



Company Overview

March 2012

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 LLC and its subsidiaries (collectively, the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. 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 in the Company's filings with the SEC.

We caution 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 "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2010.

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.

Cautionary Note Regarding Hydrocarbon Quantities



The U.S. Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserve estimates (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 reserves included in this presentation have been audited by Antero's third-party engineers. Antero's estimate of probable and possible reserves was prepared by Antero's internal reserve engineers, has not been reviewed by third-party engineers, and is provided in this presentation because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. Antero does not plan to include probable and possible reserve estimates in its filings with the SEC.

We use certain other terms in this presentation relating to estimates of hydrocarbon volumes that the SEC's guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, possible or probable reserves as defined by SEC regulations and accordingly are substantially less certain and no discount or other adjustment is included in the presentation of such numbers. 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 our 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, 2011. 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.

"Unrisked Resource" refers to Antero's internal estimates of hydrocarbon quantities that Antero's management believes may be potentially discovered through exploratory drilling or recovered with additional drilling. Unrisked resource may not constitute 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. Actual quantities that may be ultimately recovered from Antero's interests will differ substantially. Factors affecting ultimate recovery include the scope of our 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. Estimates of unrisked resource may change significantly as development of Antero's resource plays provides additional data.

"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.

Antero Resources Snapshot

- **Private E&P company headquartered in Denver, focused on unconventional resource plays**
 - Drilled and operated over 300 horizontal shale wells in Barnett, Woodford and Marcellus Shales
 - **Diversified asset base** – Marcellus Shale, Upper Devonian Shale, Piceance Mesaverde and Mancos/Niobrara Shale, Woodford Shale, Fayetteville Shale
 - **Appalachian Shale-Focused** – 78% of net 3P reserves are in Appalachia
 - 79% of capital budget is focused on the Appalachian Basin
 - Upper Devonian Shale: Drilling first of 3 horizontal wells planned for 2012
 - **High production growth** – 92% increase year-over-year to 325 MMcfe/d net today (includes 3,700 Bbls/d of liquids)
 - **Large resource base** – Over 28 Tcfe of unrisks resource will continue to feed high growth in current 5 Tcfe⁽¹⁾ proved reserve base
- **Low cost leader** – \$0.35/Mcfe 3-year all-in finding costs through 2011
 - \$1.01/Mcfe average operated net development cost over past 2-½ years – well by well basis
 - \$0.99/Mcfe estimated net future development cost in 3P reserve base
 - **Rapidly growing liquids exposure** – 7% by production volume today, forecast to grow to over 34% by 2015
 - **Large long-term hedge position** – 710 Bcfe⁽²⁾ hedged at \$5.53/MMBtu NYMEX-equivalent⁽³⁾ through 2016
- **Strong liquidity to fuel low cost growth** – Pro forma for the recently announced Marcellus midstream sale, Antero has over \$1.1 billion⁽⁴⁾ of undrawn borrowing base capacity
 - Solid, 14-bank lending group co-led by JP Morgan and Wells Fargo
 - Ready access to high yield bond market (2 issues with 2017 and 2019 maturities, rated B3/B)

1. 12/31/2011 SEC reserves using a 12/31/2011 SEC price deck of \$3.84/MMBtu, \$3.60/MMBtu, and \$4.16/MMBtu for Piceance, Arkoma and Appalachia, respectively. Appalachia, Arkoma and Fayetteville reserves audited by DeGolyer & MacNaughton, Piceance audited by Ryder Scott. WTI SEC price averaged \$96.04/Bbl.

2. Assumes 1000 BTU average heat content.

3. In order to compare hedges across basins, hedged basin prices are converted by Antero to NYMEX-equivalent prices using current basis differentials in the over-the-counter futures market.

4. Borrowing base increased to \$1.2 billion with \$850 million of bank commitments as of October 31, 2011.

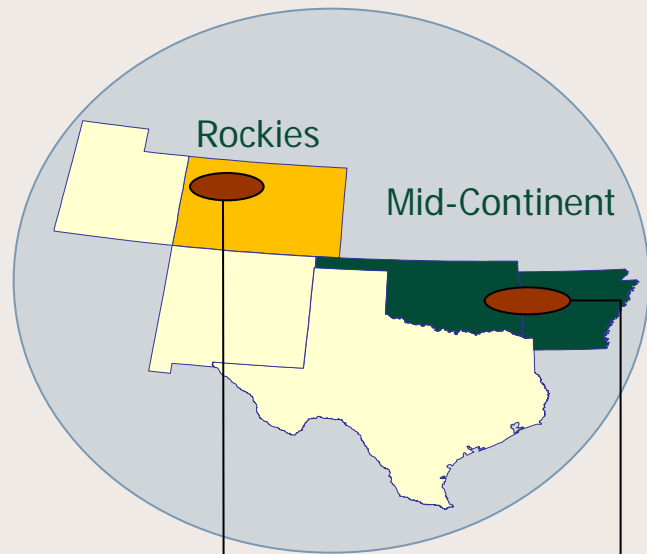
Marcellus Midstream Sale

- **Marcellus Midstream Sale** – On February 27, 2012, Antero announced the sale of Marcellus Shale gathering system assets to Crestwood for \$375 million in cash
- **Area of Dedication** – covers 104,000 net acres or almost 50% of Antero's 220,000 net acres in the Marcellus Shale play
- **Use of Proceeds** – repay bank debt initially, then for further Appalachian Basin drilling and leasehold acquisition

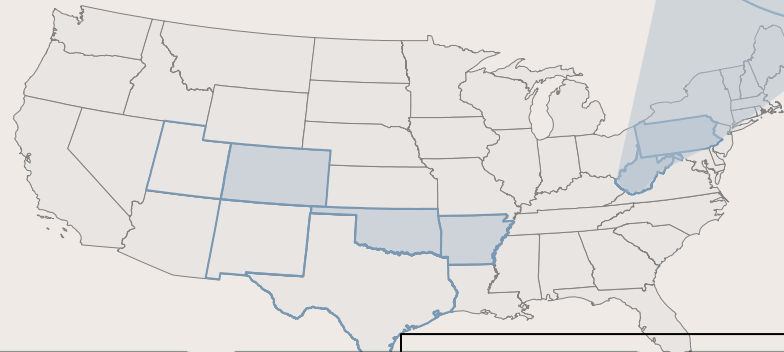
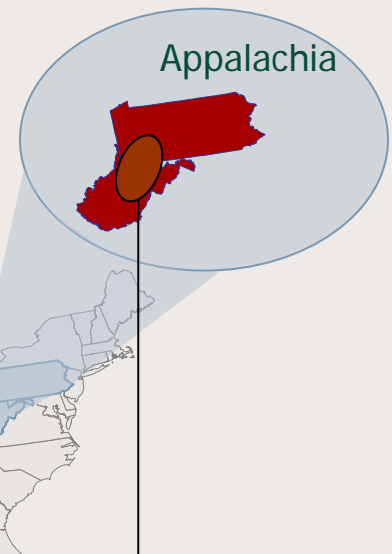
Deal Terms:

Type:	Asset Sale
Effective Date:	January 1, 2012
Closing Date:	March 2012
Purchase Price:	\$375 million cash with additional \$40 million earn-out over two years
Gatherer:	Crestwood Marcellus Midstream
Service:	All low pressure gathering services; compression services on volumes > 400 MMcfd
Fee Structure:	Fixed fees
Area of Dedication:	Approximately 127,000 gross acres, or 104,000 net acres, located in Harrison and Doddridge Counties, WV
Term:	20 years

Diversified Low-Cost Reserve Base



Total	
SEC Proved Reserves ⁽¹⁾	5.0 Tcfe
Total 3P Gas Equivalent ^(1,2)	17.4 Tcfe
Total 3P Liquids ^(1,2)	724 MMBbbls
% Liquids – 3P ⁽²⁾	25%
Proved Developed PV-10 ^(1,3)	\$1.9 Billion
Proved PV-10 ^(1,3)	\$4.1 Billion
Net Production	325 MMcfe/d
Net Acreage	362,000



Piceance–Mesaverde/Mancos Shale	
Proved Reserves ⁽¹⁾	1,502 Bcfe
Total 3P ^(1, 2)	2,873 Bcfe
Total 3P Liquids ^(1, 2)	94 MMBbbls
% Liquids – 3P	20%
Net Production	63 MMcfe/d
Net Acreage	63,000

Arkoma–Woodford Shale	
Proved Reserves ⁽¹⁾	599 Bcfe
Total 3P ^(1, 2)	910 Bcfe
Total 3P Liquids ^(1, 2)	22 MMBbbls
% Liquids – 3P	14%
Net Production	72 MMcfe/d
Net Acreage	67,000

Appalachia–Marcellus Shale	
Proved Reserves ⁽¹⁾	2,844 Bcfe
Total 3P ^(1,2)	13,491 Bcfe
Total 3P Liquids ^(1,2)	609 MMBbbls
% Liquids – 3P	27%
Net Production	180 MMcfe/d
Net Acreage	220,000

Fayetteville Shale	
Proved Reserves ⁽¹⁾	74 Bcfe
Total 3P ^(1, 2)	111 Bcfe
Net Production	10 MMcfe/d
Net Acreage	5,300

1. 12/31/2011 SEC reserves using a 12/31/2011 SEC price deck of \$3.84/MMBtu, \$3.60/MMBtu, and \$4.16/MMBtu for Piceance, Arkoma and Appalachia, respectively. Appalachia, Arkoma and Fayetteville reserves audited by DeGolyer & MacNaughton, Piceance audited by Ryder Scott. Probable and possible reserves prepared by internal reserve engineers using SEC reserves methodology. WTI SEC price averaged \$96.04/Bbl. Assumes processing (3Q 2012) and ethane recovery (1Q 2014).

2. See note on page 2 for 3P definition.

3. Includes hedge PV-10 of \$657 million.

2011 Reserve Growth

- 55% year-over-year increase in proved reserves to 5.0 Tcfe
- 85% increase in proved developed reserves to 844 Bcfe
- 2,429% reserve replacement in 2011
- \$0.42/Mcfe all-in finding cost in 2011
- 2,162 Bcfe of proved reserves added includes 86 million Bbls of NGLs primarily added due to the signing of processing and ethane takeaway agreements in Appalachia

Proved Reserves Walk Forward ⁽¹⁾	Bcfe
Balance at December 31, 2010:	3,231
Extensions, discoveries, book NGLs	2,162
Purchases	66
Performance revisions	(346)
Price revisions	(6)
Sales	(1)
Production	(89)
Balance at December 31, 2011:	5,017

1. 12/31/2011 SEC reserves using a 12/31/2011 SEC price deck of \$3.84/MMBtu, \$3.60/MMBtu, and \$4.16/MMBtu for Piceance, Arkoma and Appalachia, respectively. Appalachia, Arkoma and Fayetteville reserves audited by DeGolyer & MacNaughton, Piceance audited by Ryder Scott. WTI SEC price averaged \$96.04/Bbl. Assumes processing (3Q 2014) and ethane recovery (1Q 2014).

Antero Unrisked Net Resource Potential

- Including net 3P reserves of 17 Tcfe, Antero has 28 to 29 Tcfe of unrisked net resource potential
- Rich gas focused resource base includes approximately 1 billion Bbls of liquids
- Over 8,000 operated undrilled locations

Area	Resource	Gas (Tcf) ⁽¹⁾	Liquids (MMBbls) ⁽¹⁾	Net Resource Potential (Tcfe) ⁽¹⁾	Undrilled Operated Locations
Appalachia	Upper Devonian Shale	5	274	7	1,288
Appalachia	Marcellus Shale	10	609	14	2,309
Piceance	Mesaverde ⁽²⁾	2	96	2.5	2,868
Piceance	Mancos/Niobrara Shale ⁽²⁾	3 – 4	–	3 – 4	1,276
Arkoma	Woodford Shale ⁽²⁾	2	41	2	754
TOTAL		22 – 23	1,020	28 – 29	8,495

Significant Marcellus and Upper Devonian Shale Liquids Exposure

1. All 3P reserves as of 12/31/2011.

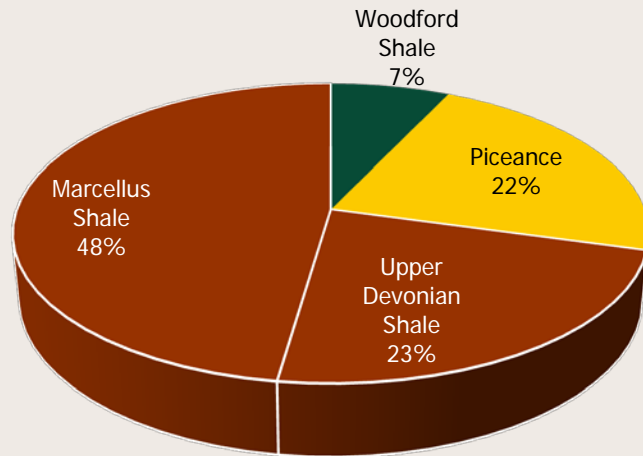
2. 1.6 Tcfe of Mesaverde resource and 1.2 Tcfe of Mancos/Niobrara resource in the Piceance Basin, 0.9 Tcfe of resource in the Arkoma Basin and all 13.5 Tcfe of Marcellus Shale resource is included in 3P reserves assuming 12/31/2011 SEC pricing.

Appalachian Shale-Focused Resource Base

- Over 70% of Antero's resource base is in the Appalachian Basin
- 23% of resource base is liquids by volume

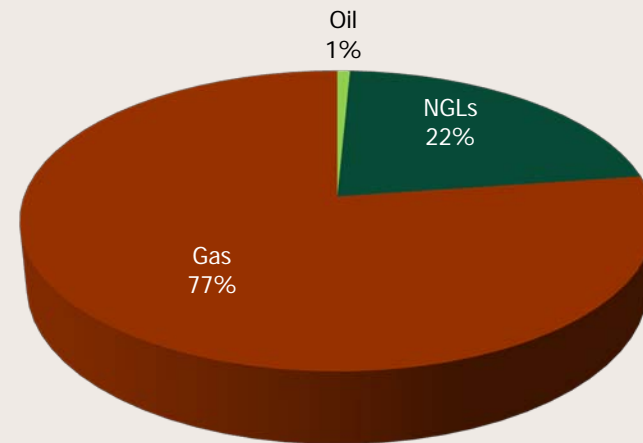
Net Unrisked Resource Potential

By Area
12/31/2011



28 Tcfe

By Product
12/31/2011

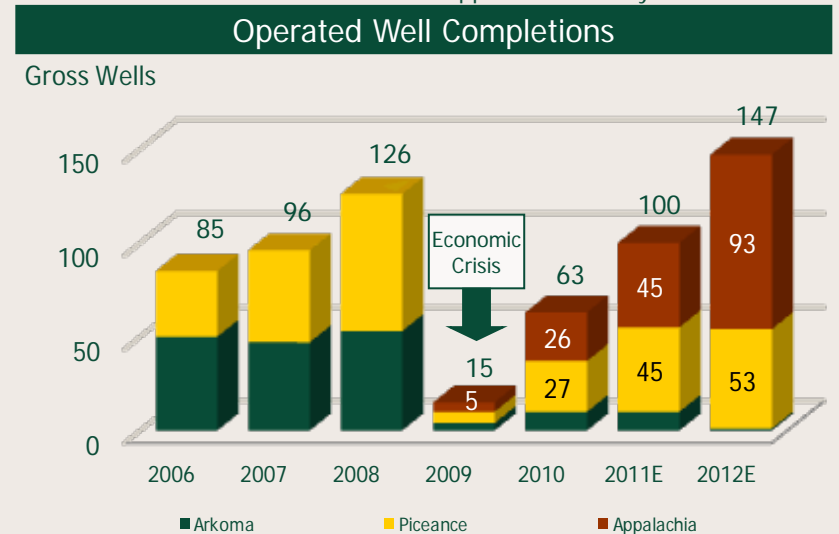
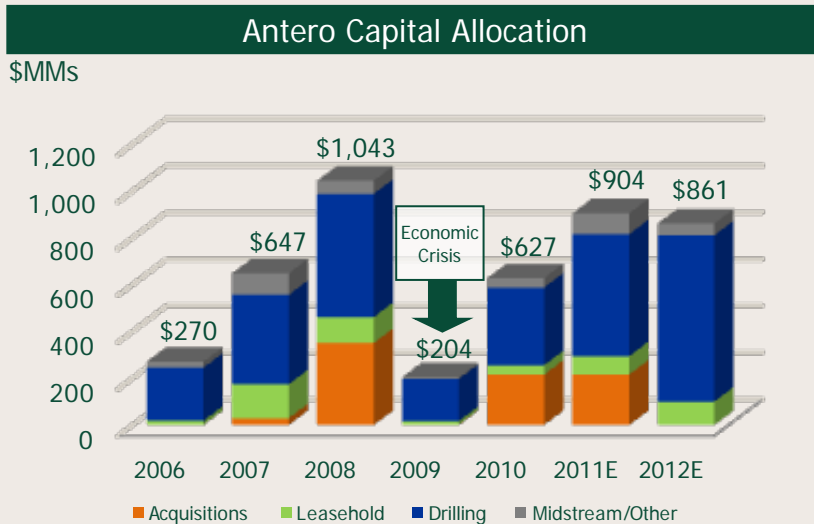
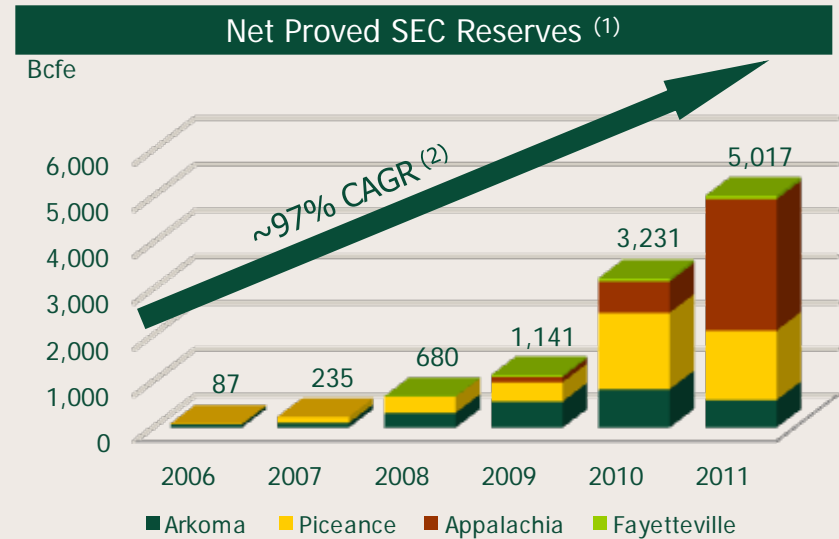
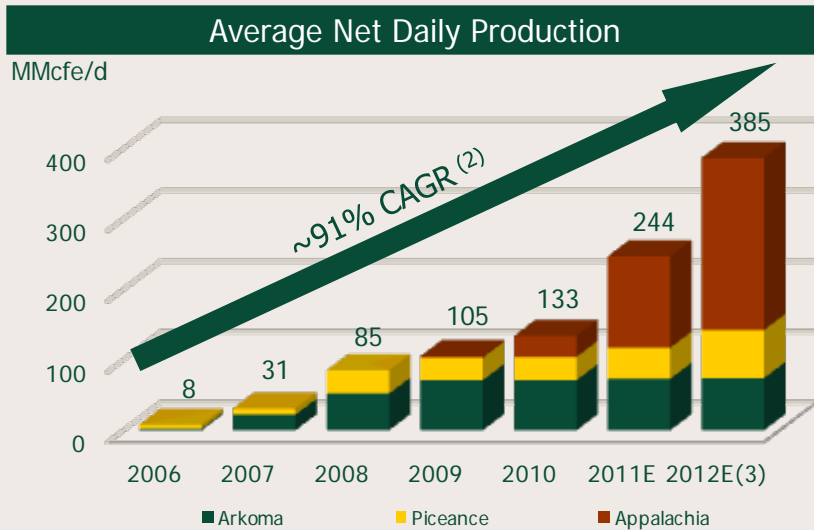


28 Tcfe

1. All 3P reserves as of 12/31/2011.

2. 1.6 Tcfe of Mesaverde resource and 1.2 Tcfe of Mancos/Niobrara resource in the Piceance Basin, 0.9 Tcfe of resource in the Arkoma Basin and all 13.5 Tcfe of Marcellus Shale resource is included in 3P reserves assuming 12/31/2011 SEC pricing.

Strong Track Record of Growth

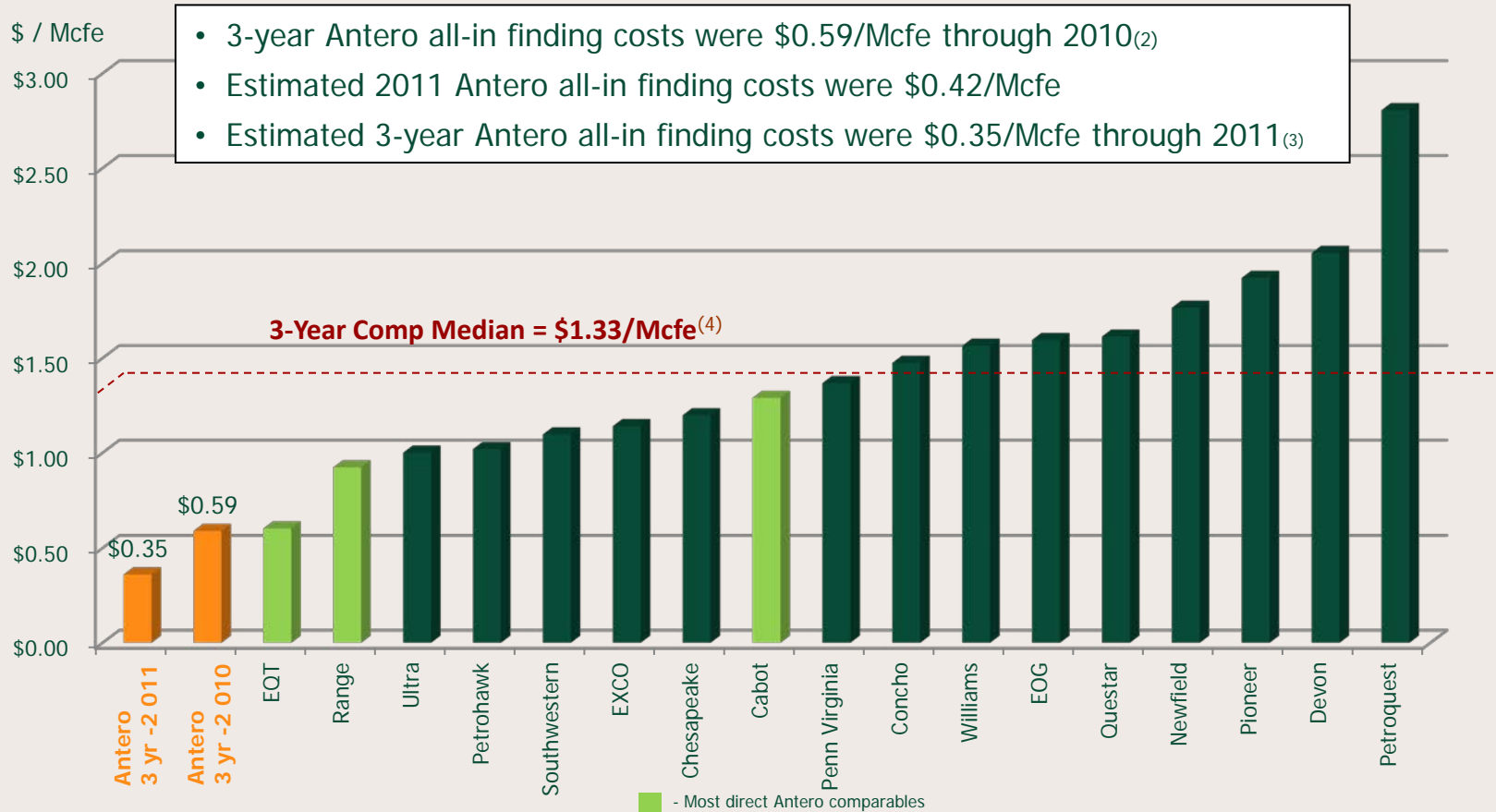


1. Proved reserves for 2006, 2007 and 2008 were determined using previously effective SEC methodology. 2009, 2010 and 2011 reserves based on current SEC methodology and pricing.
 2. CAGR = Compound Annual Growth Rate
 3. Antero net production guidance for 2012 is 370 to 400 MMcfe/d.

Industry Leading Finding Costs

- Includes all drilling, completion, land and acquisition expenditures

Industry 3-Year All-in Finding Costs through 2010⁽¹⁾



1. Source: Finding and development cost data provided by JP Morgan Research on 3/29/2011 for all companies except for Antero and EXCO. Includes all drilling capital expenditures and includes land and acquisition costs for all companies. Antero and EXCO analysis prepared by management based on public filings.

2. Antero finding costs calculated over 3 years using 12/31/2010 SEC reserves which were engineered by independent third-party engineers.

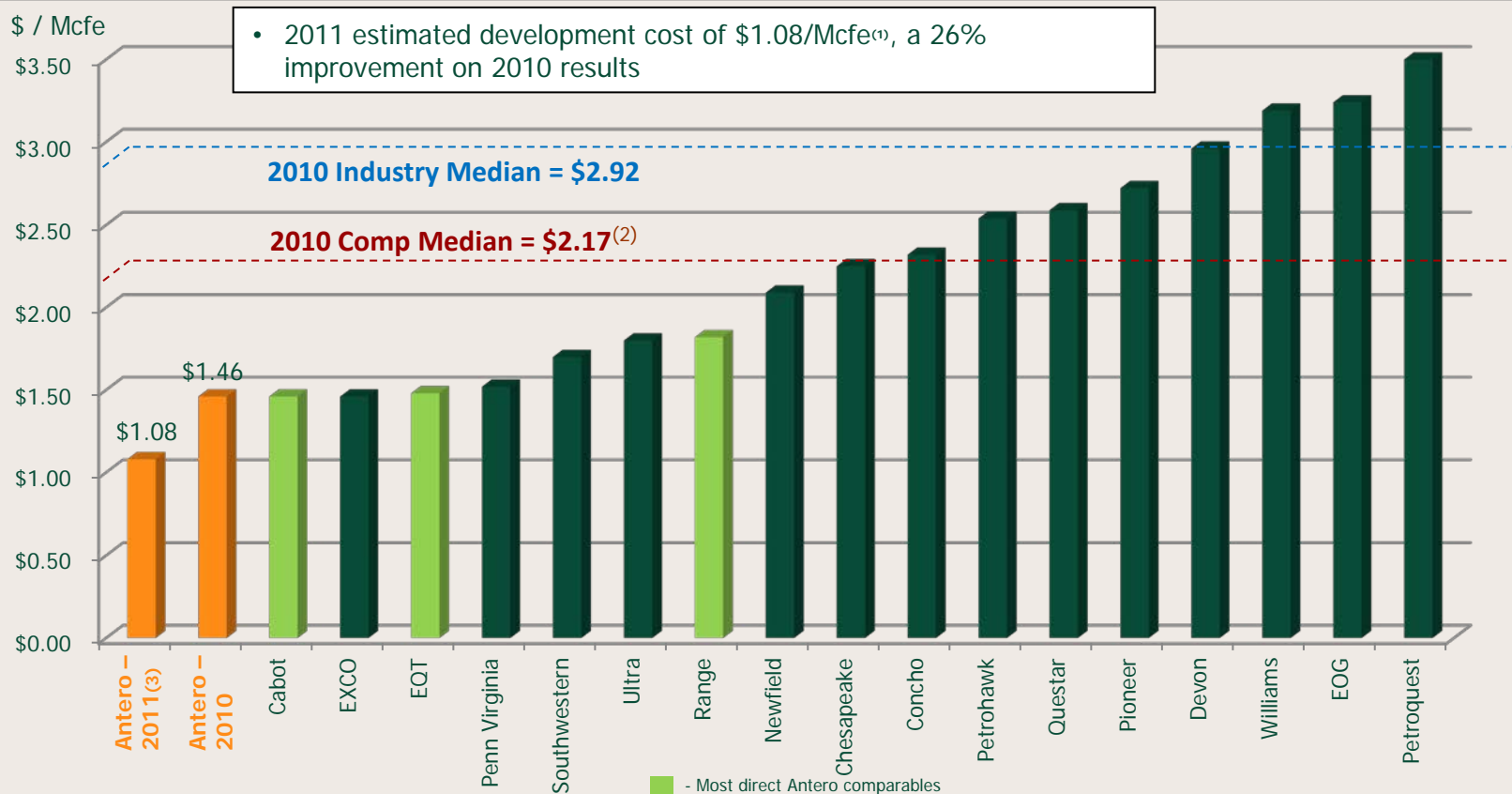
3. Antero finding costs calculated over 3 years using 12/31/2011 SEC reserves which were audited by DeGolyer & MacNaughton (Appalachia, Arkoma and Fayetteville) and Ryder Scott (Piceance). 2011 capital expenditures subject to YE 2011 financial audit.

4. Median calculated for comparable company set used in this graph.

Industry Leading Development Costs

- Per Mcfe development costs excluding land is a better measure of capital efficiency than finding costs
 - Antero was a leader in development cost in 2010 and is likely a leader in 2011

2010 Industry Development Costs⁽¹⁾

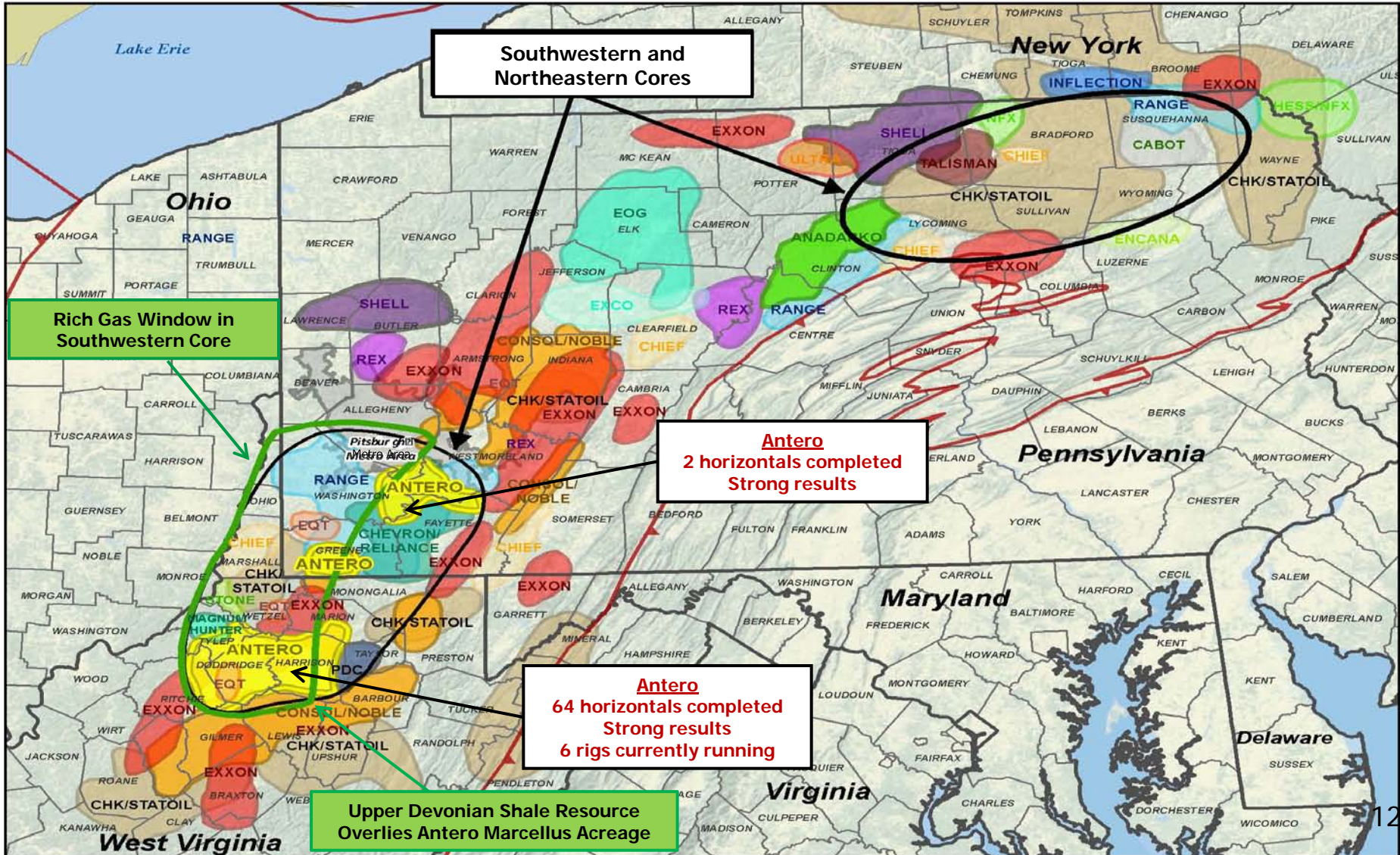


1. Source: Proved developed F&D research prepared by JP Morgan Research on 3/24/2011. Includes all drilling but excludes land and acquisition costs for all companies. Antero and EXCO analysis prepared by management based on public filings. Defined as drilling capital expenditures for the period divided by PDP and PDNP volumes added after adding back production for the period.

2. Median calculated for comparable company set used in this graph.

3. Calculated using 12/31/2011 SEC proved reserves which were audited by DeGolyer & MacNaughton (Appalachia, Arkoma and Fayetteville) and Ryder Scott (Piceance). 2011 capital expenditures subject to YE 2011 financial audit.

Marcellus Shale Position



1. Representation of key acreage positions from Company presentations.

Antero Marcellus Shale



Summary

- Majority of acreage has rich gas processing potential
- 220,000 net acres of leasehold in heart of the play
 - 61% HBP and additional 23% not expiring for 5+ years, 100% operated
- 2.8 Tcfe of proved reserves / 13.5 Tcfe of 3P reserves
- 180 MMcf/d current net operated production
- Surrounded by key Range, Chevron, Exxon Mobil, EOT and Chesapeake Marcellus wells
- Antero has completed 66 consistently strong horizontal wells; all of which are online
 - Demonstrated ability to drill wells with long laterals (6,000 ft +) in less than 30 days
- Drilling 3 Upper Devonian horizontal wells over the next 6 months – 1st well currently drilling

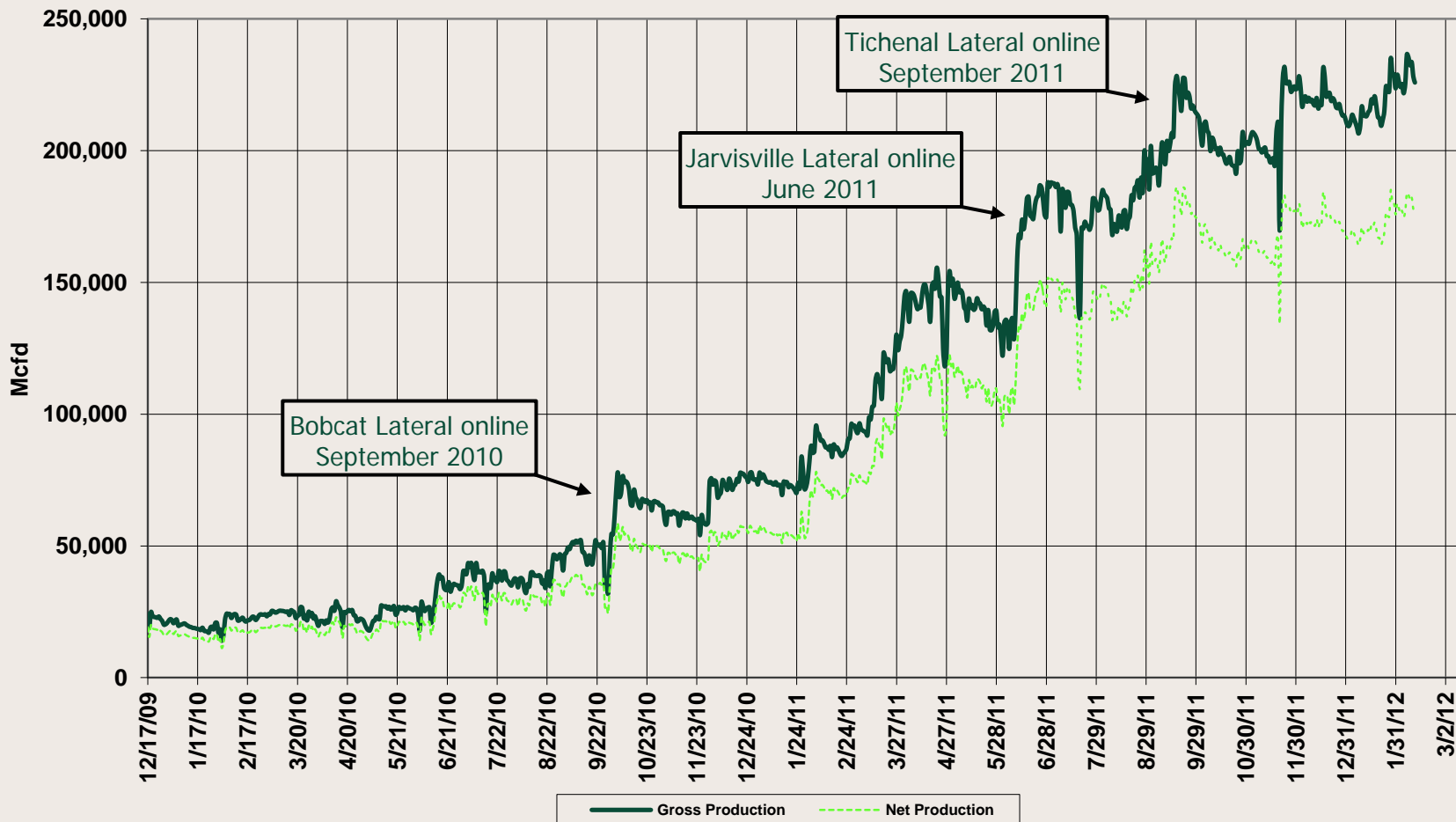
Fully Integrated

- 200 MMcf/d processing plant expected to be online August 2012 – fully dedicated to Antero
- 625,000 MMBtu/d of long-haul firm transportation or firm sales secured
- 100,000 MMBtu/d of back-haul firm transportation to Gulf Coast
- Committed to 20,000 Bbls/d ethane takeaway capacity on Enterprise ATEX pipeline to Mont Belvieu

Strong Marcellus Growth

- Antero has rapidly grown its Marcellus production over the past two years while building out midstream infrastructure

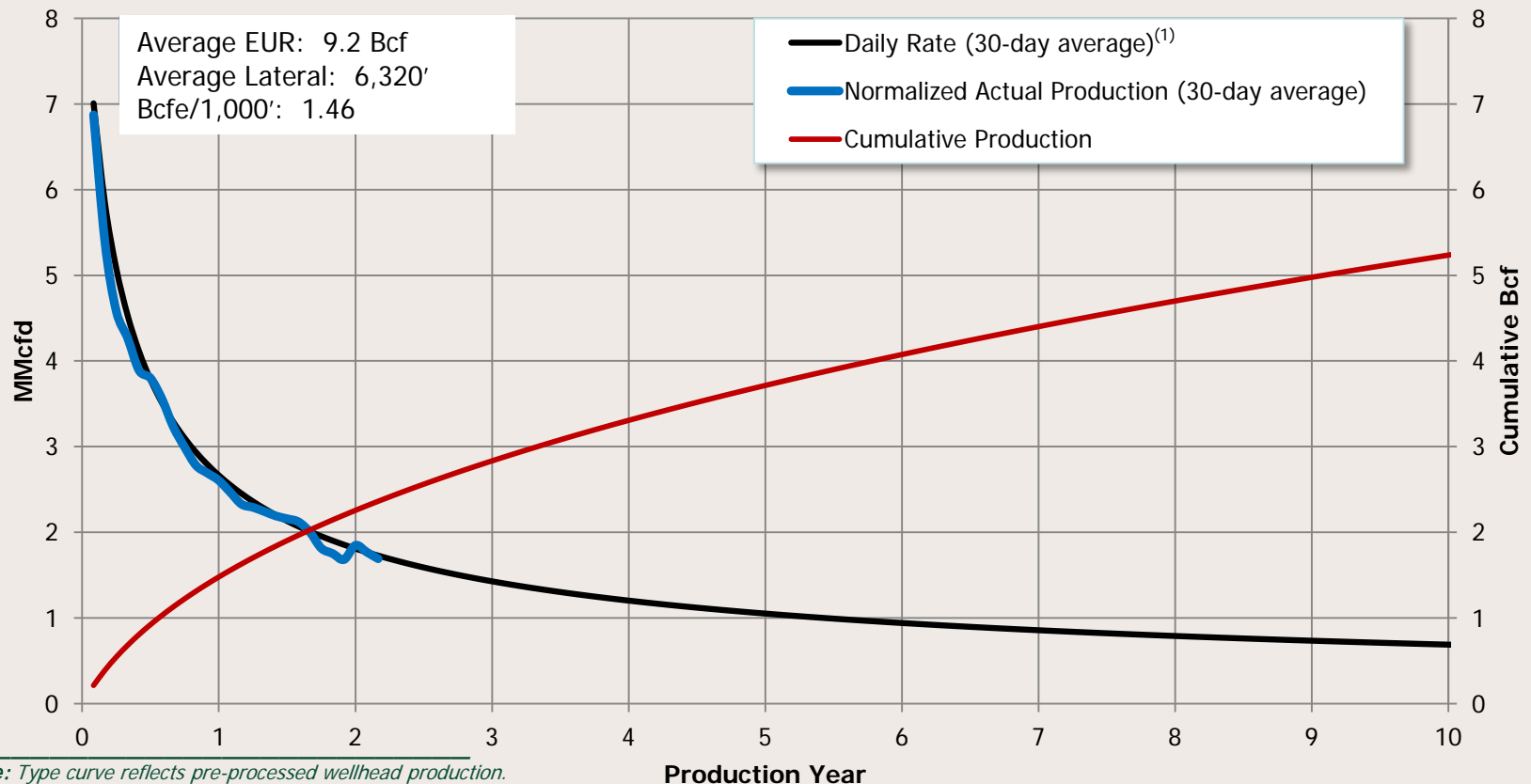
Antero Gross Operated Marcellus Production



Antero Marcellus Type Curve Support

- Antero has over 2 years of production history to support its 1.46 Bcf/1,000' of lateral recovery assumption as demonstrated by the graph and table below
 - DeGolyer & MacNaughton (D&M), Antero's third party reserve auditor, supports this type curve
- Antero's average 24-hour peak rate is 13.2 MMcfe/d in the Marcellus

	24-hour peak	30-day avg. rate	90-day avg. rate	180-day avg. rate	365-day avg. rate	545-day avg. rate
MMcfd	13.2	7.1	5.6	4.8	3.3	2.6
# of wells	66	61	57	47	25	6



*Note: Type curve reflects pre-processed wellhead production.
1. Wells normalized to time-zero.*

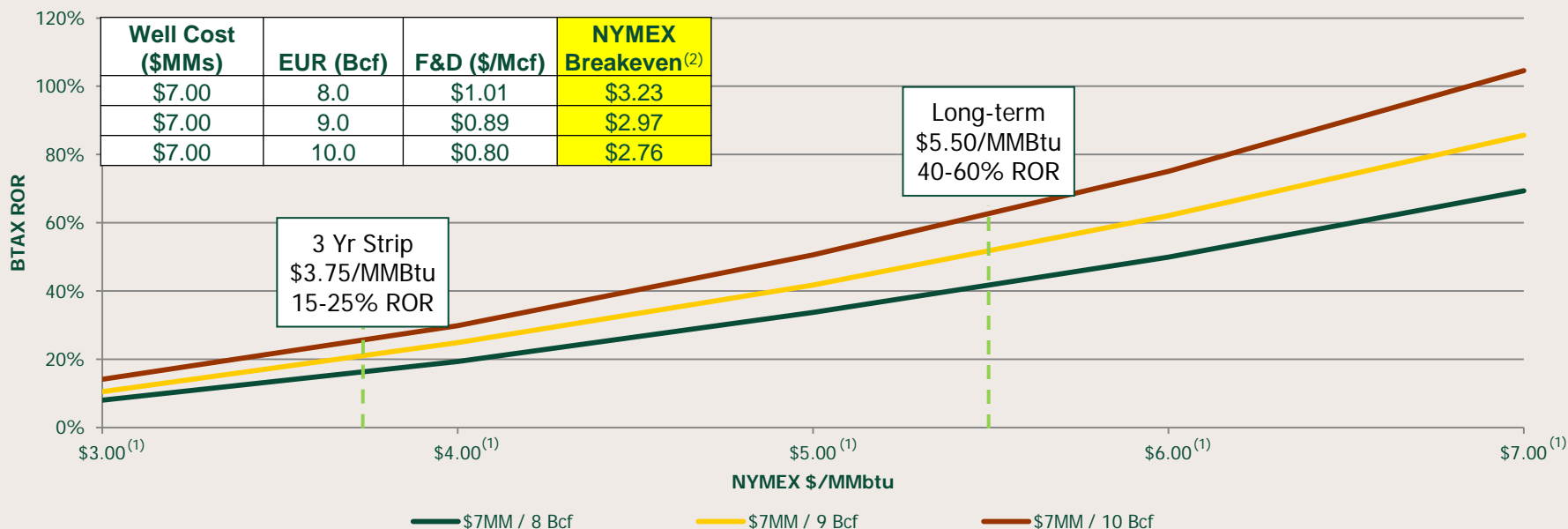
Marcellus Shale Well Economics – Horizontal Lean Gas



- Assumes 1050 Btu gas – no processing, lean gas
- Antero has an estimated 450 net horizontal drilling locations in the lean gas category (1000 to 1050 Btu)

Antero Average for First 66 Horizontal Wells			
Lateral Length	Well Cost (\$ MM)	EUR (Bcf)	Net F&D (\$/Mcf)
6,320	\$7.4	9.2	\$0.92

Marcellus Shale Well Economics -- Horizontal Lean Gas



1. Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 87% NRI assumed.
 2. Defined as 10% before tax rate-of-return.

Marcellus Shale Well Economics – Horizontal Rich Gas

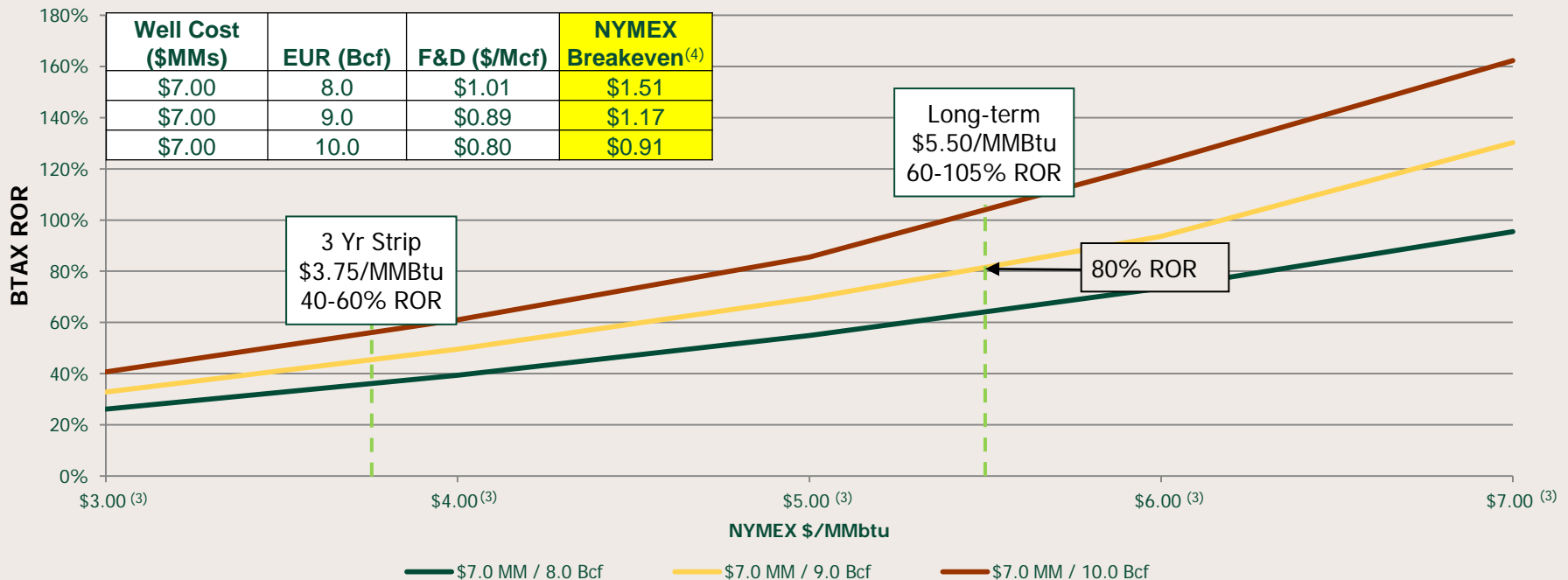


- Assumes 1150 Btu gas and includes processing margin at \$95/Bbl oil and current NGL price correlations⁽¹⁾
- Antero has an estimated 1,350 net horizontal drilling locations in the rich gas category (1050 to 1350 Btu)⁽²⁾

Antero Average for First 66 Horizontal Wells

Lateral Length	Well Cost (\$ MM)	EUR (Bcf)	Net F&D (\$/Mcf)
6,320	\$7.4	9.2	\$0.92

Marcellus Shale Well Economics -- Rich Gas (1150 BTU)

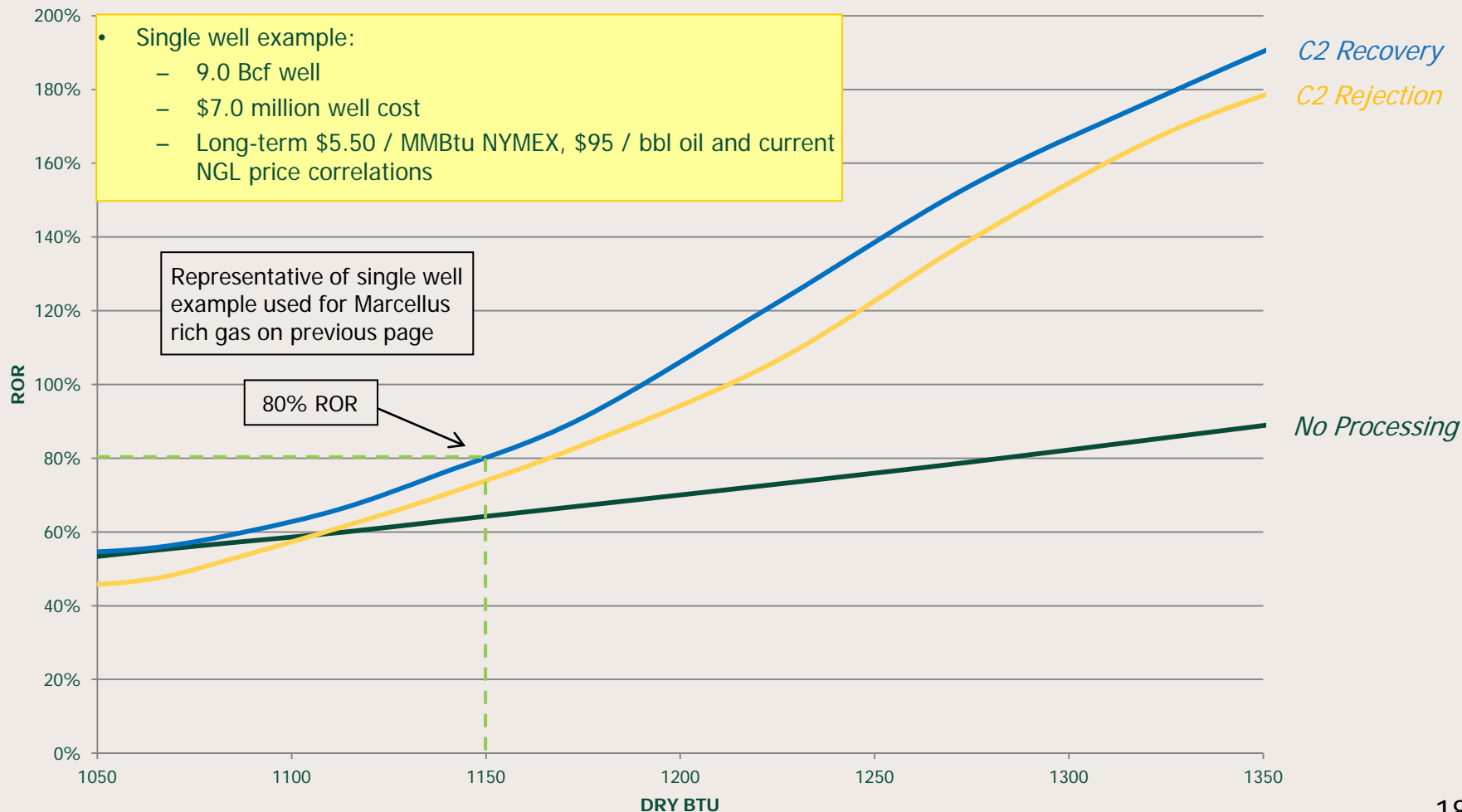


1. No processing capacity is available until plant completed (expected August 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014).
 2. Economics will vary considerably depending on Btu and other factors.
 3. Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 87% NRI assumed.
 4. Defined as 10% before tax rate-of-return.

Marcellus Processing Economics



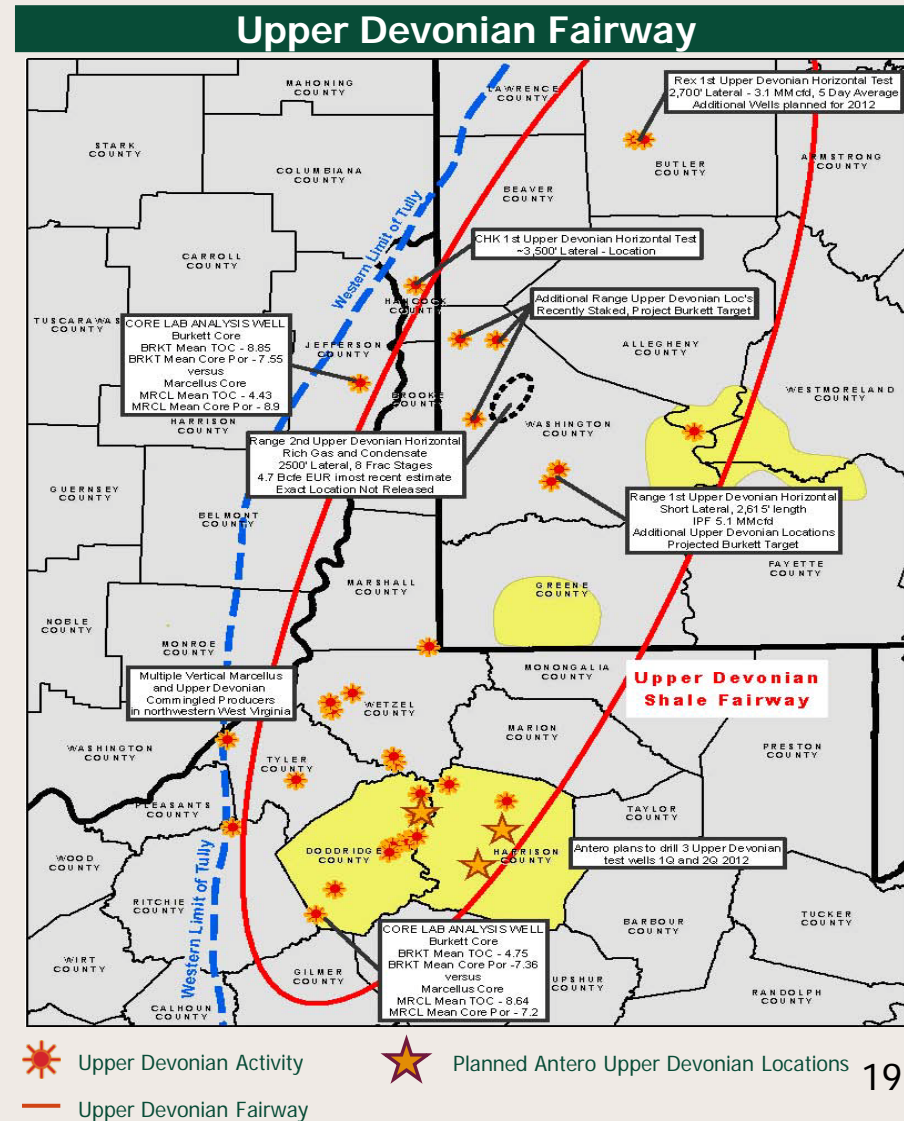
- Dramatic improvement in returns by processing higher BTU gas – Antero's Marcellus rich gas leasehold spans the 1050 to 1350 Btu spectrum



1. Fixed NYMEX gas price of \$5.50/MMBtu with appropriate basis adjustment to the Marcellus area, \$95/Bbl WTI and current NGL price correlations. 87% NRI assumed.

Upper Devonian Potential

- Upper Devonian, found at slightly shallower depths than the Marcellus Shale, around 6,500 feet true vertical depth
- Expected to be rich gas wherever the Marcellus is rich gas
- Upper Devonian lies just above of the Marcellus, separated by Tully Limestone frac barrier in a large portion of Antero's acreage
- Per Range Resources, the Upper Devonian "holds comparable hydrocarbons in place relative to the Marcellus"⁽¹⁾
- Range has drilled two test wells in the Upper Devonian so far and is expected to drill more in 2012⁽¹⁾
 - One of Range's initial wells has an estimated EUR of 4.7 Bcf with a 2,500' lateral (1.6 Bcf / 1,000')⁽²⁾
- Antero plans to drill 3 Upper Devonian test wells 1Q and 2Q 2012 – drilling 1st well now
- Antero estimates Upper Devonian potential is 7 Tcfe of net resource on its Appalachian acreage position



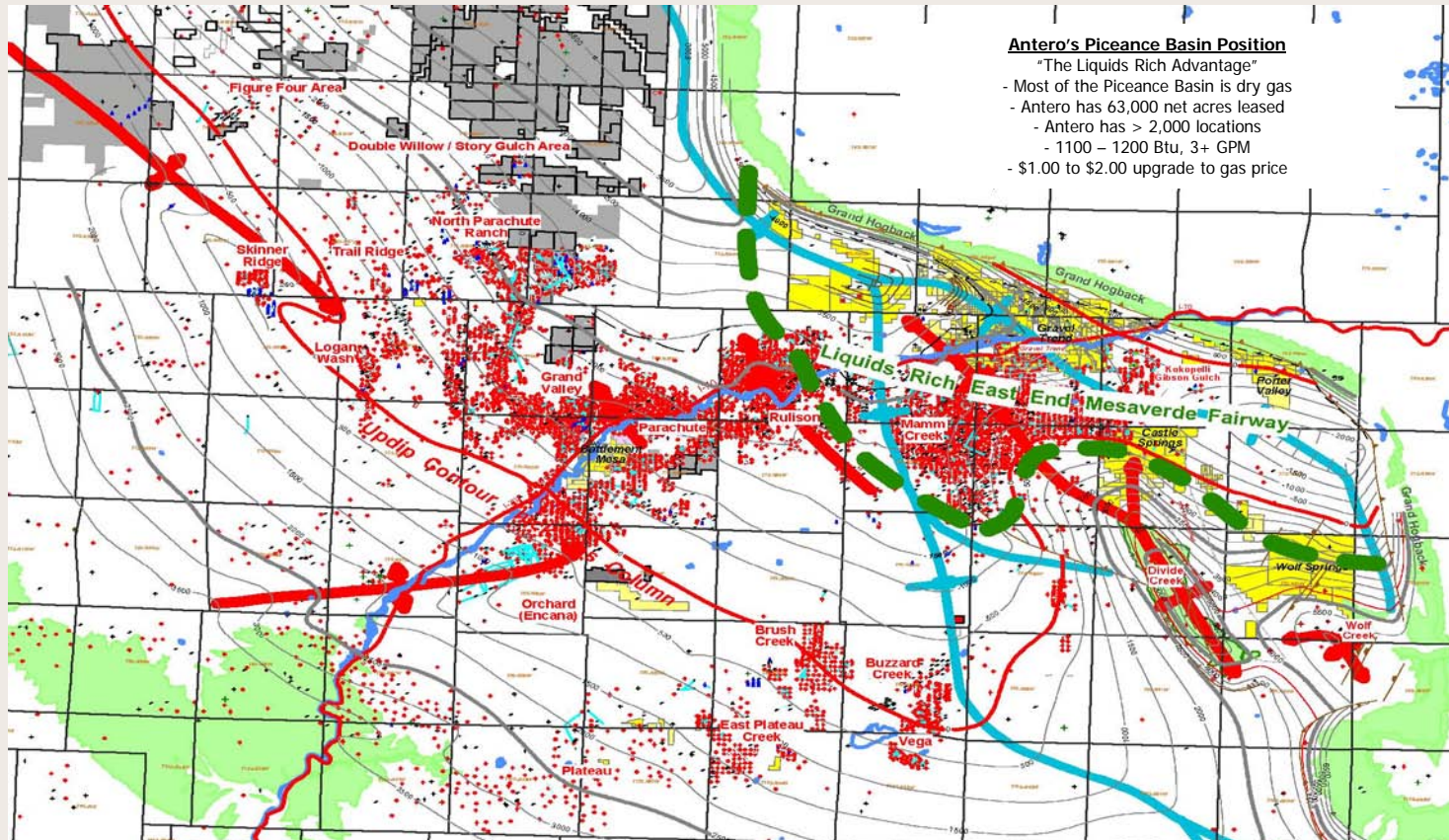
1. Per Range Resources' YE 2011 earnings call.
 2. Per Range Resources' 2Q 2011 earnings call. Calculated using a pre-processed EUR of 4 Bcf.

Piceance Basin – A Rich Gas Play

- Rich processable gas from Mesaverde
- 63,000 net acres – 40% HBP
- 1.5 Tcfe of proved reserves / 2.9 Tcfe of 3P reserves
- 63 MMcfe/d net production including 3,200 Bbls/d of NGLs and oil
- Drilled and completed over 200 wells with a 99% success rate

2012 Program:

- 1 rig drilling 53 Mesaverde development wells
 - 4 wells completing
 - 5 wells waiting on completion
 - 15 to 25% ROR at current strip prices
- Completing two pipeline infrastructure projects
- Plan to drill first horizontal Mancos/Niobrara Shale well in 2012



Piceance Well Economics – Rich Gas

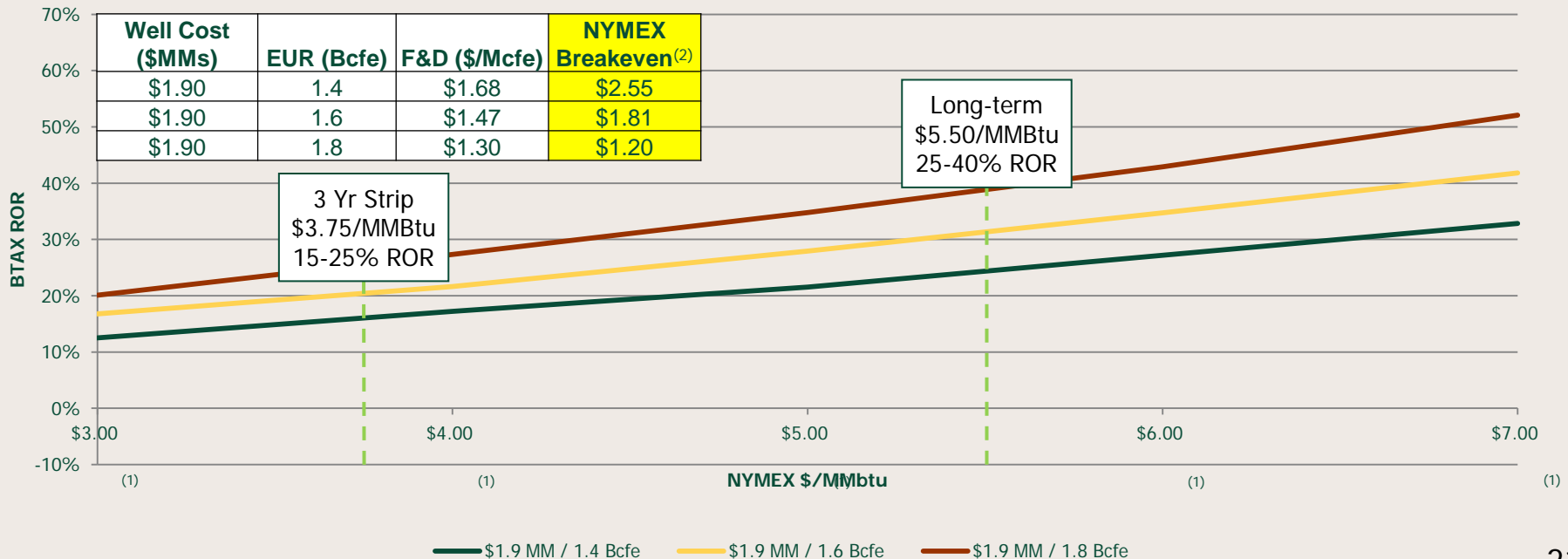


- Assumes 1140 Btu gas and includes processing margin at \$95/Bbl and current NGL price correlations
- Antero has 1,300 net Mesaverde rich gas drilling locations with well economics expected to be similar to those outlined below

Rich Gas – 45 Recently Drilled Mesaverde Gravel Trend Wells

Avg. Well Cost (\$ MM)	Avg. EUR (Bcfe)	Net F&D (\$/Mcfe)
\$1.9	1.6	\$1.49

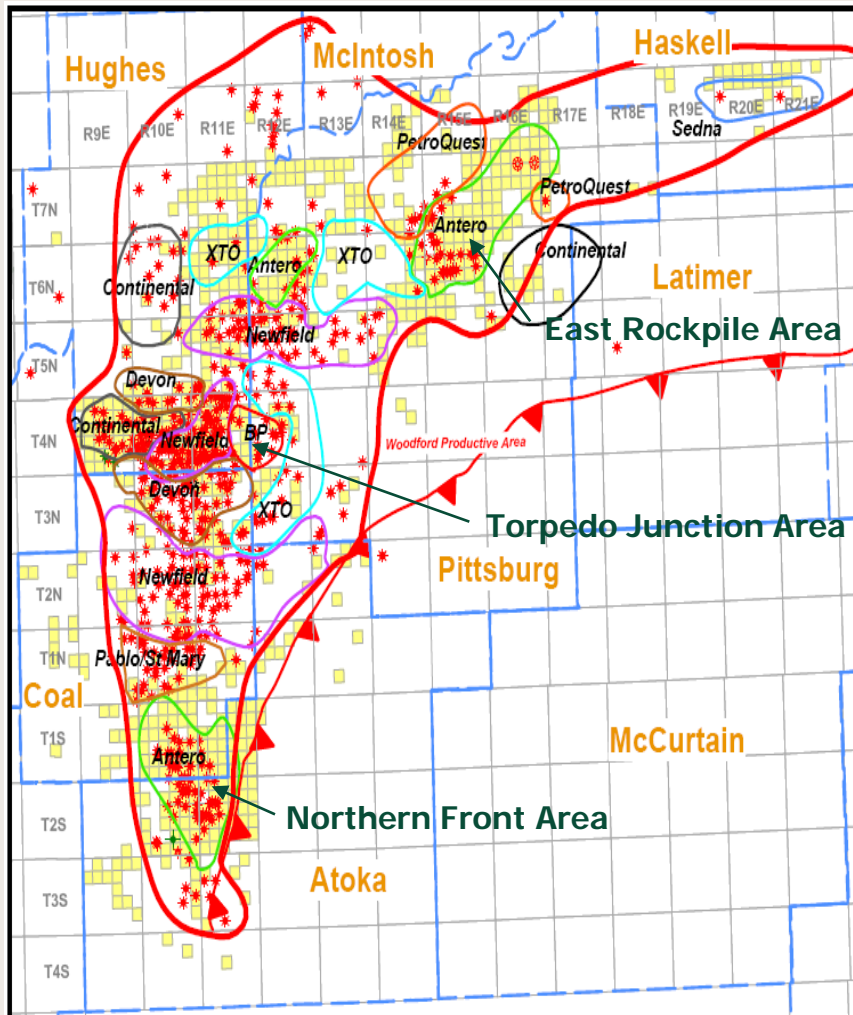
Piceance Well Economics -- Rich Gas



1. Fixed NYMEX gas prices with appropriate basis adjustment to the Piceance area. 81% NRI assumed.
 2. Defined as 10% before tax rate-of-return.

Arkoma Basin

Antero Woodford Shale Acreage Position



Woodford Shale Summary

- Rich processable gas from west side of play
- Lean gas on east side
- 599 Bcfe of net proved reserves / 910 Bcfe 3P reserves
- 67,000 net acres – 85% HBP
- Drilled and operated over 130 horizontal wells with a 97% success rate to date
- 72 MMcf/d net production
- Have 3D seismic over virtually all operated acreage
- Recent operating developments in the play include:
 - Antero currently completing four operated rich gas wells with strong initial rates

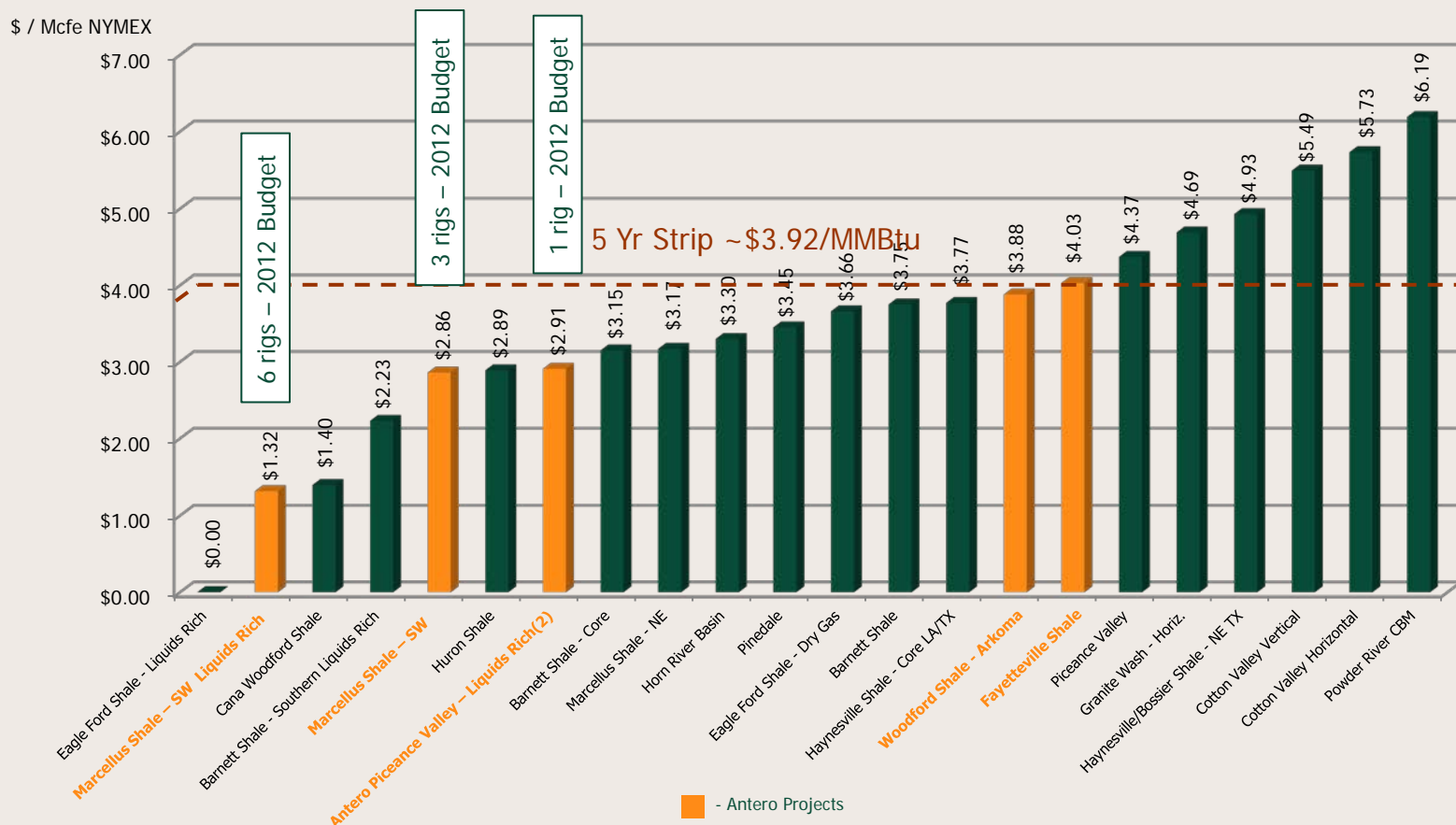
Fayetteville Shale Summary

- Non-operated lean gas
- 10 MMcf/d net production
- 5,290 net acres – 71% HBP

Low Break Even Natural Gas Prices

- Antero is low on the cost curve with a very attractive drilling portfolio – Antero projects highlighted in orange
- Antero plans to operate 10 drilling rigs on average in 2012 – focused on its highest return projects

NYMEX Break Even Price (15% ATAX ROR) – Credit Suisse Analysis⁽¹⁾



1. Source: Credit Suisse report dated 2/06/2012 – Break even price is for 15% after tax rate-of-return. Antero Piceance Valley – Liquids Rich incorporates Antero-specific assumptions as footnoted herein.

2. Antero Piceance Valley – Liquids Rich assuming 1.6 Bcfe EUR, \$1.9 million drilling and completion costs, 1140 Btu gas, \$95 per Bbl crude oil and current NGL price correlations.

Strong Hedge Position

- Antero will realize over \$1 billion⁽¹⁾ of hedge gains over the next five years from its 710 Bcfe hedge book assuming current STRIP prices
 - Protects future cash flow thereby supporting drilling plans and production growth

Antero Hedge Position – 2012 through 2016⁽²⁾

Natural Gas Swaps	Hedged Volume (MMBtu/d)	NYMEX-Equivalent Price (\$/MMBtu) ⁽²⁾	% of forecasted net tailgate gas production
2012	295,537	\$5.69	84%
2013	417,020	\$5.29	80%
2014	440,000	\$5.53	
2015	430,000	\$5.64	
2016	362,500	\$5.56	

Projected Annual Hedging Gains^{(1), (2)}

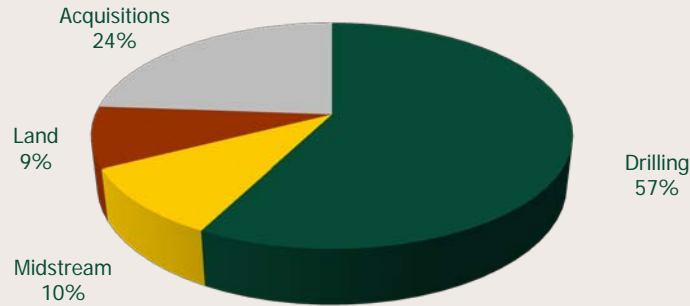


1. Based on 2/24/2012 STRIP gas prices and undiscounted.

2. Virtually all hedges are fixed price swaps, hedged to the basin. Basin prices are converted by Antero to NYMEX-equivalent prices using current basis differentials in the over-the-counter futures market.

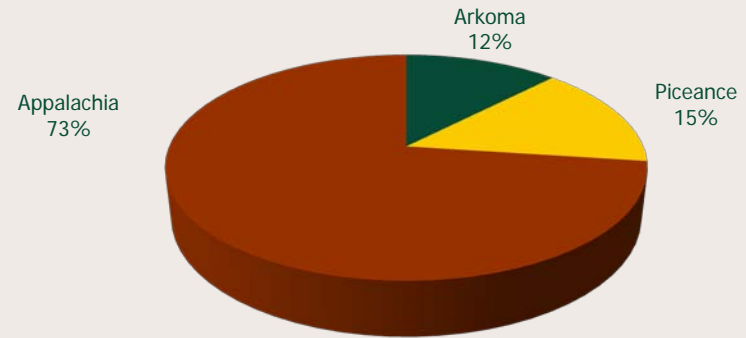
2011E and 2012E Capital Budget

2011E Capex Budget by Type



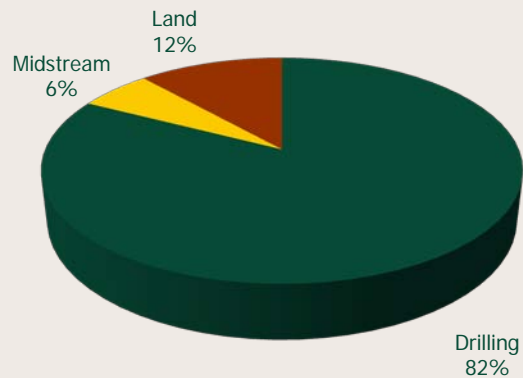
Total: \$904MM

2011E Capex Budget by Basin



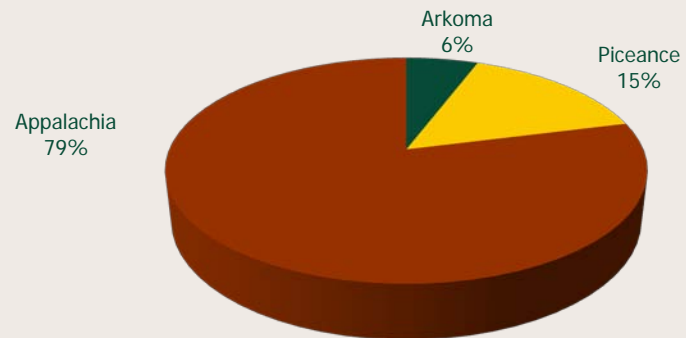
Total: \$904MM

2012E Capex Budget by Type⁽¹⁾



Total: \$861MM

2012E Capex Budget by Basin⁽¹⁾



Total: \$861MM

1. Does not include budget for acquisitions except for \$100 million of land primarily designated for Marcellus leasehold acquisitions.

Current Financial Summary



Financial Summary

	AUDITED			UNAUDITED	
	12 mos. 2008	12 mos. 2009	12 mos. 2010	12 mos. 2011(4)	12 mos. 2011(4)
\$ millions					
Adjusted for midstream sale(5)					
Summary Operating Results					
Production (Bcfe)	32	38	49	89	89
EBITDAX	\$207	\$201	\$198	\$341	\$341
Cash interest expense (1)	\$38	\$36	\$56	\$68	\$68
Proved reserves (Bcfe) (2)	680	1,141	3,231	5,017	5,017
Proved developed reserves (Bcfe) (2)	239	245	457	845	845
Proved PV 10 (3)	\$649	\$625	\$1,858	\$4,103	\$4,103
Summary Balance Sheet					
Cash and cash equivalents	\$39	\$11	\$9	\$8	\$14
Bank credit facility	397	142	128	365	0
2nd lien credit facility	225	0	0	0	0
Subordinated debt	0	0	25	25	25
Senior notes	0	375	525	925	925
Total net debt	\$583	\$506	\$669	\$1,307	\$937
Shareholders' equity	1,148	1,393	1,508	1,566	1,566
Non-controlling interest	29	30	0	0	0
Total book capitalization	\$1,760	\$1,929	\$2,177	\$2,915	\$2,545
Credit Statistics					
Total net debt / book capitalization	33.1%	26.2%	30.7%	45.5%	37.4%
Total net debt / EBITDAX	2.8x	2.5x	3.4x	3.8x	2.7x
EBITDAX / interest expense (1)	5.5x	5.6x	3.5x	5.0x	5.0x
Total net debt / proved reserves (\$/Mcf) (2)	\$0.86	\$0.44	\$0.21	\$0.26	\$0.19
Total net debt / proved developed reserves (\$/Mcf) (2)	\$2.44	\$2.07	\$1.46	\$1.55	\$1.11
Total net debt / production (\$/Mcf) (2)	\$6,671	\$4,860	\$4,983	\$5,352	\$3,834
Proved PV 10 / net debt (3)	1.1x	1.2x	2.8x	3.1x	4.4x

1. Represents cash interest paid for credit facility and \$950 million of existing bonds and notes.

2. 12/31/2011 audited SEC reserves

3. 12/31/2011 PV 10 includes hedge PV 10 of \$657 million and proved reserves pre-tax PV 10 value of \$3.4 billion. Reserves PV-10 not adjusted for new Appalachian gathering contract fees.

4. YE2011 results are subject to a year-end financial audit (unaudited).

5. Pro forma for \$375 million sale of Marcellus midstream assets

Key Credit Strengths

Diversified, stable asset base

- Significant reserve potential diversified across three of the key U.S. shale plays
- Ability to allocate capital to most profitable projects based on commodity prices, basis differentials and local cost dynamics
- Growing liquids exposure

Top tier cost structure

- Estimated 2011 all-in F&D of \$0.42/Mcfe; 3-year all-in F&D of \$0.35/Mcfe
- \$1.01/Mcfe estimated development cost over last 148 operated development wells
- Significant infrastructure investments in Piceance and Marcellus gathering, compression and water handling facilities

Large, low risk drilling inventory

- Large inventory of proved undeveloped and probable locations close to existing infrastructure
- No significant near term lease expirations; 63% of acreage HBP
- 98% drilling success rate in over 600 operated wells since inception
- 91% compound annual growth in average net daily production 2006 to 2012
- Successfully proved up over 5.0 Tcfe of reserves over the past 5+ years

Strong financial profile

- Strong liquidity – Over \$1.1 billion at December 31, 2011, pro forma for Marcellus midstream sale
- Pro forma for the Marcellus midstream sale, net debt/proved developed of \$1.11/Mcfe
- Large hedge position with 710 Bcf⁽¹⁾ currently hedged from January 1, 2012 through 2016 at approximately \$5.53/Mcfe NYMEX-equivalent basin prices
- Over 80% of estimated 2012 and 2013 net tailgate gas production hedged at \$5.69/MMBtu and \$5.29/MMBtu NYMEX-equivalent, respectively

Experienced management team

- Management with proven track record in shale gas and tight sand projects
- Core management and technical team have worked together for many years – trained by the majors
- Drilled and operated over 300 horizontal shale wells

1. Assumes 1000 Btu average heat content.

Appendix



Marcellus Shale Well Economics – Horizontal Highly-Rich Gas

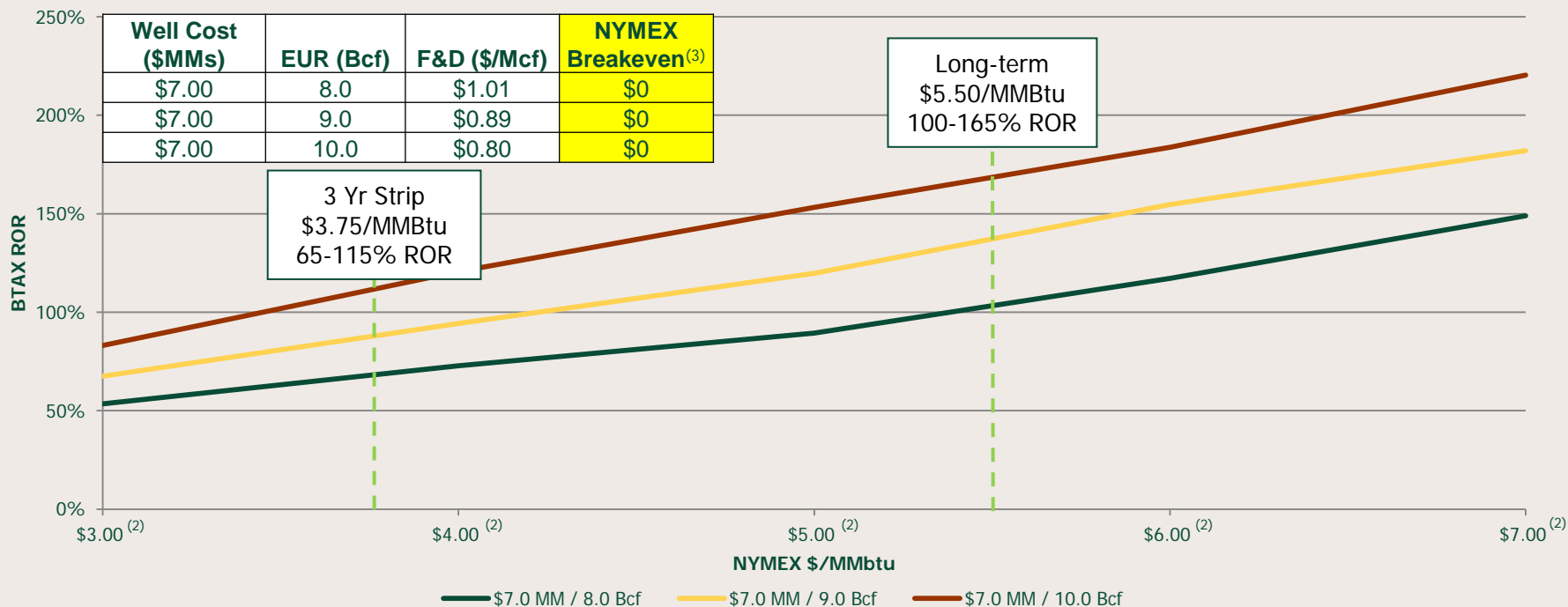


- Assumes 1250 Btu gas and includes processing margin at \$95/Bbl oil and current NGL price correlations ⁽¹⁾
- Antero has significant leasehold in the 1250 to 1350 Btu category, some of which is scheduled to be drilled in 2012

Antero Average for First 66 Horizontal Wells

Lateral Length	Well Cost (\$ MM)	EUR (Bcf)	Net F&D (\$/Mcf)
6,320	\$7.4	9.2	\$0.92

Marcellus Shale Well Economics -- Rich Gas (1250 BTU)



1. No processing capacity is available until plant completed (expected August 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). 29

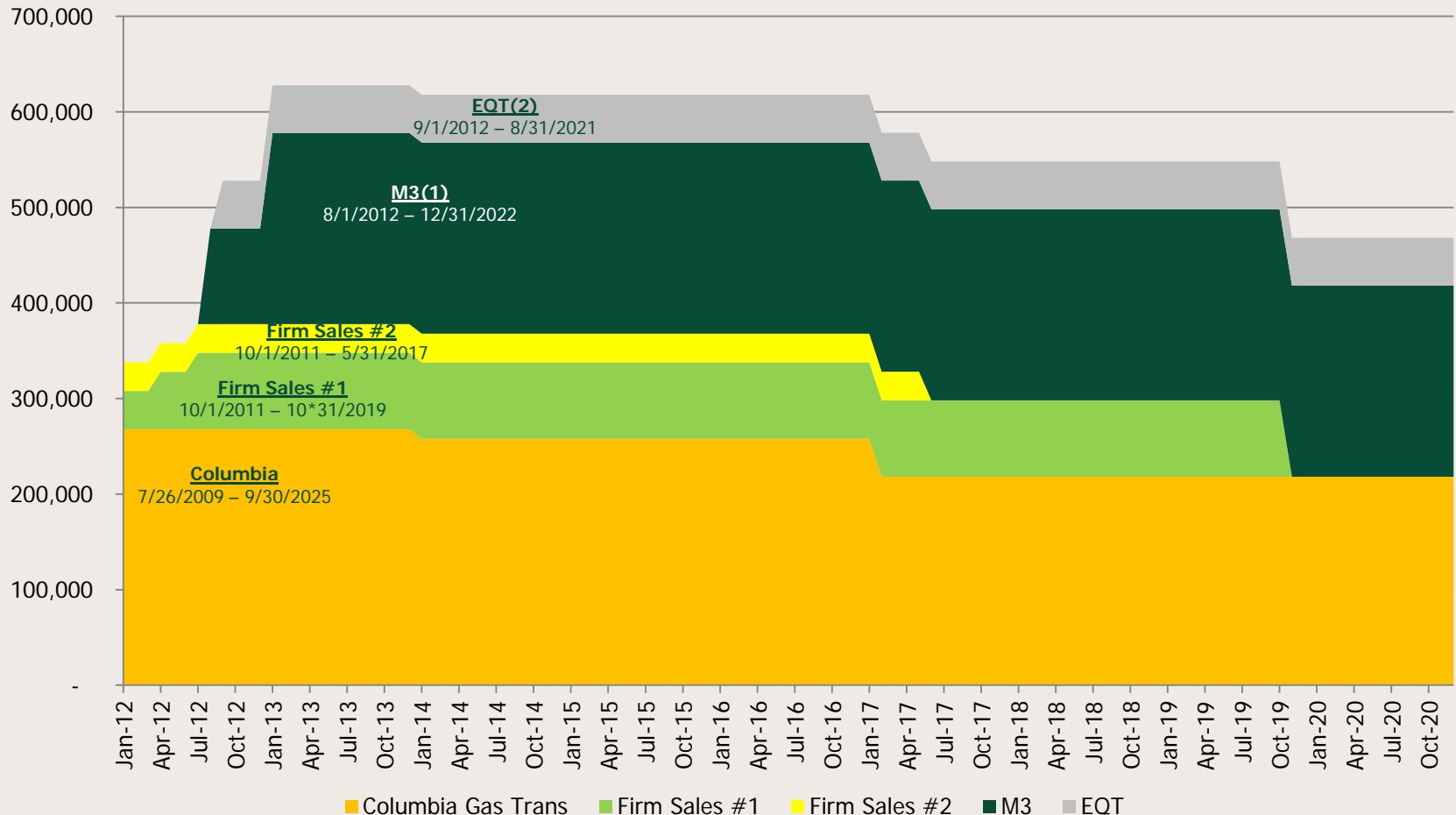
2. Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 87% NRI assumed.

3. Defined as 10% before tax rate-of-return.

Firm Transportation Coverage



- Antero has firm transportation in place to cover its gross production growth until late 2013 – pursuing additional firm transportation alternatives now



1. Assumes August 1, 2012 in-service date.
 2. Assumes September 1, 2012 in-service date.

Marcellus Midstream Sale – Enhances Liquidity



- Pro forma for the Marcellus midstream sale, Antero's liquidity at 12/31/2011 would have been almost \$1.2 billion.

Liquidity Detail

\$ Millions	As adjusted for midstream sale	
	12/31/2011(1)	12/31/2011(1)
Liquidity		
Current revolver commitment	\$850	\$850
Less: outstandings	(365)	0
Less: letters of credit	(21)	(21)
Plus: cash and cash equivalents	8	14
Liquidity	\$472	\$843
Add: Additional borrowing base capacity	350	350
TOTAL Liquidity	\$822	\$1,193

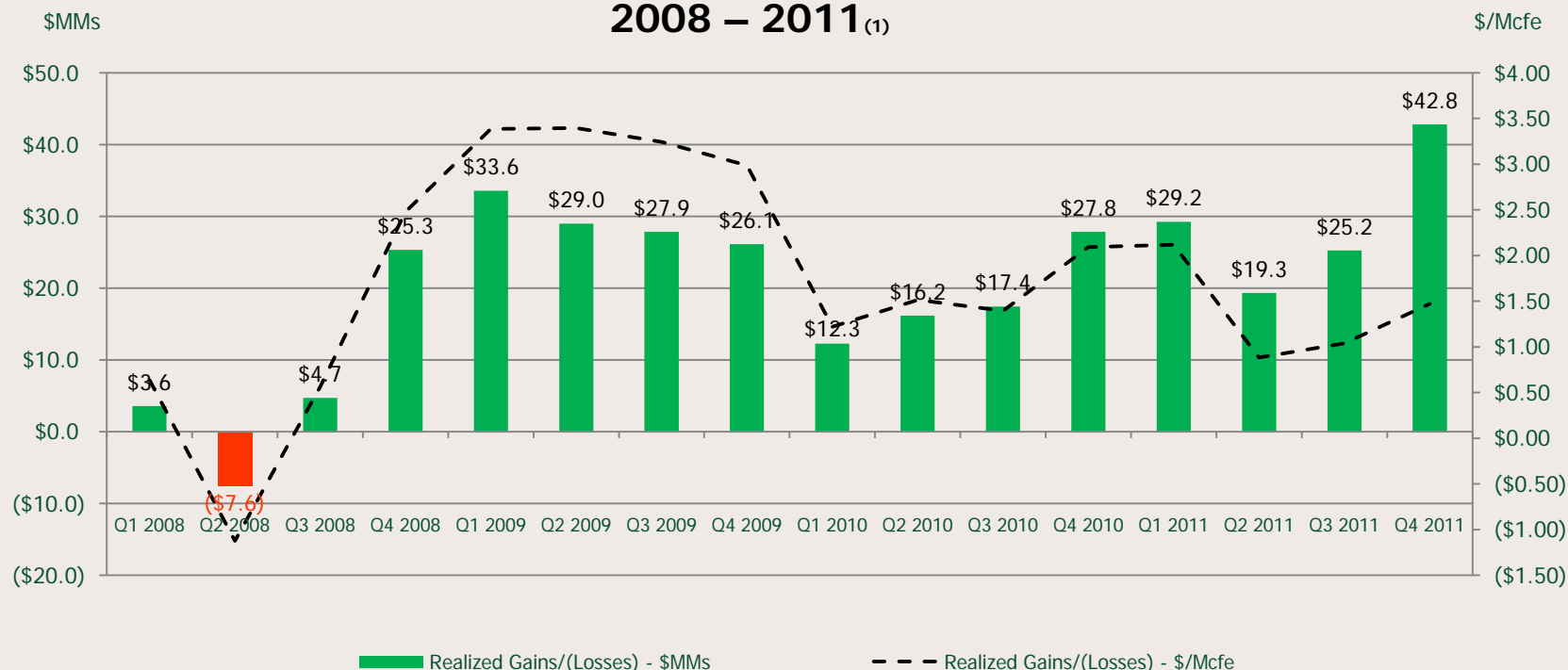
Sources/Uses

\$ millions	Marcellus midstream sale
	12/31/2011
Sources	
Midstream sale	\$375
Uses	
Repay existing credit facility	\$365
Fees and other	\$4
General corporate purposes	\$6
Total	\$375

Historical Antero Hedging Results

- Antero has realized over \$330 million of gains on commodity hedges over the past four years
 - Gains realized in 15 of last 16 quarters

Quarterly Realized Gains/(Losses)
2008 – 2011⁽¹⁾



Realized Gains/(Losses) - \$MMs

Realized Gains/(Losses) - \$/Mcf

1. YE2011 results are subject to a year-end financial audit (unaudited).

EBITDAX Reconciliation



EBITDAX

	Year Ended	
	12/31/2010	12/31/2011(1)
\$ thousands		
EBITDAX:		
Net income (loss)	228,628	392,678
Unrealized loss (gain) on commodity derivative contracts	(170,571)	(559,596)
Gain on sale of Oklahoma midstream assets	(147,559)	
Interest expense and other	59,140	74,498
Provision (benefit) for income taxes	30,009	230,452
Depreciation, depletion, amortization and accretion	134,272	170,956
Impairment of unproved properties	35,859	11,051
Exploration expense	24,794	9,876
Stock compensation expense		
Franchise taxes included in general and administrative expenses	562	2,206
Expenses related to acquisition of business	2,544	
Non-controlling interest in Centrahoma		
Loss on compressor station sale		8,700
EBITDAX	197,678	340,821

1. YE 2011 results are subject to a year-end financial audit (unaudited).