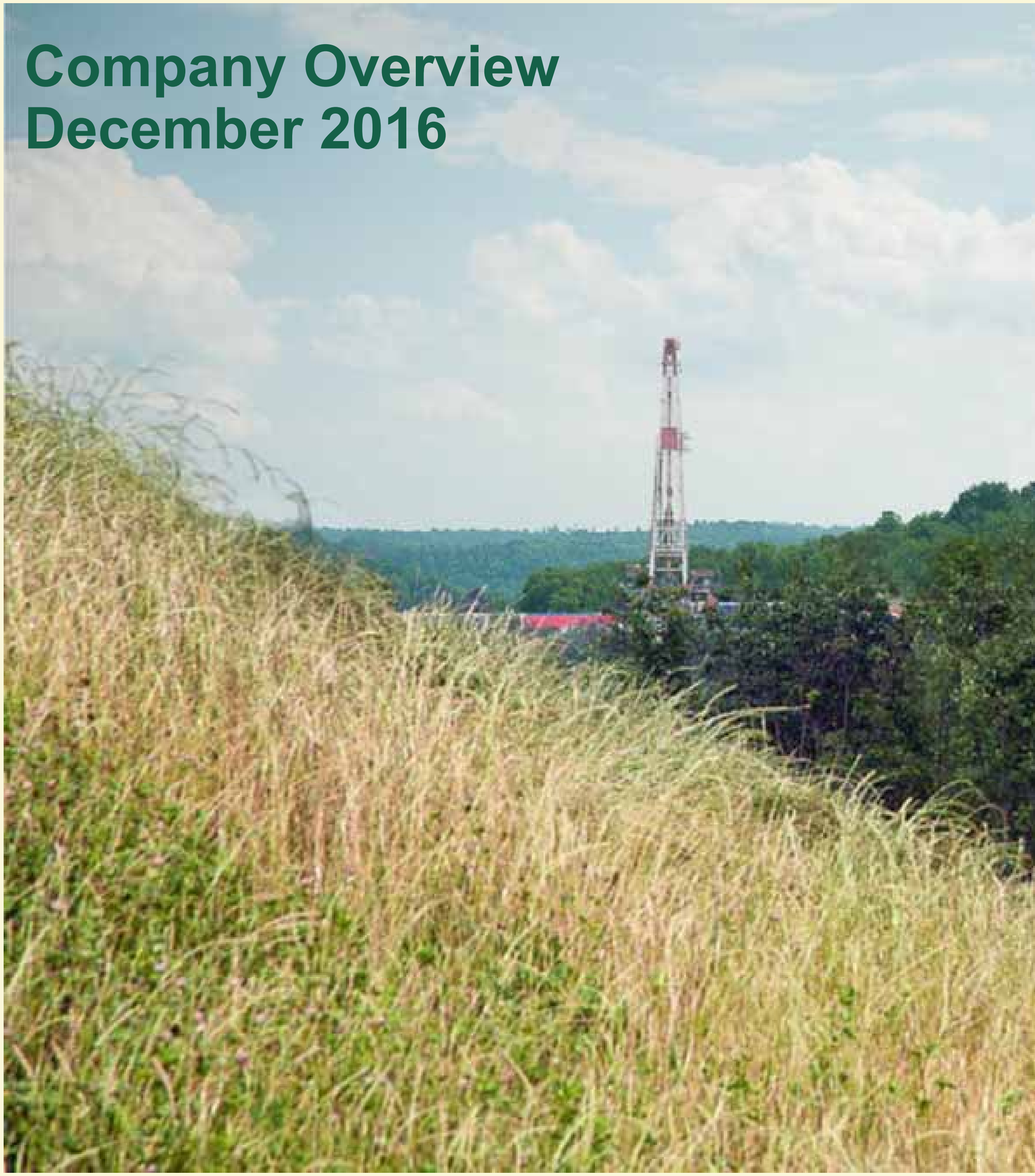
Company Overview
December 2016



FORWARD-LOOKING STATEMENTS

This presentation contains 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 statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Antero Resources Corporation and its subsidiaries (collectively, the "Company" or "Antero") expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "estimate," "project," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include estimates of the Company's reserves, expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company's subsequent filings with the SEC.

The Company cautions you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company's subsequent filings with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Antero Resources Corporation is denoted as "AR" and Antero Midstream Partners LP is denoted as "AM" in the presentation, which are their respective New York Stock Exchange ticker symbols.

ANTERO PROFILE

Market Cap………………….... $8.3 billion

Enterprise Value[(1)]…...........…$14.2 billion

LTM EBITDAX…………...…….$1.4 billion

Net Debt/LTM EBITDAX[(2)]…3.3x

Net Production (3Q 2016)… 1,875 MMcfe/d

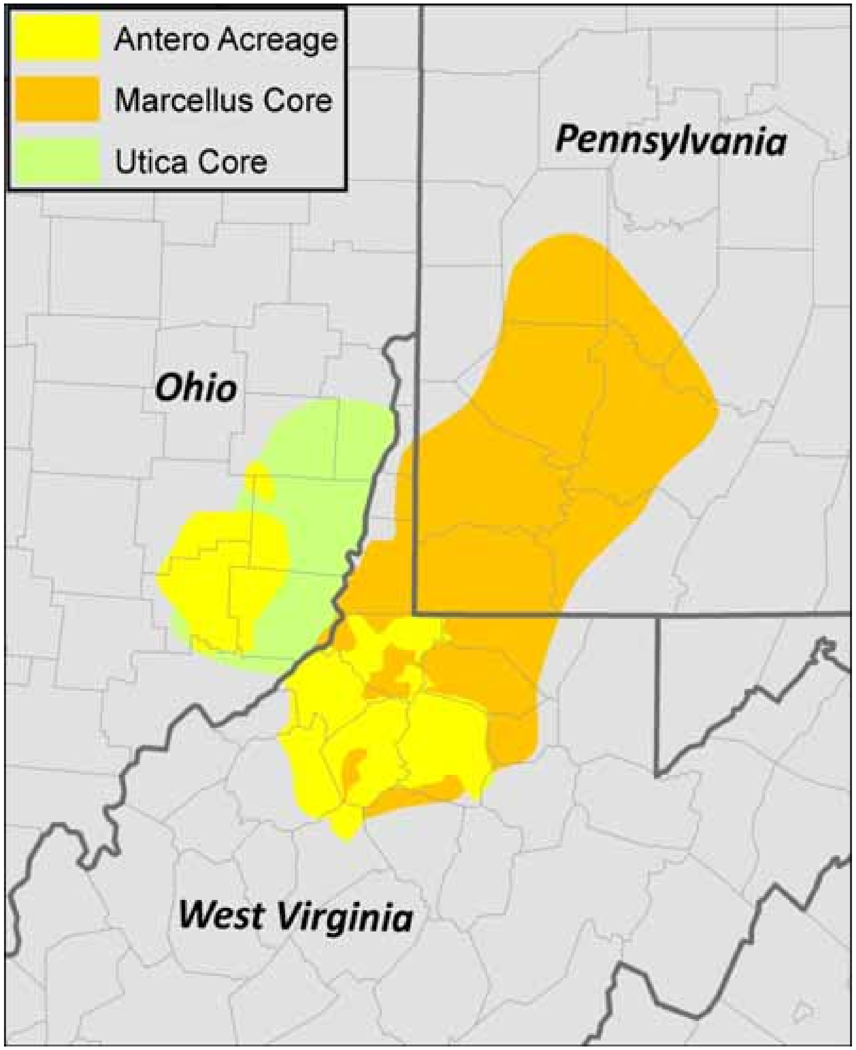
% Liquids.........................26%

3P Reserves[(3)]…………….... 42.1 Tcfe

% Natural Gas…………..... 80%

Net Acres[(4)]………………..… 629,000

AR LISTED NYSE



1. Market value as at 12/5/2016. Enterprise value based on market cap plus net debt plus minority interest ($1.4 billion) on a consolidated basis.
2. Pro forma for $175 million AR PIPE transaction on 10/3/2016, $170 million AR acreage divestiture announced on 10/26/2016 and $600 million 5.00% AR senior note offering announced on 12/7/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.
3. 3P reserves pro forma for third party acreage acquisition closed on 9/15/2016 and assuming ethane rejection.
4. Net acres pro forma for acreage divestiture announced on 10/26/2016 and additional leasing and acquisitions year-to-date.

WHY OWN ANTERO?

Momentum + Growth

- Revised production growth guidance to 20% for 2016 or 1.8 Bcfe/d
- 20% to 25% production growth target for 2017 or 2.16 to 2.25 Bcfe/d
- 6 rigs currently running, 70 DUCs at YE 2016

Attractive & Improving Well Economics

- 58% to 90% ROR at 12/1/2016 strip prices excluding hedges assuming 2.0 Bcf/1,000' EURs in high grade liquids-rich Marcellus; 52% to 75% ROR for Ohio Utica wells
- 36% reduction in well costs since 2014; multiple process improvements and higher proppant loading all improving EURs and RORs

Production Sold Forward at Premium Prices

- 86% of targeted production hedged through 2019 at $3.72/MMBtu, a $0.78 premium to strip
- $2.4 billion mark-to-market on 3.5 Tcfe hedge position as of 9/30/2016
- Over 38 Tcfe of unhedged 3P inventory to drill and produce as prices improve

Superior Realized Prices & Margins

- Realized prices and EBITDAX margins lead Appalachian peers by a wide margin
- Forecast positive basis to Nymex in 2016 and beyond due to market leading FT portfolio to superior pricing points; low average cost of $0.46 per MMBtu

Balance Sheet Strength

- $4.1 billion of consolidated liquidity available pro forma for recent transactions (9/30/2016)(1)
- Ba2/BB corporate ratings affirmed; AR borrowing base increased to $4.75 billion
- 3.3x consolidated net debt/EBITDAX pro forma for recent transactions (9/30/2016)(1)

Largest Core Drilling Inventory

- Largest core drilling inventory in the Marcellus/Utica with over 4,300 undrilled core locations including 1,600 high-graded core locations, pro forma for recent acreage acquisition
- Antero continues to be a leading consolidator in Appalachia

1. *Pro forma for $175 million AR PIPE transaction on 10/3/2016, $170 million AR acreage divestiture announced on 10/26/2016 and $600 million 5.00% AR senior note offering announced on 12/7/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.*

LONGER LATERALS IMPROVE IRR%

- Antero has been a leader in drilling longer laterals in Appalachia due to its consolidated acreage position and horizontal drilling experience

Peer 2016 average lateral: 6,500 feet[1]

Pre-Tax Economics	
IRR (%)	63%
PV-10 ($MM)	$10.0
Breakeven Nymex ($/MMBtu)	$1.09
Dev. Cost ($/Mcfe)	$0.42

Antero 2016 average lateral: 9,000 feet

Pre-Tax Economics	
IRR (%)	78%
PV-10 ($MM)	$15.0
Breakeven Nymex ($/MMBtu)	$0.89
Dev. Cost ($/Mcfe)	$0.38

AR Variance to Peer Average	
IRR (%)	+15%
PV-10 ($MM)	+$5.0
Breakeven Nymex ($/MMBtu)	($0.20)
Dev. Cost ($/Mcfe)	($0.04)

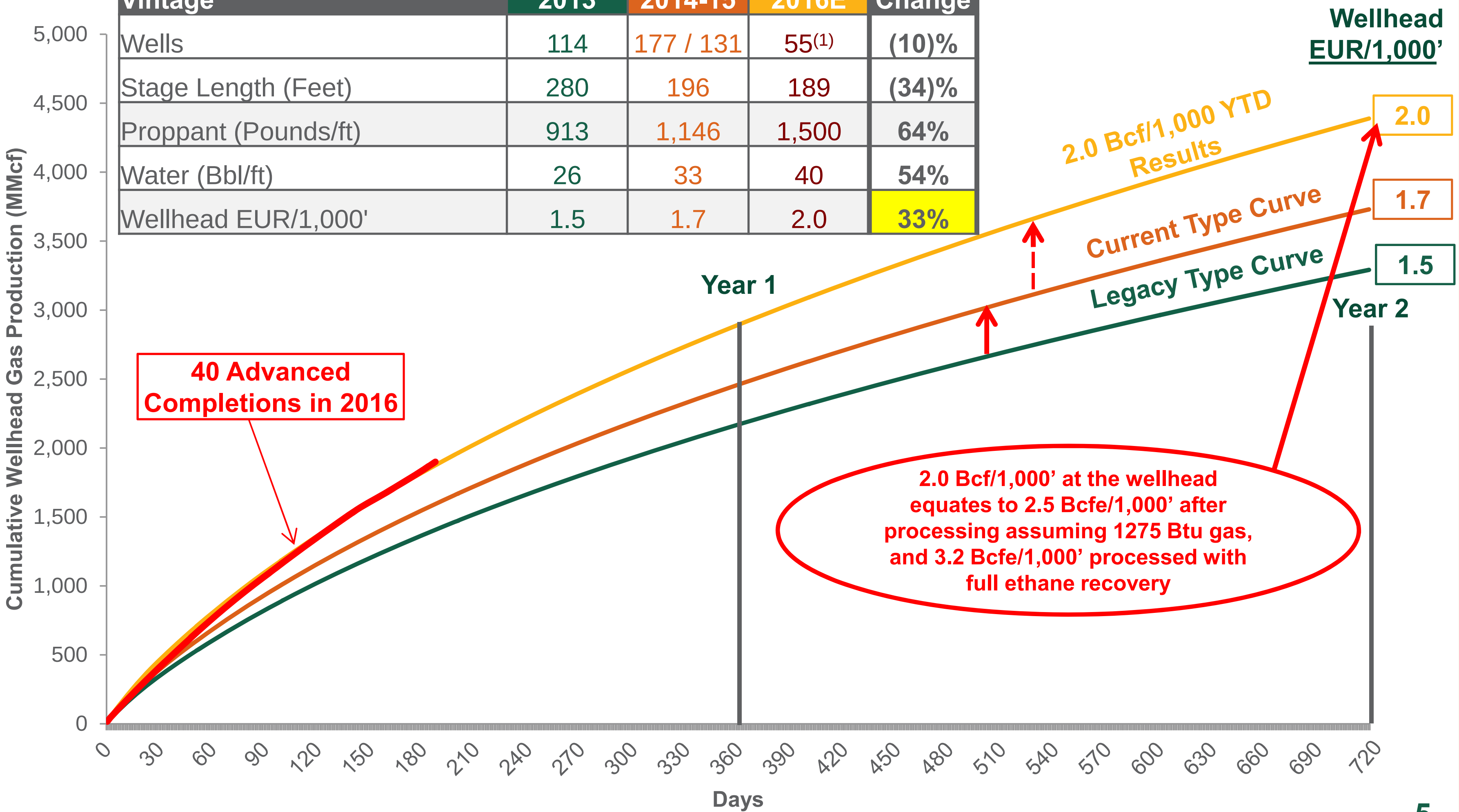
6,500 **9,000**

Note - Assumes 2.0 Bcf/1,000' type curve for the Antero Marcellus Highly-Rich Gas/Condensate (1275 – 1325 Btu).
1. Represents 2016 Marcellus average for peers including: CNX, COG, EQT, RICE, RRC based on public guidance.

OPTIMIZING WELL RECOVERIES WITH HIGHER INTENSITY COMPLETIONS

Marcellus Cumulative Gas Production Curves (Normalized to 9,000' Lateral)

Vintage	2013	2014-15	2016E	Change
Wells	114	177 / 131	55[1]	(10)%
Stage Length (Feet)	280	196	189	(34)%
Proppant (Pounds/ft)	913	1,146	1,500	64%
Water (Bbl/ft)	26	33	40	54%
Wellhead EUR/1,000'	1.5	1.7	2.0	33%



1. Represents 2016 year-to-date advanced completion wells only.

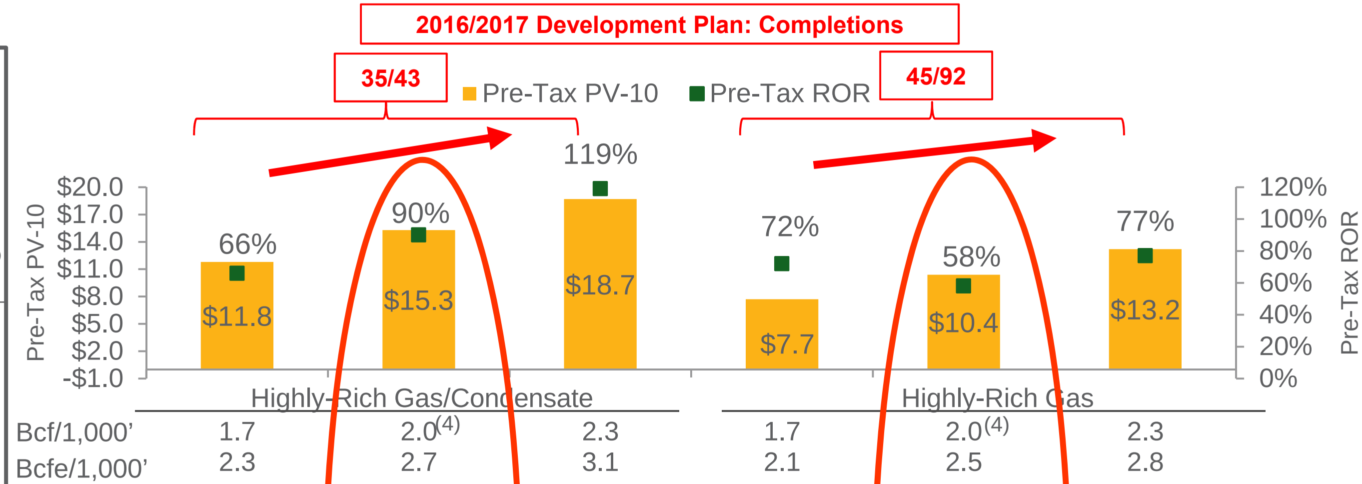
IMPROVING MARCELLUS WELL ECONOMICS

- 36% lower well cost per 1,000’ lateral and 33% higher EUR per 1,000’ since 2014 are driving rates of return significantly higher despite lower strip pricing

Assumptions

- Natural Gas – 12/1/2016 strip
- Oil – 12/1/2016 strip
- NGLs ~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2017	$3.38	$54	$27
2018	$3.04	$54	$28
2019	$2.90	$54	$28
2020	$2.91	$55	$28
2021	$2.94	$55	$29
2022-26	$3.29	$57	$30



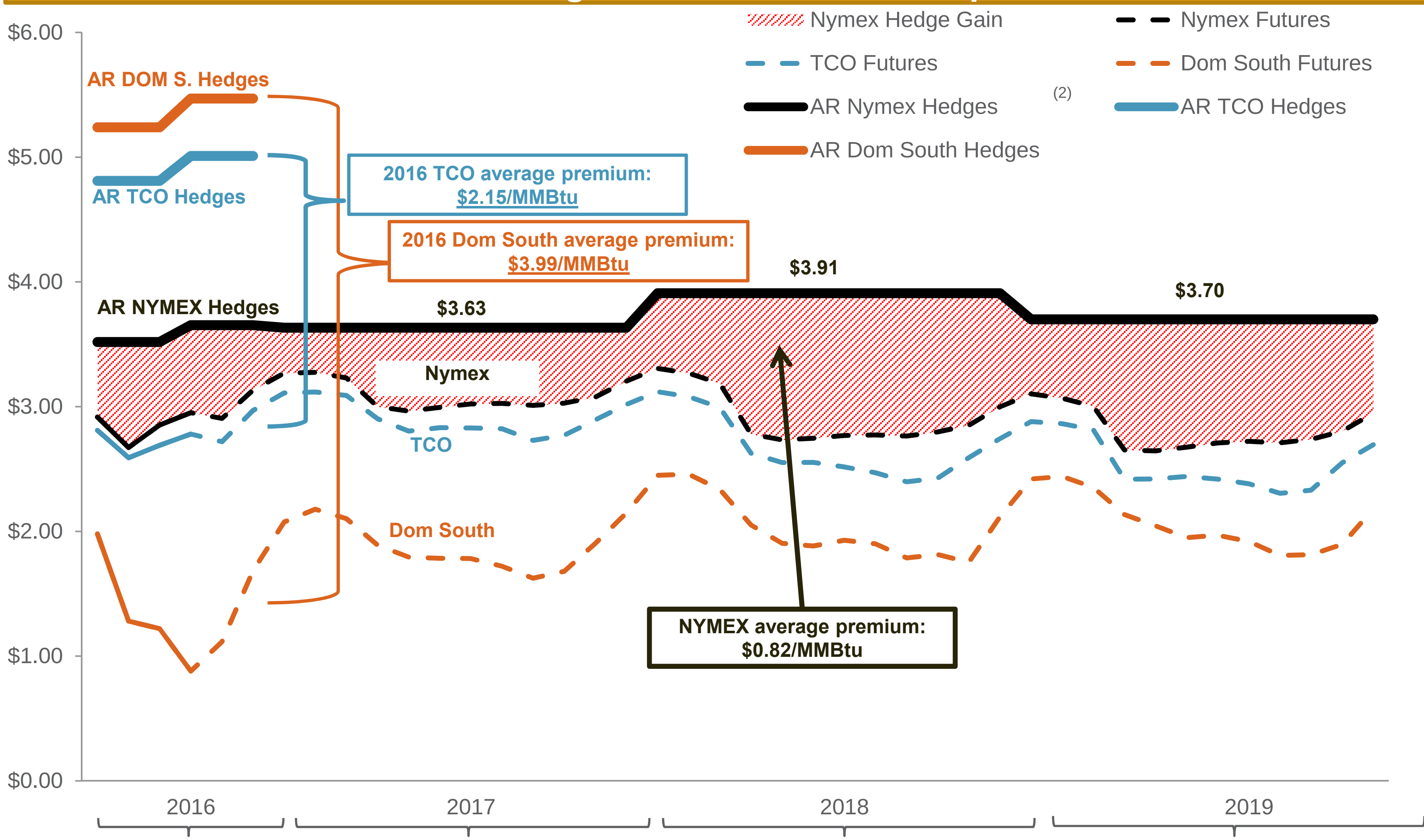
Classification[1]	Highly-Rich Gas/Condensate			Highly-Rich Gas		
BTU Regime	**1275-1325**	**1275-1325**	**1275-1325**	**1200-1275**	**1200-1275**	**1200-1275**
EUR (Bcfe):	20.8	24.4	27.9	18.8	22.1	25.2
EUR (MMBoe):	3.5	4.1	4.7	3.1	3.7	4.2
% Liquids:	33%	33%	33%	24%	24%	24%
Well Cost ($MM):	$7.8	$7.8	$7.8	$7.8	$7.8	$7.8
Wellhead Bcf/1,000’	1.7	2.0	2.3	1.7	2.0	2.3
Processed Bcfe/1,000’:	2.3	2.7	3.1	2.1	2.5	2.8
Net F&D ($/Mcfe):	$0.44	$0.38	$0.33	$0.49	$0.42	$0.36
Pre-Tax NPV10 ($MM):	$11.8	$15.3	$18.7	$7.7	$10.4	$13.2
Pre-Tax ROR:	66%	90%	119%	42%	58%	77%
Payout (Years):	1.2	0.9	0.6	1.8	1.4	1.1
Breakeven NYMEX Gas Price ($/MMBtu)[5]	$1.16	$0.89	$0.70	$2.00	$1.74	$1.54
Gross 3P Locations[3]:	664			1,235		

1. 12/1/2016 pre-tax well economics based on a 9,000’ lateral, 12/1/2016 natural gas and WTI strip pricing for 2017-2026, flat thereafter, NGLs at ~50% of WTI for 2017 and thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities. Assumes ethane rejection.
2. Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.
3. Undeveloped Marcellus well locations as of 12/31/2015 adjusted for 6/30/2016 net acreage and pro forma for recent acreage acquisition.
4. Represents actual results for first nine months of 2016.
5. Breakeven price for 15% pre-tax rate of return.

HEDGE BOOK – CAPTURES SIGNIFICANT NATURAL GAS PREMIUM

- Antero natural gas hedges not only protect the downside price risk, they average $0.85/MMbtu above 9/30/2016 strip pricing through 2019 resulting in a $2.2 billion mark-to-market benefit

AR Hedge Price vs. Futures Strip[1]

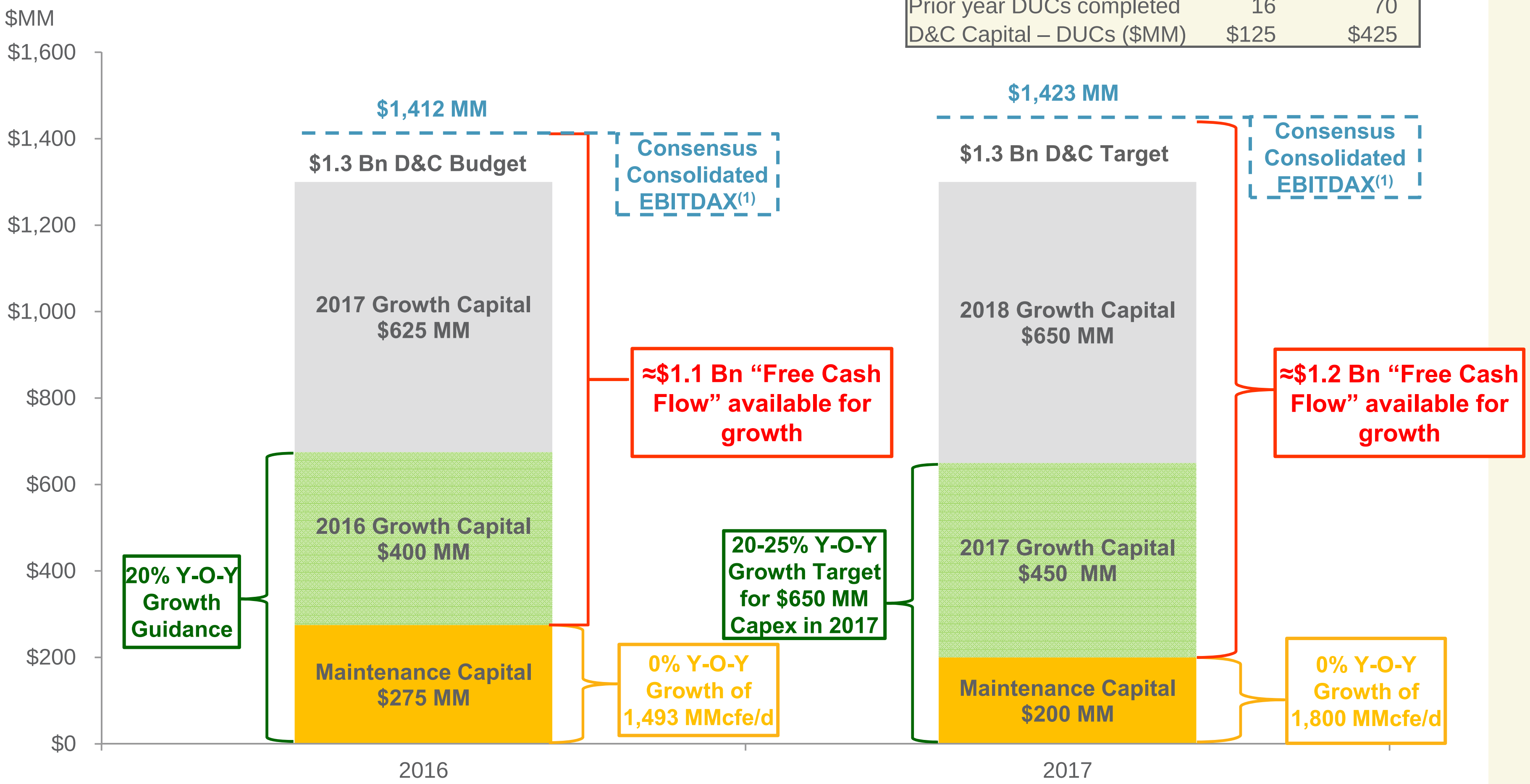


1. ICE futures as of 9/30/2016.
2. Includes Nymex, CGTLA, and Chicago hedges.

ABUNDANT FREE CASH FLOW AVAILABLE FOR GROWTH

- Antero needs only $275 million and $200 million of maintenance capital in 2016 and 2017, respectively, to keep production flat
  - Leaves over $1 billion of annual cash flow in 2016 and 2017 to invest in high rate of return growth projects
- Antero can achieve 20% year-over-year net production growth for 2017 by spending only $650 million[1]

	2016	2017
Prior year DUCs completed	16	70
D&C Capital – DUCs ($MM)	$125	$425



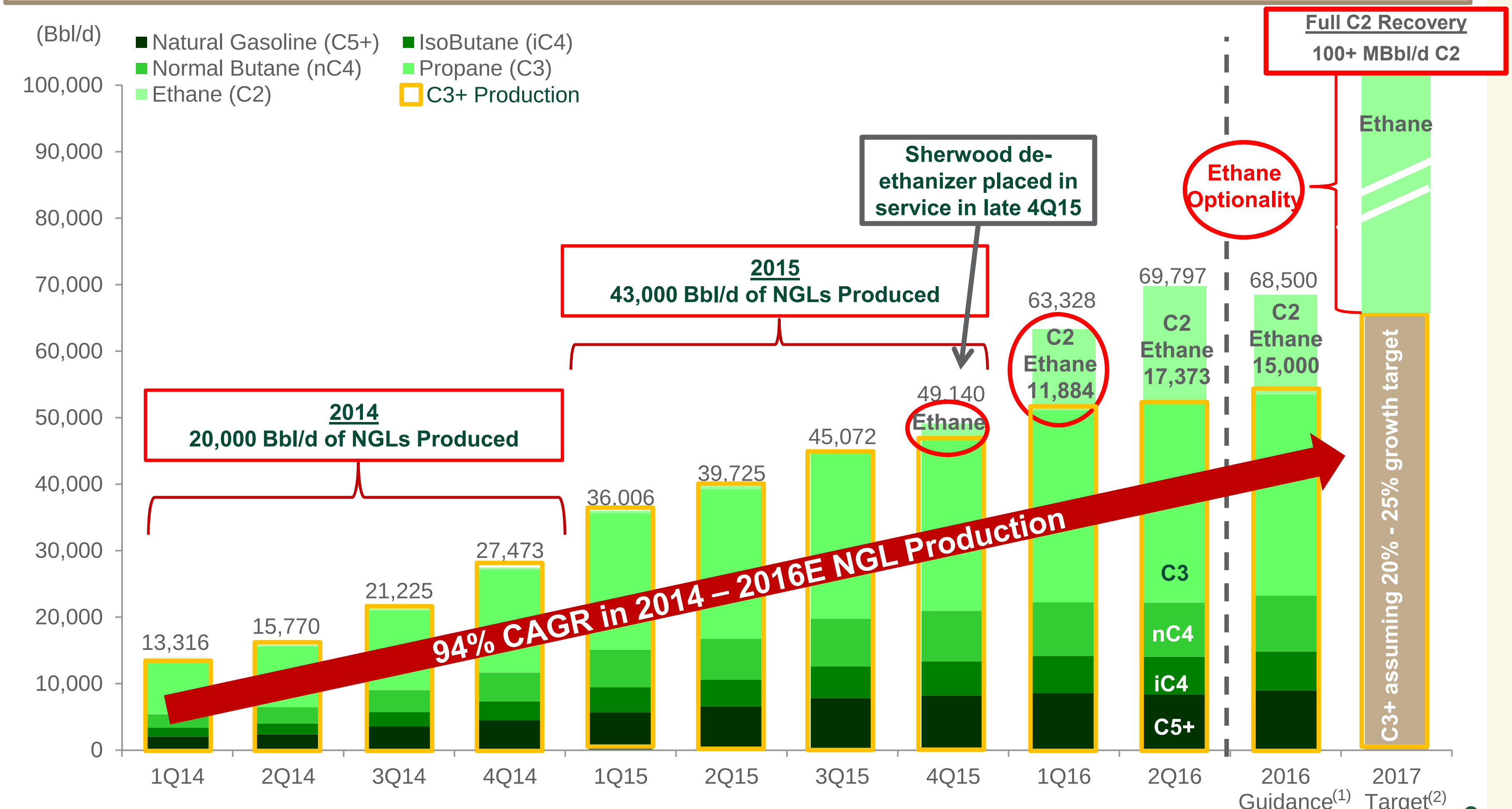
1. *Consensus EBITDAX as of 9/30/2016.*

NGL GROWTH AND ETHANE OPTIONALITY

Antero continues to rapidly grow its liquids production, with 2015 year-over-year growth of 117% and 2016 NGL production growth guidance of 59%

- Expecting significant improvement in propane (C3) and Butane (C4) basis differentials once Mariner East 2 is in-service (2017)
- Developing ethane optionality with an estimated 100,000+ Bbl/d of ethane in targeted production stream in 2017

NGL Production Growth by Purity Product (Bbl/d)



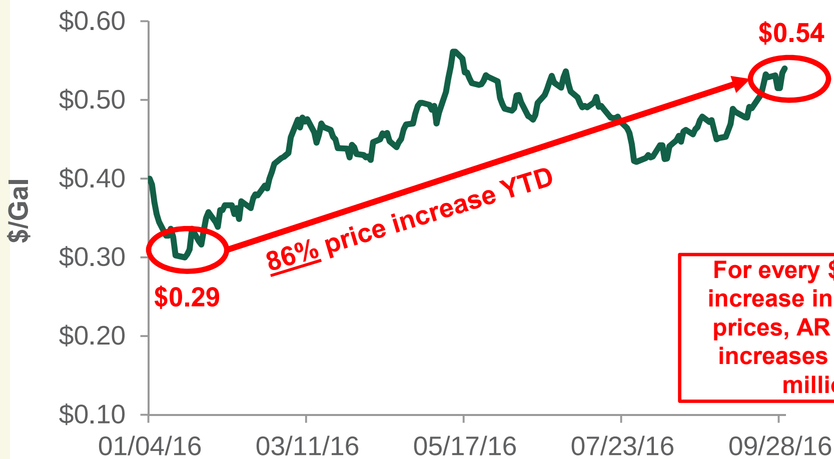
1. Assumes 15,000 Bbl/d of ethane and 53,500 Bbl/d of C3+, respectively, per guidance release on 9/6/2016. C3+ barrel composition based on 1Q16 actual barrel composition.
2. Assumes 20 – 25% year-over-year equivalent production growth in 2017. For illustrative purposes C3+ production growth assumed at same rate.

C3+ VOLUME GROWTH AND PRICE RECOVERY

Antero has 2.7 BBbls of net 3P NGL reserves

- Mariner East 2 is expected to be in-service by mid-year 2017 which should significantly reduce Antero's differential to Mont Belvieu pricing

Propane Pricing Improvement (1)



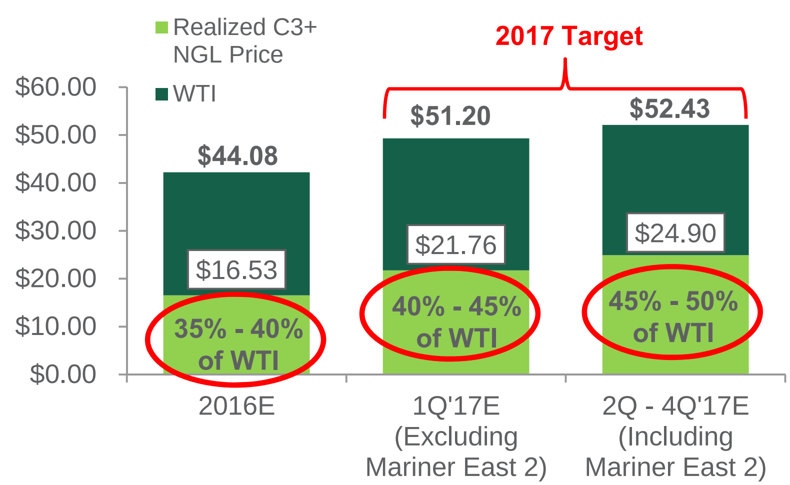
Propane Upside Impact to AR

	Mont Belvieu Pricing	Production (MBbl/d)	Propane Revenue @ MB ($MM) (2)
Q2 2016 Annualized	$0.49	30	$227

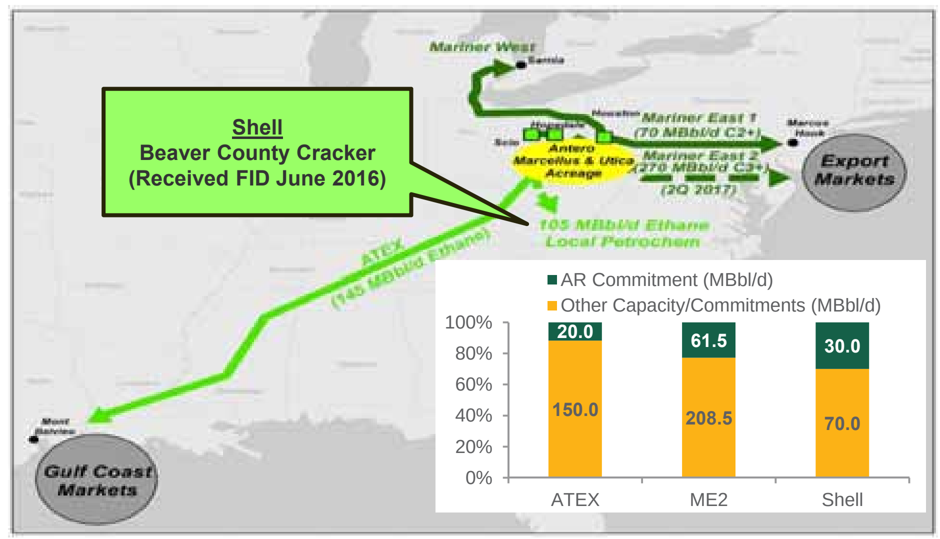
Annual Propane Revenue Sensitivity ($MM)

MB Pricing	Propane Production (MBbl/d) 30	35	40	45	50
$0.85	$394	$456	$521	$586	$652
$0.75	$348	$402	$460	$517	$575
$0.65	$301	$349	$399	$448	$498
$0.55	$255	$295	$337	$379	$422
$0.45	$209	$241	$276	$310	$345

2016 and 2017 NGL C3+ Guidance / Target (3)



NGL Takeaway

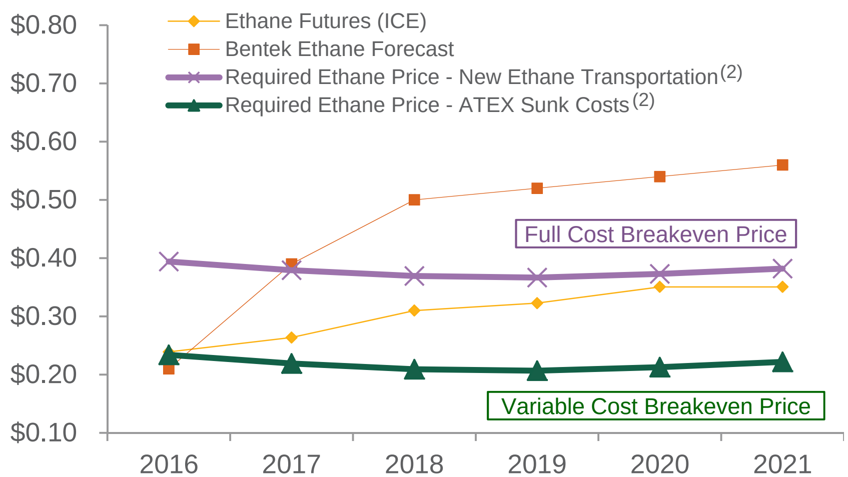


1. Based on Mont Belvieu (MB) pricing as of 9/30/2016.
2. Before Northeast differentials.
3. Based on strip pricing as of 9/30/2016 and associated NGL differentials to Mont Belvieu.

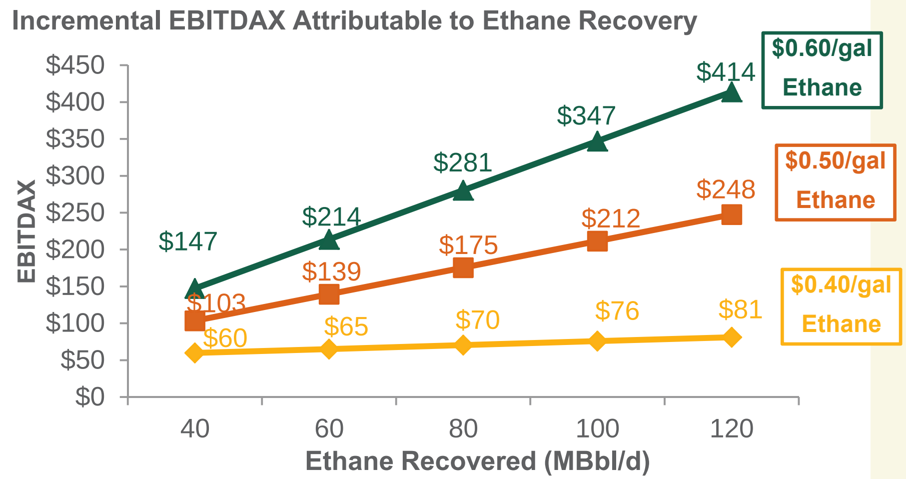
POSITIONED TO BENEFIT FROM ETHANE PRICE RECOVERY

Antero has significant exposure to upside in ethane prices (C2)

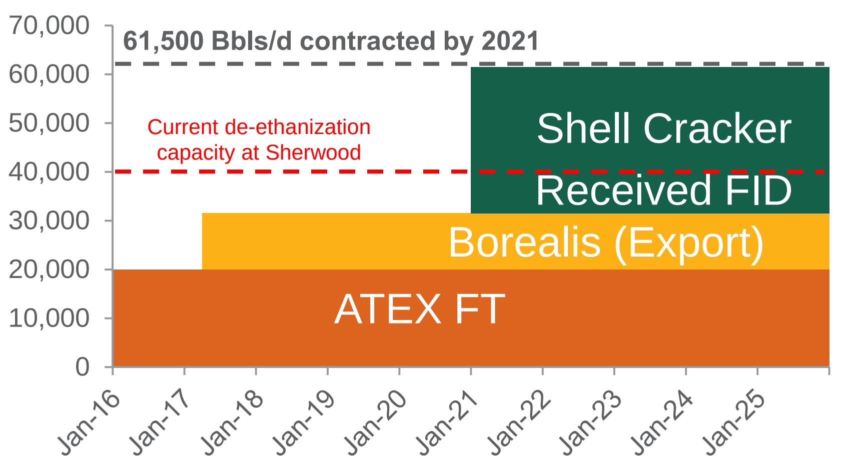
Ethane Prices ($/Gallon)[1]



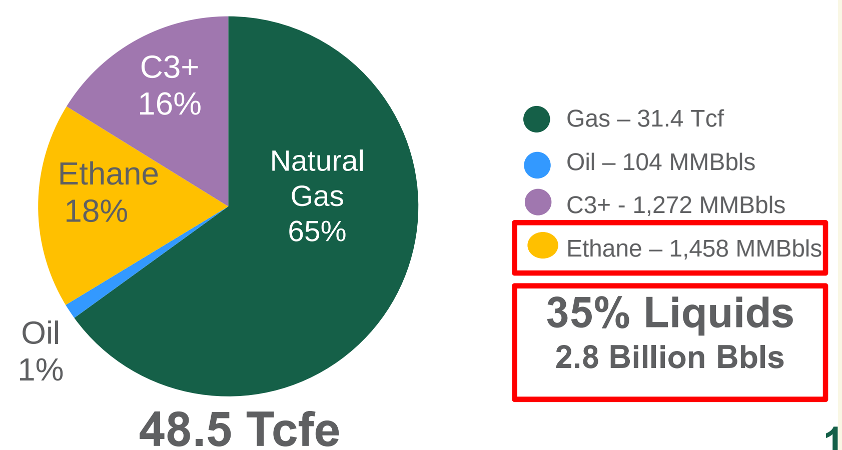
Ethane Upside Impact to AR[3]



Ethane Takeaway Capacity



Pro Forma 3P Reserves (Ethane Recovery)[4]

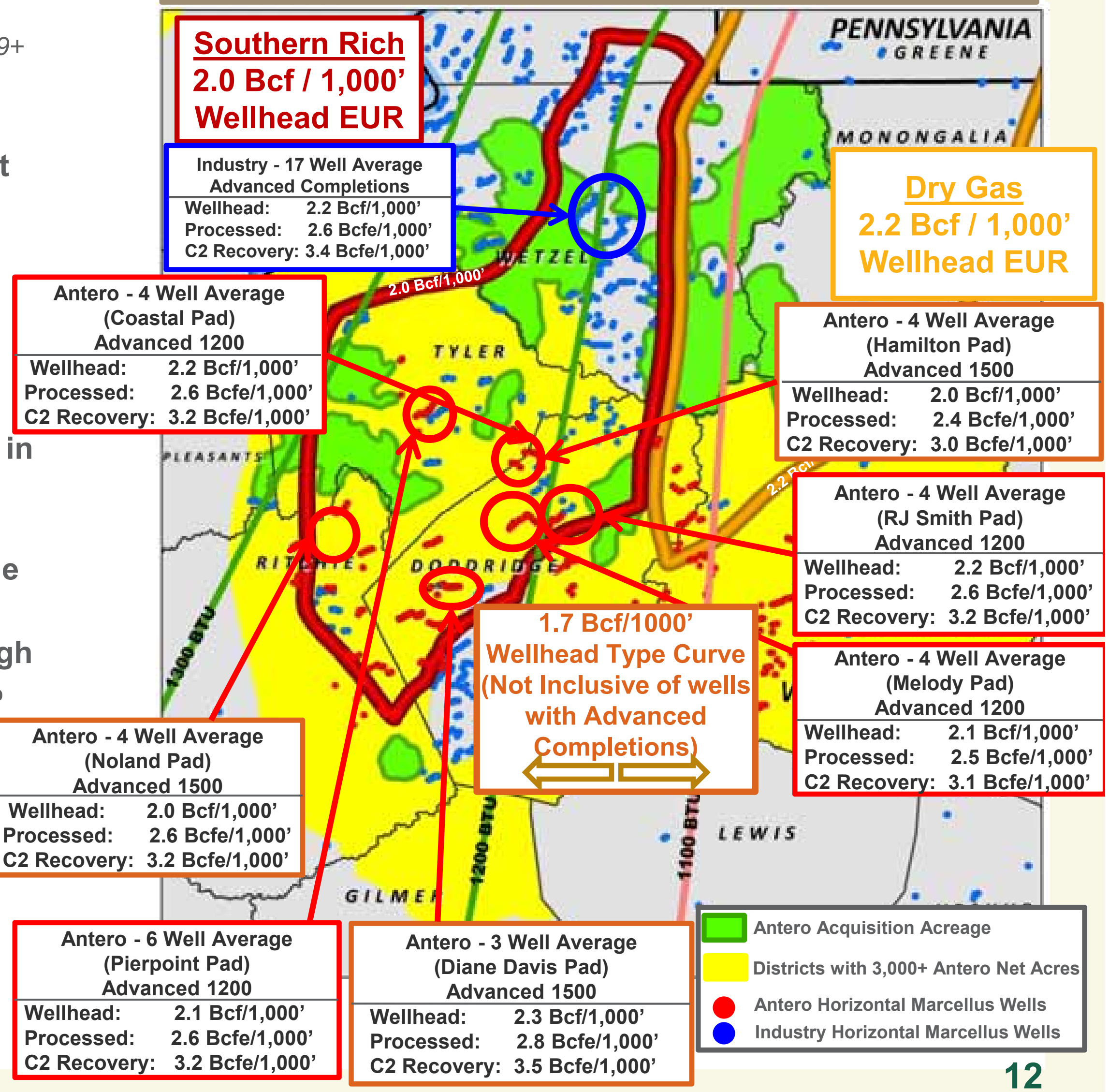


1. Ethane futures data from ICE as of 9/30/2016. Bentek forecast as of 4/26/2016.
2. Represents ethane price required to match TCO strip sales price on a realized basis. TCO strip as of 9/30/2016.
3. Represents incremental EBITDA associated with ethane recovery (vs. rejection) at prices ranging from $0.40 to $0.60 per gallon. Assumes (1) ATEX costs are sunk up to 20,000 Bbl/d, (2) $3.00 NYMEX natural gas prices and (3) Borealis firm sale at NYMEX plus pricing.
4. 12/31/2015 reserves assuming ethane recovery, pro forma for recent acreage acquisition.

CLOSED MARCELLUS ACQUISITION

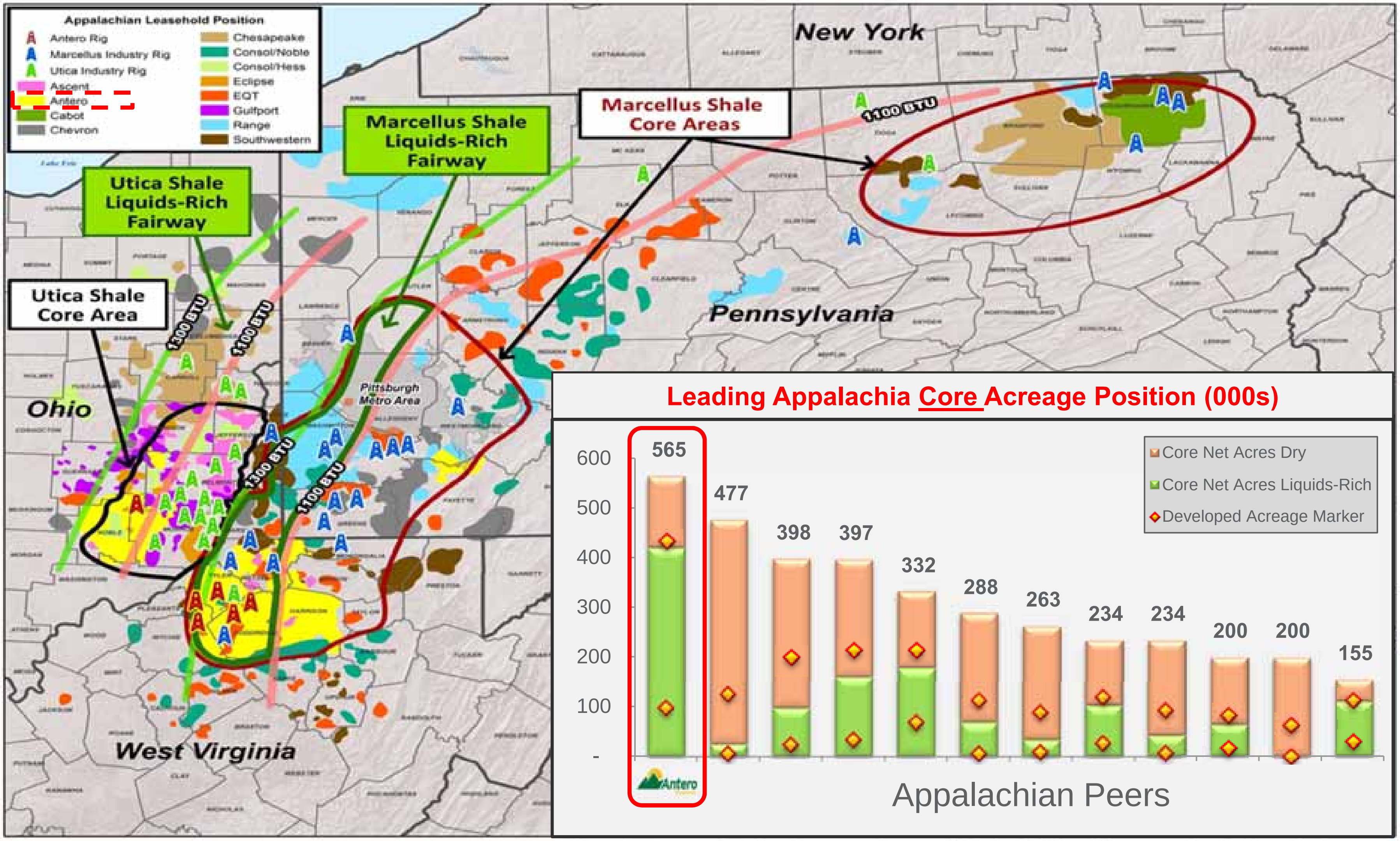
- **Strategic core inventory addition of Marcellus acreage and 3P reserves for $518 million**
  - *48% HBP with additional 44% not expiring until 2019+*
  - *16 MMcfe/d of net production*
- **Broad consolidation and new development platform for AR in Wetzel County**
  - *Adds new high-graded core county for Antero*
- **Attractive liquids-rich well economics consistent with recent Antero well results**
- **Significantly enhances dry gas optionality in the core**
- **Includes dry Utica rights on 78% of acreage**
- **Value creation for Antero Midstream through dedication of ~106,000 gross acres, a 22% increase over existing dedication**
  - *AR has a 61% LP ownership in AM*
- ***Closed September 15, 2016***

Pro Forma Acreage Position



LARGEST CORE ACREAGE POSITION IN APPALACHIA

Antero has the largest core acreage position in Appalachia, particularly as it relates to undeveloped acreage and is running 36% of the total rigs in liquids rich core areas

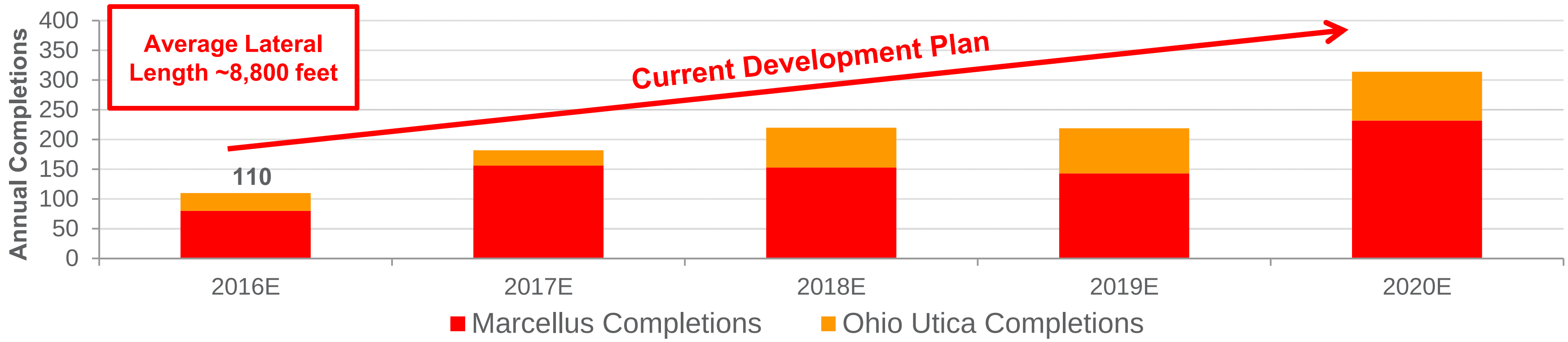


Source: Core outlines based upon Antero geologic interpretation and well control and peer net acreage positions based on investor presentations, news releases and 10-K/10-Qs. Rig information per RigData as of 11/25/2016.
Peers include Ascent (private), CHK, CNX, COG, CVX, EQT, NBL, RICE, RRC, STO, SWN.

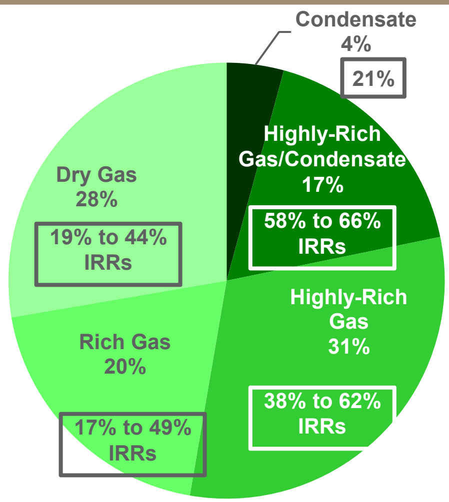
GROWTH ENGINE THROUGH 2020 AND BEYOND

Antero plans to develop over 1,000 horizontal locations in the Marcellus and Ohio Utica by the end of the decade while utilizing less than 25% of its current 3P drilling inventory

PLANNED ANTERO WELL COMPLETIONS BY YEAR



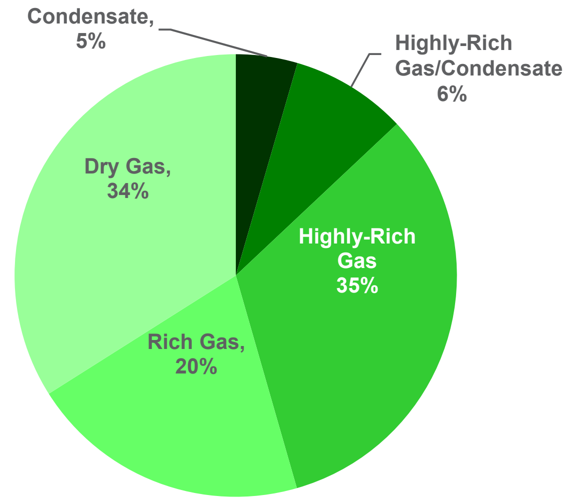
CURRENT UNDRILLED 3P LOCATIONS BY BTU REGIME [1]



4,344 Locations

Expect to place >1,000 Marcellus and Utica wells to sales by YE 2020

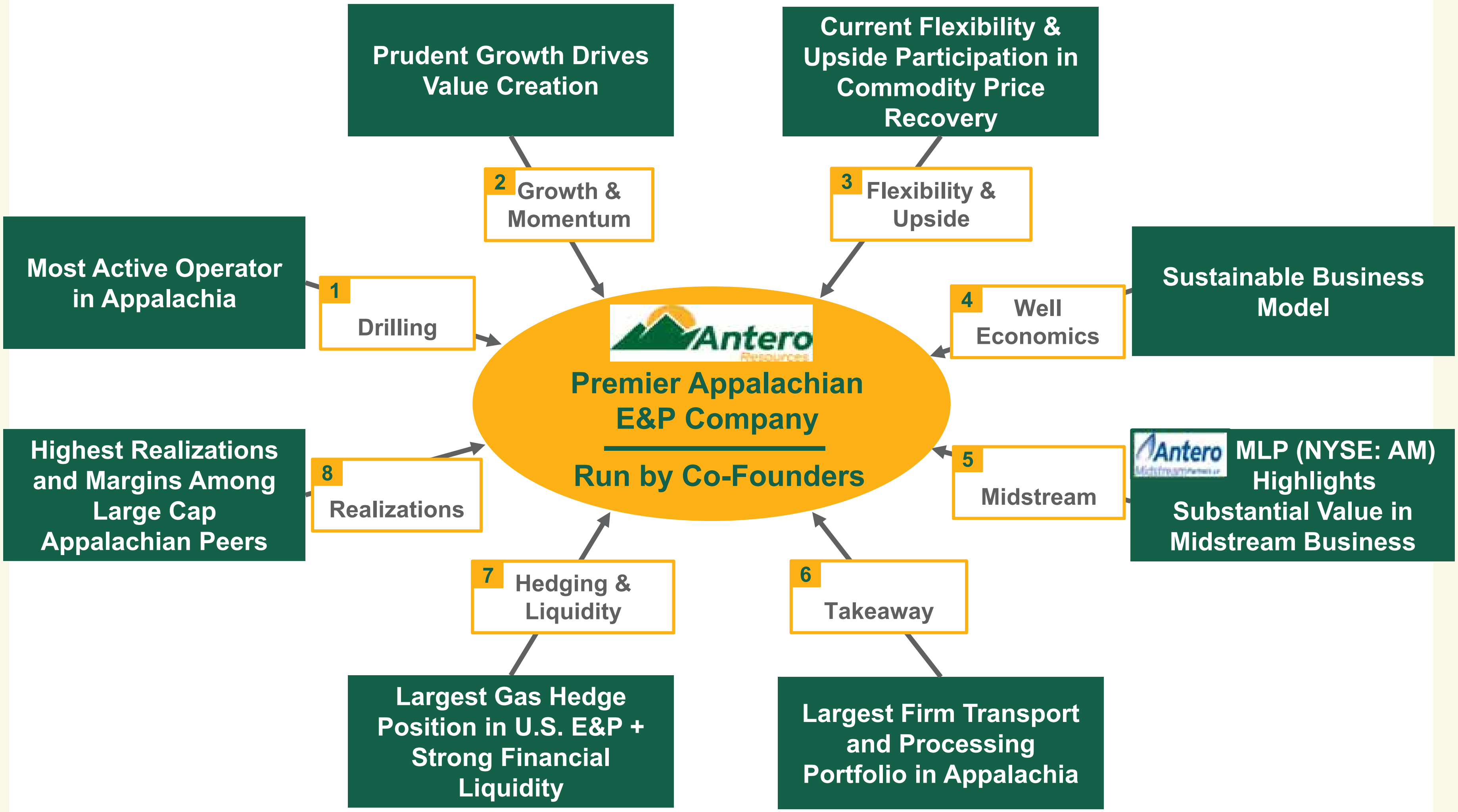
ESTIMATED YE 2020 UNDRILLED 3P LOCATIONS



≈3,300 Locations YE 2020

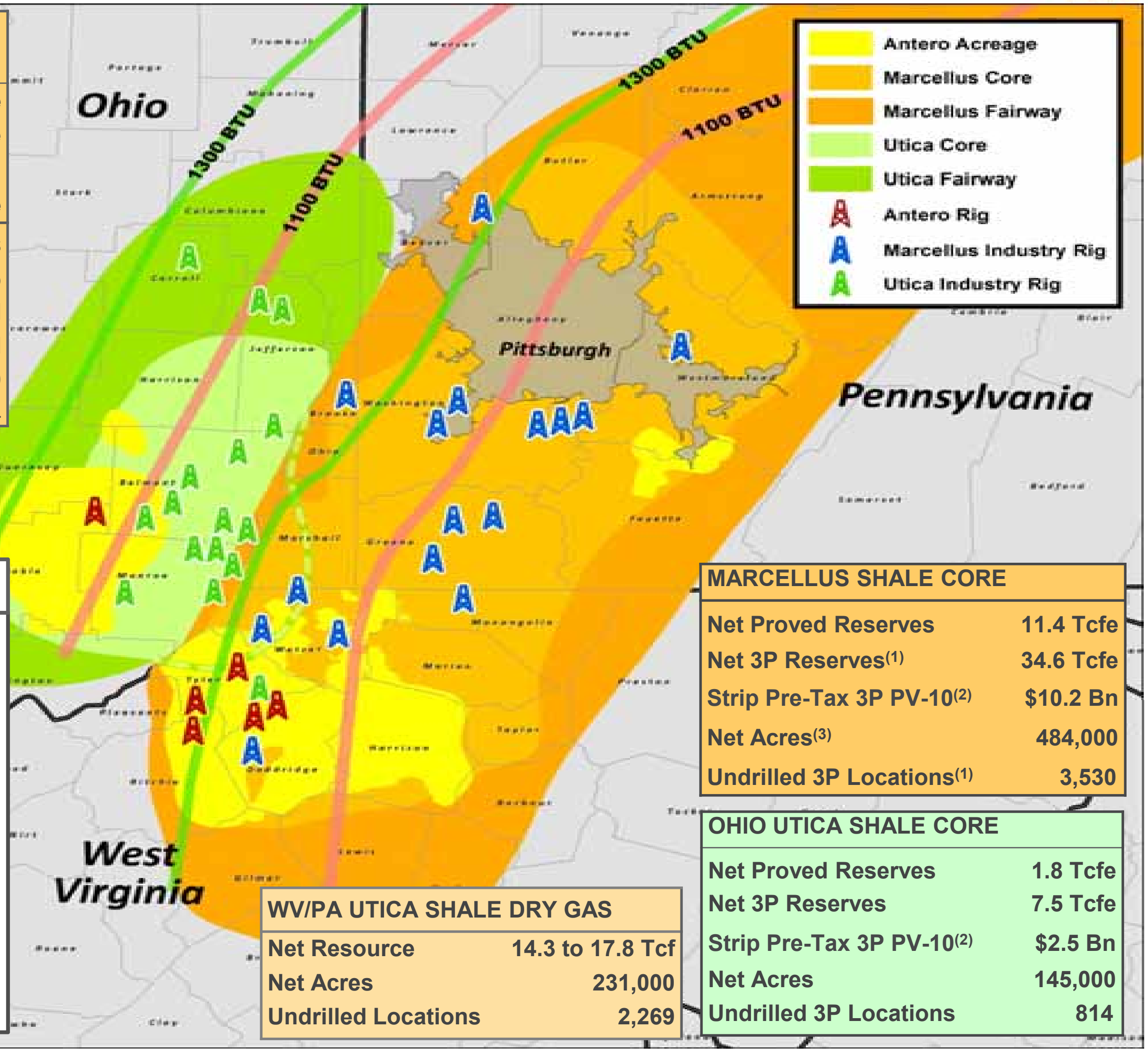
1. Marcellus and Utica 3P locations pro forma for recent acreage acquisition announced 6/9/2016. Excludes WV/PA Utica Dry locations.

LEADING UNCONVENTIONAL BUSINESS MODEL

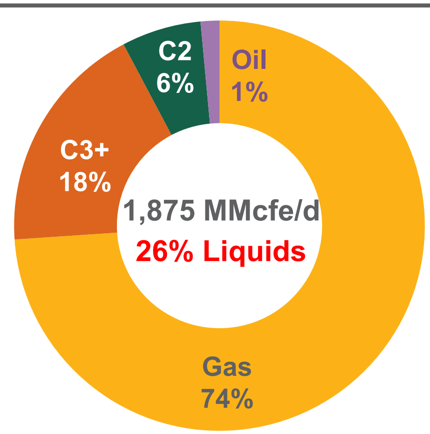


DRILLING – MOST ACTIVE OPERATOR IN APPALACHIA

AR COMBINED TOTAL – 12/31/15 RESERVES Assumes Ethane Rejection	
Net Proved Reserves	**13.2 Tcfe**
Net 3P Reserves(1)	**42.1 Tcfe**
Strip Pre-Tax 3P PV-10(2)	**$12.7 Bn**
Net 3P Reserves & Resource(1)	**57 to 60 Tcfe**
Net 3P Liquids(1)	1,377 MMBbls
% Liquids – Net 3P(1)	20%
3Q 2016 Net Production	1,875 MMcfe/d
- 3Q 2016 Net Liquids	81,460 Bbl/d
Net Acres(3)	629,000
Undrilled 3P Locations(1)	4,344



3Q 2016 Production



MARCELLUS SHALE CORE	
Net Proved Reserves	11.4 Tcfe
Net 3P Reserves(1)	34.6 Tcfe
Strip Pre-Tax 3P PV-10(2)	$10.2 Bn
Net Acres(3)	484,000
Undrilled 3P Locations(1)	3,530

OHIO UTICA SHALE CORE	
Net Proved Reserves	1.8 Tcfe
Net 3P Reserves	7.5 Tcfe
Strip Pre-Tax 3P PV-10(2)	$2.5 Bn
Net Acres	145,000
Undrilled 3P Locations	814

WV/PA UTICA SHALE DRY GAS	
Net Resource	14.3 to 17.8 Tcf
Net Acres	231,000
Undrilled Locations	2,269

Note: 2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis.

1. *3P reserve additions are unaudited. 14 to 18 Tcf Utica dry resource in WV/PA.*
2. *3P reserve pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively. $1.5 billion 3P PV-10 unaudited estimate for recent acreage acquisition, using 12/31/2015 strip pricing and same year end 2015 assumptions. Strip pre-tax PV-10 is a non-GAAP financial measure. The standardized measure was $3.2 billion as of 12/31/2015.*
3. *Virtually all WV/PA Utica Shale net acres are included among the net acres of Marcellus Shale rights as they are stacked pay formations attributable to the same leasehold. Marcellus acreage pro forma for acreage divestiture announced on 10/26/2016 and additional leasing and acquisitions year-to-date.*

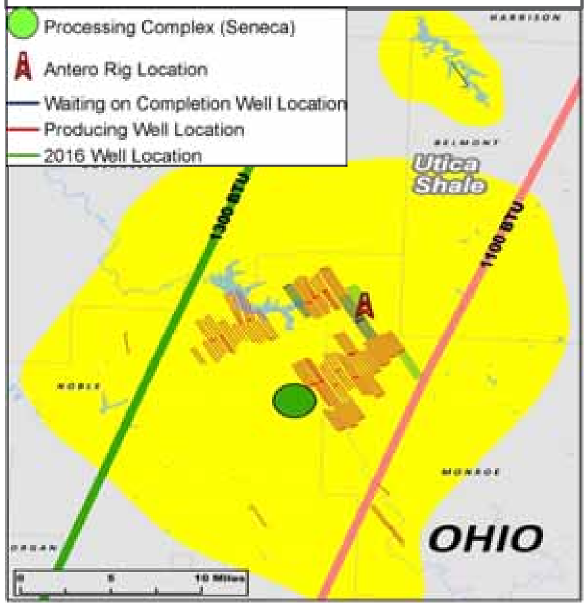
DRILLING – CONTINUOUS OPERATING IMPROVEMENT

Antero Resources

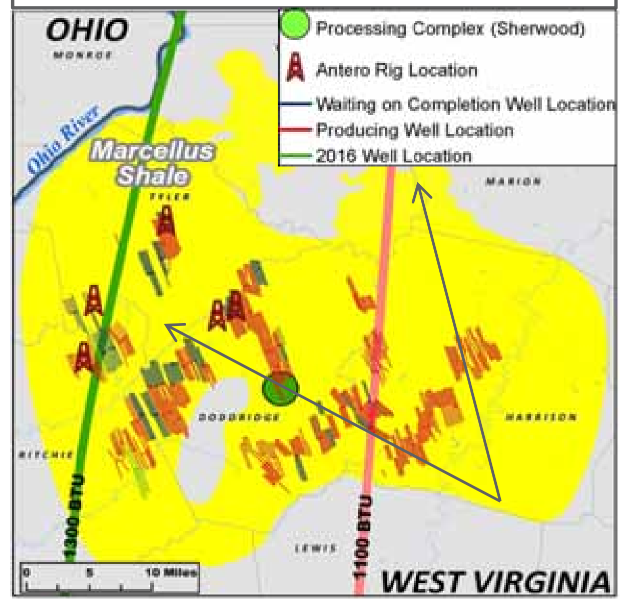
Operating Highlights

- Top 20 best drilling footage days in Marcellus since 2009 have all occurred in 2016, including 7,274' drilled in 24 hours in West Virginia on the Hunter 1H
- Currently completing longest lateral in company history at 14,024 feet
- Stayed within targeted zone for 98% of lateral length of all wells drilled in Q3 2016
- Increased sand placement during completions to 99% in Q3 2016
- Increased proppant and water loading by 25% in 2016 with encouraging results to date
- Utilizing zipper fracs to increase frequency to 7 to 8 stages per day

Utica Shale Ohio



Marcellus Shale



	Utica 2014	Utica 2015	Utica Q3 2016	Utica Q3 2016 vs. 2014	Marcellus 2014	Marcellus 2015	Marcellus Q3 2016	Marcellus Q3 2016 vs. 2014
Activity Levels								
Average Rigs Running	4	5	1	(75%)	14	9	5	(64%)
Average Completion Crews	2.0	3.0	1.0	(50%)	5.5	2.0	3.0	(45%)
Operational Improvements								
Drilling Days	29	31	16	(45%)	29	24	14	(53%)
Average Lateral Length (Ft)	8,543	8,575	9,000	5%	8,052	8,910	9,000	12%
Stages per Well	47	49	51	9%	40	45	45	12%
Stage Length	183	175	175	4%	200	200	200	0%
Stages per Day	3.2	3.7	5.0	56%	3.2	3.5	4.5	41%
Well Cost & Performance Improvements								
D&C per 1,000' of lateral ($MMs)	$1.55	$1.36	$1.01	(35%)	$1.34	$1.18	$0.86	(36%)
Wellhead EUR per 1,000' of lateral (Bcf) [1]	1.4	1.6	1.6	14%	1.5	1.7	2.0	33%
Processed EUR per 1,000' of lateral (Bcfe) [1][2]	1.5	1.8	1.8	20%	1.8	1.9	2.4	33%
Net development cost (F&D) per Mcfe [2][3]	$1.28	$0.94	$0.70	(46%)	$0.88	$0.73	$0.42	(52%)

1. *Based on statistics for wells completed within each respective period.*
2. *Ethane rejection assumed.*
3. *Current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 81% NRI in Utica and 85% NRI in Marcellus.*

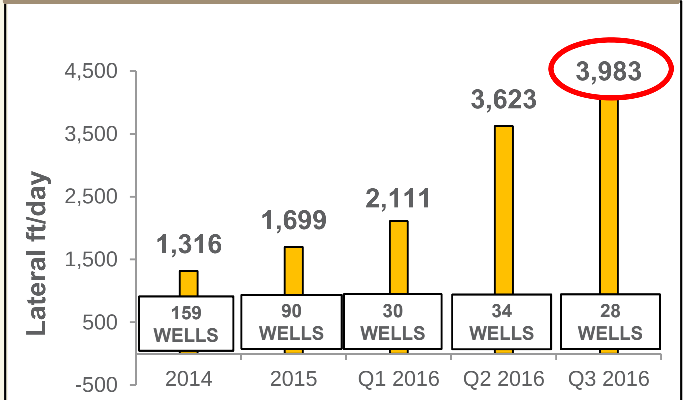
DRILLING – STEP CHANGE IN AR MARCELLUS DRILLING FOOTAGE

New drilling techniques and technologies are shaving 10 days off drilling times from spud of surface to final release and up to 25% off drilling AFEs

Key Drilling Highlights:

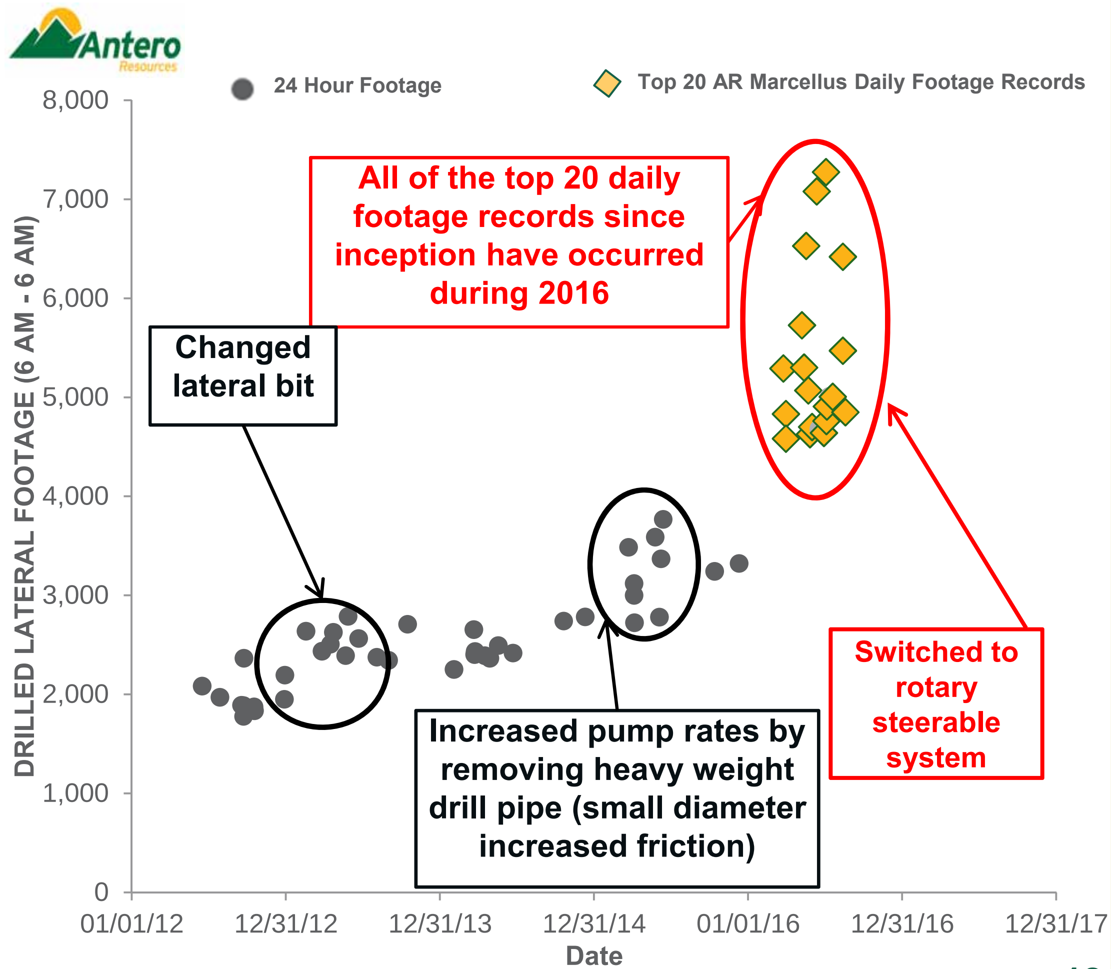
- Driven by technology and process advancements, **all of the top 20 Antero daily footage records have been achieved in 2016**, quickly establishing a new benchmark in Marcellus drilling performance
- Drilled **7,274' feet in a lateral in 24 hours**, exceeding previous record by over 1,000 feet
- Lateral **feet drilled per day has increased 3x** since 2014 to 3,983' in 3Q 2016

Marcellus Average Lateral Ft/Day(1)



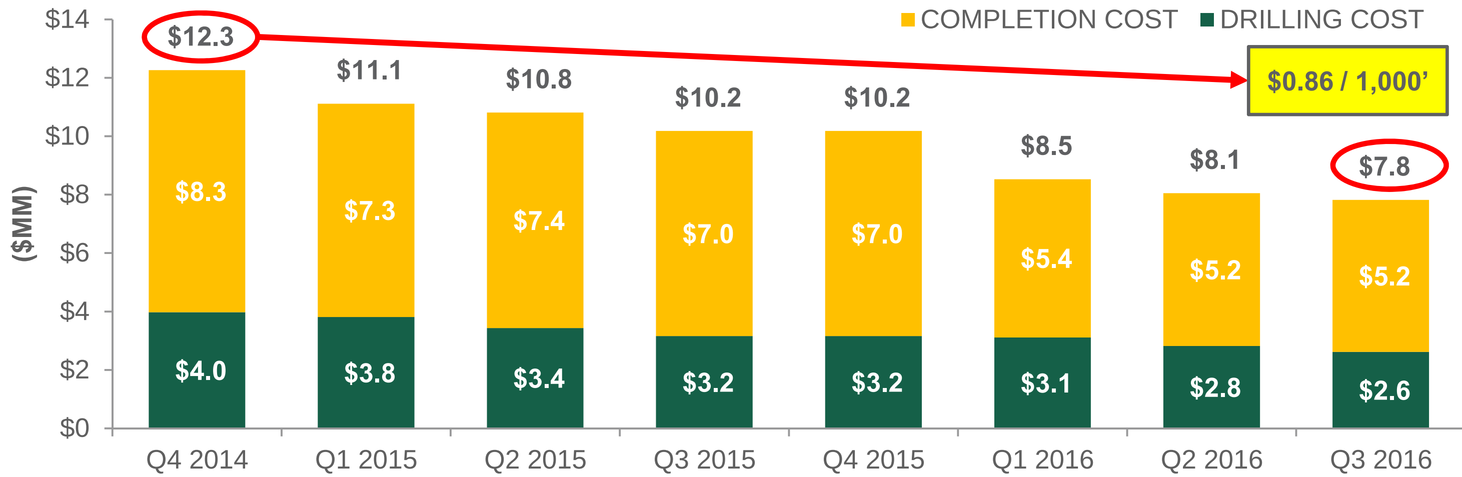
(1) For wells drilled in each period.

Top 50 Antero Marcellus Daily Footage Records



DRILLING – PROVEN TRACK RECORD OF WELL COST REDUCTIONS

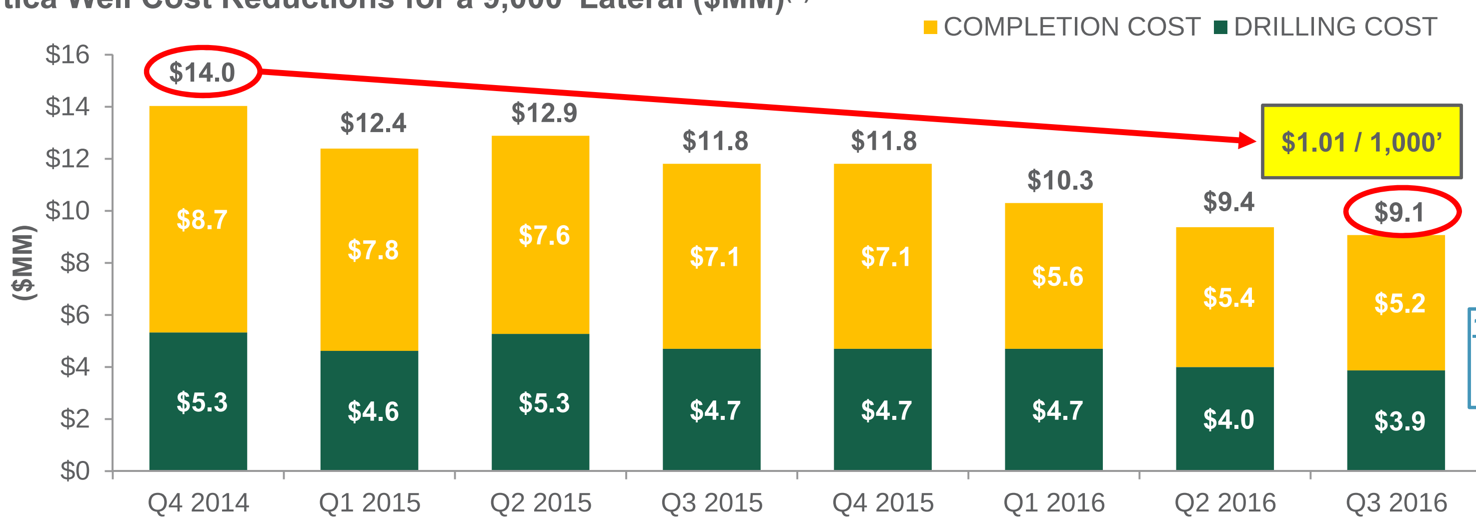
Marcellus Well Cost Reductions for a 9,000' Lateral ($MM)(1)



36% Reduction in Marcellus well costs since Q4 2014

18% Reduction vs. well costs assumed in YE 2015 reserves

Utica Well Cost Reductions for a 9,000' Lateral ($MM)(2)



35% Reduction in Utica well costs since Q4 2014

15% Reduction vs. well costs assumed in YE 2015 reserves

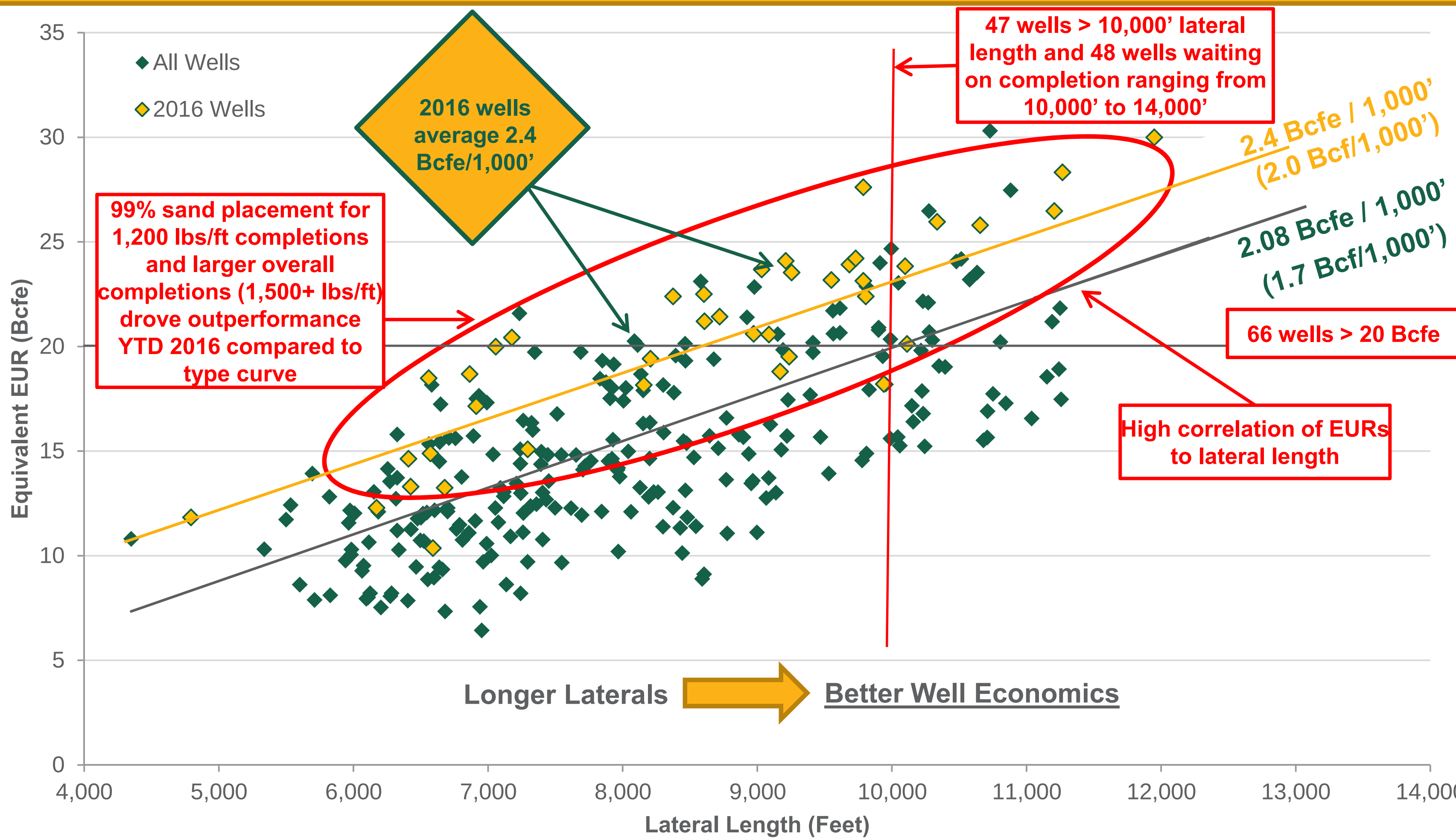
NOTE: Based on statistics for drilled wells within each respective period.
1. Based on 200 ft. stage spacing.
2. Based on 175 ft. stage spacing.

DRILLING – MARCELLUS IMPROVEMENTS DRIVING VALUE CREATION

High correlation of EURs to lateral length – no degradation in results out to 12,000' laterals

- Antero has led the way with long lateral drilling programs – 3Q 2016 completions had average F&D cost of $0.42 per Mcfe

Antero Marcellus EUR vs. Lateral Length(1)(2)

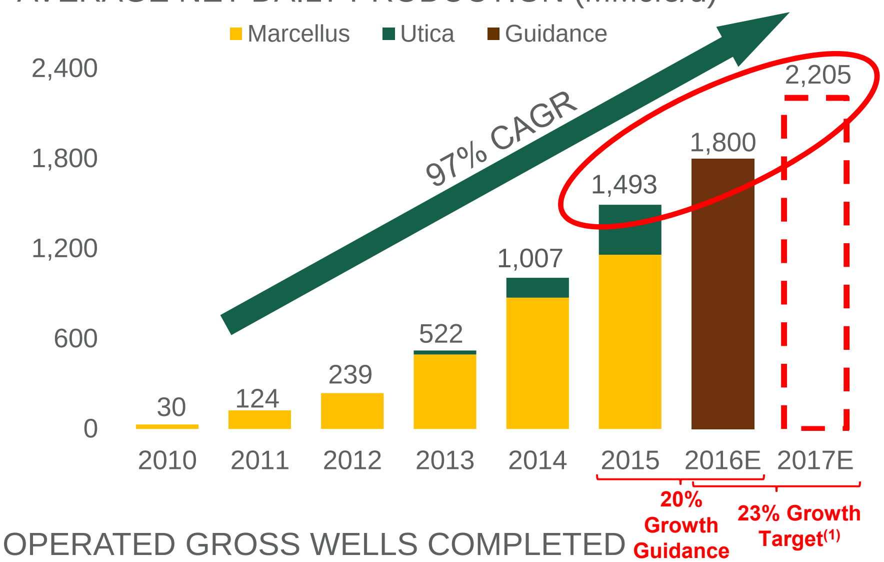


1. *All 291 wells completed since 2014 when Antero transitioned to shorter stage length completions (SSL).*
2. *EUR's include condensate and NGL processing (C3+) but assume ethane rejection.*

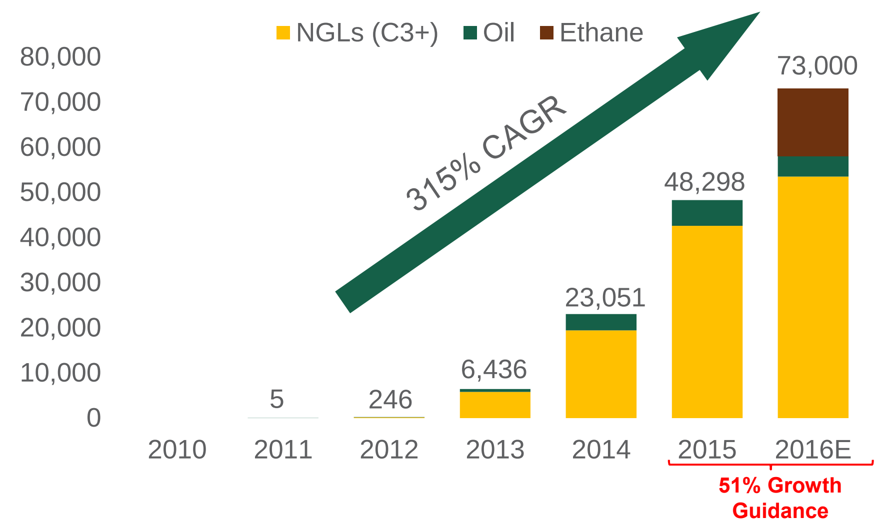
GROWTH & MOMENTUM – THROUGH THE DOWN CYCLE

- Antero is in the unique position of sustaining growth and value creation through the price down cycle

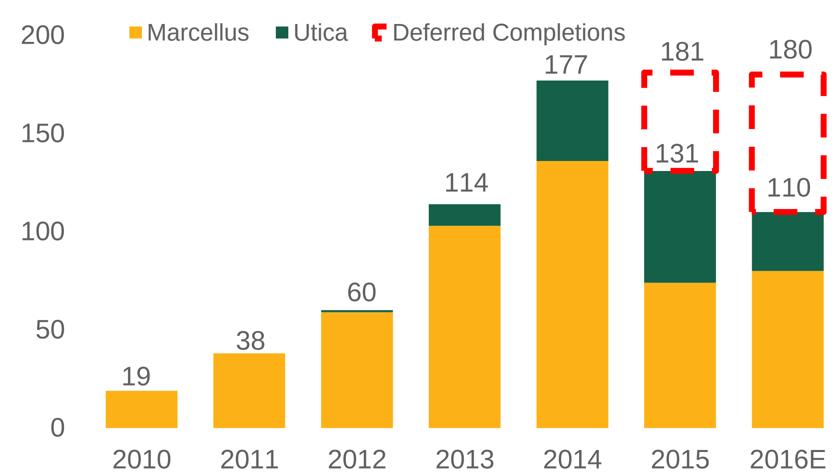
AVERAGE NET DAILY PRODUCTION (MMcfe/d)



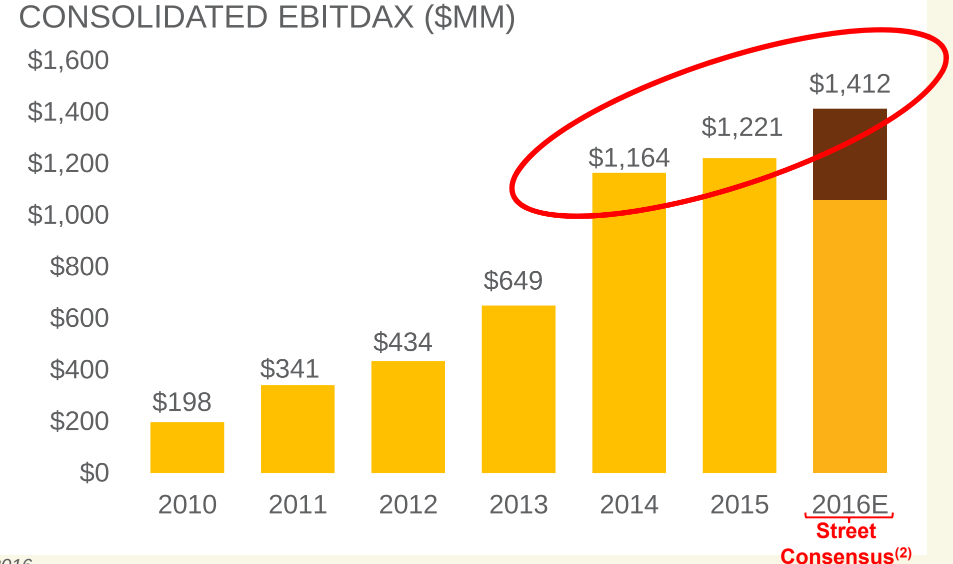
AVERAGE NET DAILY LIQUIDS PRODUCTION (Bbl/d)



OPERATED GROSS WELLS COMPLETED



CONSOLIDATED EBITDAX ($MM)

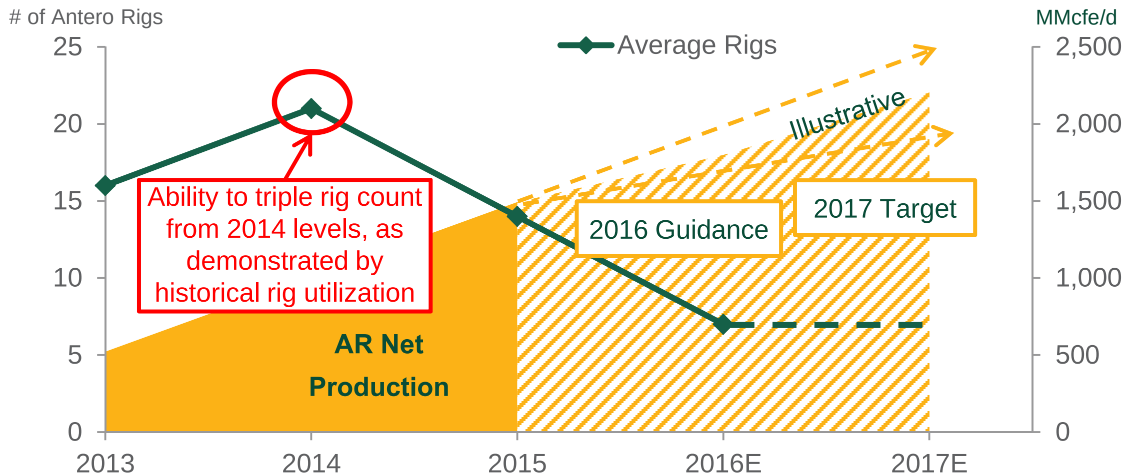


1. Represents midpoint of updated 2017 production target of 20% to 25% per press release dated 9/6/2016.
2. Represents Bloomberg street consensus estimates as of 12/1/2016.

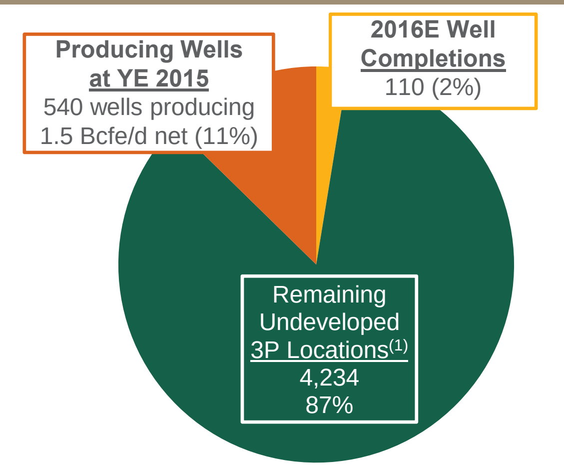
FLEXIBILITY & UPSIDE – ANTERO THRIVES WITH RISING PRICES

- As the most active operator in Appalachia, Antero has kept its workforce intact while also preserving the ability to accelerate efficiently when commodity prices recover
- Accelerated development is further enhanced by Antero's ability to flow incremental production to the most favorable price indices using Antero's firm transport portfolio
- Despite its large hedge position, Antero has tremendous leverage to natural gas and NGL prices due to scale of its 3P reserves and development infrastructure

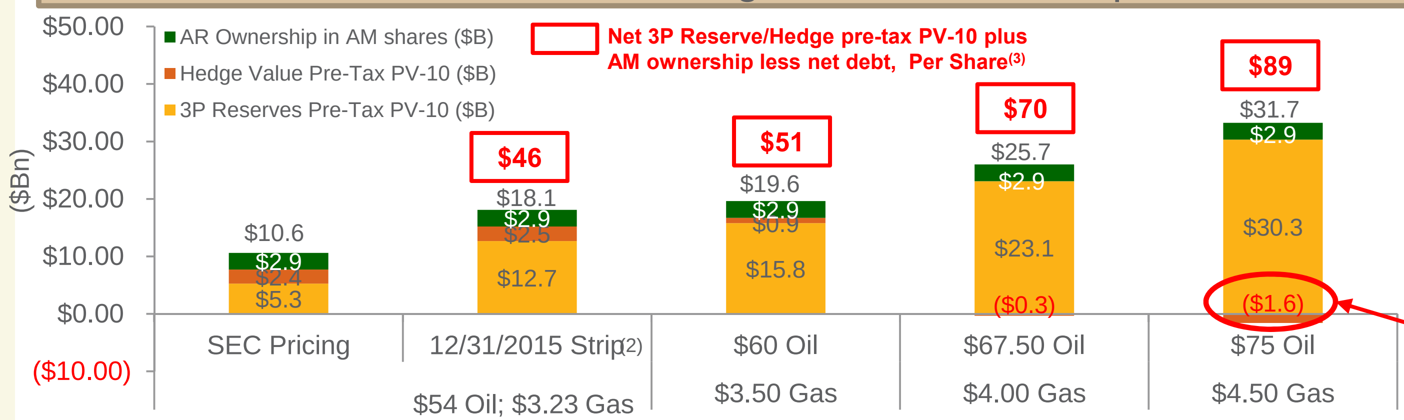
Optionality to Accelerate Development



Substantial Inventory



3P Reserve/Hedge Pre-Tax PV-10 Upside Value(3)(4)



Increase in pre-tax PV10 value does not include the addition of locations; represents upside in prices only on 12/31/15 locations

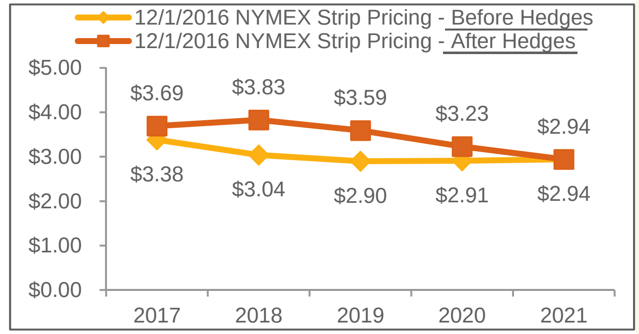
Increase in reserve pre-tax PV-10 is well in excess of hedge PV-10 lost at higher prices

Note: Assumes NGL prices equal to 37.5% of WTI for 2016 and 50% of WTI thereafter. All PV-10 values are on a pre-tax basis.
1. *Total 3P locations of 3,719 less 110 planned completions in 2016. Pro forma for 625 locations added in recent acreage acquisition.*
2. *Strip pricing as of December 31, 2015 for each of the first ten years and flat thereafter.*
3. *Pro forma PV-10 of 3P reserves and hedges less $3.7 billion of pro forma net debt as of 9/30/2016, plus market value of 108.9 million AM units owned by AR (as of 9/30/2016).*
4. *Assumes 313.9 million AR shares pro forma as at 9/30/2016.*

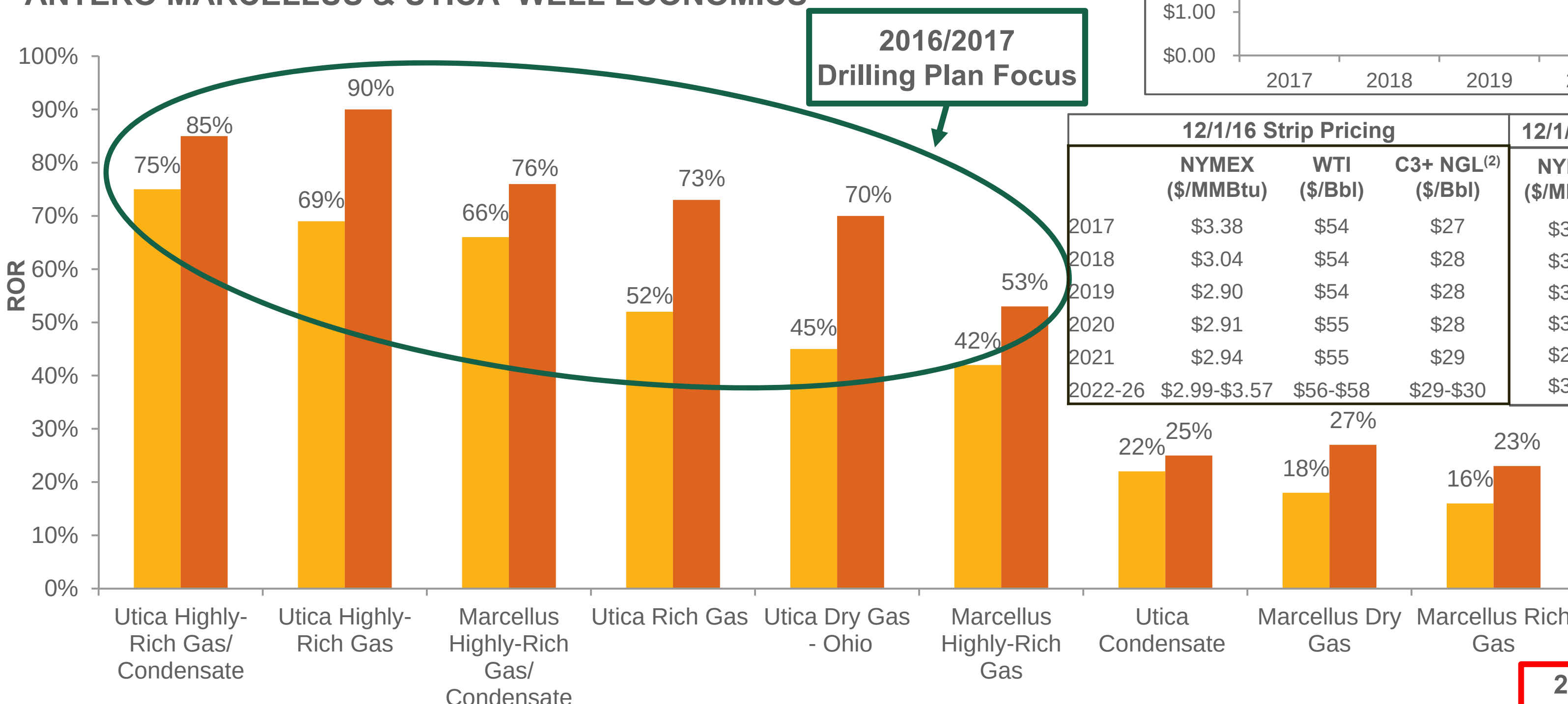
WELL ECONOMICS – SUSTAINABLE BUSINESS MODEL

Antero Resources

- At 12/1/2016 strip pricing, Antero has 2,713 locations with well economics that exceed 20% rate of return (excluding hedges), pro forma for third-party acquisition
  - *Including hedges, these locations generate rates of return of approximately 27% to 98%*
- Rates of return include pad, facilities, cash production expenses (including midstream and FT costs)
  - *See assumptions pages in appendix for further detail*



ANTERO MARCELLUS & UTICA WELL ECONOMICS(1)(2)(3)



	12/1/16 Strip Pricing			12/1/16 Hedge Pricing	
	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL(2) ($/Bbl)	NYMEX ($/MMBtu)	C3+ NGL ($/Bbl)
2017	$3.38	$54	$27	$3.69	$21
2018	$3.04	$54	$28	$3.83	$28
2019	$2.90	$54	$28	$3.59	$28
2020	$2.91	$55	$28	$3.23	$28
2021	$2.94	$55	$29	$2.94	$29
2022-26	$2.99-$3.57	$56-$58	$29-$30	$3.29	$30

2,713 "High Grade" Drilling Locations

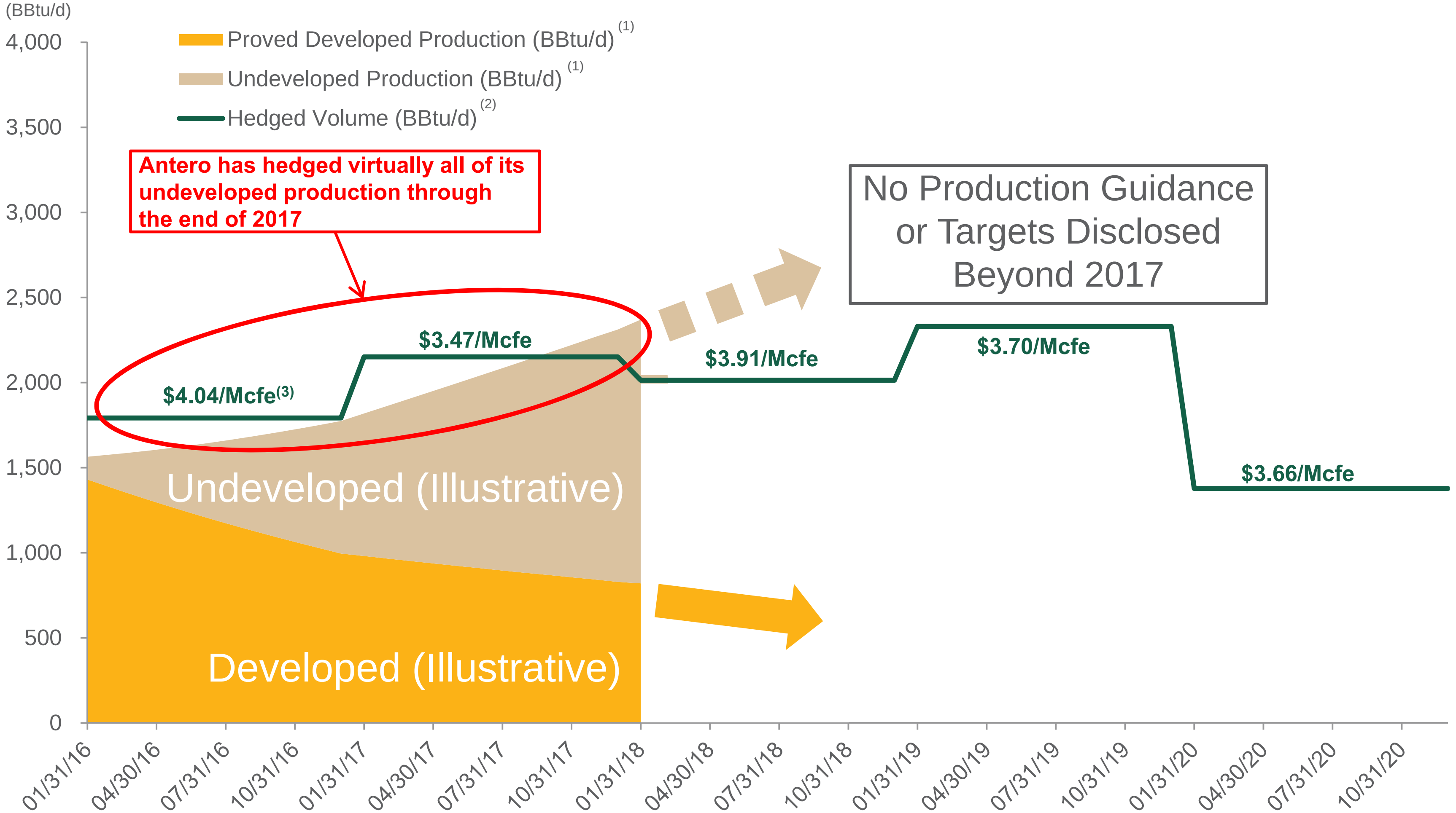
Locations(4)								
98	108	664	161	263	1,235	184	940	691

1. *12/1/2016 pre-tax well economics based on a 9,000' lateral, 12/1/2016 natural gas and WTI strip pricing for 2017-2026, flat thereafter, NGLs at ~50% of WTI for 2017 and thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *ROR @ 12/1/2016 Strip Pricing – After Hedges reflects 12/1/2016 well cost ROR methodology with the 9/30/2016 hedge value allocated based on 2017-2021 projected production volumes resulting in blend of strip and hedge prices.*
3. *Marcellus well count, adjusted for 6/30/2016 net acreage and pro forma for third-party acquisition per press release dated 6/9/2016, assumes 1.7 Bcf/1,000' type curve.*
4. *Undeveloped well locations as of 12/31/2015 adjusted for 6/30/2016 acreage changes.*

WELL ECONOMICS – HEDGING UNDEVELOPED PRODUCTION

Antero has hedged a significant portion of its forecasted undeveloped production stream from wells yet to be drilled at prices well above current strip pricing, including virtually all of its undeveloped production forecast through the end of 2017

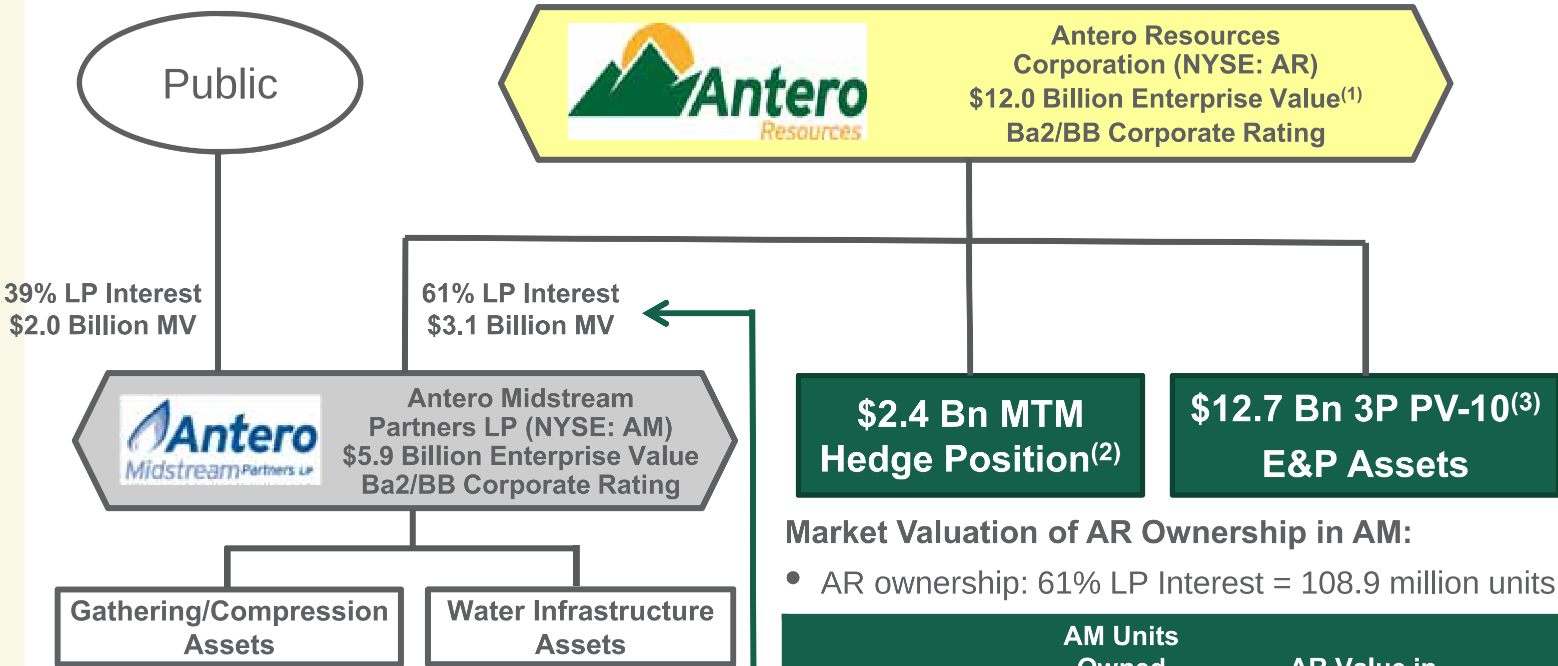
Natural Gas Hedged Volume vs. Production



1. Represents illustrative Antero production forecast, adjusted for residue gas BTU content of 1100 BTU.
2. Hedged volume as of 9/30/2016.
3. Represents average hedge price for three months ending 12/31/2016.

MIDSTREAM – MLP (NYSE: AM) HIGHLIGHTS
SUBSTANTIAL VALUE IN MIDSTREAM BUSINESS

Corporate Structure Overview



MLP Benefits:
- Funding vehicle to expand midstream business
- Highlights value of Antero Midstream
- Liquid asset for Antero Resources

Market Valuation of AR Ownership in AM:

- AR ownership: 61% LP Interest = 108.9 million units

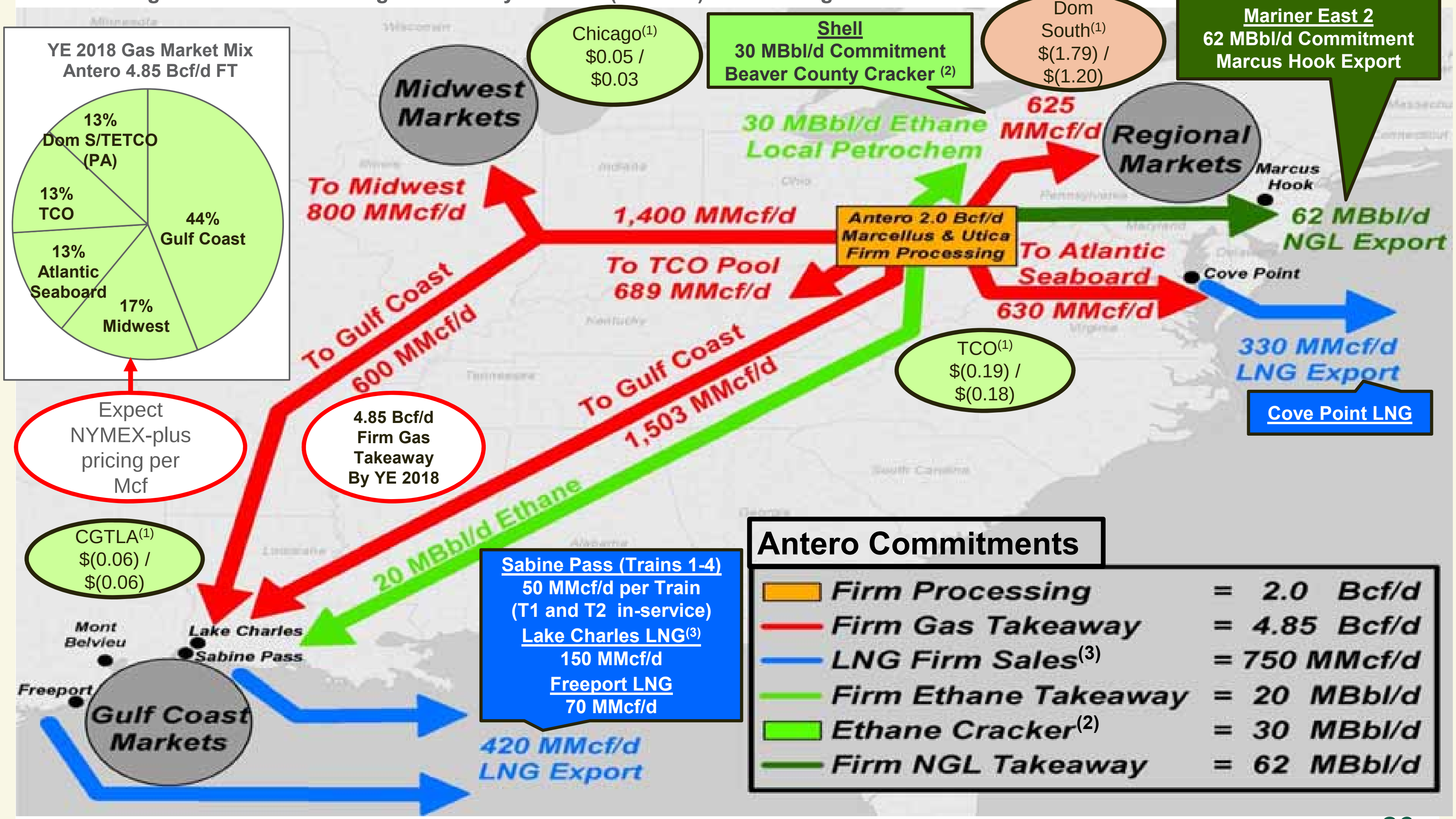
AM Price per Unit	AM Units Owned by AR (MM)	AR Value in AM LP Units ($MMs)	Value Per AR Share(4)
$24	109	$2,614	$8
$25	109	$2,723	$9
$26	109	$2,831	$9
$27	109	$2,940	$9
$28	**109**	**$3,059**	**$10**
$29	109	$3,161	$10
$30	109	$3,267	$10

1. AR enterprise value includes market value of AR stock and AR net debt only. Market values (MV) as of 12/5/2016 and includes subordinated LP units; balance sheet data as of 9/30/2016. ***Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay AR bank debt, $170 million AR acreage divestiture announced on 10/26/2016 and $600 million 5.00% AR senior note offering announced on 12/7/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.***
2. 3.5 Tcfe hedged at $3.65/Mcfe average price through 2022 with mark-to-market (MTM) value of $2.4 billion as of 9/30/2016.
3. 3P pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively. ***Includes unaudited $1.5 billion 3P PV-10 from recent acreage acquisition per press release dated 6/9/2016 and exercise of tag along right.***
4. Based on 313.9 million AR shares outstanding pro forma for 6.7 million share AR PIPE on 10/3/2016, and 176.9 million AM units outstanding as of 9/30/2016.

TAKEAWAY – LARGEST FT PORTFOLIO IN NORTHEAST

- Antero's natural gas firm transportation (FT) portfolio builds to 4.85 Bcf/d by YE 2018 with 87% serving favorable markets, for an average demand fee of $0.46/MMBtu and positive weighted average basis differential to NYMEX after assumed Btu uplift for gas

Antero Long Term Firm Processing & Takeaway Position (YE 2018) – Accessing Favorable Markets

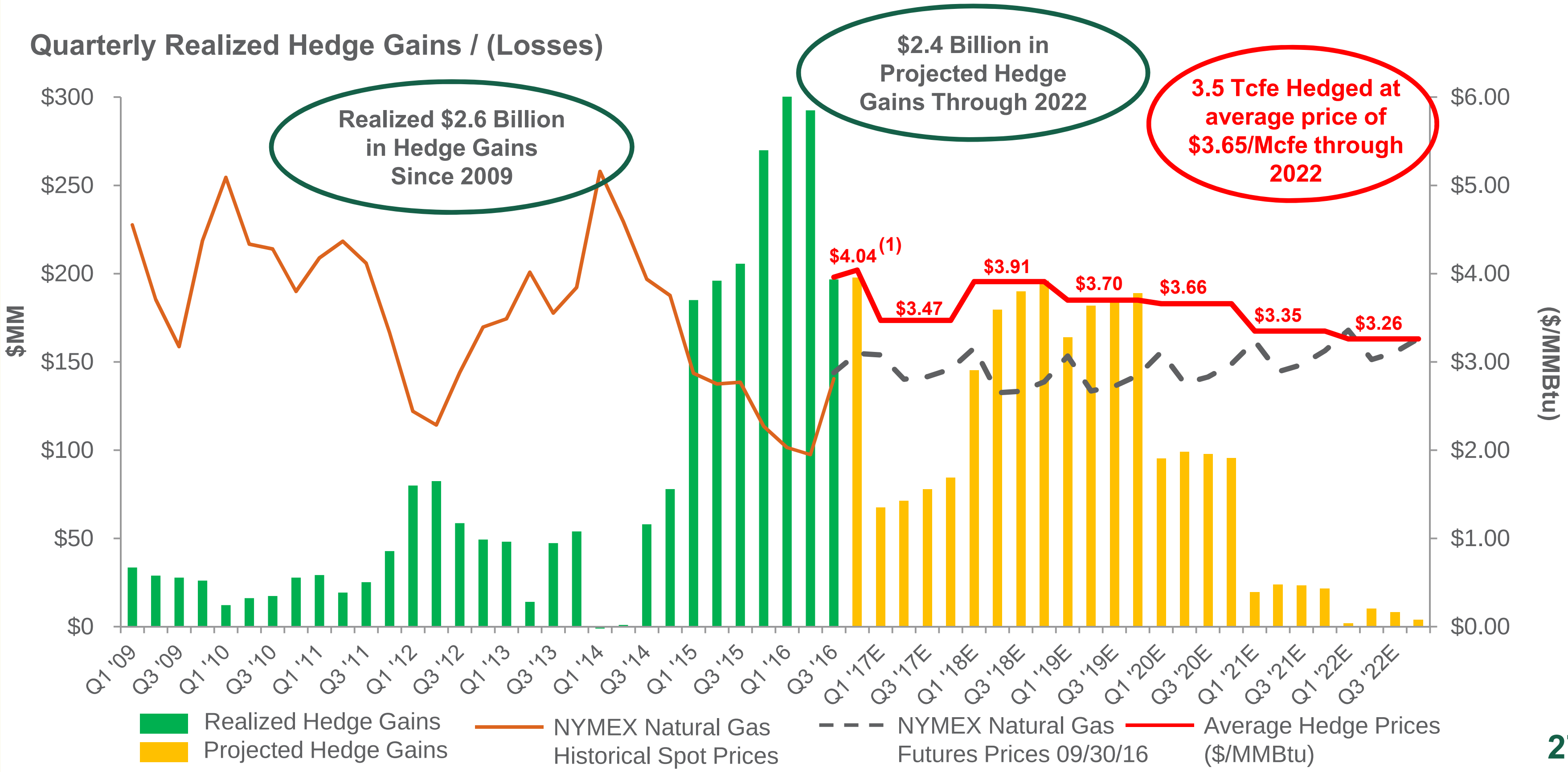


1. November 2016 and full year 2017 futures basis, respectively, provided by Intercontinental Exchange dated 9/30/2016. Favorable markets shaded in green.
2. Shell announced final investment decision (FID) on 6/7/2016.
3. Lake Charles LNG 150 MMcf/d commitment subject to Shell FID.

HEDGING – INTEGRAL TO BUSINESS MODEL

- Hedging is a key component of Antero's business model which includes development of a large, repeatable drilling inventory
  - *– Locks in higher returns in a low commodity price environment and reduces the amount of time for well payouts, thereby enhancing liquidity*
- Antero has realized $2.6 billion of gains on commodity hedges since 2009
  - *– Gains realized in 30 of last 31 quarters, or 97% of the quarters since 2009*
- Based on Antero's hedge position and strip pricing as of 9/30/2016, the unrealized commodity derivative value is $2.4 billion
- Significant additional hedge capacity remains under the credit facility hedging covenant for 2020 – 2022 period

Quarterly Realized Hedge Gains / (Losses)



1. *Represents average hedge price for three months ending 12/31/2016.*

LIQUIDITY – STRONG BALANCE SHEET AND FLEXIBILITY

Antero Resources (NYSE:AR)

Pro Forma 9/30/2016 Debt[(1)]

Debt Type	$MM
Credit facility	$208
6.00% senior notes due 2020	-
5.375% senior notes due 2021	1,000
5.125% senior notes due 2022	1,100
5.625% senior notes due 2023	750
5.00% senior notes due 2025	600
Total	**$3,658**

Liquid Non-E&P Assets

Asset Type	$MM
Commodity derivatives[(2)]	$2,430
AM equity ownership[(3)]	3,134
Cash	10
Total	**$5,574**

Liquid "non-E&P assets" of $5.6 Bn significantly exceeds total debt of $3.7 billion pro forma for recent offerings

Pro Forma Liquidity

Asset Type	$MM
Cash	$10
Credit facility – commitments[(4)]	4,000
Credit facility – drawn	(208)
Credit facility – letters of credit	(709)
Total	**$3,093**

Approximately $3.1 billion of liquidity at AR pro forma for recent offerings plus an additional $2.9 billion of AM units

Antero Midstream (NYSE:AM)

9/30/2016 Debt [(4)]

Debt Type	$MM
Credit facility	$170
5.375% senior notes due 2024	650
Total	**$820**

Liquid Assets

Asset Type	$MM
Cash	$9
Total	**$9**

Only 15% of AM credit facility capacity drawn following recent $650 million senior notes offering

Liquidity

Asset Type	$MM
Cash	$9
Credit facility – capacity	1,157
Credit facility – drawn	(170)
Credit facility – letters of credit	-
Total	**$996**

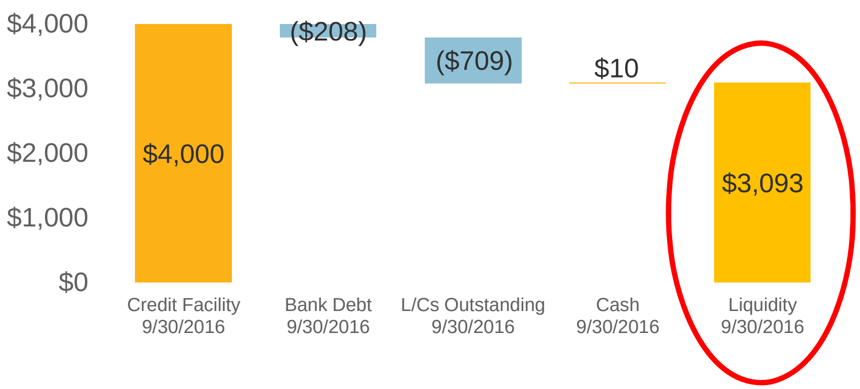
Approximately $1.0 billion of liquidity at AM following recent senior notes offering

1. *All balance sheet data as of 9/30/2016. Antero Resources pro forma for $175 million private placement on 10/3/2016, $170 million AR acreage divestiture announced on 10/26/2016 and $600 million 5.00% AR senior note offering announced on 12/7/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.*
2. *Mark-to-market as of 9/30/2016.*
3. *Based on AR ownership of AM units and closing price as of 12/1/2016.*
4. *AR credit facility commitments of $4.0 billion, borrowing base of $4.75 billion.*

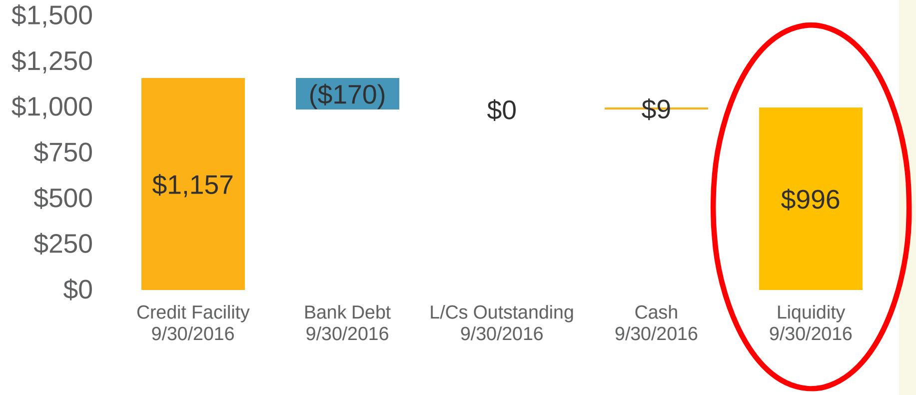
LIQUIDITY – ATTRACTIVE DEBT TERM STRUCTURE

- Approximately $4.1 billion of combined AR and AM financial liquidity as of 9/30/2016, pro forma for $175 million AR PIPE on 10/3/2016, $170 million acreage divestiture announced on 10/25/2016 and $600 million senior note offering announced on 12/7/2016
- No leverage covenant in AR bank facility, only interest coverage and working capital covenants

PRO FORMA AR LIQUIDITY POSITION ($MM)[1][2]

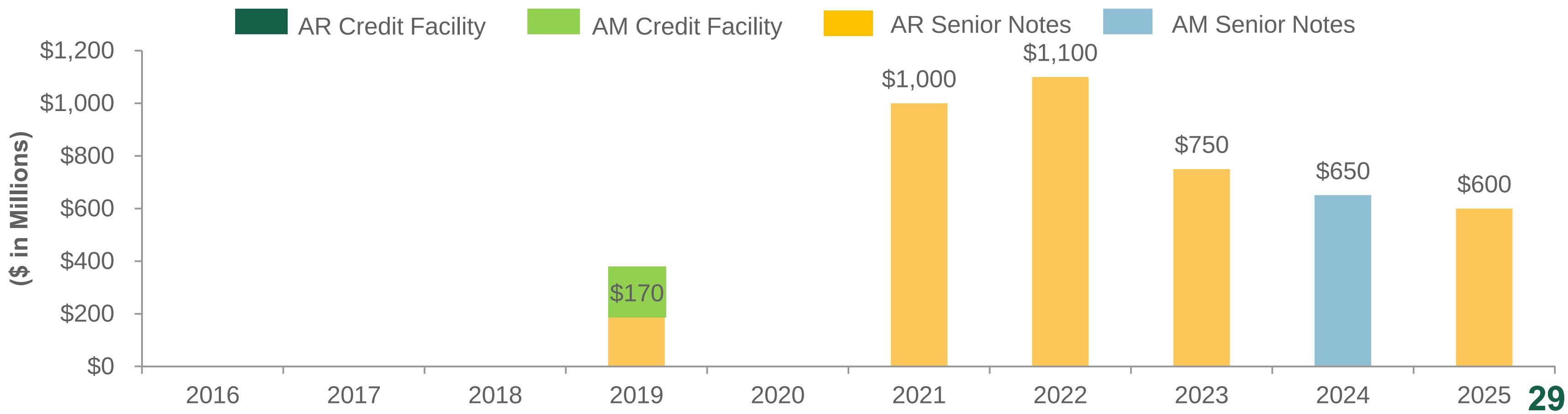


PRO FORMA AM LIQUIDITY POSITION ($MM)



- Recent credit facility increases, equity and high yield offerings have allowed Antero to reduce its cost of debt to 5.1% and significantly enhance liquidity with an average debt maturity of January 2023

PRO FORMA DEBT MATURITY PROFILE[1][2]



1. Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay AR bank debt and $170 million AR acreage divestiture announced on 10/26/2016.
2. Pro forma for $600 million 5.00% AR senior note offering announced on 12/7/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.

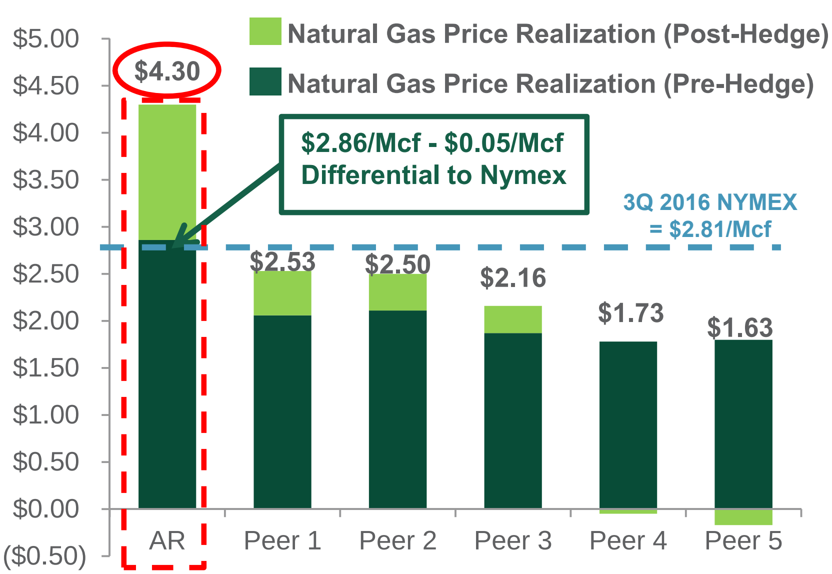
REALIZATIONS – A LEADER IN REALIZATIONS & MARGINS

- Antero continues to be a leader in its peer group in price realizations and EBITDAX unit margins

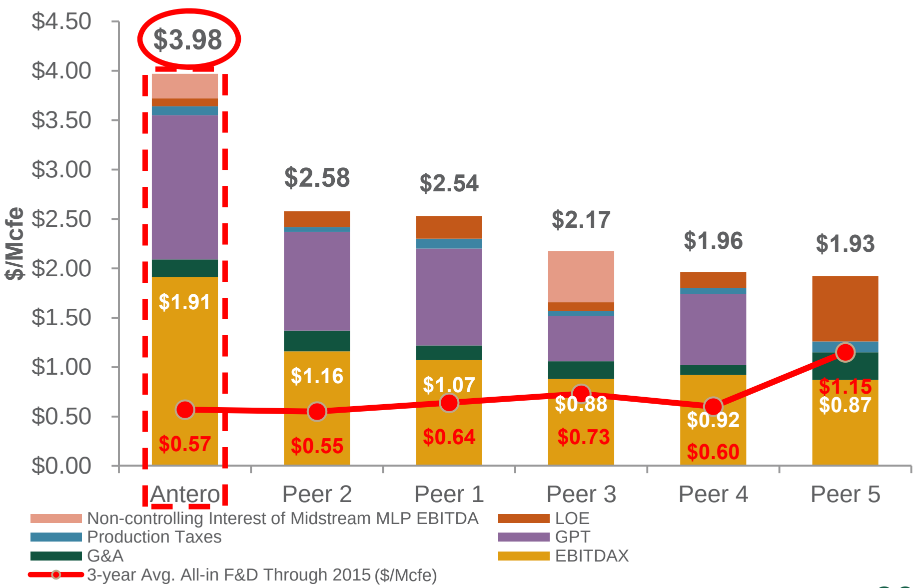
3Q 2016 Natural Gas Realizations ($/Mcf)

Region	3Q 2016 % Sales	Average NYMEX Price	Average Differential	Average BTU Upgrade	Pre-Hedge Realized Price	Hedge Effect	3Q 2016 Realized Gas Price	NYMEX Premium/ Discount
TCO	51%	$2.81	$(0.20)	$0.27	$2.88	$0.05	$2.93	$0.12
Chicago/MichCon	27%	$2.81	($0.14)	$0.28	$2.95	$0.00	$2.95	$0.14
Gulf Coast	21%	$2.81	$(0.36)	$0.26	$2.71	$0.66	$3.37	$0.56
Dom South/TETCO	1%	$2.81	$(1.67)	$0.12	$1.26	$0.73	$1.99	$(0.82)
Total Wtd. Avg.	**100%**	**$2.81**	**$(0.23)**	**$0.28**	**$2.86**	**$1.44**	**$4.30**	**$1.49**

3Q 2016 Natural Gas Realizations(1)(2)



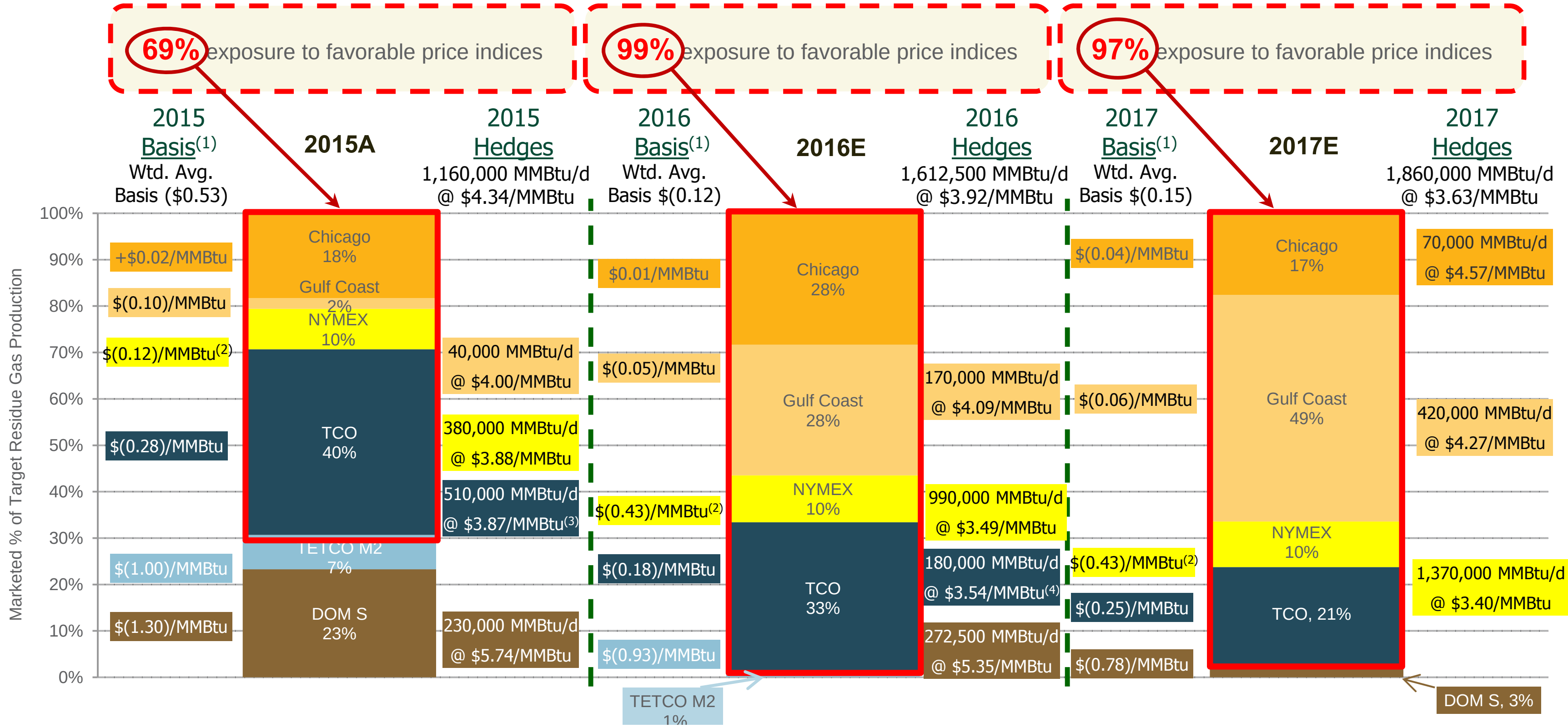
3Q 2016 Price Realization & EBITDAX Margin vs F&D(2)(3)



1. Includes natural gas hedges.
2. Source: Public data from 3Q 2016 earnings releases. Peers include COG, CNX, EQT, RRC and SWN.
3. Includes realized hedge gains and losses. Operating costs include lease operating expenses, production taxes, gathering, processing and firm transport costs and general and administrative costs. 3-year proved reserve average all-in F&D from 2013-2015. Calculation = (Development costs + exploration costs + leasehold costs) / Total reserves added (2015 ending reserves – 2013 beginning reserves + 3-year reserve sales – 3-year reserve purchases + 3-year accumulated production + 2015 SEC price revisions). AR price realization includes $0.02 of midstream revenues; EBITDAX excludes AR's midstream EBITDA not attributable to AR's ownership.

REALIZATIONS – FAVORABLE PRICE INDICES

- Antero's exposure to favorable gas price indices like Chicago, Gulf Coast, NYMEX and TCO is expected to increase to >99% in 2016
- Improved 2016 realizations driven by Stonewall gathering pipeline which was placed in-service December 1, 2015 and will eliminate virtually all swing sales at Dominion South and Tetco in 2016



($/Mcf)	2015A	2016E
NYMEX Strip Price[1]	$2.66	$2.47
Basis Differential to NYMEX[1]	$(0.53)	$(0.12)
BTU Upgrade[5]	$0.24	$0.24
Estimated Realized Hedge Gains	$1.44	$1.50
Realized Gas Price with Hedges	$3.81	$4.10
Premium to NYMEX	+$1.15	+$1.63
Liquids Impact	+$0.29	+$0.10
Premium to NYMEX w/ Liquids	+$1.44	+$1.73
Realized Gas-Equivalent Price	$4.10	$4.16

Current markets indicate positive differential in 2016

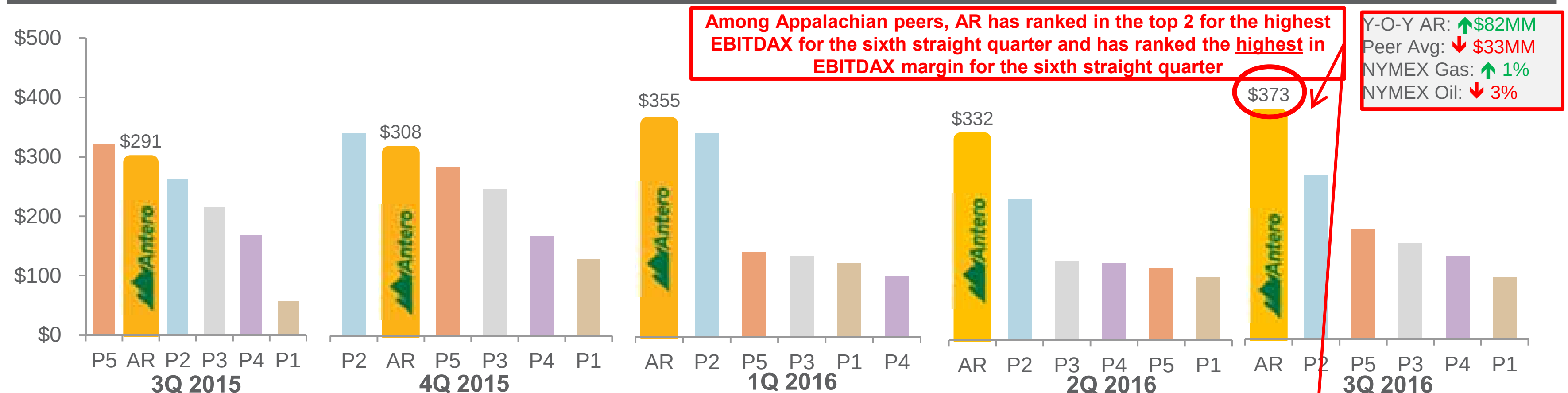
Note: Hedge volumes as of 12/31/2015.

1. *Based on 12/31/2015 strip pricing and actuals for 2015.*
2. *Differential represents contractual deduct to NYMEX-based firm sales contract.*
3. *Represents 120,000 MMBtu/d of TCO index hedges and 390,000 MMBtu/d of TCO basis hedges that are matched with NYMEX hedges for presentation purposes.*
4. *Represents 60,000 MMBtu/d of TCO index hedges and 120,000 MMBtu/d of TCO basis hedges that are matched with NYMEX hedges for presentation purposes.*
5. *Based on BTU content of residue sales gas.*

REALIZATIONS – HIGHEST EBITDAX & MARGINS AMONG PEERS

- Antero has extended its lead among Appalachian Basin peers in both EBITDAX and EBITDAX margin

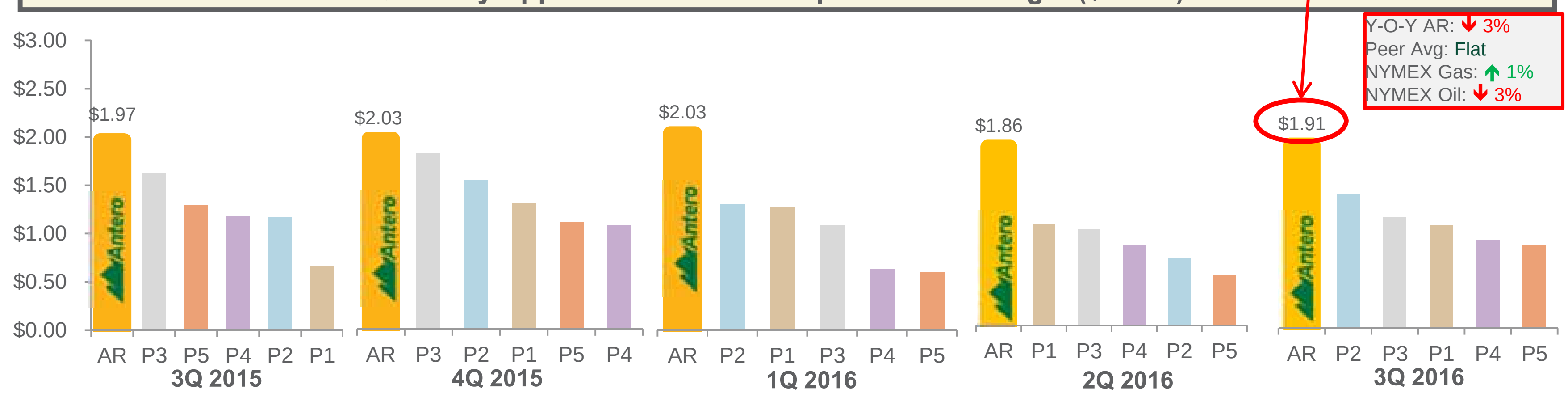
Quarterly Appalachian Peer Group EBITDAX ($MM)(1)



AR Peer Group Ranking – Improving Over Time

#2	#2	#1	#1	#1

Quarterly Appalachian Peer Group EBITDAX Margin ($/Mcfe)(1)



AR Peer Group Ranking – Top Tier

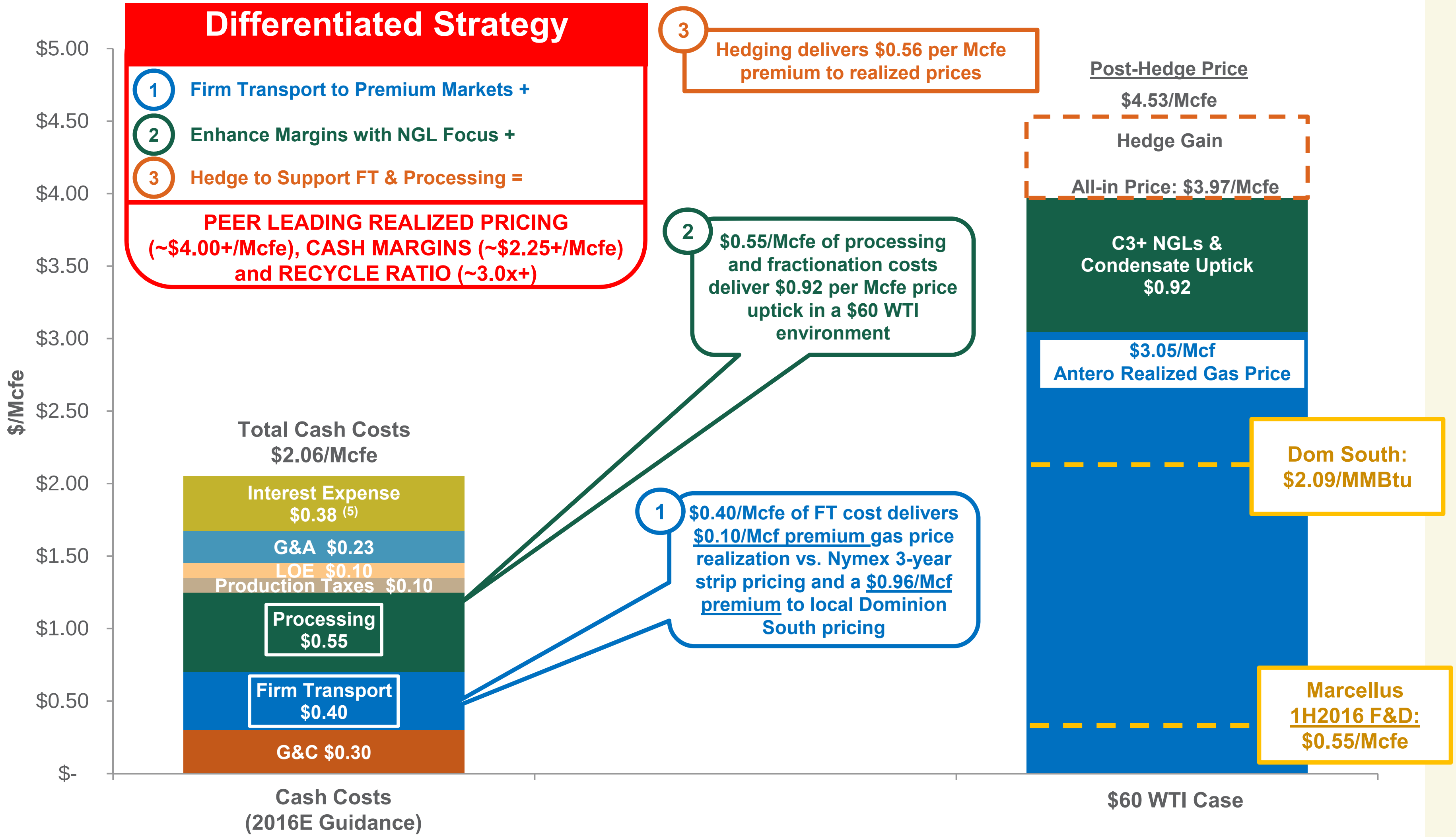
#1	#1	#1	#1	#1

Note: AR and EQT EBITDAX margin excludes EBITDA from midstream MLP associated with noncontrolling interest. AR consolidated EBITDAX margin for 3Q 2016 was $2.16/Mcfe. CNX excludes EBITDAX contribution from coal operations.

1. Source: Public data from form 10-Qs and 10-Ks and Wall Street research. Peers include COG, CNX, EQT , RICE, RRC and SWN where applicable

REALIZATIONS – DRIVEN BY ANTERO'S DIFFERENTIATED STRATEGY

Unit Cash Cost vs. 3-Year Average Realized Pricing(1)(2)(3)(4)



1. Excludes hedge gains and net marketing expense.
2. All three WTI sensitivity cases assume Henry Hub natural gas strip pricing through 3Q2018, as of 9/30/2016.
3. Assumes 4Q2016-3Q2018 weighted average C3+ NGL realization of 45% of WTI.
4. Assumes 1250 BTU.
5. Based on 1H 2016 interest expense and actual production.

REALIZATIONS – ANTERO FIRM TRANSPORT ELIMINATES NORTHEAST BASIS RISK

Antero Expected Pricing: 2017-2020 ($/MMBtu)	
Forecasted Realized Natural Gas Price [1]	Nymex + ~$0.10
- Average FT Expense (operating expense)	$(0.46)
- Average Net Marketing Expense	$(0.10)
= Net Natural Gas Price vs. Nymex	$(0.46)
Dom South and Tetco M2 Realized Natural Gas Strip [2]	Nymex - $(0.83)
Antero Pricing Relative to Northeast Differential	+$0.37

Even with the relative tightening of local basis indicated in the futures market, Antero's expected netback through the end of the decade (after deducting FT and marketing costs) is $0.37 per MMBtu higher than the local Dominion South and TETCO M2 indices

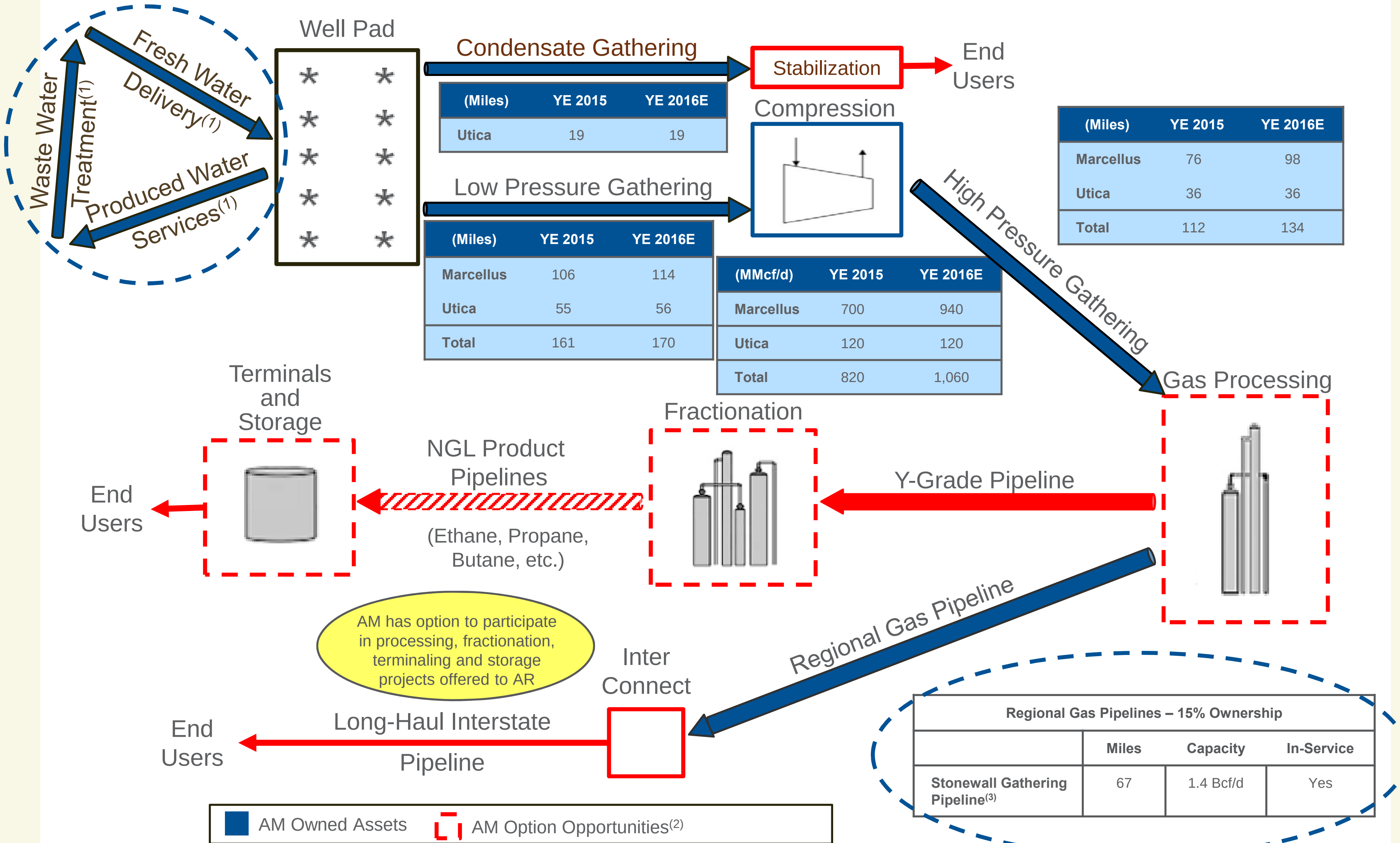
1. *Based on management forecast of net production, BTU of future production and the 2017 through 2020 futures strip for various indices that Antero can access with its firm transport portfolio.*
2. *Assumes 50/50 DOM S and TETCO M2 split, from ICE futures as of 12/1/2016.*

Antero Midstream (NYSE: AM)
Asset Overview

Antero Midstream Partners LP

FULL VALUE CHAIN BUSINESS MODEL

AM recently exercised its option on 15% interest in Stonewall, adding a regional gas gathering pipeline to its portfolio



Condensate Gathering

(Miles)	YE 2015	YE 2016E
Utica	19	19

Low Pressure Gathering

(Miles)	YE 2015	YE 2016E
Marcellus	106	114
Utica	55	56
Total	161	170

Compression

(MMcf/d)	YE 2015	YE 2016E
Marcellus	700	940
Utica	120	120
Total	820	1,060

High Pressure Gathering

(Miles)	YE 2015	YE 2016E
Marcellus	76	98
Utica	36	36
Total	112	134

Regional Gas Pipelines – 15% Ownership			
	Miles	Capacity	In-Service
Stonewall Gathering Pipeline(3)	67	1.4 Bcf/d	Yes

1. Acquired by AM from AR for a $1.05 billion upfront payment and a $125 million earn out in each of 2019 and 2020.
2. Antero Midstream has a right of first offer on 220,000 dedicated net acres for processing and fractionation pro forma for recent acreage acquisition.
3. Antero Midstream owns 15% stake in Stonewall pipeline.

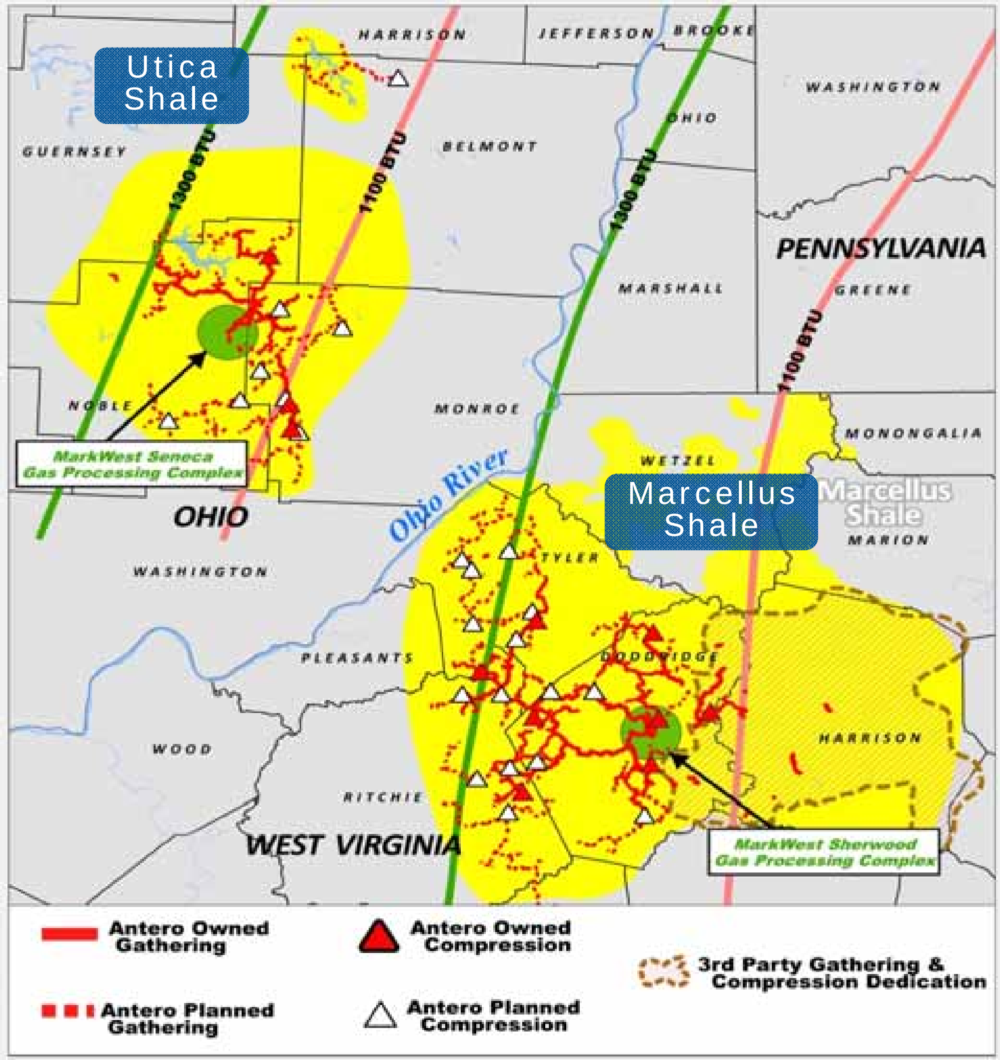
ANTERO MIDSTREAM GATHERING AND COMPRESSION ASSET OVERVIEW

Gathering and Compression Assets

- Gathering and compression assets in core of rapidly growing Marcellus and Utica Shale plays
  - Acreage dedication of ~576,000 gross leasehold acres for gathering and compression services
  - Additional stacked pay potential with dedication on ~278,000 gross acres of Utica deep rights underlying the Marcellus in WV and PA
  - 100% fixed fee long term contracts
- AR owns 61% of AM units (NYSE: AM)

Projected Gathering and Compression Infrastructure[1]

	Marcellus Shale	Utica Shale	Total
YE 2015 Cumulative Gathering/ Compression Capex ($MM)	**$981**	**$462**	**$1,443**
Gathering Pipelines (Miles)	182	91	273
Compression Capacity (MMcf/d)	700	120	820
Condensate Gathering Pipelines (Miles)	-	19	19
2016E Gathering/Compression Capex Budget ($MM)[2]	**$235**	**$20**	**$255**
Gathering Pipelines (Miles)	30	1	31
Compression Capacity (MMcf/d)	240	-	240
Condensate Gathering Pipelines (Miles)	-	-	-



1. Represents inception to date actuals as of 12/31/2015 and 2016 guidance.
2. Includes both expansion capital and maintenance capital.

ANTERO MIDSTREAM WATER BUSINESS OVERVIEW

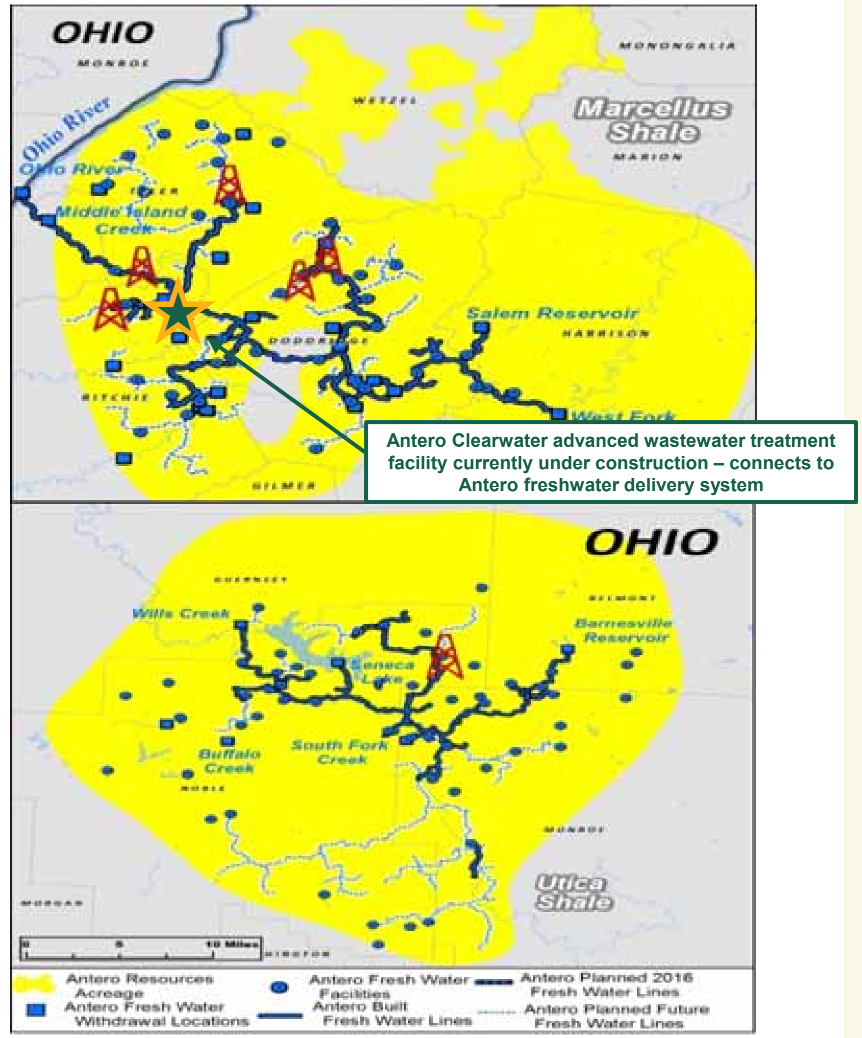
- AM acquired AR's integrated water business for $1.05 billion plus earn out payments of $125 million at year-end in each of 2019 and 2020
  - The acquired business includes Antero's Marcellus and Utica freshwater delivery business, the fully-contracted future advanced wastewater treatment complex and all fluid handling and disposal services for Antero

Water Business Assets

- Fresh water delivery assets provide fresh water to support Marcellus and Utica well completions
  - Year-round water supply sources: Clearwater Facility, Ohio River, local rivers & reservoirs[2]
  - 100% fixed fee long term contracts

Projected Water Business Infrastructure[1]

	Marcellus Shale	Utica Shale	Total
YE 2015 Cumulative Fresh Water Delivery Capex ($MM)	**$469**	**$62**	**$531**
Water Pipelines (Miles)	184	75	259
Fresh Water Storage Impoundments	22	13	35
2016E Fresh Water Delivery Capex Budget ($MM)[3]	**$40**	**$10**	**$50**
Water Pipelines (Miles)	20	9	29
Fresh Water Storage Impoundments	1	-	1
Cash Operating Margin per Well[4]	**$950k - $1,050k**	**$825k - $925k**	
2016E Advanced Waste Water Treatment Budget ($MM)			**$130**
2016E Total Water Business Budget ($MM)			**$180**



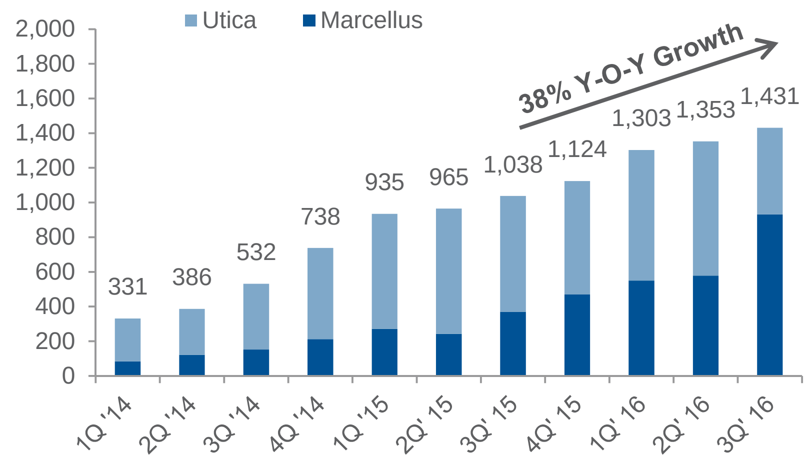
Note: Antero acreage position reflects tax districts in which greater than 3,000 net acres are owned.

1. *Represents inception to date actuals as of 12/31/2015 and 2016 guidance.*
2. *All Antero water withdrawal sites are fully permitted under long-term state regulatory permits both in WV and OH.*
3. *Includes both expansion capital and maintenance capital.*
4. *Marcellus assumes fee of $3.69 per barrel subject to annual inflation and 38 barrels of water per lateral foot that utilize the fresh water delivery system based on 9,000 foot lateral. Operating margin excludes G&A. Utica assumes fee of $3.64 per barrel subject to annual inflation and 34 barrels of water per lateral foot that utilize the fresh water delivery system based on 9,000 foot lateral. Water volumes assume 5% recycling. Operating margin excludes G&A.*

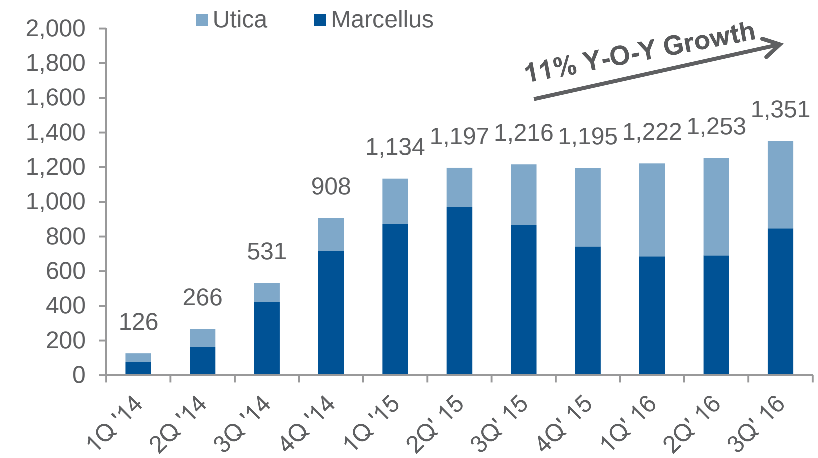
HIGH GROWTH MIDSTREAM THROUGHPUT

- Antero production growth drives substantial volume growth and value creation in Antero Midstream

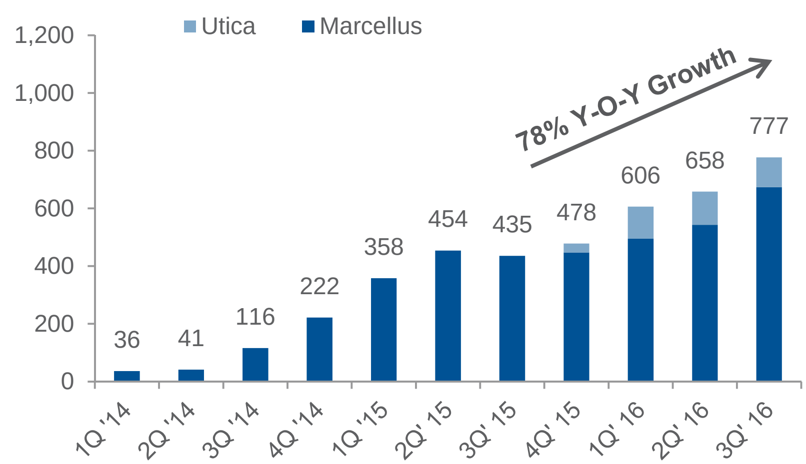
Low Pressure Gathering (MMcf/d)



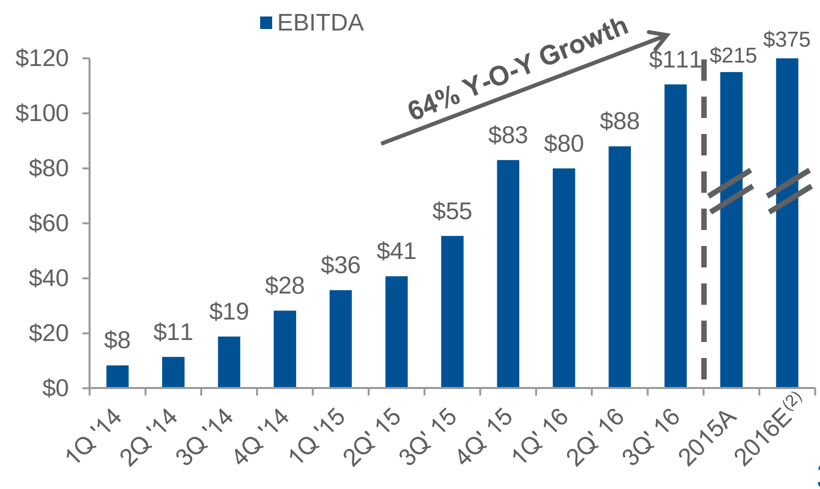
High Pressure Gathering (MMcf/d)



Compression (MMcf/d)



Adjusted EBITDA ($MM)[1]



Note: Y-O-Y growth based on 3Q'15 to 3Q'16.

1. *Represents adjusted EBITDA attributable to the Partnership.*
2. *Represents midpoint of updated 2016 guidance.*

SIGNIFICANT FINANCIAL FLEXIBILITY

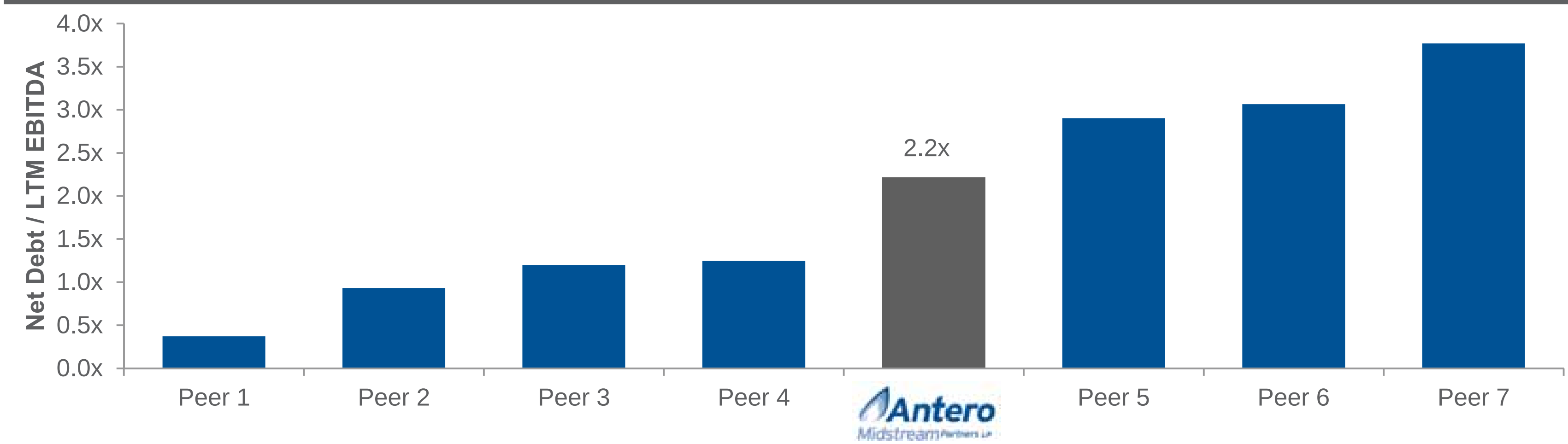
AM Liquidity (9/30/2016)

($ in millions)	
Revolver Capacity	$1,157
Less: Borrowings	170
Plus: Cash	9
Liquidity	$996

Financial Flexibility

- $1.5 billion revolver in place to fund future growth capital (5.0x Debt/EBITDA Cap)
- Liquidity of $996 million at 9/30/2016 based off $1,157 million revolver
- Sponsor (NYSE: AR) has Ba2/BB corporate debt ratings
- AM corporate debt ratings also Ba2/BB

AM Peer Leverage Comparison[1]



1. As of 9/30/2016. Peers include TEP, EQM, WES, RMP, SHLX, DM, and CNNX.

KEY CATALYSTS FOR ANTERO

1	Production and Cash Flow Growth	Guiding to production growth of 20% in 2016 and targeting 20% to 25% in 2017, with 86% of forecasted production hedged through 2019 at $3.72/MMBtu, a $0.78 premium to strip
2	Continued Operational Improvement	36% lower well cost per 1,000’ lateral and 33% higher EUR per 1,000’ since 2014 are driving rates of return significantly higher despite lower strip pricing
3	Sustainability of Antero’s Integrated Business Model	Large, low unit cost core Marcellus and Utica natural gas drilling inventory with associated liquids generates attractive returns supported by long-term natural gas hedges, takeaway portfolio and downstream LNG and NGL sales agreements
4	Exposure to Commodity Upside	Most active developer in the lowest cost basin with growing production base and firm transport to favorable markets; over 38 Tcfe of unhedged 3P reserves increase ~$10 billion in pre-tax PV-10 value with a 50% recovery in commodity prices
5	Midstream MLP Growth	Antero owns 61% of Antero Midstream Partners and thereby participates directly in its growth and value creation; acquisition of integrated water business from Antero expected to result in distributable cash flow per unit accretion in 2016
6	Consolidation	Antero is well positioned to continue to be a leading consolidator in Appalachia

APPENDIX

ANTERO CAPITALIZATION – CONSOLIDATED

($ in millions)	9/30/2016	Pro Forma(4) 9/30/2016	As Adjusted Pro Forma(5) 9/30/2016
Cash	$19	$19	$19
AR Senior Secured Revolving Credit Facility	605	260	208
AM Bank Credit Facility	170	170	170
6.00% Senior Notes Due 2020	525	525	-
5.375% Senior Notes Due 2021	1,000	1,000	1,000
5.125% Senior Notes Due 2022	1,100	1,100	1,100
5.625% Senior Notes Due 2023	750	750	750
5.00% Senior Notes Due 2025			600
5.375% Senior Notes Due 2024 – AM	650	650	650
Net Unamortized Premium	6	6	6
Total Debt	$4,806	$4,461	$4,483
Net Debt	$4,787	$4,442	$4,465
Financial & Operating Statistics			
LTM EBITDAX(1)	$1,368	$1,368	$1,368
LTM Interest Expense(2)	$249	$243	$241
Proved Reserves (Bcfe) (12/31/2015)	13,215	13,215	13,215
Proved Developed Reserves (Bcfe) (12/31/2015)	5,838	5,838	5,838
Credit Statistics			
Net Debt / LTM EBITDAX	3.5x	3.2x	3.3x
Net Debt / Net Book Capitalization	37%	35%	35%
Net Debt / Proved Developed Reserves ($/Mcfe)	$0.82	$0.76	$0.76
Net Debt / Proved Reserves ($/Mcfe)	$0.36	$0.34	$0.34
Liquidity			
Credit Facility Commitments(3)	$5,157	$5,157	$5,157
Less: Borrowings	(775)	(430)	(378)
Less: Letters of Credit	(709)	(709)	(709)
Plus: Cash	19	19	19
Liquidity (Credit Facility + Cash)	**$3,692**	**$4,037**	**$4,089**

AR LISTED NYSE®

AM LISTED NYSE®

1. *LTM and 9/30/2016 EBITDAX reconciliation provided in Appendix.*
2. *LTM interest expense adjusted for all capital market transactions since 1/1/2015.*
3. *AR lender commitments at $4.0 billion and borrowing base capacity at $4.75 billion. AM credit facility capacity at $1,157 million.*
4. *Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay bank facility and $170 million AR acreage divestiture announced on 10/26/2016 and expected to close in December 2016.*
5. *Pro forma for $600 million 5.00% AR senior notes offering announced on 12/7/2016 to refinance $525 million 6.00% senior notes at 103% and including transaction expenses. Assumes redemption of 6% senior notes.*

ANTERO RESOURCES – UPDATED 2016 GUIDANCE

Key Operating & Financial Assumptions

Key Variable	Updated 2016 Guidance[1]	Previous 2016 Guidance
Net Daily Production (MMcfe/d)	**1,800**	**1,750**
Net Residue Natural Gas Production (MMcf/d)	1,365	1,355
Net C3+ NGL Production (Bbl/d)	53,500	52,500
Net Ethane Production (Bbl/d)	15,000	10,000
Net Oil Production (Bbl/d)	4,500	3,500
Net Liquids Production (Bbl/d)	73,000	66,000
Natural Gas Realized Price Premium to NYMEX Henry Hub Before Hedging ($/Mcf)[2][3]	+$0.00 to $0.05	+$0.00 to $0.10
Oil Realized Price Differential to NYMEX WTI Oil Before Hedging ($/Bbl)	$(10.00) - $(11.00)	$(10.00) - $(11.00)
C3+ NGL Realized Price (% of NYMEX WTI)[2]	35% - 40%	35% - 40%
Ethane Realized Price (Differential to Mont Belvieu) ($/Gal)	$0.00	$0.00
Operating:		
Cash Production Expense ($/Mcfe)[4]	$1.40 - $1.50	$1.50 - $1.60
Marketing Expense, Net of Marketing Revenue ($/Mcfe)	$0.15 - $0.20	$0.15 - $0.20
G&A Expense ($/Mcfe)	$0.20 - $0.22	$0.20 - $0.25
Operated Wells Completed	110	110
Drilled Uncompleted Wells	70	70
Average Operated Drilling Rigs	≈ 7	≈ 7
Capital Expenditures ($MM):		
Drilling & Completion	$1,300	$1,300
Land	$100	$100
Total Capital Expenditures ($MM)	**$1,400**	**$1,400**

1. *Updated guidance per press release dated 09/06/2016.*
2. *Based on current strip pricing as of August 30, 2016.*
3. *Includes Btu upgrade as Antero's processed tailgate and unprocessed dry gas production is greater than 1000 Btu on average.*
4. *Includes lease operating expenses, gathering, compression and transportation expenses and production taxes.*

ANTERO MIDSTREAM – UPDATED 2016 GUIDANCE

Antero Midstream Partners LP

Key Operating & Financial Assumptions

Key Variable	Updated 2016 Guidance[1]	Previous 2016 Guidance
Financial:		
Net Income ($MM)	$205 - $225	$165 - $190
Adjusted EBITDA ($MM)	$365 - $385	$325 - $350
Distributable Cash Flow ($MM)	$315 - $335	$275 - $300
Year-over-Year Distribution Growth	30%	30%
Operating:		
Low Pressure Pipeline Added (Miles)	9	9
High Pressure Pipeline Added (Miles)	22	22
Compression Capacity Added (MMcf/d)	240	240
Fresh Water Pipeline Added (Miles)	30	30
Capital Expenditures ($MM):		
Gathering and Compression Infrastructure	$240	$240
Fresh Water Infrastructure	$40	$40
Advanced Wastewater Treatment	$130	$130
Stonewall Gathering Pipeline Option	$45	$45
Maintenance Capital	$25	$25
Total Capital Expenditures ($MM)	$480	$480

1. *Updated guidance per press release dated 09/06/2016.*

ETHANE RECOVERY ECONOMICS AND POTENTIAL VOLUMES

Antero Resources

RECOVERING ETHANE: ARBITRAGE VS. NATURAL GAS PRICING

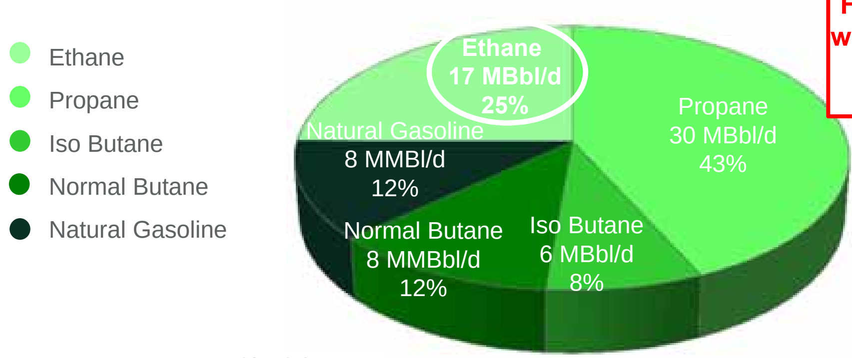
Example C2 Recovery Decision

	Assuming \$3.00/MMBtu Natural Gas		
	\$ / MMBtu	**C2 Conversion Factor**	**\$/Gal**
Natural Gas Price	\$3.00		
Less: Variable Transport Costs	(0.08)		
Less: July TCO Differential	(0.15)		
Realized Pricing	\$2.77	15.175	\$0.18
Plus: De-Ethanization Fee			0.05
Required Ethane Price to Recover (ATEX Sunk)			**\$0.23**
Plus: New Ethane Transportation			0.15
Required Ethane Price to Recover (New Transportation)			**\$0.38**

Assuming ATEX costs are sunk and NYMEX gas prices are \$3.00/MMBtu, ethane would need to be at least \$0.23 per gallon for Antero to recover ethane (up to its 20 MBbl/d ATEX Commitment)

Assuming incremental ethane transport costs \$0.15/gallon and NYMEX gas prices are \$3.00/MMBtu, ethane price would need to be at least \$0.38/gallon for Antero to recover ethane above its 20 MBbl/d ATEX commitment and 11.5 MBbl/d Borealis firm sale

2Q 2016 NGL PRODUCTION (PARTIAL C2 RECOVERY)

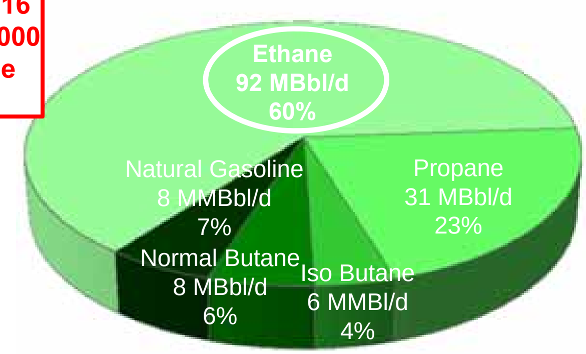


	% of C2+ Bbl
Ethane	25%
Propane	43%
Iso Butane	8%
Normal Butane	12%
Natural Gasoline	12%
Total	**100%**

70 MBbl/d 2Q 2016 C2+ Actual Production

2Q 2016 NGL PRODUCTION (FULL C2 RECOVERY)

Full C2 Recovery in Q2 2016 would have resulted in 75,000 Bbl/d of additional ethane production



	% of C2+ Bbl
Ethane	63%
Propane	21%
Iso Butane	4%
Normal Butane	6%
Natural Gasoline	6%
Total	**100%**

145 MBbl/d 2Q 2016 C2+ Potential Production

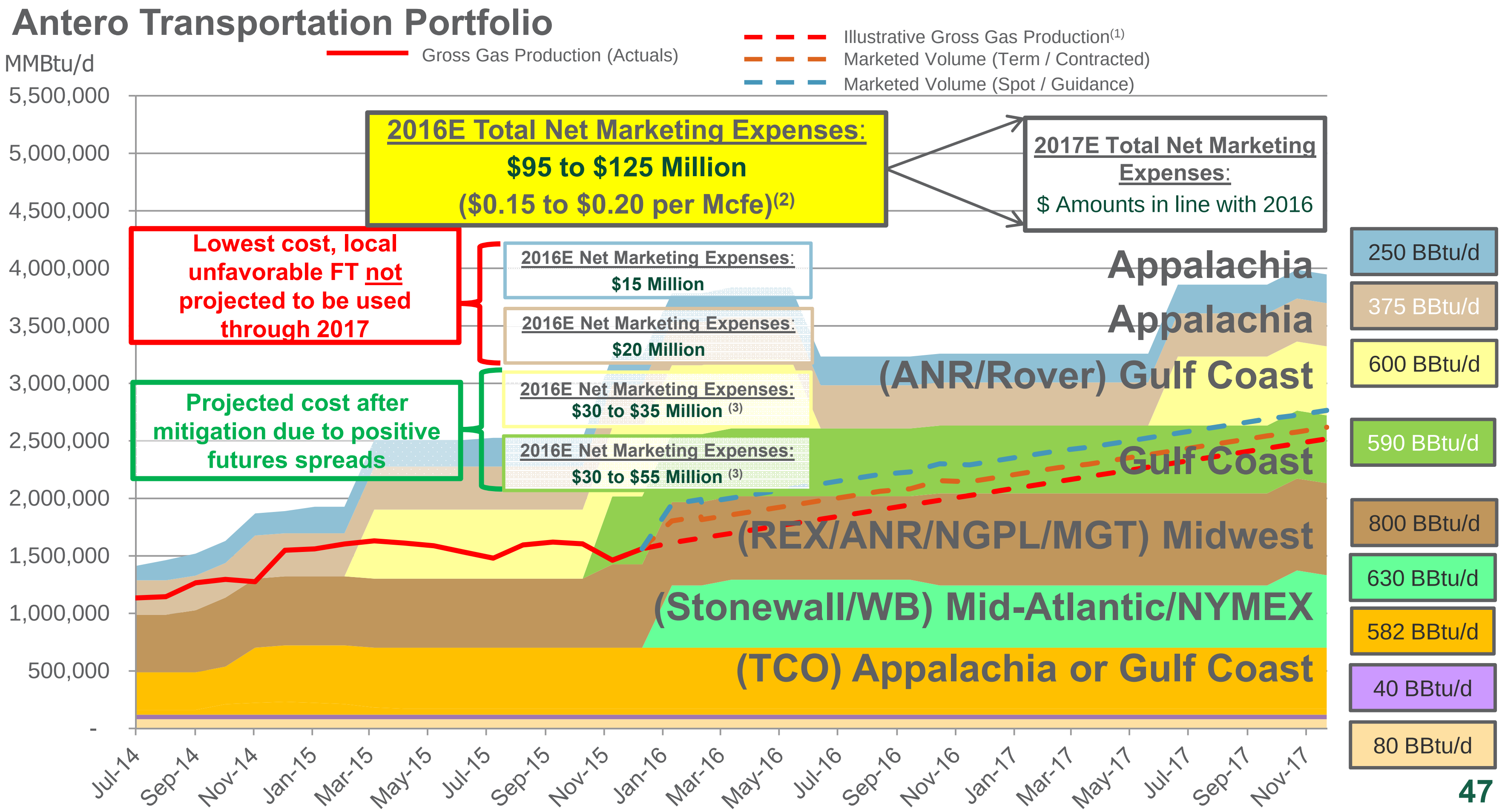
1. Incremental ethane transport cost assumed to be \$0.15/gallon. For illustrative purposes only.

FIRM TRANSPORTATION AND SALES PORTFOLIO

- While Antero has excess FT in place through 2017, the expected cost of unutilized FT is estimated to be modest at well under 10% of EBITDA

Columbia	Stonewall/Tennessee	Momentum III	EQT	REX/MGT/ANR
7/26/2009 – 9/30/2025	11/1/2015– 9/30/2030	9/1/2012 – 12/31/2023	8/1/2012 – 6/30/2025	7/1/2014 – 12/31/2034

ANR	Stonewall/WB	Firm Sales #1	Firm Sales #2
3/1/2015– 2/28/2045	11/1/2015 – 9/30/2037	10/1/2011– 10/31/2019	1/1/2013 – 5/31/2022

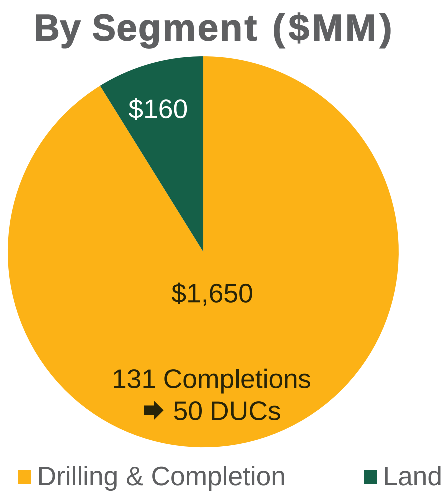


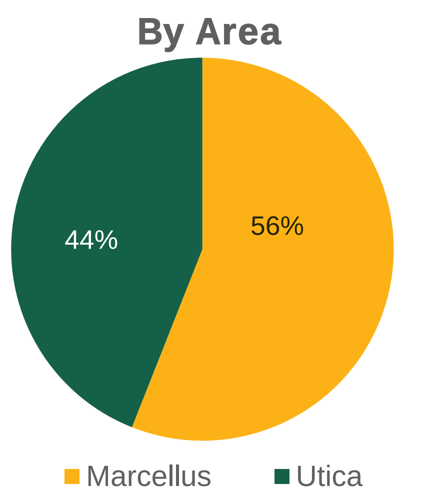
1. Assumes production growth guidance of 20% in 2016 and targeted 20% to 25% annual production growth in 2017.
2. Based on 2016 production guidance of 1.800 Bcfe/d.
3. Assumes 30% to 50% mitigation on excess capacity and current spreads based on strip pricing as of 12/31/2015.

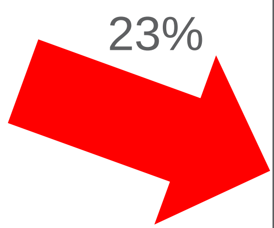
2016 CAPITAL BUDGET

- Antero's 2016 initial capital budget is $1.4 billion, a 23% decrease from 2015 capital expenditures of $1.8 billion and a 58% decline from 2014 capital expenditures

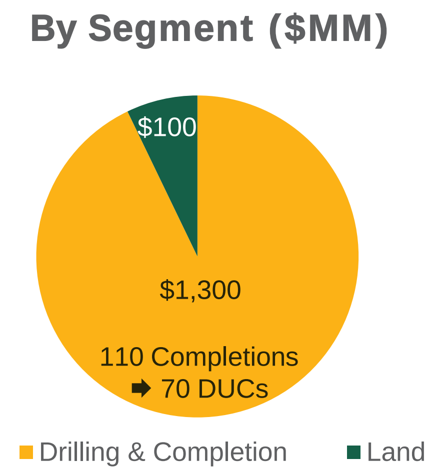
$1.8 Billion – 2015[1]

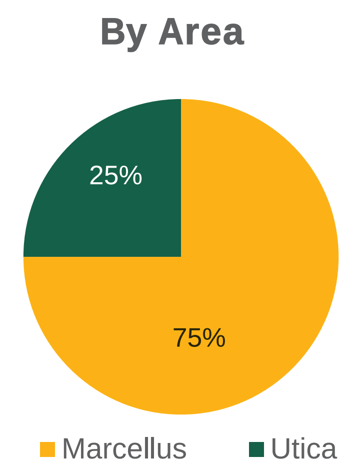






$1.4 Billion – 2016



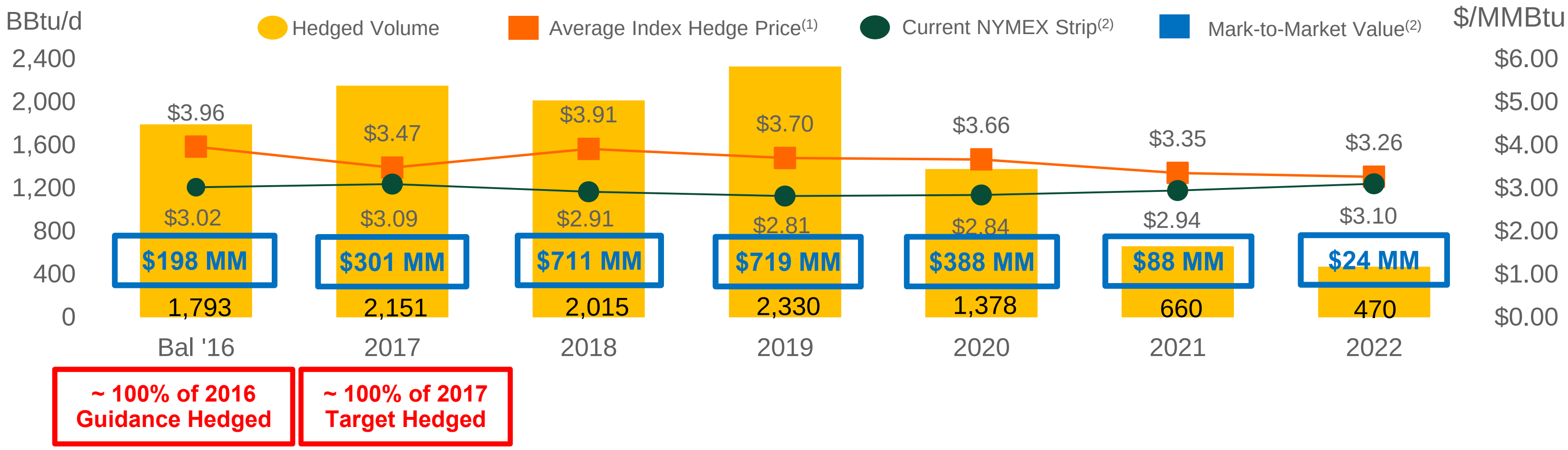


1. Excludes $39 million for leasehold acquisitions in 2015. DUCs are drilled but uncompleted wells at year-end.

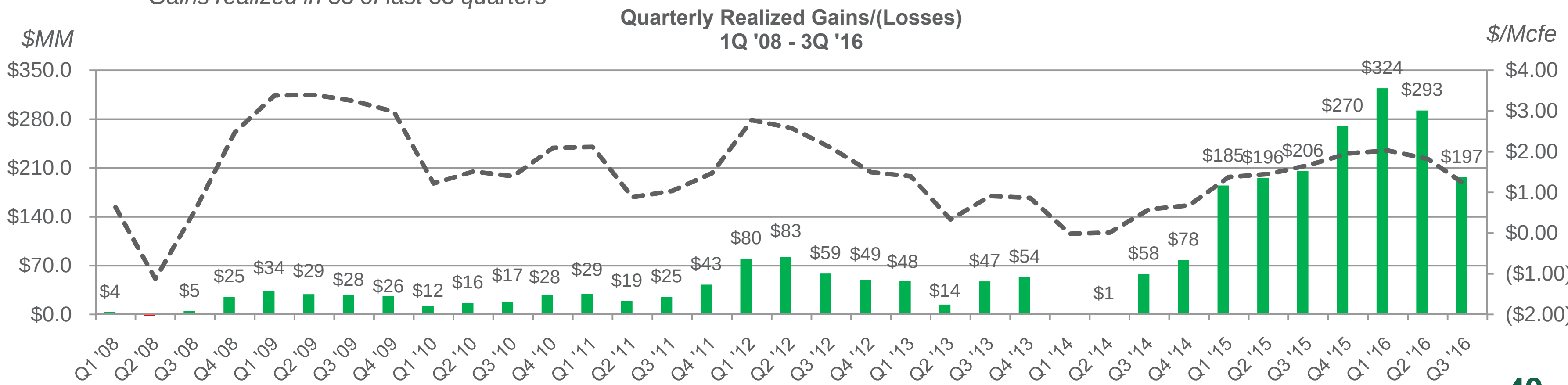
LARGEST GAS HEDGE POSITION IN U.S. E&P

- ~$2.4 billion mark-to-market unrealized gain based on 9/30/2016 prices
- 3.5 Tcfe hedged from October 1, 2016 through year-end 2022 at $3.65 per MMBtu

COMMODITY HEDGE POSITION



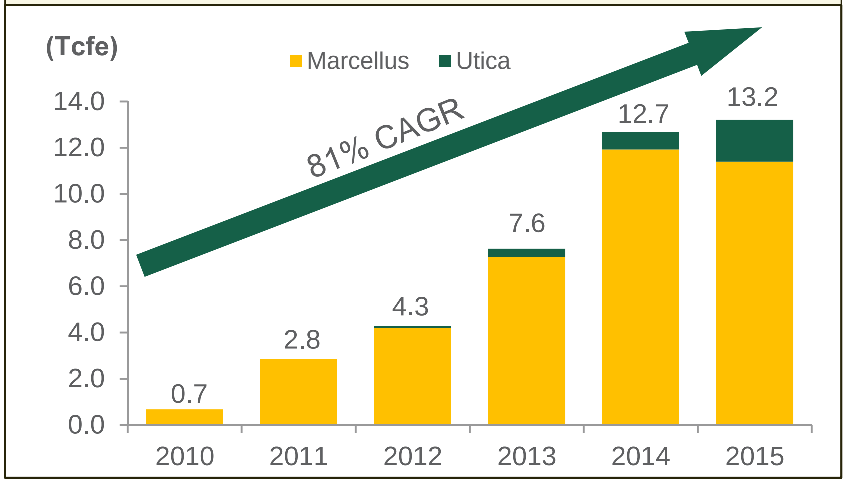
- Hedging is a key component of Antero's business model due to the large, repeatable drilling inventory
- Antero has realized $2.6 billion of gains on commodity hedges since 2008
  - *Gains realized in 33 of last 35 quarters*



1. Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio; excludes impact of TCO basis hedges. 30,000 Bbl/d of propane hedged in 2016, 27,500 Bbl/d hedged in 2017 and 2,000 Bbl/d hedged in 2018. 20,000 Bbl/d of ethane hedged in 2017 and 1,000 Bbl/d of oil hedged in 2017.
2. As of 9/30/2016.

OUTSTANDING RESERVE GROWTH

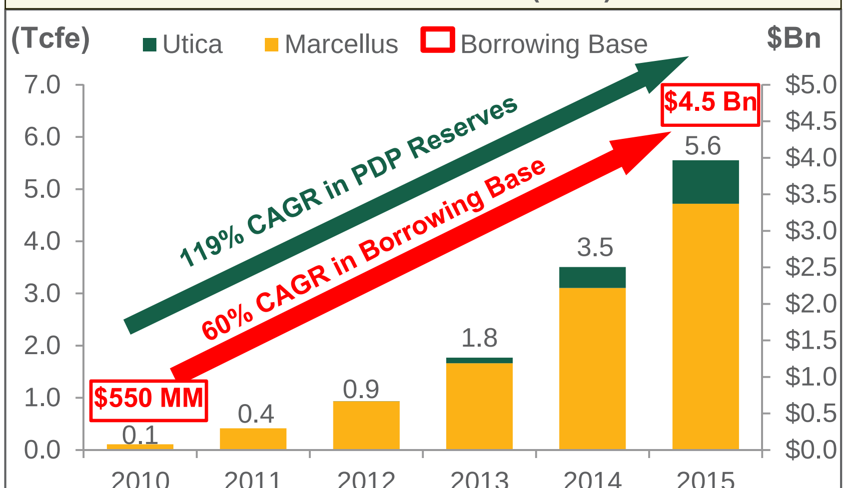
NET PROVED RESERVES (Tcfe)[1]



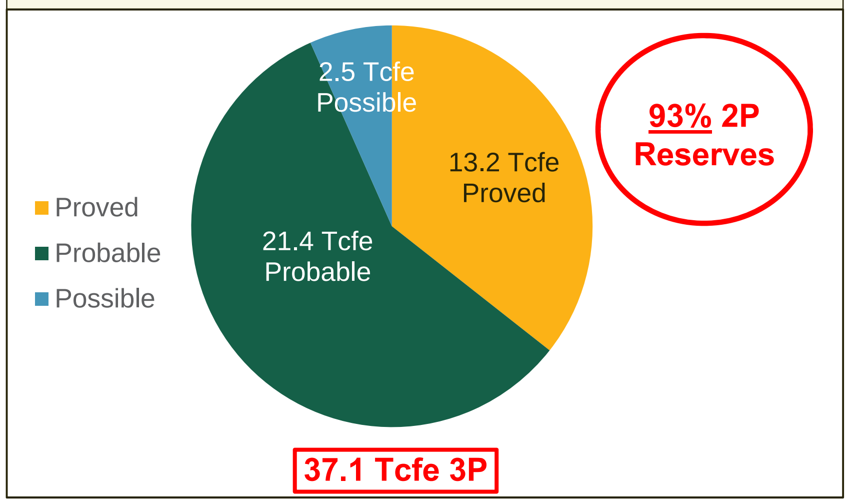
2015 RESERVE ADDITIONS

- Proved reserves increased 4% to 13.2 Tcfe at 12/31/2015 with a pre-tax PV-10 of $6.7 billion at SEC pricing, including $3.1 billion of hedges
  - Proved PV-10 at strip pricing of $8.2 billion, including $2.5 billion of hedges
- 3P reserves were 37.1 Tcfe at 12/31/2015 with a pre-tax PV-10 of $6.8 billion at SEC pricing, including $3.1 billion of hedges
  - 3P PV-10 at strip pricing of $13.7 billion, including $2.5 billion of hedges
- All-in finding and development cost of $0.80/Mcfe for 2015 (includes land and all price and performance revisions)
- Drill bit only finding and development cost of $0.71/Mcfe for 2015
- Only 69% of 3P Marcellus locations booked as SSL (1.7 Bcf/1,000' type curve) at 12/31/2015
- **Negligible Utica Shale WV/PA dry gas reserves booked – estimated net resource of 12.5 – 16 Tcf**

NET PDP RESERVES (Tcfe)[1]



3P RESERVES BY VOLUME – 2015[1]

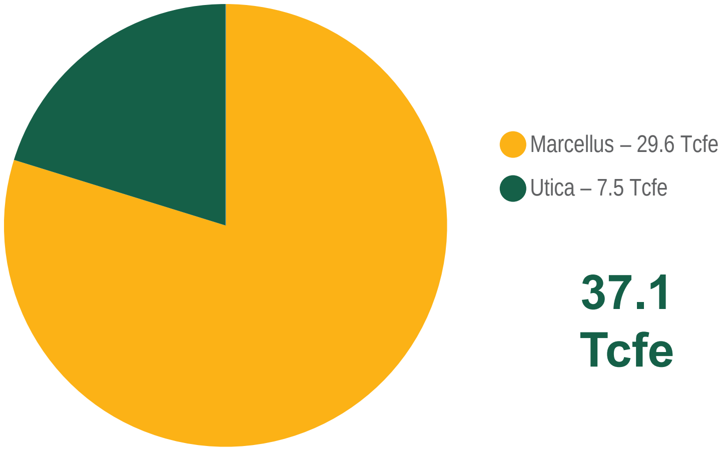


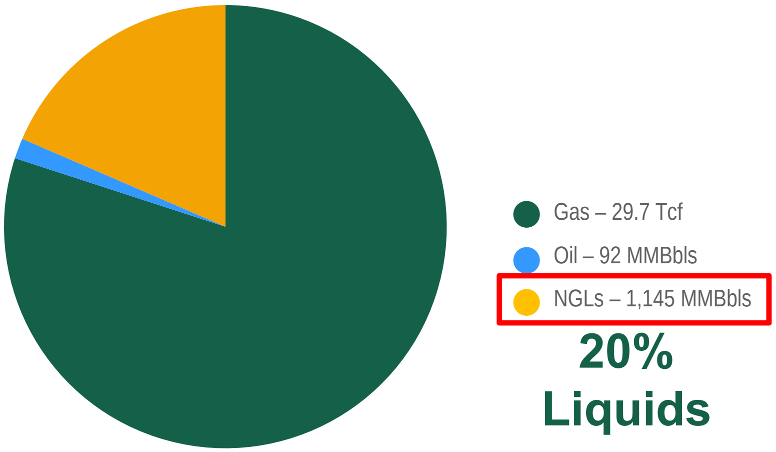
1. 2012, 2013, 2014 and 2015 reserves assuming ethane rejection. 2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis. **2015 is not pro forma for recent acreage acquisition.**

CONSIDERABLE RESERVE BASE WITH ETHANE OPTIONALITY

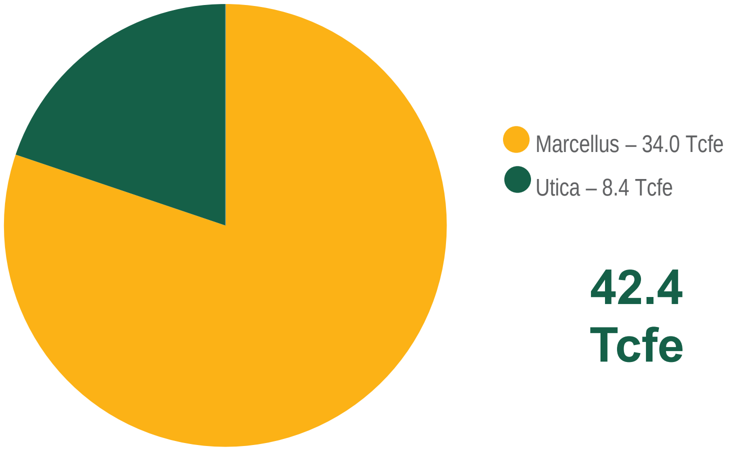
- 27 year proved reserve life based on 2015 production annualized
- Reserve base provides significant exposure to liquids-rich projects
  - *3P reserves of over 2.4 BBbl of NGLs and condensate in ethane recovery mode; 35% liquids*
  - *Incudes 1.2 BBbl of ethane*

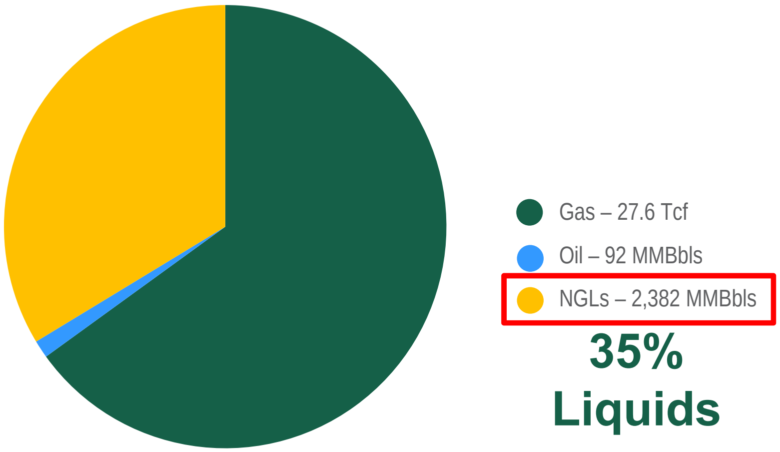
ETHANE REJECTION(1)(2)





ETHANE RECOVERY(1)



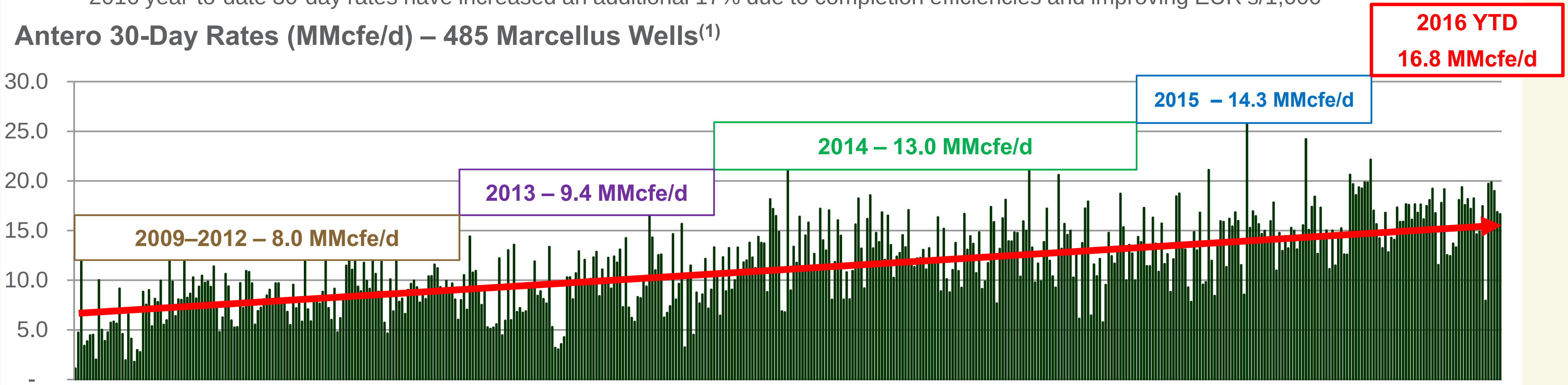


1. *Ethane rejection occurs when ethane is left in the wellhead gas stream as the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the BTU content of the residue gas at the outlet of the processing plant is higher. Producers will elect to "reject" ethane when the price received for the higher BTU residue gas is greater than the price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the BTU content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate NGL product.*
2. *1.1 Tcfe of ethane reserves (182 million barrels) was included in 12/31/2015 reserves from the Marcellus Shale as the first de-ethanizer was placed online at the MarkWest Sherwood facility in December 2015 and Antero's first ethane sales contract is expected to commence in 2017 upon the completion of Mariner East 2.* ***Not pro forma for recent acreage acquisition.***

INCREASING RECOVERIES AND LOW VARIANCE IN MARCELLUS

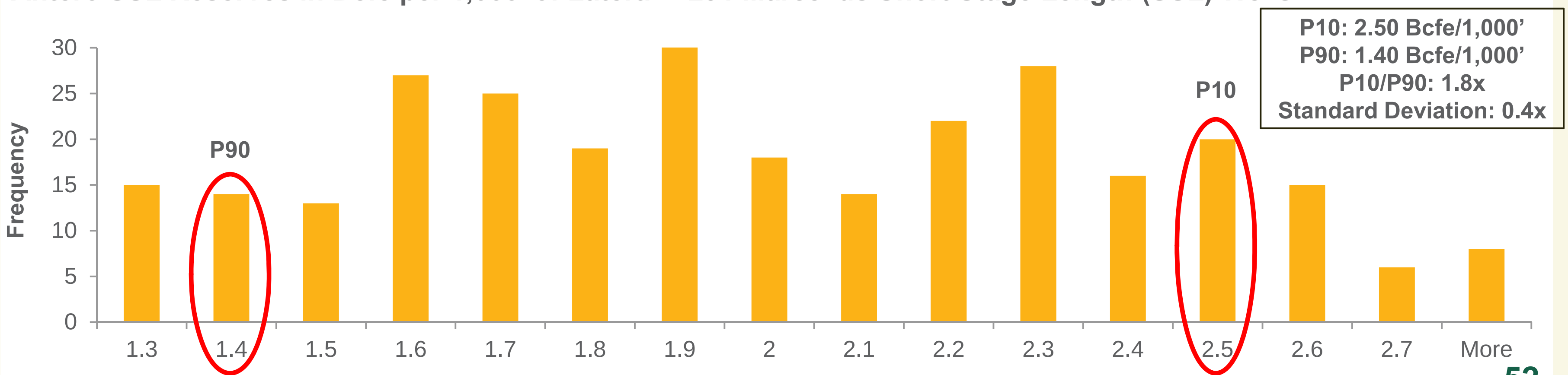
- Antero's Marcellus average 30-day rates have increased by 79% over the past three years as the Company increased per well lateral lengths by 20% and shortened stage lengths by 53% compared to year-end 2013
  - 2016 year-to-date 30-day rates have increased an additional 17% due to completion efficiencies and improving EUR's/1,000'

Antero 30-Day Rates (MMcfe/d) – 485 Marcellus Wells(1)



- SSL results have been highly consistent and predictable, with a standard deviation of only +/-0.4 around the 1.7 Bcf/1,000' average (equates to 2.0 Bcfe/1,000')
- These wells provide the basis for AR's undeveloped 3P reserve evaluations
- Antero 3P reserves are evaluated quarterly by AR engineers and audited annually by DeGolyer and MacNaughton
  - *Proved reserves volume delta at YE2015: 0.9%*
  - *Probable/Possible volume delta at YE2015: 1.9%*

Antero SSL Reserves in Bcfe per 1,000' of Lateral – 291 Marcellus Short Stage Length (SSL) Wells(2)



1. Processed rates converting C3+ NGLs and condensate at 6:1. Ethane rejected and sold in gas stream.
2. As of 9/30/2016.

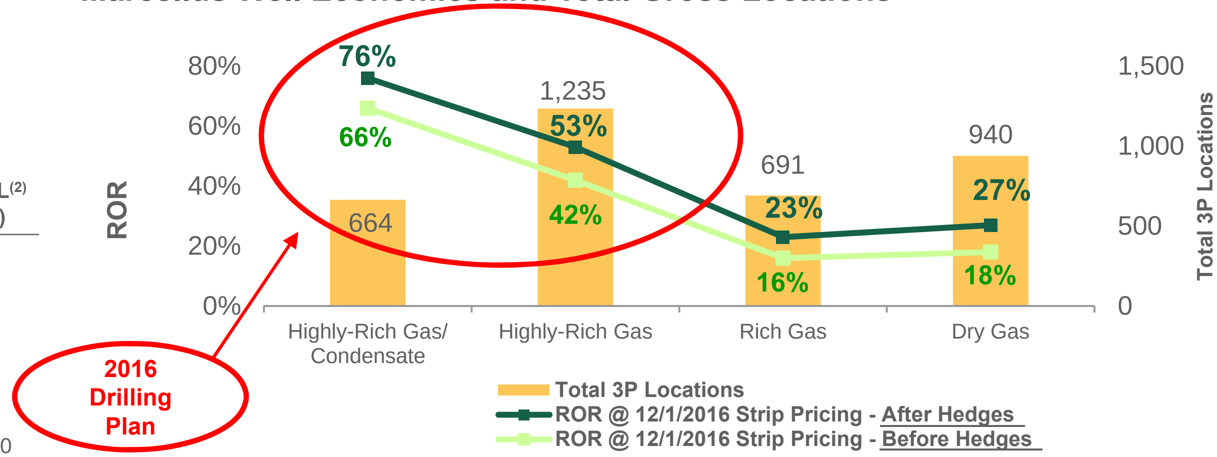
MARCELLUS SINGLE WELL ECONOMICS
– IN ETHANE REJECTION

Assumptions

- Natural Gas – 12/1/2016 strip
- Oil – 12/1/2016 strip
- NGLs –~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2017	$3.38	$54	$27
2018	$3.04	$54	$28
2019	$2.90	$54	$28
2020	$2.91	$55	$28
2021	$2.94	$55	$29
2022-26	$2.99-$3.57	$56-$58	$29-$30

Marcellus Well Economics and Total Gross Locations[1]



Classification	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1313**	**1250**	**1150**	**1050**
EUR (Bcfe):	20.8	18.8	16.8	15.3
EUR (MMBoe):	3.5	3.1	2.8	2.6
% Liquids:	33%	24%	12%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000
Well Cost ($MM):	$7.8	$7.8	$7.8	$7.8
Bcfe/1,000':	2.3	2.1	1.9	1.7
Net F&D ($/Mcfe):	$0.44	$0.49	$0.55	$0.60
Direct Operating Expense ($/well/month):	$1,498	$1,498	$1,498	$1,498
Direct Operating Expense ($/Mcf):	$0.92	$0.92	$1.17	$0.70
Transportation Expense ($/Mcf):	$0.28	$0.28	$0.28	$0.28
Pre-Tax NPV10 ($MM):	$11.8	$7.7	$1.6	$2.1
Pre-Tax ROR:	66%	42%	16%	18%
Payout (Years):	1.2	1.8	5.3	4.6
Gross 3P Locations in BTU Regime[3]:	664	1,235	691	940

1. *12/1/2016 pre-tax well economics based on 1.7 Bcf/1,000' type curve for a 9,000' lateral, 12/1/2016 natural gas and WTI strip pricing for 2017-2026, flat thereafter, NGLs at ~50% of WTI for 2017 and thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.*
3. *Undeveloped well locations as of 12/31/2015 adjusted for 6/30/2016 net acreage and pro forma for 625 added through recent acreage acquisition.*

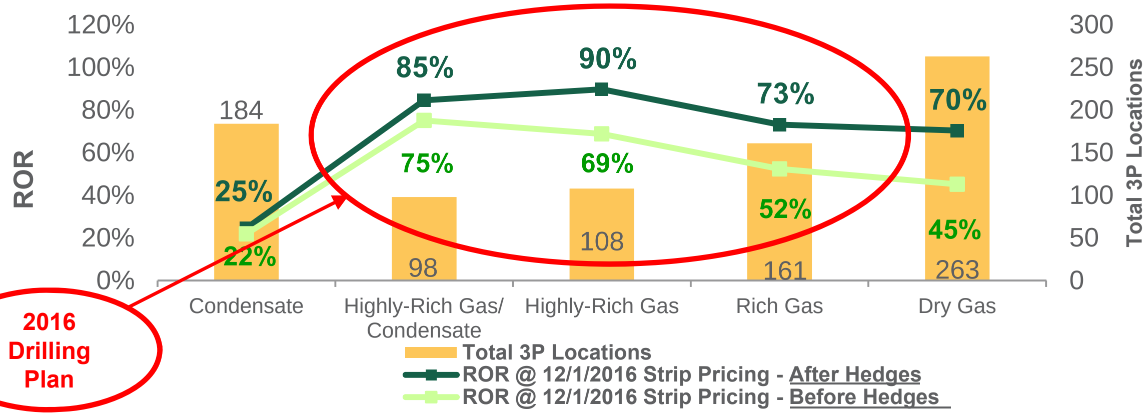
UTICA SINGLE WELL ECONOMICS
– IN ETHANE REJECTION

Assumptions

- Natural Gas – 12/1/2016 strip
- Oil – 12/1/2016 strip
- NGLs –~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2017	$3.38	$54	$27
2018	$3.04	$54	$28
2019	$2.90	$54	$28
2020	$2.91	$55	$28
2021	$2.94	$55	$29
2022-26	$2.99-$3.57	$56-$58	$29-$30

Utica Well Economics and Gross Locations[1]



Classification	Condensate	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1275**	**1235**	**1215**	**1175**	**1050**
EUR (Bcfe):	9.4	17.0	25.3	23.8	21.4
EUR (MMBoe):	1.6	2.8	4.2	4.0	3.6
% Liquids	35%	26%	21%	14%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000	9,000
Well Cost ($MM):	$8.9	$8.9	$9.4	$9.4	$9.4
Bcfe/1,000':	1.0	1.9	2.8	2.7	2.4
Net F&D ($/Mcfe):	$1.17	$0.65	$0.46	$0.49	$0.54
Fixed Operating Expense ($/well/month):	$2,788	$2,788	$2,788	$2,788	$1,498
Direct Operating Expense ($/Mcf):	$0.99	$0.99	$0.99	$0.99	$0.50
Direct Operating Expense ($/Bbl):	$2.73	$2.73	$2.73	-	-
Transportation Expense ($/Mcf):	$0.55	$0.55	$0.55	$0.55	$0.55
Pre-Tax NPV10 ($MM):	$3.4	$11.5	$12.7	$10.0	$8.5
Pre-Tax ROR:	22%	75%	69%	52%	45%
Payout (Years):	3.5	1.0	1.1	1.3	1.5
Gross 3P Locations in BTU Regime[3]:	184	98	108	161	263

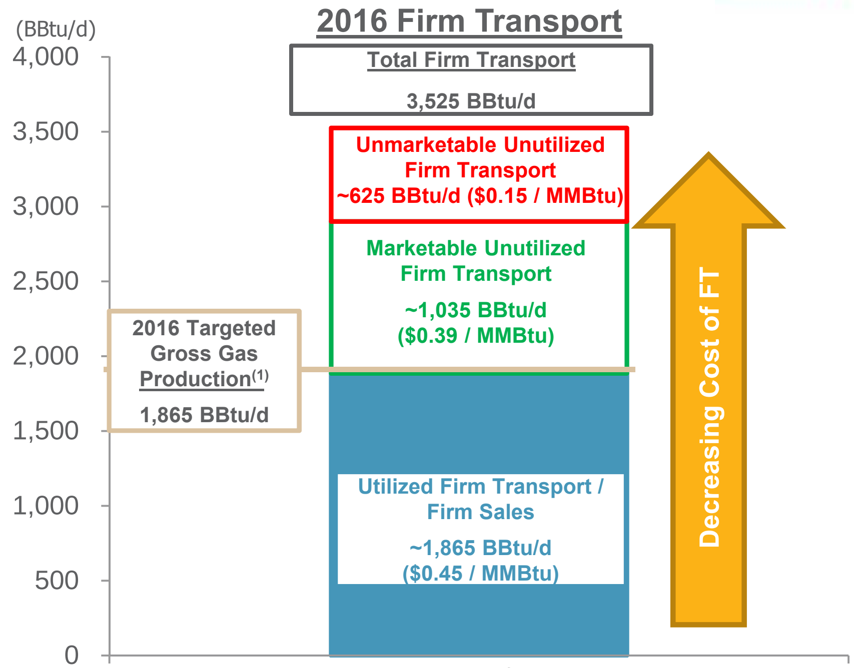
1. *12/1/2016 pre-tax well economics based on a 9,000' lateral, 12/1/2016 natural gas and WTI strip pricing for 2017-2026, flat thereafter, NGLs at ~50% of WTI for 2017 and thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.*
3. *Undeveloped well locations as of 12/31/2015. 3P locations representative of BTU regime; EUR and economics within regime will vary based on BTU content.*

PORTFOLIO APPROPRIATELY DESIGNED TO ACCOMMODATE GROWTH

- **Antero projects firm transportation in excess of equity gas production of approximately 1,660 BBtu/d in 2016**

FT Segment (Location)	Excess Capacity (BBtu/d)	Marketable / Unmarketable
Columbia / TGP (Marcellus)	560	Marketable
ANR North / ANR South (Utica)	475	Marketable
EQT / M3 (Marcellus)	625	Unmarketable
Total Excess Firm Transport	**1,660**	

- **Expect to market or mitigate a portion of the cost of approximately 1,035 BBtu/d of the excess FT with 3rd party gas**
- **Expect to fully utilize FT portfolio by 2019, based on five year development plan (excludes Appalachia based FT directed to unfavorable indices)**



	2016 FT Portfolio and Projected Gas Sales
Net Gas Production Target (MMcf/d) (1)	1,355
Net Revenue Interest Gross-up	*80%*
Gross Gas Production Target (MMcf/d)	1,695
BTU Upgrade (2)	x1.100
Gross Gas Production Target (BBtu/d)	**1,865**
Firm Transportation / Firm Sales (BBtu/d)	**3,525**
Estimated % Utilization of FT/FS	*53%*
Excess Firm Transportation	**1,660**
Marketable Firm Transport (BBtu/d) (3)	1,035
Unmarketable Firm Transportation	625
Estimated % Utilization of FT/FS Portfolio (Including Marketable FT)	**82%**

1. *Based on 2016 net daily gas production guidance.*
2. *Assumes 1100 BTU residue sales gas.*
3. *Represents excess firm transportation that is deemed marketable to 3rd parties based on a positive differential between the receipt and delivery points of the FT capacity, less variable transport cost.*

FT MARKETING EXPENSE UPDATE

2016 Projected Marketing Expenses:

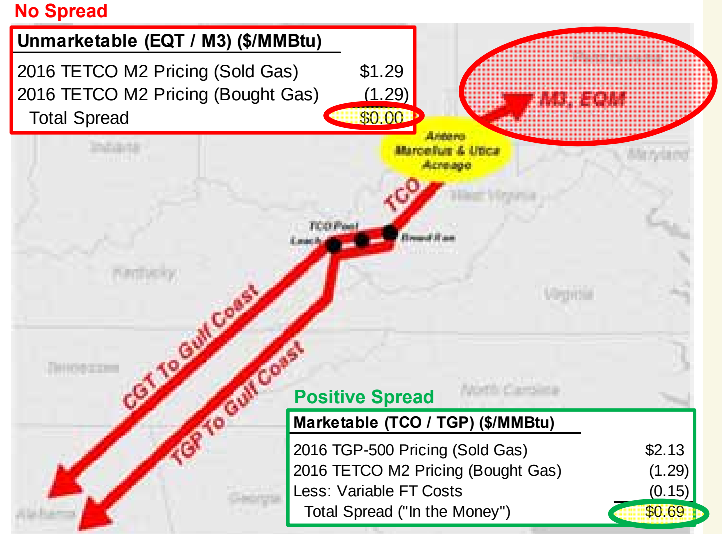
($ in millions, except per unit amounts)	Demand Fee ($ / MMBtu)	2016E Marketing Expenses	2016E Marketing Revenue	2016E Marketing Expenses, Net
"Unmarketable" Firm Transport				
625 BBtu/d of EQT / M3 Appalachia FT	$0.15	$35	-	$35
"Marketable" Firm Transport Capacity				
560 BBtu/d of Columbia / TGP	$0.49	$101	$42 - $71	$31 - $59
475 BBtu/d of ANR North / ANR South	$0.24	42	$6 - $11	$32 - $36
Sub-Total		$144	$48 - $82	$63 - $95
Grand Total - 2016 Marketing Expenses, Net		$179	$48 - $82	**~$95 to $125 MM**
$ / Mcfe - 2016 Targeted Production [1]		*$0.28*	*$0.08 - $0.13*	***$0.15 - $0.20***

2016 Marketing Revenue Projection:

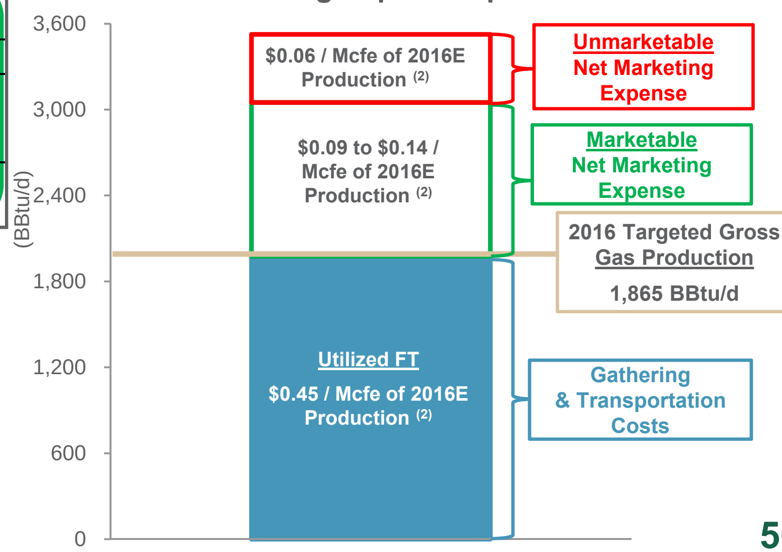
	2016E Marketing Spread ($ / MMBtu) [2]	2016E Marketing Revenue Assuming % Volume Mitigated: 30%	50%
"Marketable" Firm Transport Capacity			
560 BBtu/d of Columbia / TGP	$0.69	$42	$71
475 BBtu/d of ANR North / ANR South	$0.12	6	11
Sub-Total		$48	$82
$ / Mcfe - 2016E Targeted Production [1]		*$0.08*	*$0.13*

Based on the 2016 guidance of 20% annual production growth, Antero projects net marketing expenses of $0.15 to $0.20 per Mcfe in 2016

Illustrative Marketing Example:



2016 FT and Marketing Expenses per Unit:



NOTE: Analysis based on strip pricing as of 03/31/2016.

1. *Represents 2016 net production growth guidance of 20% to 1,800 MMcfe/d.*
2. *Spread for each respective "marketable" firm transport represents the difference between the gas price Antero would receive at the delivery point of each pipeline versus the price Antero would pay to buy gas at the receipt point of each piece of capacity, less the variable costs to transport on each segment of firm transportation.*

POSITIVE RATINGS MOMENTUM

Antero Resources

- **Given Antero's stable credit metrics through the commodity price crisis and improved leverage profile, Antero requests a ratings upgrade from Moody's**

Moody's / S&P Historical Corporate Credit Ratings

Moody's Rating Rationale

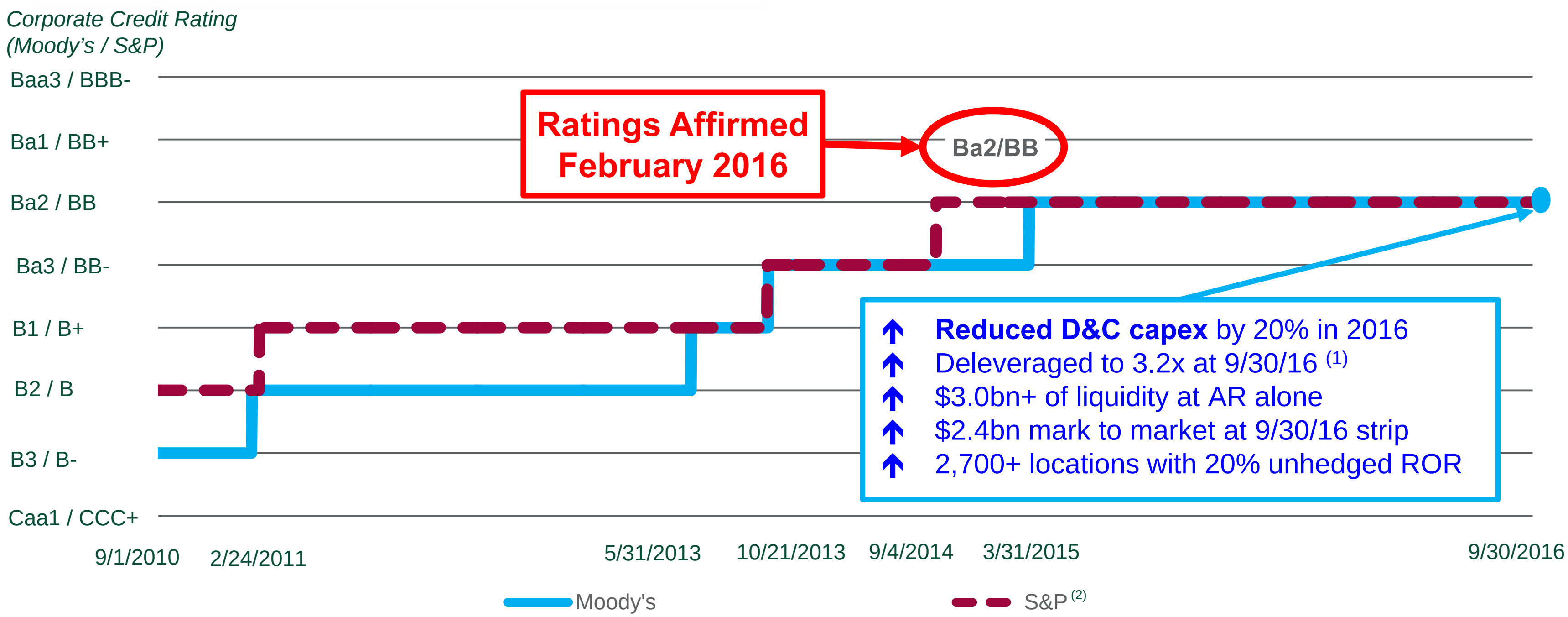
"Moody's confirmed Antero Resources' rating, which reflects its strong hedge book through 2018 and good liquidity. Antero has $3.1 billion in unrealized hedge gains, $3 billion of availability under its $4 billion committed revolving credit facility and a 67% interest in Antero Midstream Partners LP.

- Moody's Credit Research, February 2016

S&P Rating Rationale

"Outlook Stable. The affirmation reflects our view that Antero will maintain funds from operations (FFO)/Debt above 20% in 2016, as it continues to invest and grow production in the Marcellus Shale. The company has very good hedges in place, which will limit exposure to commodity prices."

- S&P Credit Research, February 2016



1. Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay bank facility and $170 million AR acreage divestiture announced on 10/26/2016.
2. Represents corporate credit rating of Antero Resources Corporation / Antero Resources LLC.

HEALTH, SAFETY, ENVIRONMENT & COMMUNITY

Antero Core Values: Protect Our People, Communities And The Environment

Strong West Virginia Presence

- 79% of all Antero Marcellus employees and contract workers are West Virginia residents

- **Antero named Business of the Year for 2013 in Harrison County, West Virginia "For outstanding corporate citizenship and community involvement"**

- **Antero representatives recently participated in a ribbon cutting with the Governor of West Virginia for the grand opening of the first natural gas fueling station in the state; Antero supported the station with volume commitments for its NGV truck fleet**

Keys to Execution	
Local Presence	▪ Antero has more than 3,500 employees and contract personnel working full-time for Antero in West Virginia. 79% of these personnel are West Virginia residents. ▪ District office in Marietta, OH ▪ District office in Bridgeport, WV ▪ 267 (51%) of Antero's 522 employees are located in West Virginia and Ohio
Safety & Environmental	▪ Five company safety representatives and 57 safety consultants cover all material field operations 24/7 including drilling, completion, construction and pipelining ▪ 37 person environmental staff plus outside consultants monitor all operations and perform baseline water well testing
Natural Gas Vehicles (NGV)	▪ Antero supported the first natural gas fueling station in West Virginia ▪ Antero has 30 NGV trucks and plans to continue to convert its truck fleet to NGV
Pad Impact Mitigation	▪ Closed loop mud system – no mud pits ▪ Protective liners or mats on all well pads in addition to berms
Natural Gas Powered Drilling Rigs & Frac Equipment	▪ 5 of Antero's contracted drilling rigs are currently running on natural gas ▪ Two natural gas powered clean fleet frac crews operating
Green Completion Units	▪ All Antero well completions use green completion units for completion flowback, essentially eliminating methane (CH_4) emissions (full compliance with EPA 2015 requirements)
Central Fresh Water System & Water Recycling	▪ Numerous sources of water – built central water system to source fresh water for completions ▪ Building state of the art wastewater treatment facility in WV (60,000 Bbl/d) ▪ Will recycle virtually all flowback and produced water when facility in-service
LEED Gold Headquarters Building	▪ Corporate headquarters in Denver, Colorado LEED Gold Certified

CLEAN FLEET & CNG TECHNOLOGY LEADER

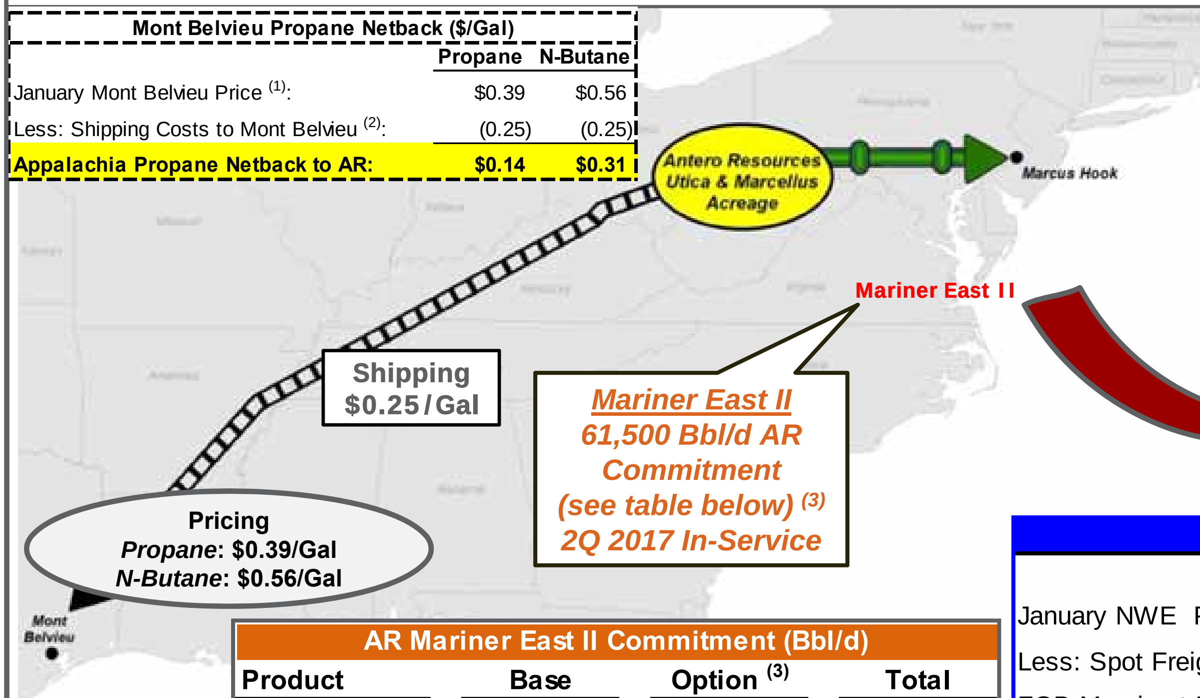
- Antero has two clean completion fleets operating to both enhance the economics of its completion operations and reduce the environmental impact
- Replaces diesel engines (for pressure pumping) with electric motors powered by natural gas-fired electric generators
- A clean fleet allows Antero to fuel part of its completion operations from field gas instead of more expensive diesel fuel. Benefits of using a clean fleet include:
  - Reduce fuel costs by up to 80% representing cost savings of up to $40,000/day
  - Reduces NOx and CO emissions by 99%
  - Eliminates 25 diesel truckloads from the roads for an average well completion
  - Reduces silica dust to levels 90% below OSHA permissible exposure limits resulting in a safer and cleaner work environment
  - Significantly reduces noise pollution from a well site
  - Is the most environmentally responsible completion solution in the oil and gas industry
- Additionally, Antero utilizes compressed natural gas (CNG) to fuel its truck fleet in Appalachia
  - Antero supported the first natural gas fueling station in West Virginia
  - Antero has 30 NGV trucks and plans to continue to convert its truck fleet to NGV

NGL EXPORTS AND NETBACKS STEP-UP BY 2Q 2017

- Upon in-service of Mariner East II, Antero will have the ability to market its propane and n-butane to international buyers, which we expect will provide uplifts of <u>$0.16/Gal</u> and <u>$0.18/Gal</u>, respectively, to the current netbacks received from propane and n-butane volumes shipped to Mont Belvieu today
  - *– In the meantime, Antero has 30,000 Bbl/d of propane hedged at $0.59/Bbl in 2016*
- Commitment to Mariner East II results in <u>approximately $127 million</u> in combined incremental annualized cash flow from propane and n-butane sales (~$86 MM from propane and ~$41 MM from n-butane)

Mont Belvieu Propane Netback ($/Gal)

	Propane	N-Butane
January Mont Belvieu Price [1]:	$0.39	$0.56
Less: Shipping Costs to Mont Belvieu [2]:	(0.25)	(0.25)
Appalachia Propane Netback to AR:	**$0.14**	**$0.31**



AR Mariner East II Commitment (Bbl/d)

Product	Base	Option [3]	Total
Ethane (C2)	11,500	-	11,500
Propane (C3)	35,000	35,000	70,000
Butane (C4)	15,000	15,000	30,000
Total	**61,500**	**50,000**	**111,500**

NWE Netback ($/Gal)

	Propane	N-Butane
January NWE Price [1]:	$0.56	$0.76
Less: Spot Freight [4]:	($0.07)	($0.08)
FOB Margin at Marcus Hook:	$0.49	$0.68
Less: Pipeline & Terminal Fee [5]:	(0.19)	(0.19)
Appalachia Netback to AR:	**$0.30**	**$0.49**
Upside to Appalachia Netback:	***$0.16***	***$0.18***

1. *Source: Intercontinental exchange as of 12/31/2015.*
2. *Source of graphic: Tudor Pickering Holt & Co. research presentation dated June 16, 2015.*
3. *As an anchor shipper on Mariner East II, Antero has the right to expand its NGL commitment with notice to operator.*
4. *Shipping rates based on benchmark Baltic shipping rate of $59.57/ton as of 12/31/15, adjusted for number of shipping days to NWE.*
5. *Pipeline fee equal to $0.0725/gal, per Mariner East I tariff. Terminal fee equal to $0.12/gal, per TPH report dated June 16, 2015.*

ANTERO RESOURCES DECEMBER 31, 2015 RESERVES

- Antero's proved reserves were 13.2 Tcfe, while its 3P reserves were 37.1 Tcfe
- Proved pre-tax PV-10 at strip prices was $5.7 billion, while the 3P pre-tax PV-10 was $11.2 billion
  - Including hedges, the proved pre-tax PV-10 was $8.2 billion while the 3P pre-tax PV-10 was $13.7 billion

Reserves Detail – 12/31/2015

Marcellus Shale

	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	PV-10 ($MM) Strip(2)
Proved	8,073	555	11,406	$2,749	$4,544
Probable	14,216	458	16,961		
Possible	1,025	43	1,282		
Total 3P	23,314	1,056	29,649	$2,885	$8,647
% Liquids(3)			21%		

Ohio Utica Shale

	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	PV-10 ($MM) Strip(2)
Proved	1,459	58	1,809	$885	$1,140
Probable	3,972	83	4,468		
Possible	951	40	1,191		
Total 3P	6,381	181	7,468	$863	$2,535
% Liquids(3)			15%		

Combined Reserves

	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	PV-10 ($MM) Strip(2)
Proved	9,532	614	13,215	$3,634	$5,684
Probable	18,188	540	21,429		
Possible	1,975	83	2,472		
Total 3P	29,695	1,237	37,117	$3,748	$11,182
% Liquids(3)			20%		

1. *2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis.*
2. *Pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively.*
3. *Represents liquids volumes as a percentage of total volumes. Combined liquids comprised of 1,145 million barrels of NGLs (including 182 million barrels of ethane) and 92 million barrels of oil.*

ANTERO RESOURCES EBITDAX RECONCILIATION

EBITDAX Reconciliation

($ in millions)	Quarter Ended 9/30/2016	LTM Ended 9/30/2016
EBITDAX:		
Net income including noncontrolling interest	$268.2	$(121.1)
Commodity derivative fair value (gains)	(530.4)	(670.7)
Net cash receipts on settled derivatives instruments	196.7	1,083.5
Interest expense	59.8	246.1
Income tax expense (benefit)	140.9	(153.6)
Depreciation, depletion, amortization and accretion	199.7	752.1
Impairment of unproved properties	11.8	107.9
Exploration expense	1.2	4.0
Equity-based compensation expense	26.4	94.3
Equity in earnings of unconsolidated affiliate	(1.5)	(2.0)
Contract termination and rig stacking	0.0	27.6
Consolidated Adjusted EBITDAX	**$372.8**	**$1,368.1**

ANTERO MIDSTREAM EBITDA RECONCILIATION

EBITDA and DCF Reconciliation

$ in thousands	Nine months ended September 30, 2015	2016
Reconciliation of Net Income to Adjusted EBITDA and Distributable Cash Flow:		
Net income	$110,097	$163,352
Interest expense	5,266	12,885
Depreciation expense	63,515	74,100
Accretion of contingent acquisition consideration	-	10,384
Equity-based compensation	17,663	19,366
Equity in earnings from unconsolidated affiliate	-	(2,027)
Adjusted EBITDA	$196,541	$278,060
Pre-Water Acquisition net income attributed to parent	(40,193)	-
Pre-Water Acquisition depreciation expense attributed to parent	(18,767)	-
Pre-Water Acquisition equity-based compensation expense attributed to parent	(3,445)	-
Pre-Water Acquisition interest expense attributed to parent	(2,326)	-
Adjusted EBITDA attributable to the Partnership	131,810	278,060
Cash interest paid - attributable to Partnership	(2,215)	(11,751)
Cash reserved for payment of income tax witholding upon vesting of Antero Midstream LP equity-based compensation awards	-	(3,000)
Cash to be received from unconsolidated affiliate	-	2,998
Maintenance capital expenditures attributable to Partnership	(10,001)	(16,156)
Distributable Cash Flow	$119,594	$250,151

CAUTIONARY NOTE

Regarding Hydrocarbon Quantities

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserve estimates (collectively, “3P”). Antero has provided internally generated estimates for proved, probable and possible reserves in this presentation in accordance with SEC guidelines and definitions. The estimates of proved, probable and possible reserves as of December 31, 2015 included in this presentation have been audited by Antero’s third-party engineers. Unless otherwise noted, reserve estimates as of December 31, 2015 assume ethane rejection and strip pricing.

Actual quantities that may be ultimately recovered from Antero’s interests may differ substantially from the estimates in this presentation. Factors affecting ultimate recovery include the scope of Antero’s ongoing drilling program, which will be directly affected by commodity prices, the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates.

In this presentation:

- “3P reserves” refer to Antero’s estimated aggregate proved, probable and possible reserves as of December 31, 2015. The SEC prohibits companies from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
- “EUR,” or “Estimated Ultimate Recovery,” refers to Antero’s internal estimates of per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. These quantities do not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or the SEC’s oil and natural gas disclosure rules.
- “Condensate” refers to gas having a heat content between 1250 BTU and 1300 BTU in the Utica Shale.
- “Highly-Rich Gas/Condensate” refers to gas having a heat content between 1275 BTU and 1350 BTU in the Marcellus Shale and 1225 BTU and 1250 BTU in the Utica Shale.
- “Highly-Rich Gas” refers to gas having a heat content between 1200 BTU and 1275 BTU in the Marcellus Shale and 1200 BTU and 1225 BTU in the Utica Shale.
- “Rich Gas” refers to gas having a heat content of between 1100 BTU and 1200 BTU.
- “Dry Gas” refers to gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.