



Second Quarter 2019 Earnings Call Presentation

AUGUST 1, 2019

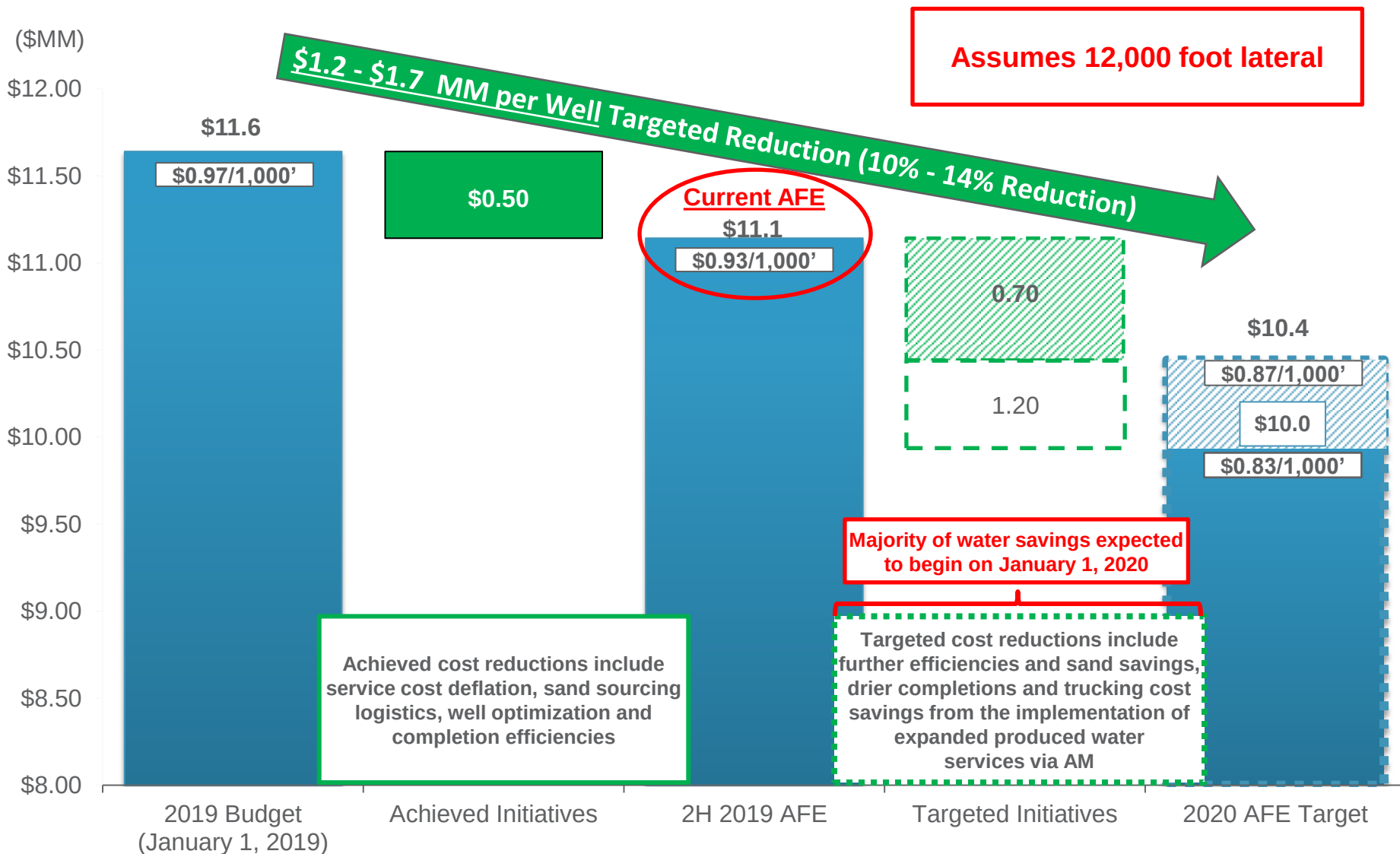
This presentation includes “forward-looking statements.” Such forward-looking statements are subject to a number of risks and uncertainties, many of which are not under AR’s control. All statements, except for statements of historical fact, made in this presentation regarding activities, events or developments 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, 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 Antero Midstream, which are subject to Board approval by the Board of Antero Midstream, and there can be no assurance that such approval will be obtained, future financial position, future technical improvements and future marketing opportunities, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All forward-looking statements speak only as of the date of this 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, 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, 2018 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2019.

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, and (ii) Net Debt. Please see “Antero Definitions” and “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.

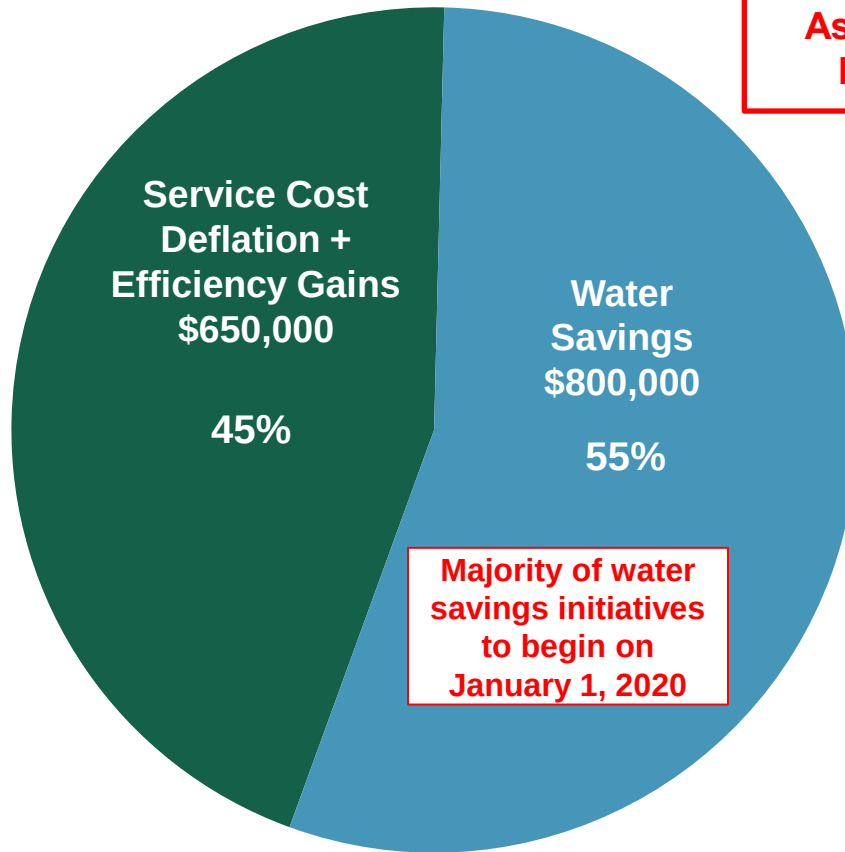
Targeted Marcellus Well Cost Reductions (January 2019 AFE to 2020 Target)



Cost Reduction Initiatives Breakdown

AR has achieved approximately \$500,000 per well in cost reductions since the January 2019 budget with the remaining ~\$950,000 per well expected to begin in 2020

Targeted Marcellus Well Cost Reductions Percentage Breakdown ⁽¹⁾



Assumes 12,000'
lateral length

Majority of water
savings initiatives
to begin on
January 1, 2020

Well Cost Reduction Calculation (Midpoint of Target Range)

$$\frac{\$1.45 \text{ MM}}{12,000'} = \$0.12 \text{ MM} / 1,000' \text{ Reduction}$$

$$\$0.97 - \$0.12 = \$0.85 \text{ MM} / 1,000'$$

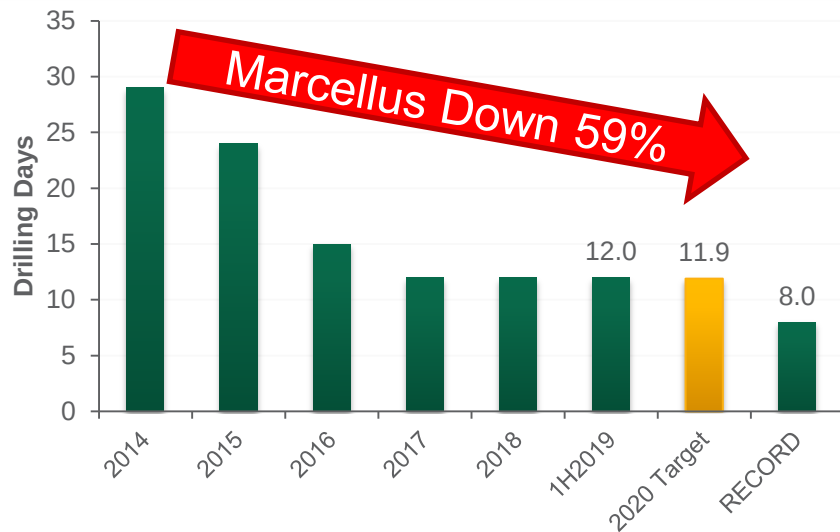
\$1.45 MM per well Cost Reduction ⁽¹⁾

Note: Assumes 12,000 foot lateral.

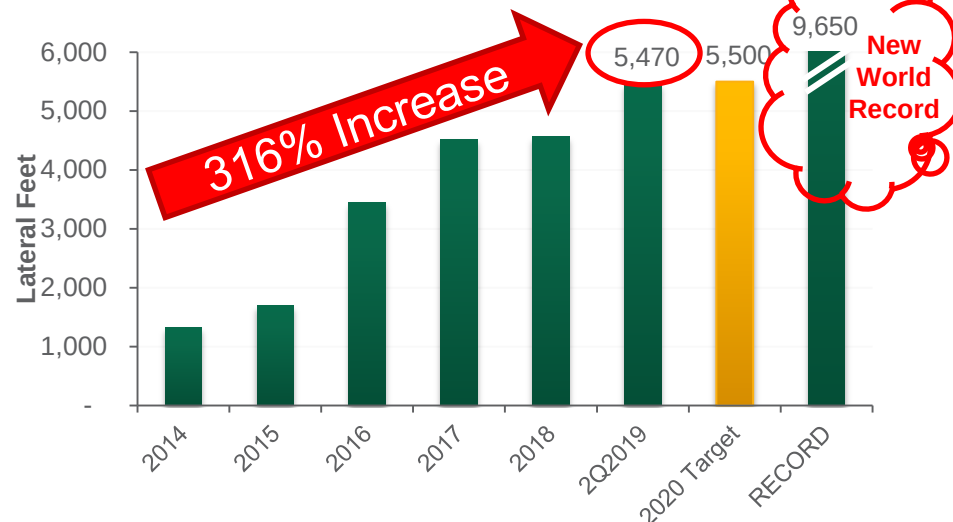
1) Total per well cost reduction of \$1.45 MM and percentages breakout are based on the midpoint of total targeted well cost savings.

Marcellus Drilling and Completion Efficiencies

Drilling Days



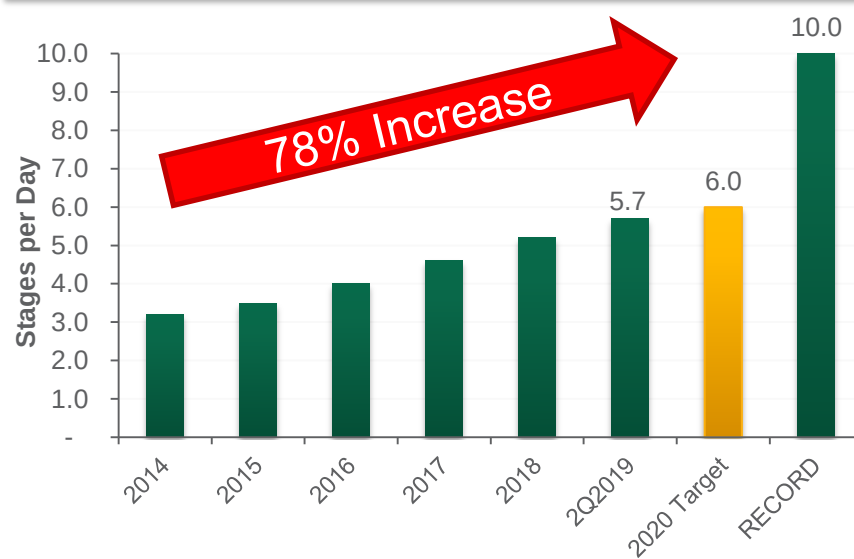
Average Lateral Feet Drilled per Day



Average Lateral Length Drilled per Well

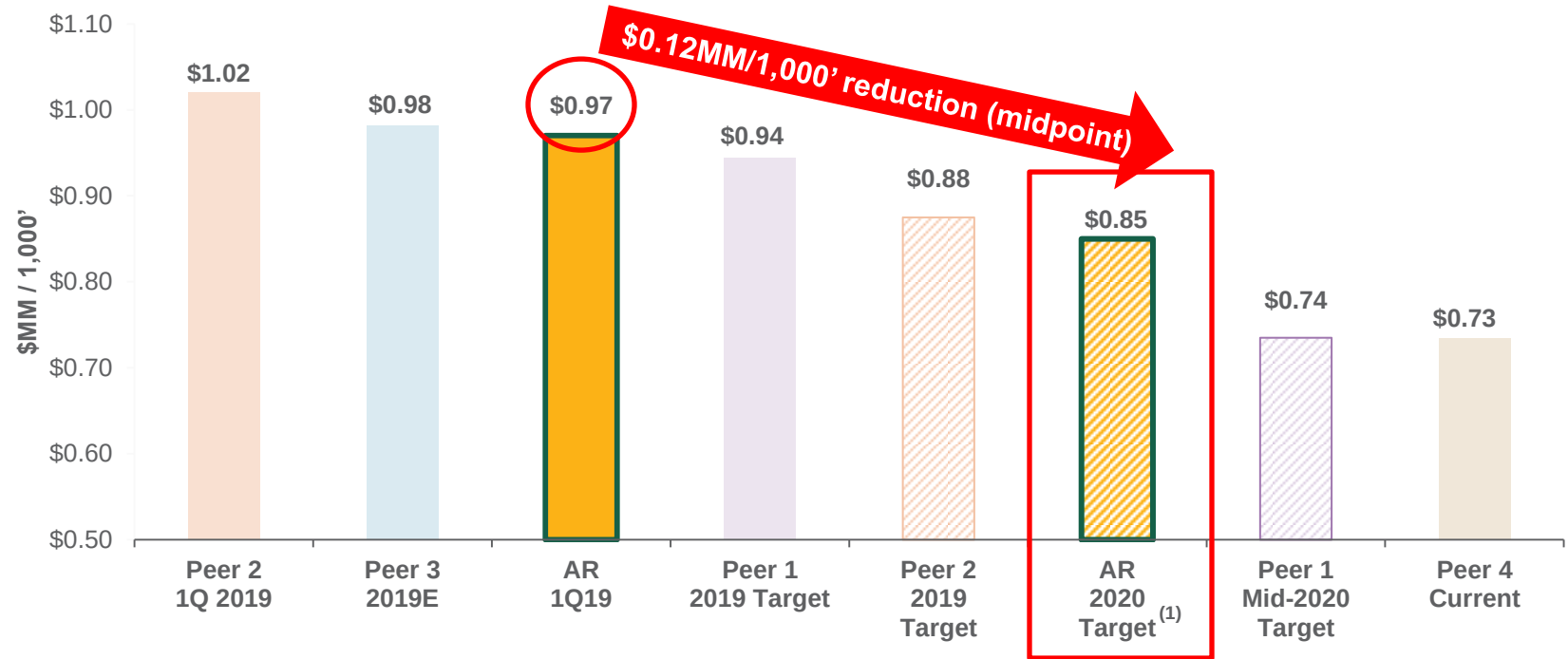


Completion Stages per Day



Appalachian Peer Marcellus Well Cost Comparison

Southwest Marcellus Peer Well Costs (\$MM/1,000')



Average Lateral Length	10,000	9,300	12,000	10,462	10,000	12,000	12,000	10,000
Proppant (lbs/ft) ⁽²⁾	2,167	2,315	2,000	2,700	?	2,000	2,200	1,451
Water (Bbls/ft) ⁽²⁾	35	38	42	37	?	35	47	37

Note: Based on company public data via press releases and investor presentations unless denoted as otherwise.
 1) AR 2020 target based on midpoint of \$0.83/1,000' to \$0.87/1,000' well cost target range. See slide three for details.
 2) Represents IHS data. Peers include CNX, EQT, RRC and SWN.

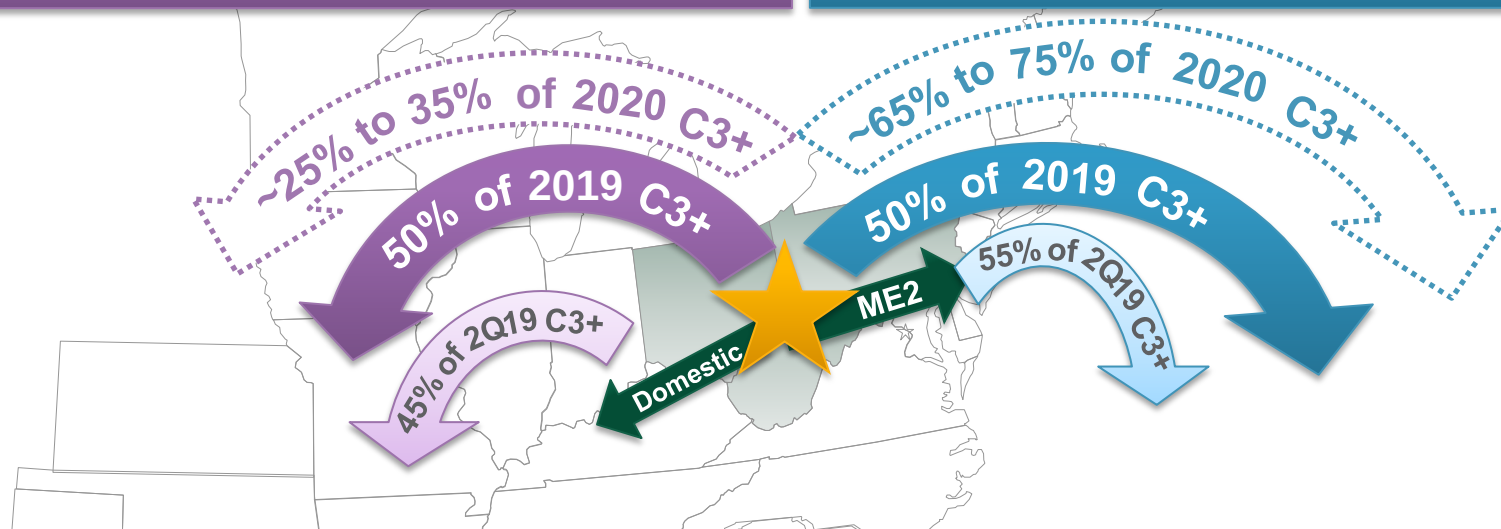
Inflection Point in NGL Marketing and Pricing

With the first full quarter of the ME2 pipeline in service, Antero realized a \$0.19 per gallon premium to Mont Belvieu on 55% of its C3+ NGLs

Diversified exposure to both international and domestic markets results in Antero realizing a C3+ NGL sales price effectively in line with Mont Belvieu pricing

Domestic Markets

International Markets



AR 2Q 2019 C3+ NGL Realized Pricing Breakdown ⁽¹⁾

	Domestic ⁽²⁾	International ⁽³⁾	2Q 2019 Average
Sales Point	Hopedale	Marcus Hook	Blended
% of AR C3+ Volume	45%	55%	100%
Premium / (Discount) to Mont Belvieu (\$/Gal)	(\$0.14)	\$0.19	\$0.04

Antero 2019 C3+ NGL Pricing Guidance ⁽¹⁾

	Domestic	International	Combined
Sales Point	Hopedale	Marcus Hook	Blended
% of AR C3+ Volume	50%	50%	100%
Expected Premium / (Discount) to Mont Belvieu (\$/Gal)	(\$0.075) - (\$0.125)	\$0.10 - \$0.15	(\$0.01) - \$0.04

Note: 2020 blend of 70% international / 30% domestic assumes ME2 is fully in service with 275,000 Bbl/d of capacity.

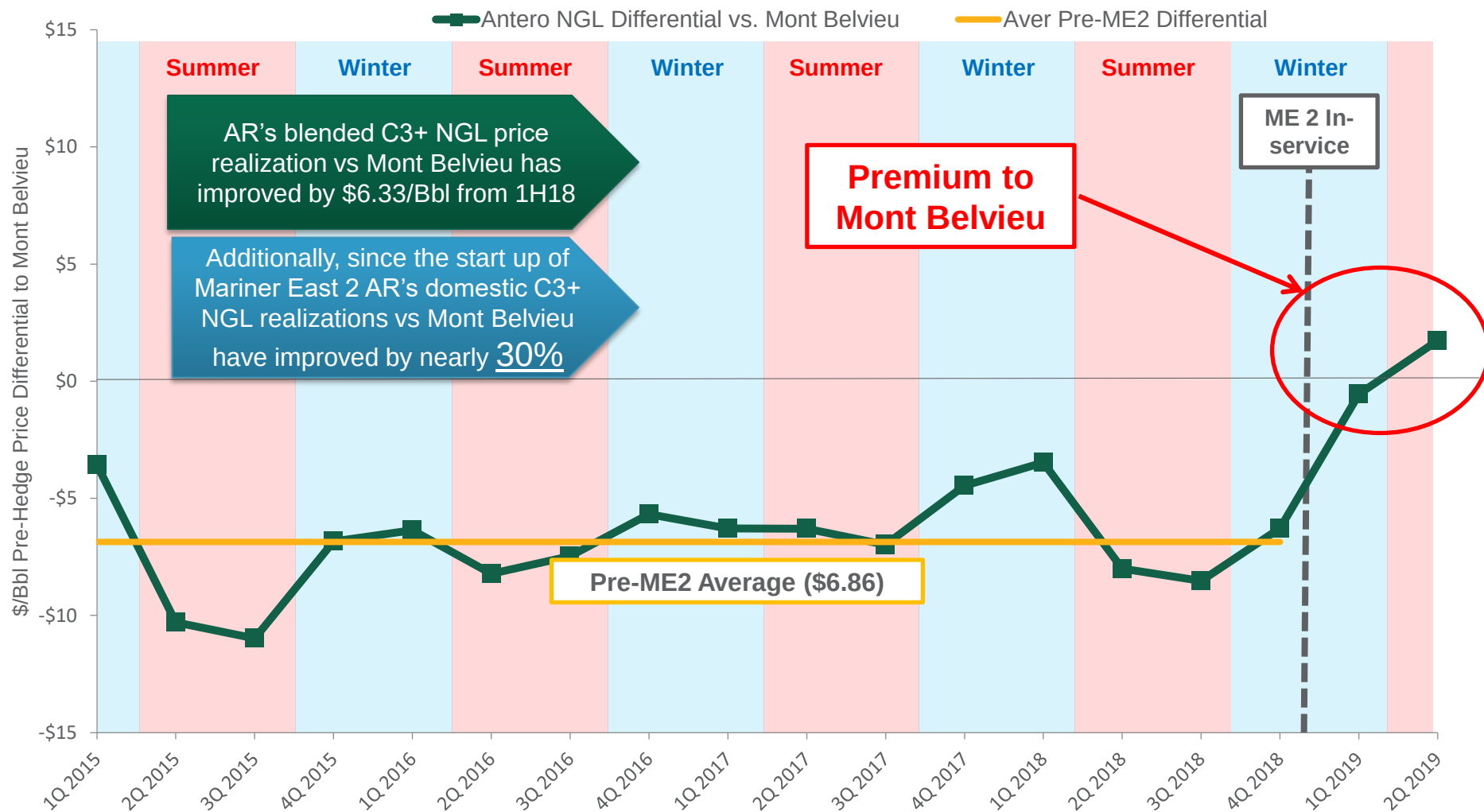
1) Based on Antero C3+ NGL component barrel which consists of 56% C3 (propane), 10% isobutane (Ic4), 17% normal butane (Nc4) and 17% natural gasoline (C5+).

2) Domestic pricing

Improvement in Northeast NGL Differentials

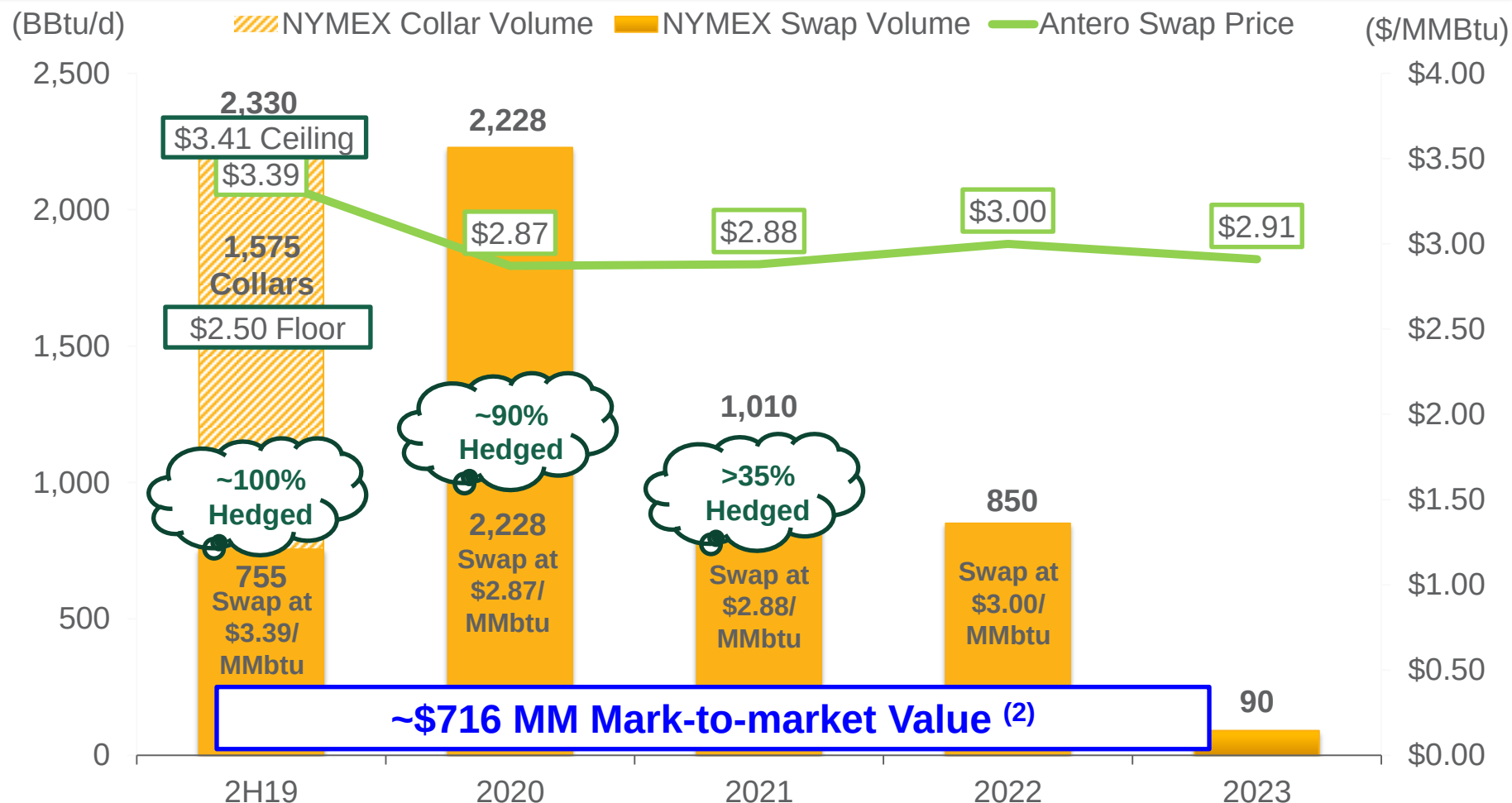
The 1Q 2019 in-service of Mariner East II has improved AR's 1H 2019 NGL price differentials to Mont Belvieu by \$6.33/Bbl vs 1H18, flipping to a premium to Mont Belvieu

Antero Blended NGL Differential vs. Mont Belvieu



AR has consistently executed a comprehensive commodity hedging program with \$4.5 billion of realized hedge gains since 2008 ⁽¹⁾

Antero Natural Gas Hedge Profile



Note: Percentage hedged represents percent of expected natural gas production hedged based on a 10% CAGR from the midpoint of 2019 natural gas production guidance.

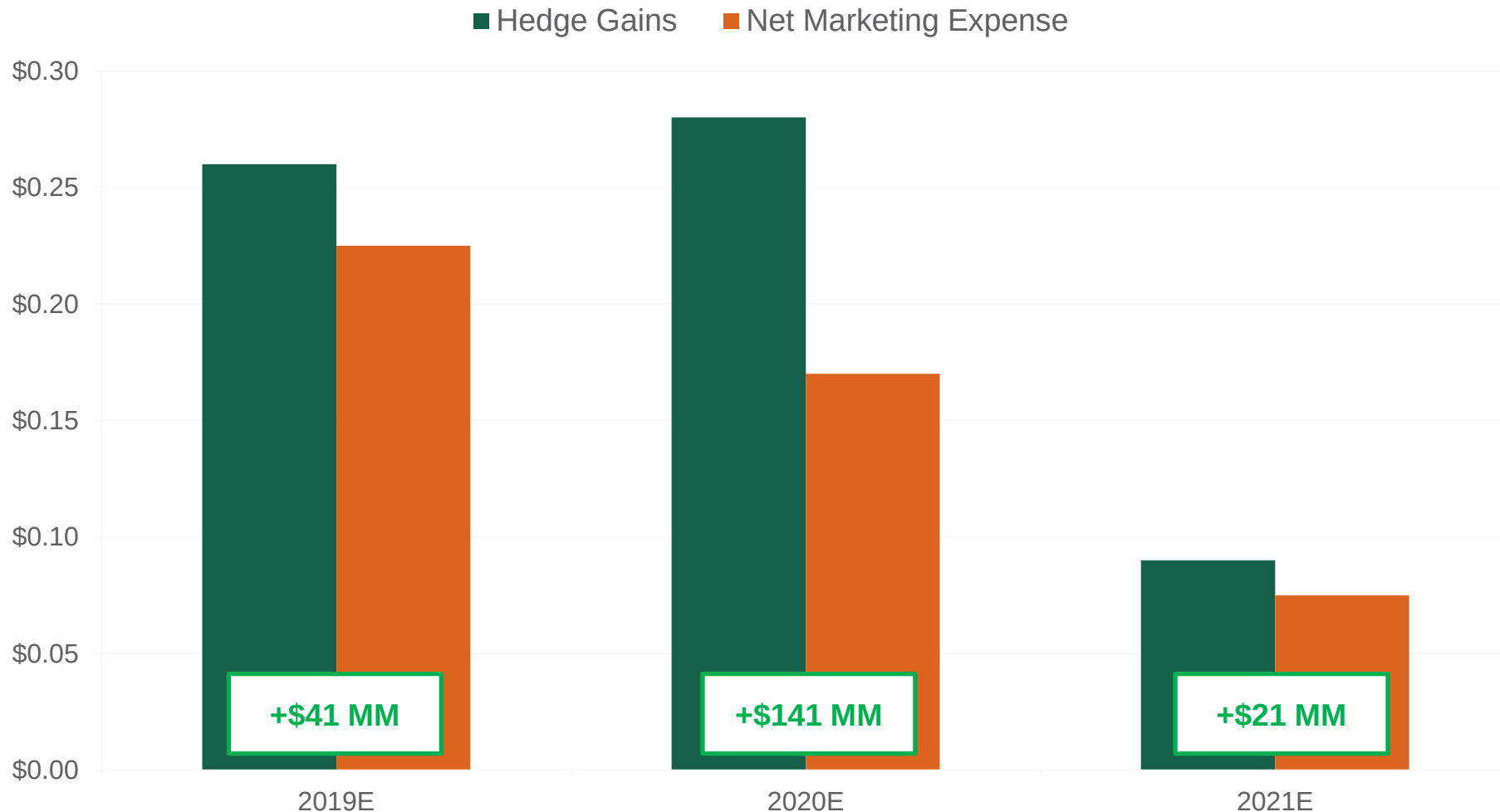
1) Through 6/30/19.

2) Based on hedge position and strip pricing as of 6/30/19.

AR Hedge Gains Offset Net Marketing Expense

Antero's hedge gains offset net marketing expense through 2021 until the point in 2022 when the firm transportation is essentially filled ⁽¹⁾

Hedge Gains vs Net Marketing Expense (\$/Mcf)



Note: 2019 expected net marketing expense based on updated 2019 guidance.

1) 2019E hedge gains include actual settled derivatives through 6/30/19. Hedge position as of 6/30/2019 and hedge gains based on strip pricing as of 7/30/2019.

2) Net marketing expense represents forecasted unutilized transport cost divided into estimated production assuming 10% production CAGR off of midpoint of 2019 guidance.

AR Hedge Book Leads Appalachian Peers

During 2Q 2019, AR layered on 810 MMBtu/d of 2020 natural gas hedges increasing its percentage of expected natural gas production volume to ~90%

2020 Appalachian Peer Hedge Profile

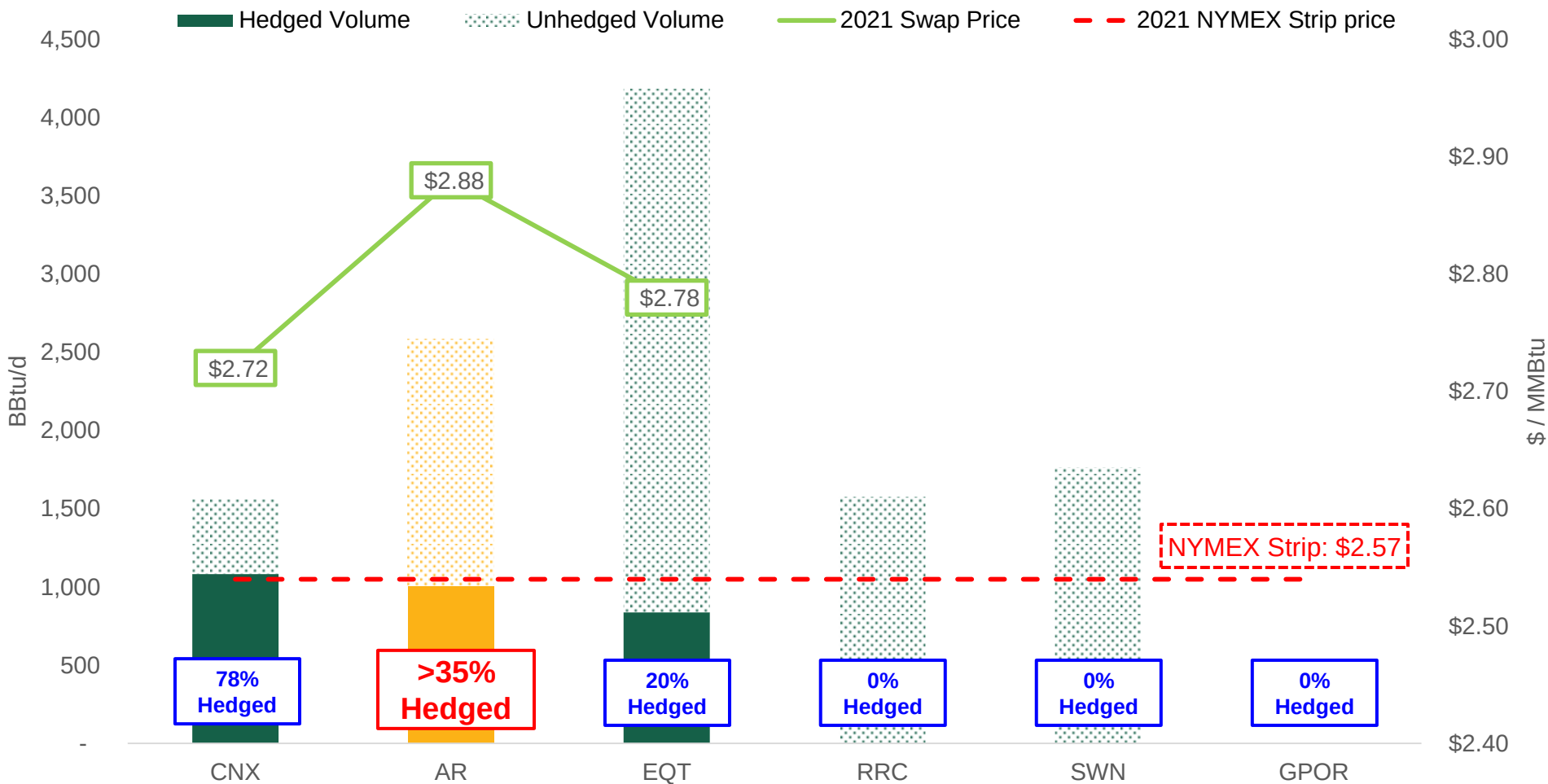


Source: Bloomberg, Public Data; AR internal estimates.

Note: NYMEX Strip Price as of 7/29/2019. AR production based on 10% growth from the midpoint of 2019 guidance and peer percentage of production hedged is based on consensus natural gas production as of 7/29/2019.

During 2Q 2019, AR layered on 300 MMBtu/d of 2021 natural gas hedges increasing its percentage of expected natural gas production volume to over 35%

2021 Appalachian Peer Hedge Profile



Source: Bloomberg, Public Data; AR internal estimates.

Note: NYMEX Strip Price as of 7/29/2019. AR production based on 10% growth CAGR from midpoint of 2019 production guidance. Peer percentage of production hedged is based on consensus natural gas production as of 7/29/2019.

Antero has the liquidity, scale, deep inventory and capital efficiency to continue to develop in today's commodity price environment

Strong Financial Position

- Low 2x leverage with \$730 MM absolute debt reduction since 2014 ⁽¹⁾
- AM share ownership of \$1.4 B provides \$200 MM+ of annual cash flow via dividends
- World class hedge book with \$712 MM mark-to-market ⁽¹⁾
- Credit facility of \$4.5 B reaffirmed in 2Q19
- Only \$175 MM drawn on revolver with \$2.5 B in lender commitments
- Strong corporate debt ratings of Ba2/BB+/BBB-

Scale and Capital Efficiency

- Large, growing production base and prudent growth with capital spending approximately within cash flow
- Low average annual maintenance capital on sizable production base
- Peer-leading liquids-rich inventory provides running room and diversified, resilient commodity mix through price cycles

Credit Facility Summary



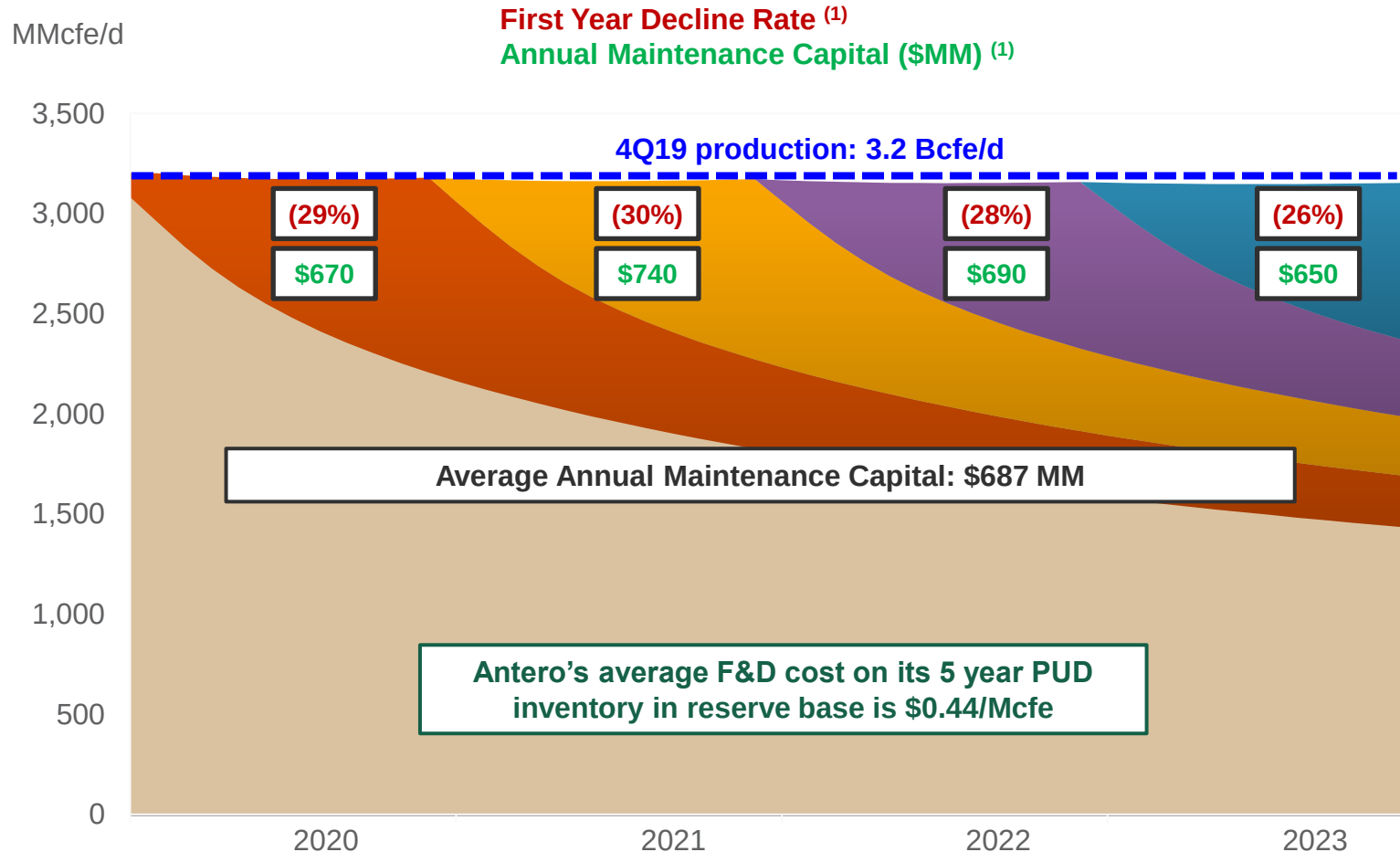
Note: Revolver borrowings as of 6/30/2019. AR market cap and AM share value as of 7/29/2019.

1) Leverage, liquidity and hedge mark-to-market as of 6/30/2019. See appendix for Non-GAAP items and reconciliation. Leverage is calculated as net debt / LTM adjusted EBITDAX.

Maintenance Capital and Decline Rate Projections

- Capital required to maintain flat production is a function of the base decline rate, which is a function of growth over the prior 12 months, as well as the beginning production level and capital efficiency

3.2 Bcfe/d – AR's 4Q 2019 Production



Note: Based on Antero reservoir engineering team analysis.

1) Represents capital required each year to maintain production at the respective target levels (3.2 Bcfe/d). Decline rate represents Q4 over Q4 change in production.

Producer resiliency is a key attribute for a sustainable development plan:



Scale / Liquids Diversification

Largest NGL producer and 4th largest gas producer with ~1,700 premium undrilled core locations with breakeven natural gas prices below current strip pricing ⁽¹⁾



Ongoing Capital Efficiency Initiatives

Targeting 10% - 14% lower well costs and lower D&C capital in 2020 ⁽²⁾ and at least 20% lower per unit LOE over the next 12 months



World Class Hedge Book

100% of natural gas hedged in 2019 and ~90% and over 35% of projected natural gas production hedged in 2020 and 2021, respectively



Industry-Leading FT Portfolio

Delivers NYMEX+ natural gas pricing ⁽³⁾ and Mont Belvieu+ NGL pricing on LPG exported volumes



Strong Balance Sheet

2.3x leverage, \$1.6 B of liquidity and strong credit ratings of Ba2/BB+/BBB- ⁽³⁾

The AR business model delivers multiple ways to “Win”

(1) Strip pricing as of 7/30/2019.

(2) Refer to slide three for details. Assumes similar well completion activity to 2019 guidance of ~120 wells turned in line.

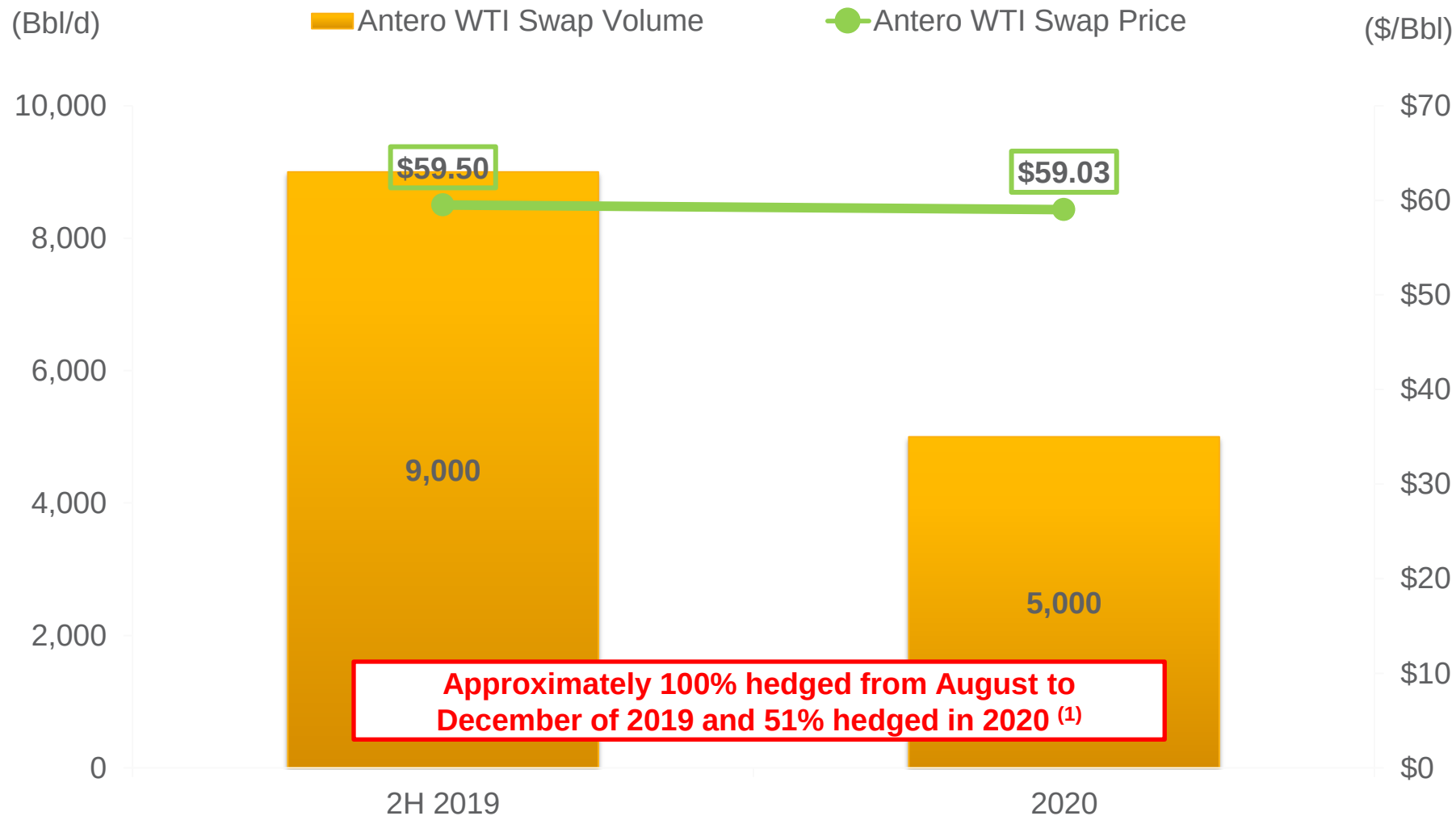
(3) After adjusting for Btu.

(4) See appendix for Non-GAAP items and reconciliation. Leverage is calculated as net debt / LTM adjusted EBITDAX. Leverage as of 6/30/19.



Appendix

Antero Oil Hedge Profile

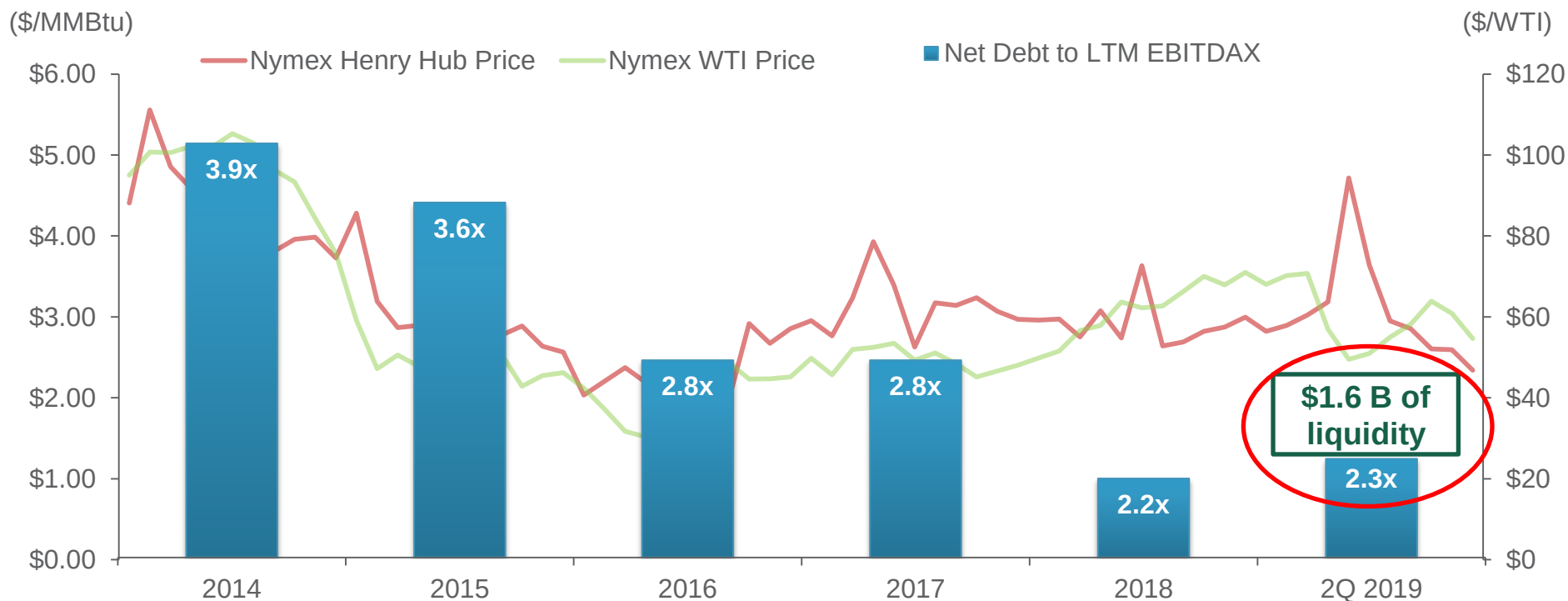


1) Assumes 10% production growth from midpoint of 2019 guidance.

Deleveraging Through Commodity Price Volatility

AR has reduced its leverage from 3.9x at YE 2014 to 2.3x at 2Q 2019, despite a ~36% reduction in average NYMEX natural gas prices and a ~40% reduction in WTI oil prices

AR Net Debt / LTM EBITDAX Since 2014⁽¹⁾



Operational Achievements From 2014 to 2Q19

Reduced drilling days by ~60% in the Marcellus

Increased average lateral feet drilled per day by >3,000 feet

Increased lateral lengths per well by nearly 30%

Increased completion stages per day by over 70%

Reduced Marcellus per well costs by ~\$500K

(1) EBITDAX and Net Debt are non-GAAP measures. Please see appendix.

AR has the capital efficiency, financial strength and scale to deliver a right-sized development plan in today's commodity price environment

		2014	2019E		Change
Operations and Efficiency	D&C Capex Budget	\$2.6 Bn	\$1.3 Bn	↓	(\$1.3) Bn
	Drilling Rigs	21	4	↓	(17)
	PUD Development Costs (\$/Mcfe) ⁽¹⁾	\$0.92	\$0.44	↓	(\$0.48)
Financial Strength	Total Debt	\$4.4 B	\$3.6 B ⁽²⁾	↓	(\$800)MM
	Leverage	3.9x	2.3x ⁽²⁾	↓	(1.6x)
	Current Year Gas % Hedged	100%	100%	↔	No change
Scale	Net Production	1.0 Bcfe/d	3.2 Bcfe/d	↑	2.2 Bcfe/d
	Liquids Production	4 MBbl/d	149 MBbl/d	↑	145 MBbl/d
	Proved Developed Reserves	3.8 Tcfe	10.4 Tcfe ⁽³⁾	↑	6.6 Tcfe
	Proved Reserves	12.7 Tcfe	18.0 Tcfe ⁽³⁾	↑	5.3 Tcfe

(1) Per unit PUD development costs represent year end 2014 and year end 2018 costs per Mcfe, respectively. (3) Reserve data as of 12/31/2014 and 12/31/2018, respectively.

(2) Total debt and leverage as of 6/30/2019.

Adjusted EBITDAX: 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, gain or loss on early extinguishment of debt, gain or loss on sale of assets, gain or loss on changes in the fair value of contingent acquisition consideration, contract termination and rig stacking costs, and equity in earnings or loss of Antero Midstream. Adjusted EBITDAX also includes distributions received from limited partner interests in Antero Midstream common units prior to the closing of the simplification transaction on March 12, 2019.

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.

Proved Undeveloped (PUD) F&D Cost Per Unit: Proved undeveloped F&D costs per unit 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. Proved undeveloped F&D costs per unit 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 proved undeveloped F&D costs per unit, and therefore a reconciliation to GAAP is not practicable.

The calculation for proved undeveloped F&D cost per unit is based on future development costs required for the development of proved undeveloped reserves, divided by total proved undeveloped reserves.

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, gain or loss on early extinguishment of debt, gain or loss on sale of assets, gain or loss on changes in the fair value of contingent acquisition consideration, contract termination and rig stacking costs, and equity in earnings or loss of Antero Midstream. Adjusted EBITDAX also includes distributions received from limited partner interests in Antero Midstream 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 gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of Antero's operations from period to period by removing the effect of its capital structure from its operating structure; and
- is used by 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. Adjusted EBITDAX, as defined by our credit facility, is used by our lenders pursuant to covenants under our revolving credit facility and the indentures governing the Company's senior notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the Company's net income, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. 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.

LTM Adjusted EBITDAX Reconciliation

	Twelve months ended June 30, 2019	
(in thousands)		
Net income and comprehensive income attributable to Antero Resources Corporation	\$	744,966
Commodity derivative fair value gains		(85,692)
Gains on settled commodity derivatives		187,678
Marketing derivative fair value gains		43
Losses on settled marketing derivatives		(21,471)
Gain on sale of assets		951
Gain on deconsolidation of Antero Midstream Partners LP		(1,406,042)
Interest expense		226,390
Income tax expense		193,555
Depletion, depreciation, amortization, and accretion		909,012
Impairment of unproved properties		567,707
Exploration expense		2,042
Gain on change in fair value of contingent acquisition consideration		100,840
Equity-based compensation expense		34,167
Equity in (earnings) loss of Antero Midstream Partners LP		(58,411)
Equity in (earnings) loss of unconsolidated affiliates		(15,402)
Distributions from Antero Midstream Partners LP		178,925
Contract termination and rig stacking		13,964
Simplification transaction fees		6,297
Adjusted EBITDAX	\$	1,588,519
AR bank credit facility	\$	175,000
5.375% AR senior notes due 2021		1,000,000
5.125% AR senior notes due 2022		1,100,000
5.625% AR senior notes due 2023		750,000
5.000% AR senior notes due 2025		600,000
Net unamortized premium		1,095
Net unamortized debt issuance costs		(23,716)
Total debt		3,602,379
Less: AR cash and cash equivalents		—
Debt	\$	3,602,379