. Assumes 2Q2020 natural gas production of 2.364 Bcf/d. Note: 2.2 Bcf/d of AR natural gas volumes are hedged through 2021 at a weighted average of $2.82/MMBtu.
2. Assumes 2Q2020 C3+ NGL production of 131 MBbl/d.
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>Thousand Metric Tons</th>
<th>Tons/MBOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>457</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>427</td>
<td>2.7</td>
</tr>
<tr>
<td>2019</td>
<td>422</td>
<td>2.3</td>
</tr>
</tbody>
</table>

Methane Leak Loss Rate
- OF Industry Target 2025
- Upstream Sector Target
- 2018 OF Upstream Sector Avg.
- AR 2019
- 1.0% decrease

2019 Antero vs 2018 Industry GHG Emission Intensity

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

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, EQNR, FANG, HES, MPC, NBL, RRC, RDS, SWN and XEC.
Executive Summary

Natural Gas & NGL Macro

Detailed Asset Overview

Appendix
## U.S. Natural Gas

### Supply
- 6.0 Bcf/d reduction from 2019 to 87 Bcf/d and 8.0 Bcf/d aggregate reduction expected by YE 2021 due to decline in associated gas from shale oil basins (Permian, Eagle Ford, SCOOP/STACK)
- Flat production from gas producers who will stick to capital discipline
- High Storage of 4.0 Tcf expected for end of injection season in November but low storage of 1.0 Tcf expected for end of withdrawal season in March 2021

### Demand
- 5 Bcf/d+ summer 2020 reduction in pre-COVID LNG exports of 9 Bcf/d due to cargo cancellations
- LNG feedgas demand expected to increase from 4.9 Bcf/d in August to 7 or 8 Bcf/d by October
- U.S. demand has remained steady YoY at 75 Bcf/d this summer; Mexican exports up YoY to 6 Bcf/d

### Outlook for Natural Gas
- Significant U.S. associated gas production decline both medium and long-term with no medium-term U.S. demand destruction and rebounding LNG and Mexican export demand

## U.S. NGLs

### Supply
- U.S. NGL production projected to decline by 1 MMBbl/d through 2021, driven by reduced drilling activity in shale oil basins
- International NGL production “associated” with OPEC oil production decreased 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 create an inelastic demand pull for NGL products
- Asian economies recovering from COVID-19 pandemic and Chinese tariffs on LPG were lifted in early 2020

### Outlook for NGLs
- The impact of the decline in shale oil activity on “associated NGL” supply is expected to be even more pronounced than the impact on associated gas supply while global LPG demand of ~ 10 MMBbl/d remains stable
- Increased U.S. export capacity relative to supply has tightened domestic Mont Belvieu pricing to international pricing

---

Sources: July EIA Short Term Energy Outlook, S&P Global Platts estimates and J.P. Morgan Commodities Strategy Team Research. LPG is comprised of NGL components propane and butane.
### Significant Reduction in Drilling Rigs

- Since March 6\(^{th}\), the total U.S. rig count has declined by 528 rigs, or ~69%, and oil focused rig count has declined by 74%.
  - NGL production “associated” with shale oil activity represents 65% of total U.S. NGL production and is expected to decline due to the recent collapse in oil prices and rig count.

### U.S. Oil & Gas Drilling Rig Count Since 3/6/2020

<table>
<thead>
<tr>
<th>Region</th>
<th>3/6/2020 Rigs</th>
<th>8/21/2020 Rigs</th>
<th>Change Since 3/6/20</th>
<th>Current Dry Gas Production Bcf/d (^{(1)})</th>
<th>Current NGL Production MBbls/d (^{(2)})</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil Focused</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permian</td>
<td>429</td>
<td>128</td>
<td>(301) (70%)</td>
<td>11.4</td>
<td>1,690</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>79</td>
<td>9</td>
<td>(70) (89%)</td>
<td>4.9</td>
<td>597</td>
</tr>
<tr>
<td>Bakken</td>
<td>52</td>
<td>10</td>
<td>(42) (81%)</td>
<td>1.9</td>
<td>397</td>
</tr>
<tr>
<td>SCOOP/STACK</td>
<td>41</td>
<td>10</td>
<td>(31) (76%)</td>
<td>3.3</td>
<td>360</td>
</tr>
<tr>
<td>DJ Niobrara</td>
<td>28</td>
<td>7</td>
<td>(21) (75%)</td>
<td>2.5</td>
<td>454</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>629</td>
<td>164</td>
<td>(465) (74%)</td>
<td>24.0</td>
<td>3,498</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Region</th>
<th>3/6/2020 Rigs</th>
<th>8/21/2020 Rigs</th>
<th>Change Since 3/6/20</th>
<th>Current Dry Gas Production Bcf/d (^{(1)})</th>
<th>Current NGL Production MBbls/d (^{(2)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachia/Haynesville</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marcellus</td>
<td>32</td>
<td>23</td>
<td>(9) (28%)</td>
<td>26.3</td>
<td>808</td>
</tr>
<tr>
<td>Haynesville</td>
<td>41</td>
<td>37</td>
<td>(4) (10%)</td>
<td>11.9</td>
<td>44</td>
</tr>
<tr>
<td>Utica</td>
<td>14</td>
<td>8</td>
<td>(6) (43%)</td>
<td>6.3</td>
<td>147</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>87</td>
<td>68</td>
<td>(19) (22%)</td>
<td>44.5</td>
<td>999</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Region</th>
<th>3/6/2020 Rigs</th>
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<th>Current NGL Production MBbls/d (^{(2)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other</td>
<td>50</td>
<td>6</td>
<td>(44) (88%)</td>
<td>18.9</td>
<td>912</td>
</tr>
<tr>
<td><strong>Total U.S.</strong></td>
<td>766</td>
<td>238</td>
<td>(528) (69%)</td>
<td>87.4</td>
<td>5,409</td>
</tr>
</tbody>
</table>

- Rig reduction led by oil focused areas with a 465 rig, or 74% reduction since March 6\(^{th}\).

---

2) NGL production per Platts monthly average C2+ NGL estimate for July 2020 as of 7/30/2020. Assumes ~2.7 MMbbl/d of ethane, or 46% of total C2+ NGL forecast.

Source: Baker Hughes and S&P Global Platts.
Since March 6th, U.S. completion crew count has declined by 233 crews, or 74%, and oil focused completion crew count has declined by 78%.

### U.S. Oil & Gas Drilling Completion Crew Count Since 3/6/2020

<table>
<thead>
<tr>
<th>Region</th>
<th>3/6/2020</th>
<th>8/21/2020</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>Completion</td>
<td>%</td>
<td>Bcf/d (1)</td>
<td>MBbls/d (2)</td>
<td></td>
</tr>
<tr>
<td><strong>Oil Focused</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permian</td>
<td>125</td>
<td>37</td>
<td>(88) (70%)</td>
<td>11.4</td>
<td>1,690</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>44</td>
<td>4</td>
<td>(40) (91%)</td>
<td>4.9</td>
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<td>Bakken</td>
<td>31</td>
<td>7</td>
<td>(24) (77%)</td>
<td>1.9</td>
<td>397</td>
</tr>
<tr>
<td>SCOOP/STACK</td>
<td>28</td>
<td>4</td>
<td>(24) (86%)</td>
<td>3.3</td>
<td>360</td>
</tr>
<tr>
<td>DJ Niobrara</td>
<td>19</td>
<td>2</td>
<td>(17) (89%)</td>
<td>2.5</td>
<td>454</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>247</td>
<td>54</td>
<td>(193) (78%)</td>
<td>24.0</td>
<td>3,498</td>
</tr>
<tr>
<td><strong>Appalachia/Haynesville</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Appalachia</td>
<td>26</td>
<td>19</td>
<td>(7) (27%)</td>
<td>32.6</td>
<td>955</td>
</tr>
<tr>
<td>Haynesville</td>
<td>18</td>
<td>4</td>
<td>(14) (78%)</td>
<td>11.9</td>
<td>44</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>44</td>
<td>23</td>
<td>(21) (48%)</td>
<td>44.5</td>
<td>999</td>
</tr>
<tr>
<td><strong>Other</strong></td>
<td>26</td>
<td>7</td>
<td>(19) (73%)</td>
<td>18.9</td>
<td>912</td>
</tr>
<tr>
<td><strong>Total U.S.</strong></td>
<td>317</td>
<td>84</td>
<td>(233) (74%)</td>
<td>87.4</td>
<td>5,409</td>
</tr>
</tbody>
</table>

- **Completion crew count reduction led by oil focused areas with a 193, or 78% crew reduction since March 6th.**
- **Down 9% from 3/6/20**
- **Down 11% from 3/6/20**
- **27% of U.S. dry gas production**
- **65% of U.S. NGL production**
- **51% of U.S. dry gas production**
- **18% of U.S. NGL production**
- **NGL production “associated” with shale oil activity represents 65% of total U.S. NGL production and is expected to decline due to the collapse in oil prices and rig count.**

Source: Primary Vision and S&P Global Platts. Appalachia completion crew count based on Antero internal estimate to address discrepancies in Primary Vision data for Appalachia.


2) NGL production represents Platts monthly average C2+ NGL estimate for July 2020. Estimate as of 7/30/2020. Assumes ~2.7 MMBbl/d of ethane, or 46% of total C2+ NGL forecast.
Material Impact to NGL Production in the U.S.

The oil price decline is expected to have a pronounced impact on U.S. NGL supply, 65% of which comes from shale oil plays.

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

- Jan-20 Forecast
- Jul-20 Forecast

**Note:** Represents Platts Analytics data as of July 30, 2020.

LPG Export Capacity

- Gulf Coast export capacity is now plentiful, which has helped clear the domestic market and has tightened Mont Belvieu LPG pricing to international pricing.

Expected shale oil shut-ins in mid-2020 incorporated with latest forecast.
Domestic and international LPG prices are improving on a relative basis to crude oil, driven by resilient global demand for LPG from petrochemicals and res/com.  

### C3+ NGL Prices & % of WTI (1)

<table>
<thead>
<tr>
<th>($/Bbl)</th>
<th>% of WTI</th>
<th>MB C3+ NGL ($/Bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$35</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$25</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$15</td>
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<tr>
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<tr>
<td>$5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Historical MB C3+/WTI%
- 5-year avg: ~60%

#### C3+ Price as % of WTI
- 1Q20A: 48%
- 2Q20A: 66%
- 3Q20E: 57%
- 4Q20E: 58%

### Far East Index (FEI) Propane Prices & % of Brent (2)

<table>
<thead>
<tr>
<th>($/Bbl)</th>
<th>% of Brent</th>
<th>FEI Propane ($/Bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$35</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$25</td>
<td></td>
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<tr>
<td>$20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$15</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### FEI Propane Price
- 1Q20A: 64%
- 2Q20A: 84%
- 3Q20E: 65%
- 4Q20E: 69%

Source: ICEdata Mont Belvieu, Far East Index, WTI and Brent strip pricing as of 8/21/2020

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+).

2) Forecasted C3+ NGLs represent ICEdata Mont Belvieu strip pricing as of 8/21/2020. Forecasted FEI propane represents ICEdata Far East Index propane strip pricing as of 8/21/2020.
NGL Pricing Outlook

• Limited liquidity in the futures market for C3+ NGL products often does not capture anticipated value further out in the curve
• A bottoms-up analysis of supply/demand fundamentals suggests NGL prices have significant upside to the current strip

[Citi C3+ NGL Mont Belvieu Price Deck vs Current Strip (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+).

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+). Citi Research price deck published 6/29/2020. ICEdata Mont Belvieu strip pricing as of 8/6/2020.
Northeast LPG Supply & Demand

- Northeast LPG markets became oversupplied in 2015 and were forced to transport via rail, which was relieved by Mariner East 2 coming online in early 2019
- The Northeast is now “long” LPG pipeline takeaway capacity with more capacity expected to come on line in 1Q 2021 on ME2

Northeast LPG NGL Supply vs. Demand & Takeaway Capacity (Excluding Rail)

- “Long” Local Demand and Pipeline Capacity = Tight Differentials  
  ~$(2.00)/Bbl vs. Mont Belvieu
- “Short” Local Demand & Pipeline Capacity = Wide Differentials  
  ~$(6.00)/Bbl vs. Mont Belvieu
- ME2 Realized Effect = +$4.00/bbl  
  Differential Improvement

Executive Summary

Natural Gas & NGL Macro

Detailed Asset Overview

Appendix
Energy Industry Realities

- Commodity prices are cyclical
- Energy is a capital intensive business
- Long-term planning & execution are critical

Commodity Price Risk

- Opportunistically Hedge Commodities ~93% hedged on natural gas through 2021
- Utilize Firm Transport - substantially reduces basis risk in an increasingly tight Appalachia takeaway capacity
- Drive leverage lower & improve financial flexibility

Capital Intensity

- Develop highest rate of return locations across asset portfolio while maintaining flat production profile
- Drive down capital and operating costs to maximize free cash flow

Execution

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

1) Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.375 Bcf/d in 2020 and flat production in 2021.
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 capital spending with cash flow

2. Maintain liquidity & strengthen balance sheet with medium term leverage target below 2-times

3. Develop highest rate of return locations across asset portfolio

4. Use hedges and firm transport to protect cash flow and balance sheet

Tied to 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 are expected to result in approximately $616 million of savings in 2020 compared to AR’s 2019 initial budget.

**Cost Savings Update**

**Well Cost Reduction Progress**
- 2020 D&C of $705/lateral foot, a 27% reduction from $970/ft at the beginning of 2019
- $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

**2020 Savings (1)**
- $334 MM ($970/ft - $705/ft) x 12,000’ = $3.18 MM
- $3.18 MM per well x 105 wells = $334 MM

**Water Savings Driving LOE Lower**
- 2Q20 represented a 38% reduction from 2019
- Expect to save $90 MM in 2020 as a result of increased blending operations combined with reduced trucking costs
- ~54% reduction from 2019

**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 due to headcount reductions in 2019, natural employee attrition and a reduction across the board in expenses
- $24 MM

**Grand Total Cost Reset for 2020**
- ~$616 MM

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

1) Based on midpoint 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)

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual 2018</th>
<th>Actual 2019</th>
<th>Original Budget (Feb 2020)</th>
<th>Revised Budget (Mar 2020)</th>
<th>Current Budget (Apr 2020)</th>
</tr>
</thead>
<tbody>
<tr>
<td>D&amp;C Capital</td>
<td>$1,490</td>
<td>$1,270</td>
<td>$1,150</td>
<td>$1,000</td>
<td>$750</td>
</tr>
<tr>
<td>Maintenance</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance Capital</td>
<td>$163</td>
<td>$131</td>
<td>$125</td>
<td>$125</td>
<td>$105</td>
</tr>
<tr>
<td>Well Completions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$580</td>
<td>$65</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Maintenance assumes $671/ft well cost and 13,000’ laterals (for additional details on maintenance capex see slide 26).
**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 ~65 wells

\[ \frac{213 \text{ Bcfe}}{3.27 \text{ Bcfe per well}} = 65.1 \text{ wells} \]

**Maintenance D&C Capital**

65 wells $8.7 MM per well = $566 MM

**Field and Operating Capital**

- Roads
- Working interest optimization
- Pad construction costs

**Maintenance Field Capital:**

~$14 MM

---

**Antero Average Development Well**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Avg. Lateral Length per Well</td>
<td>13,000’</td>
</tr>
<tr>
<td>Bcfe/1,000’</td>
<td>2.71</td>
</tr>
<tr>
<td>Wellhead Gas BTU</td>
<td>1265</td>
</tr>
<tr>
<td>Well Cost ($671/ft)</td>
<td>$8.7 MM</td>
</tr>
<tr>
<td>Net F&amp;D Cost</td>
<td>$0.305/Mcfe</td>
</tr>
<tr>
<td>C2 Recovery (1)</td>
<td>35% to 40%</td>
</tr>
<tr>
<td>Well Spacing</td>
<td>830’</td>
</tr>
</tbody>
</table>

**First Year Recovery Volumes**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Gross (Bcfe)</td>
<td>6.42</td>
</tr>
<tr>
<td>Net (Bcfe)</td>
<td>5.16</td>
</tr>
</tbody>
</table>

**Note:** Maintenance capital is net of ORRI transaction and VPP 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.

---

**$580 MM Maintenance D&C Capital**
Average Lateral Length per Well

59% Increase

Lateral Drilling Feet per Day

366% Increase

Drilling Days – Spud to Spud

64% Decrease

Completion Stages per Day

169% Increase

Note: Percentage increase and decrease arrows represent change in Marcellus data from 2014 through 2Q 2020.
• **Significant Reduction in Well Costs already “in-hand”**
  - Reduced well costs by ~30% ($3.5 million per well)

**Marcellus Well Cost Reductions (January 2019 AFE to Current 2020)**

- **$3.5 MM Per Well Reduction (30% Reduction)**
- Assumes 12,000 foot lateral

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>$11.6</td>
<td>$970/ft</td>
<td>$1.9</td>
<td>$9.7</td>
<td>$1.3</td>
<td>$8.5</td>
<td>$8.1</td>
</tr>
<tr>
<td>$11.5</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$11.0</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$10.5</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$10.0</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$9.5</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$9.0</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$8.5</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$8.0</td>
<td>$970/ft</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$7.5</td>
<td>$970/ft</td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

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

Recent Cost Reductions:
- Further drilling & completion efficiencies
- Expanded produced water services via AM pipeline system
- Further service cost deflation
1. Balance Capex with Cash Flow – LOE Reductions

- **Materially Reducing LOE**
  - Reducing LOE by 45% in 2020 (~$90 MM+)

### Antero Lease Operating Expense Reductions (2020 Target)

<table>
<thead>
<tr>
<th>Description</th>
<th>2020E LOE Pre-Water Savings Initiatives</th>
<th>Existing Wells Produced Water (after 90 days, 70% of total)</th>
<th>New 2020 Completions Produced Water (after 90 days, 30% of total)</th>
<th>Contined Water Initiative + Efficiencies</th>
<th>2020E LOE Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>$194.0</td>
<td>$42.0</td>
<td>$32.0</td>
<td>$16.0</td>
<td>$104.0</td>
<td></td>
</tr>
<tr>
<td>$0.15/Mcfe</td>
<td>$0.03/Mcfe</td>
<td>$0.03/Mcfe</td>
<td>$0.01/Mcfe</td>
<td>$0.08/Mcfe</td>
<td></td>
</tr>
<tr>
<td>45% Reduction ($90 MM+)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- $42 MM ($0.03/Mcfe) reduction driven by $6/Bbl savings related to wells already on sales
- $32 MM ($0.03/Mcfe) reduction driven by $6/Bbl savings related to new wells in 2020
- $16 MM ($0.01/Mcfe) reduction driven by trucking performance, service cost deflation and efficiencies
Significant Steps Taken to Strengthen Balance Sheet

The execution of $751 MM in asset sales, discounted senior note repurchases and the convertible notes offering has positioned AR to address upcoming bond maturities.

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>6/30/2020 Liquidity</td>
<td>$973</td>
</tr>
<tr>
<td>VPP Proceeds</td>
<td>$220</td>
</tr>
<tr>
<td>Convertible Notes Net Proceeds</td>
<td>$242</td>
</tr>
<tr>
<td>Tender Offer Repurchases (Aug 2020)</td>
<td>($335)</td>
</tr>
<tr>
<td>As Adjusted 6/30/2020 Liquidity</td>
<td>$1,100</td>
</tr>
<tr>
<td>ORRI Contingent Payments</td>
<td>$102</td>
</tr>
<tr>
<td>Expected 2H 2020 Free Cash Flow</td>
<td>$175</td>
</tr>
<tr>
<td>YE 2020E Liquidity (3)</td>
<td>$1,377</td>
</tr>
<tr>
<td>Remaining 2021 + 2022 Senior Notes</td>
<td>$985</td>
</tr>
</tbody>
</table>

Note: 6/30/2020 liquidity represents borrowing availability under AR’s credit facility based on $2.64 Bn of lender commitments, less $730 MM of letters of credit and less $926 MM of borrowings as of 6/30/2020.

1) Includes $183 MM of 2021 bonds tendered and repurchased @ $98, $88 MM of 2022 bonds tendered and repurchased @ $86 and $96 MM of 2023 bonds tendered and repurchased @78, plus accrued and unpaid interest.

2) Forecasted year-end 2020 liquidity assumes no change in bank credit facility. Includes 2Q 2021 contingent payment from ORRI transaction for comparison purposes to outstanding 2021 + 2022 bonds.

3) Remaining market value based on bond pricing as of 8/24/2020 of $97 for the senior notes due in 2021 and $83 for the senior notes due in 2022.
Develop Highest ROR Locations

**AR Resource Overview**

**Large Delineated 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 undrilled 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**
- ~1,000 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 (1)

---

1) Net revenue interest (NRI). Net of ORRI transaction. Assumes Antero achieves production thresholds under ORRI agreement generating contingent payments and satisfying development commitments.
Develop Highest ROR Locations - Premium NGL Price Realizations

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>
<tr>
<td>Blended</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Expected Premium / (Discount) to Mont Belvieu ($/Gal)</td>
<td>0.00 - 0.05</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

Mariner East

FROM BAKKEN

FROM ROCKIES

FROM PERMIAN

FROM ROCKIES

CONWAY

Mont Belvieu

AR is the largest C3+ producer with the most international exposure in Appalachia

Anchor shipper on ME2

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

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”

Producer Advantaged & Unconstrained: Antero Resources in Appalachia

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 July 2020. 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+). Assumes blended sales of 50% domestic and 50% international.
Antero’s average unhedged half cycle rate of return for its near-term development program areas is 52%.

Antero Half Cycle Well Economics by BTU Regime

Pre-tax Rate of Return (ROR)

- Marcellus - Highly Rich Gas 1250 BTU: 59%
- Marcellus - Highly Rich Gas 1225 BTU: 57%
- Marcellus - High Rich Gas 1275 BTU: 56%
- Marcellus - Highly Rich Gas 1215 BTU: 52%
- Utica - Dry Gas 1050 BTU: 48%
- Marcellus Dry Gas 1050 BTU: 42%

Note: Assumes 8/7/2020 strip pricing. Half cycle burdened, post-ORRI with 71% of AM fee, variable FT costs and no charge for G&A or land. Assumes 13,000’ lateral lengths, 180 days spud to 1st sales and 2,000 lb/ft completions.
• AR monetized 100 BBtu/d of its 2021 hedges for proceeds of $29 million, attributable to the volumes included in the recently announced ORRI transaction
• In conjunction with the VPP transaction, AR restructured some of its 2020 – 2023 hedges

Antero Natural Gas Hedge Profile (1)

Note: Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.375 Bcf/d in 2020 and flat production in 2021.
1) Strip pricing and hedge position as of 8/21/2020 pro forma for $29 million hedge monetization in July 2020 and VPP hedge restructuring (only for natural gas hedges - excludes liquids).
4.2 Bcf/d Firm Gas Takeaway

Firm Transport is a Competitive Advantage

- Gulf Coast
  - 51%
- Midwest
  - 19%
- Regional
  - 13%
- TCO Pool
  - 9%
- Atlantic Seaboard
  - 8%
- FT Destination
  - 4%
Firm Transport Protects Basis

Hedges + Firm Transportation + Liquids-Rich focus provides price stability and supports sustainable long-term development

Strategy: Pair Hedges & FT

Hedge Portfolio Supports Firm Pipeline Commitments

Firm Transportation Portfolio Allows Antero Resources to achieve:

Premium Price Certainty Eliminates basis risk by delivering to NYMEX-related markets

Effectively Hedge NYMEX Index Allows Antero to directly hedge the absolute price

Result: Low Natural Gas Pricing Volatility

Appalachia Differentials

Antero Realized Differential

Appalachian Average Basis

Antero Average Basis

Note: Pricing reflects pre-hedge pricing.
1) Reflects discount to NYMEX for Appalachia in-basin pricing at Dominion South & TETCO M2 indices.
2) Represents simple average discount to NYMEX for Antero firm transportation capacity.
**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>D&amp;C Capex Budget (1)</td>
<td>$1.275 B</td>
<td>$750 B</td>
<td>($0.525) B</td>
</tr>
<tr>
<td>F&amp;D Costs ($/Mcfe)</td>
<td>$0.44(2)</td>
<td>$0.30(3)</td>
<td>($0.14)</td>
</tr>
<tr>
<td>Cost Structure ($/Mcfe)</td>
<td>$2.48</td>
<td>$2.35</td>
<td>($0.13)</td>
</tr>
<tr>
<td>Asset Sales (YE)</td>
<td>$100 MM</td>
<td>$775 MM(4)</td>
<td>$875 MM</td>
</tr>
<tr>
<td>Total Debt (YE)</td>
<td>$3.8 B</td>
<td>$3.0 B</td>
<td>($800) MM</td>
</tr>
<tr>
<td>Gas Hedge Position</td>
<td>75% @ $2.50</td>
<td>92% @ $2.83</td>
<td>17% / $0.33</td>
</tr>
<tr>
<td>Net Production (1)</td>
<td>3.2 Bcfe/d</td>
<td>3.5 Bcfe/d</td>
<td>0.30 Bcfe/d</td>
</tr>
<tr>
<td>Liquids (1)</td>
<td>161 MBbl/d</td>
<td>190 MBbl/d</td>
<td>29 MBbl/d</td>
</tr>
<tr>
<td>PDP Reserves (YE) (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, is a non-GAAP measure. See appendix for more information.

(1) Represents 2019 actuals and 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 22% based on reduction of well cost AFE from $868/ft. at YE 2019 to current $675/ft.
(4) Assumes the midpoint of asset sale target of $750 MM to $1 B.
Antero is well positioned for both the commodity price outlook and energy transition as a large, low cost natural gas and NGL producer with strong ESG metrics.

### Key Investment Attributes

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scale / Operating Leverage</td>
<td>3rd Largest natural gas producer and 2nd largest NGL producer in the U.S. with exposure to strengthening commodity prices</td>
</tr>
<tr>
<td>Material Cost Reduction Initiatives</td>
<td>AR has targeted ~$616 MM in reductions to 2020 capital and operating expenses</td>
</tr>
<tr>
<td>Asset Sale Progress</td>
<td>AR has announced $751 MM of asset sales since December 2019</td>
</tr>
<tr>
<td>Unsecured Financing</td>
<td>Issued $250 MM of convertible senior notes due 2026 to refinance a portion of near term maturities</td>
</tr>
<tr>
<td>Free Cash Flow Profile</td>
<td>2020 capex budget of $750 MM positions Antero to generate $175 MM (1) of 2H2020 Free Cash Flow at current strip prices</td>
</tr>
<tr>
<td>Robust Liquidity</td>
<td>Pro forma YE 2020 estimated liquidity of $1.4 B to address the remaining 2021 and 2022 bond maturities</td>
</tr>
</tbody>
</table>

1) Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.
Antero Resources Executive Summary

Natural Gas & NGL Macro

Detailed Asset Overview

Appendix
Strategic Updates in 2020

**Convertible Note Issuance (8/18/2020)**
- $250 MM convertible senior note issuance due 2026
  - Coupon rate of 4.25% with $4.34 per share strike price
  - Demonstrates access to unsecured debt financing

**Closed VPP Transaction (8/11/2020)**
- $220 MM VPP sale to an affiliate of J.P. Morgan
  - Net production of 60 MMcf/d for second half of 2020, 75 MMcf/d in 2021 then declines to 40 MMcf/d by the first half of 2027
  - Transaction value based on pricing of NYMEX Henry Hub, less $0.60/MMBtu (transport costs and basis differentials)
  - Attractive mid-single digit cost of capital for PDP asset

**Announced Cash Tender Offer for 2021, 2022 & 2023 Notes (8/24/2020)**
- $367 MM of senior notes purchases:
  - Purchased $183 MM of 2021 senior notes at a 2% discount price of $98
  - Through modified Dutch tender offer purchased $88 MM of the 2022 senior notes at a 14% discount price of $86 and $96 MM of the 2023 senior notes at a 22% discount price of $78

**Closed ORRI Transaction With Sixth Street Partners (6/12/2020)**
- Overriding royalty interest (ORRI) transaction with Sixth Street for proceeds of $402 MM
- $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, respectively

**Hedge Monetization (July 2020)**
- Monetized 100 MMBtu/d of 2021 natural gas hedges in July 2020 for $29 MM to align hedges with 2021 projected net volumes, adjusted for the volumes associated with the ORRI transaction

**Debt Repurchases and Borrowing Base (4Q 2019 through 3Q 2020)**
- Have repurchased $1.3 B of senior notes including open market purchases and the recent debt tender at an average discount of 17% reducing absolute debt by~$210 MM and annualized interest expense by $33 MM
- Antero’s $2.85 B borrowing base remains unchanged following the ORRI and VPP transactions
### As Adjusted Capitalization Table

<table>
<thead>
<tr>
<th>AR Capitalization (in millions)</th>
<th>As Reported on June 30, 2020</th>
<th>VPP / Bond Repurchases / Tender Offer (1)</th>
<th>As Adjusted June 30, 2020</th>
<th>Adjustments for Convertible Senior Notes (2)</th>
<th>As Further Adjusted June 30, 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revolving Credit Facility</td>
<td>$926</td>
<td>$126</td>
<td>$1,052</td>
<td>($242)</td>
<td>$810</td>
</tr>
<tr>
<td>5.375% Senior Notes Due November 2021</td>
<td>$516</td>
<td>($199)</td>
<td>$317</td>
<td></td>
<td>$317</td>
</tr>
<tr>
<td>5.125% Senior Notes Due December 2022</td>
<td>$756</td>
<td>($88)</td>
<td>$668</td>
<td></td>
<td>$668</td>
</tr>
<tr>
<td>5.625% Senior Notes Due June 2023</td>
<td>$744</td>
<td>($134)</td>
<td>$610</td>
<td></td>
<td>$610</td>
</tr>
<tr>
<td>5.000% Senior Notes Due March 2025</td>
<td>$590</td>
<td>$0</td>
<td>$590</td>
<td></td>
<td>$590</td>
</tr>
<tr>
<td>Convertible Senior Notes Due 2026</td>
<td>$250</td>
<td></td>
<td>$250</td>
<td></td>
<td>$250</td>
</tr>
<tr>
<td>Net Debt (Total Debt – Cash) (2)(3)</td>
<td>$3,532</td>
<td>($294)</td>
<td>$3,237</td>
<td>$8</td>
<td>$3,245</td>
</tr>
<tr>
<td>LTM Adjusted EBITDAX (3)</td>
<td>$983</td>
<td></td>
<td>$983</td>
<td></td>
<td>$983</td>
</tr>
<tr>
<td>Net Debt / LTM Adjusted EBITDAX (3)</td>
<td>3.6x</td>
<td></td>
<td>3.3x</td>
<td></td>
<td>3.3x</td>
</tr>
</tbody>
</table>

**Note:** Capitalization excludes net unamortized debt issuance costs.

1) Pro forma for VPP proceeds of $220 million, hedge monetization of $29 million and bond repurchases that occurred between June 30, 2020 and August 17, 2020. Includes $183 MM of 2021 bonds tendered and repurchased @ $98, $88 MM of 2022 bonds tendered and repurchased @ $86 and $96 MM of 2023 bonds tendered and repurchased @78, plus accrued and unpaid interest.

2) Assumes convertible note transaction fees and legal expenses of $8 million. Assumes no exercise of greenshoe.

3) Adjusted EBITDAX and net debt are non-GAAP metrics – see appendix for details.
Antero intends to “net share settle” the convertible notes but will have the option upon conversion to settle in cash, shares, or any combination:
- Non-callable for 3.5 years
- Callable on or after 3/1/24 if stock price exceeds 130% of conversion price for a specified period of time

Antero repurchased ~37MM shares since 4Q19 at an average price of $1.75

Net Share Settle Illustration

Conversion example at $6.00/share
Conversion value = $6.00 x 57.6MM = $345MM
Settled in cash = $250 MM
Settled in shares = $95MM ÷ $6.00 per share = 15.9 MM shares or 5.9% dilution

Net Share Settle Value ($MM)  Par Value ($MM)  Total Conversion Value ($MM)

AR Share Price Assumption at Conversion ($/Share)

Stock appreciation from $3.62
0%  38%  66%  93%  121%  149%  176%  204%  232%  259%

Note: $3.62 share price reflects closing price on date of issuance. Based on pre-conversion shares outstanding of 268 MM. Chart assumes conversion at maturity. The impact of a “make-whole fundamental change” is not incorporated in the chart above.
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 Oil and Pentane (C5) Hedge Profile

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 in 2021.

1) Based on hedge position and strip pricing as of 8/21/2020.
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.
Antero Non-GAAP Measures

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 a reconciliation 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. In 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.
### Antero Resources Net Debt & LTM EBITDAX Reconciliation

#### Reconciliation of net loss to Adjusted EBITDAX:

<table>
<thead>
<tr>
<th>Description</th>
<th>December 31, 2019</th>
<th>June 30, 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net loss and comprehensive loss attributable to Antero Resources Corporation</td>
<td>$ (2,163,686)</td>
<td></td>
</tr>
<tr>
<td>Net loss and comprehensive loss attributable to noncontrolling</td>
<td>(46)</td>
<td></td>
</tr>
<tr>
<td>Depletion, depreciation, amortization, and accretion</td>
<td>850,159</td>
<td></td>
</tr>
<tr>
<td>Impairment of oil and gas properties</td>
<td>1,214,771</td>
<td></td>
</tr>
<tr>
<td>Impairment of midstream assets</td>
<td>7,800</td>
<td></td>
</tr>
<tr>
<td>Commodity derivative fair gains</td>
<td>(610,731)</td>
<td></td>
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<tr>
<td>Gains on settled commodity derivatives</td>
<td>708,137</td>
<td></td>
</tr>
<tr>
<td>Equity-based compensation expense</td>
<td>19,409</td>
<td></td>
</tr>
<tr>
<td>Provision for income tax benefit</td>
<td>(632,458)</td>
<td></td>
</tr>
<tr>
<td>Gain on early extinguishment of debt</td>
<td>(156,151)</td>
<td></td>
</tr>
<tr>
<td>Equity in loss of unconsolidated affiliates</td>
<td>278,709</td>
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</tr>
<tr>
<td>Impairment of equity investment</td>
<td>1,078,222</td>
<td></td>
</tr>
<tr>
<td>Distributions/dividends from unconsolidated affiliates</td>
<td>182,940</td>
<td></td>
</tr>
<tr>
<td>Loss on sale of equity investments</td>
<td>108,745</td>
<td></td>
</tr>
<tr>
<td>Water earnout</td>
<td>(125,000)</td>
<td></td>
</tr>
<tr>
<td>Gain on sale of assets</td>
<td>(31)</td>
<td></td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>206,910</td>
<td></td>
</tr>
<tr>
<td>Exploration expense</td>
<td>885</td>
<td></td>
</tr>
<tr>
<td>Contract termination and rig stacking</td>
<td>11,133</td>
<td></td>
</tr>
<tr>
<td>Transaction fees</td>
<td>6,138</td>
<td></td>
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<tr>
<td><strong>Adjusted EBITDAX</strong></td>
<td><strong>985,855</strong></td>
<td></td>
</tr>
<tr>
<td>Description</td>
<td>December 31, 2019</td>
<td></td>
</tr>
<tr>
<td>----------------------------------------------------------------------------</td>
<td>-------------------</td>
<td></td>
</tr>
<tr>
<td>Net loss and comprehensive loss attributable to Antero Resources Corporation</td>
<td>$340,129</td>
<td></td>
</tr>
<tr>
<td>Net income and comprehensive income attributable to noncontrolling interests</td>
<td>46,993</td>
<td></td>
</tr>
<tr>
<td>Commodity derivative fair value gains</td>
<td>(463,972)</td>
<td></td>
</tr>
<tr>
<td>Losses on settled commodity derivatives</td>
<td>325,090</td>
<td></td>
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<tr>
<td>Loss on sale of assets</td>
<td>951</td>
<td></td>
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<tr>
<td>Gain on deconsolidation of Antero Midstream</td>
<td>(1,406,042)</td>
<td></td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>228,111</td>
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</tr>
<tr>
<td>Gain on early extinguishment of debt</td>
<td>(36,419)</td>
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</tr>
<tr>
<td>Provision for income tax benefit</td>
<td>(74,110)</td>
<td></td>
</tr>
<tr>
<td>Depletion, depreciation, amortization, and accretion</td>
<td>918,629</td>
<td></td>
</tr>
<tr>
<td>Impairment of oil and gas properties</td>
<td>1,300,444</td>
<td></td>
</tr>
<tr>
<td>Impairment of midstream assets</td>
<td>14,782</td>
<td></td>
</tr>
<tr>
<td>Impairment of equity investments</td>
<td>467,590</td>
<td></td>
</tr>
<tr>
<td>Exploration expense</td>
<td>884</td>
<td></td>
</tr>
<tr>
<td>Equity-based compensation expense</td>
<td>23,559</td>
<td></td>
</tr>
<tr>
<td>Equity in loss of unconsolidated affiliate - AMC</td>
<td>143,216</td>
<td></td>
</tr>
<tr>
<td>Distributions from unconsolidated affiliates</td>
<td>157,956</td>
<td></td>
</tr>
<tr>
<td>Contract termination and rig stacking</td>
<td>14,026</td>
<td></td>
</tr>
<tr>
<td>Loss on sale of equity investment shares</td>
<td>108,745</td>
<td></td>
</tr>
<tr>
<td>Water earnout</td>
<td>(125,000)</td>
<td></td>
</tr>
<tr>
<td>Simplification transaction fees</td>
<td>15,482</td>
<td></td>
</tr>
<tr>
<td><strong>Antero Midstream Related Adjustments</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net income and comprehensive income attributable to noncontrolling interests</td>
<td>(46,993)</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream interest expense, net</td>
<td>(16,815)</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream loss on extinguishment of debt</td>
<td>(21,770)</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream depreciation, accretion of ARO and accretion of contingent consideration</td>
<td>(6,982)</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream impairment</td>
<td>(2,477)</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream equity-based compensation expense</td>
<td>12,264</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream gain on sale</td>
<td>(61,319)</td>
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</tr>
<tr>
<td>Antero Midstream equity in earnings of unconsolidated affiliates</td>
<td>(15,021)</td>
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</tr>
<tr>
<td>Antero Midstream distributions from unconsolidated affiliates</td>
<td>95,183</td>
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</tr>
<tr>
<td>Equity in earnings of Antero Midstream</td>
<td>—</td>
<td></td>
</tr>
<tr>
<td>Distributions from Antero Midstream</td>
<td>—</td>
<td></td>
</tr>
<tr>
<td>Antero Midstream simplification transaction fees</td>
<td>(9,185)</td>
<td></td>
</tr>
<tr>
<td><strong>Adjusted EBITDAX</strong></td>
<td>$1,247,671</td>
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</tbody>
</table>