First Quarter 2015 Conference Call

May 6, 2015

Forward Looking Statements

Statements in this presentation that are not historical facts are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. For example, we make statements about significant potential opportunities for our business; future earnings; resource potential; cash flow and liquidity; capital expenditures; reserve and production growth; potential drilling locations; plans for our operations, including drilling, fracture stimulation activities, and the completion of wells; and potential markets for our oil, NGLs, and gas, among other things, that are forward looking and anticipatory in nature. These statements are based on management's experience and perception of historical trends, current conditions, and anticipated future developments, as well as other factors believed to be appropriate. We believe these statements and the assumptions and estimates contained in this presentation are reasonable based on information that is currently available to us. However, management's assumptions and the company's future performance are subject to a wide range of business risks and uncertainties, both known and unknown, and we cannot assure that the company can or will meet the goals, expectations, and projections included in this presentation. Any number of factors could cause our actual results to be materially different from those expressed or implied in our forward looking statements, including (without limitation): economic conditions in the United States and globally; domestic and global demand for oil and natural gas; volatility in oil, gas, and natural gas liquids pricing; new or changing government regulations, including those relating to environmental matters, permitting, or other aspects of our operations; the geologic quality of the company's properties with regard to, among other things, the existence of hydrocarbons in economic quantities; uncertainties inherent in the estimates of our oil and natural gas reserves; our ability to increase oil and natural gas production and income through exploration and development; drilling and operating risks; the success of our drilling techniques in both conventional and unconventional reservoirs; the success of the secondary and tertiary recovery methods we utilize or plan to employ in the future; the number of potential well locations to be drilled, the cost to drill them, and the time frame within which they will be drilled; the ability of contractors to timely and adequately perform their drilling, construction, well stimulation, completion and production services; the availability of equipment, such as drilling rigs, and infrastructure, such as transportation pipelines; the effects of adverse weather or other natural disasters on our operations; competition in the oil and gas industry in general, and specifically in our areas of operations; changes in the company's drilling plans and related budgets; the success of prospect development and property acquisition; the success of our business and financial strategies, and hedging strategies; conditions in the domestic and global capital and credit markets and their effect on us; the adequacy and availability of capital resources, credit, and liquidity including (without limitation) access to additional borrowing capacity; and uncertainties related to the legal and regulatory environment for our industry, and our own legal proceedings and their outcome.

Further information on the risks and uncertainties that may effect our business is available in the company's filings with the Securities and Exchange Commission. We strongly encourage you to review those filings. Rex Energy does not assume or undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Potential Drilling Locations

Our estimates of potential drilling locations are prepared internally by our engineers and management and are based upon a number of assumptions inherent in the estimate process. Management, with the assistance of engineers and other professionals, as necessary, conducts a topographical analysis of our unproved prospective acreage to identify potential well pad locations using operationally approved designs and considering several factors, which may include but are not limited to access roads, terrain, well azimuths, and well pad sizes. For our operations in Pennsylvania, we then calculate the number of horizontal well bores for which the company appears to control sufficient acreage to drill the lateral wells from each potential well pad location to arrive at an estimated number of net potential drilling locations. For our operations in Ohio, we calculate the number of horizontal well bores that may be drilled from the potential well pad and multiply this by the company's net working interest percentage of the proposed unit to arrive at an estimated number of net potential drilling locations. In both cases, we then divide the unproved prospective acreage by the number of net potential drilling locations to arrive at an average well spacing. Management uses these estimates to, among other things, evaluate our acreage holdings and to formulate plans for drilling. Any number of factors could cause the number of wells we actually drill to vary significantly from these estimates, including: the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, lease expirations, regulatory approvals and other factors.

Butler Operated Area Joint Venture

Key Business Terms	Description
Total Wells	32
Total Consideration	$67 million; $16.6 million received at closing
16 Butler Legacy Wells	ArcLight = 35% WI
16 Moraine East Wells	ArcLight = 35% WI
ArcLight Reversion WI	½ of the original WI

Highlights of JV Structure

- Reduces 2015 capital expenditures by $60 million, or 30%, while retaining >25% 2015 production growth
- Strong acreage valuation
- Rex retains 100% of all future locations
- Acreage can be held with less capital
- Geologic risk shared with partner
- Lower cost of capital than equity
- Accretive to future F&D
- Residual value of reversionary interest at PV-10 strip pricing is ~$500K / well[1]

	Moraine East	PUD Offset[2]	Total
Reserves Added	8.8 Bcfe	11.9 Bcfe	20.7 Bcfe
Capital Cost	$3.7 MM	N/A	$3.7 MM
		F&D =	~$0.18/mcfe

[1]Assumes NYMEX Strip pricing as of March 2, 2015, with gas differential of $0.80 per MMBtu.
[2]Assumes one PUD booked per producing lateral in Moraine East Area.

Upcoming Divestitures & Joint Ventures

Current / In Process Asset Divestitures & JV's

Butler Operated Area JV

- Closed on March 30, 2015
- $16.6 million received at closing – initial contract value of $67.6 million with option for JV partner to participate as 20% working interest partner in additional 17 wells in 2016 with value of $21.4 million

Keystone Clearwater Divestiture

- Investment bank engaged to market transaction
- Expect to close transaction by June 30, 2015
- Proceeds estimated to bring in $60 - $80 million

Illinois Basin

- Engaged Evercore as an advisor to explore monetization
- 100% crude oil asset
- Average net production of ~2,000 bbls/d

Moraine East JV

- Continue to explore potential long-term partner in Moraine East to develop liquids-rich locations

Potential / Possible Asset Divestitures

Appalachia Non-Op

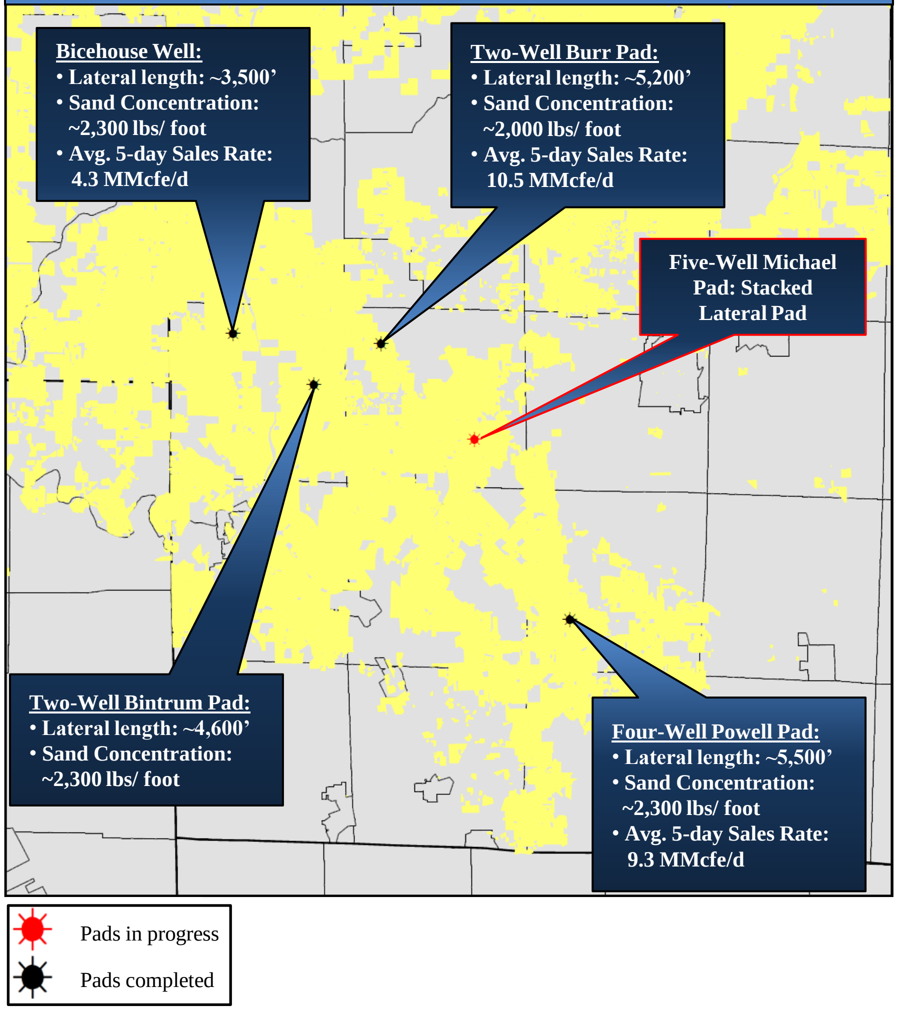
- WPX (current operator) is currently marketing 100% of the assets
- Includes midstream and upstream assets

Ohio Utica Warrior South

- Net average daily production of 3,860 boe/d
- Acreage located in Guernsey, Noble and Belmont counties in Ohio

Legacy Butler Operated Area: Marcellus

Legacy Butler Operated Area – Marcellus[1]



Recent Developments

- Placed into sales nine wells during the first quarter of 2015
  - Average lateral length of 4,900 feet
  - Combination of increased lateral lengths and 25% increase in sand concentrations used during completions expected to yield increased IP rates and improved performance to type curves
  - Two wells placed into sales in early 2Q15
- Reduced cost to drill and complete wells by approximately 5% to $5.7 million per well, assuming a 5,000 foot lateral, as compared to previously reported $6.0 million per well
  - Attributable to operational efficiencies and improved pricing from service providers
  - Expect to achieve an additional 3% - 5% of cost reductions by mid-year 2015

Acreage & Inventory

Total Net Acres	~62,600
Average Working Interest	~70%
Gross / Net Identified Potential Drilling Locations[2]	319 / 223
Current Well Spacing (Lateral Feet)	650'

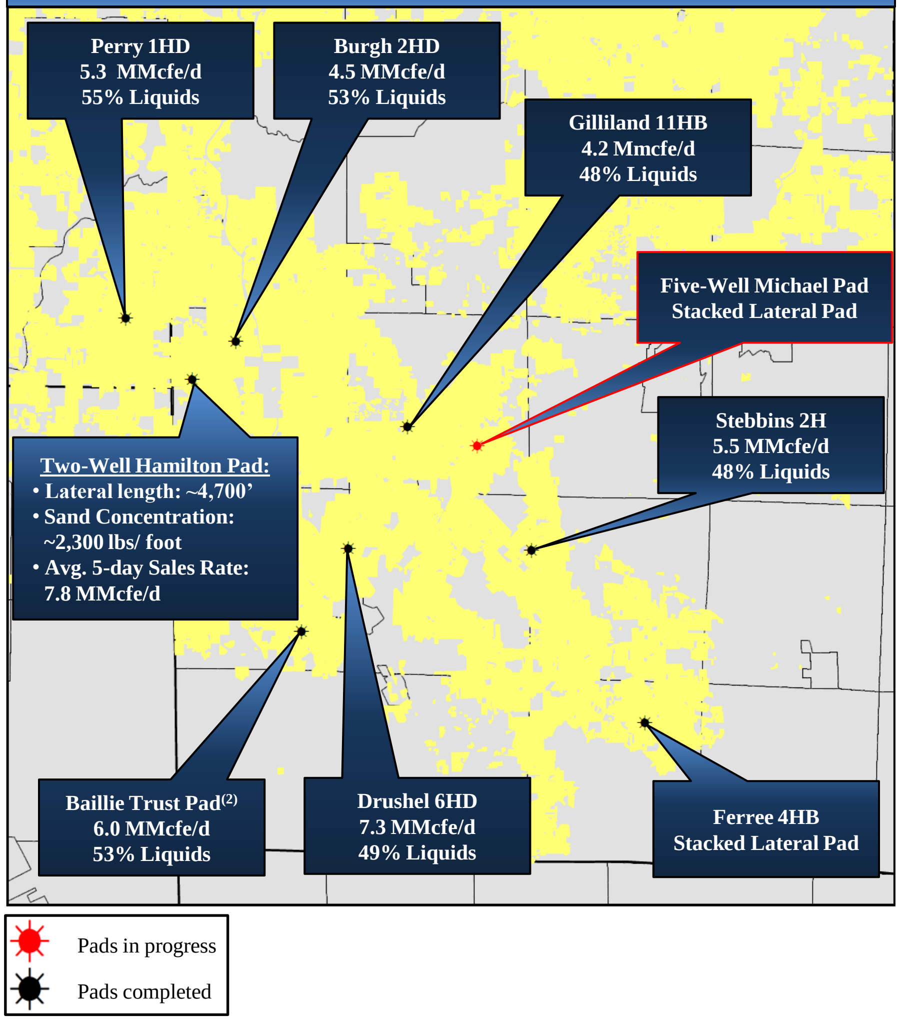
2015 Drilling Plan

Rigs	1 (w/ Upper Devonian & Moraine East)
Wells Drilled	10
Wells Completed	17

(1) All production results are on a per well basis
(2) See note on Potential Drilling Locations on page 3

Legacy Butler Operated Area: Upper Devonian

Legacy Butler Operated Area – Upper Devonian[(1)]



Recent Developments

- Placed into sales the five-well Ferree pad - second planned stacked Upper Devonian Burkett/Marcellus pad
  - Preliminary analysis indicates no communication between the Upper Devonian Burkett formation and Marcellus formation
- Third planned test – Five-well Michael pad, testing multiple stacked Upper Devonian Burkett/Marcellus laterals
- Hamilton well results on par with Marcellus results

Acreage & Inventory

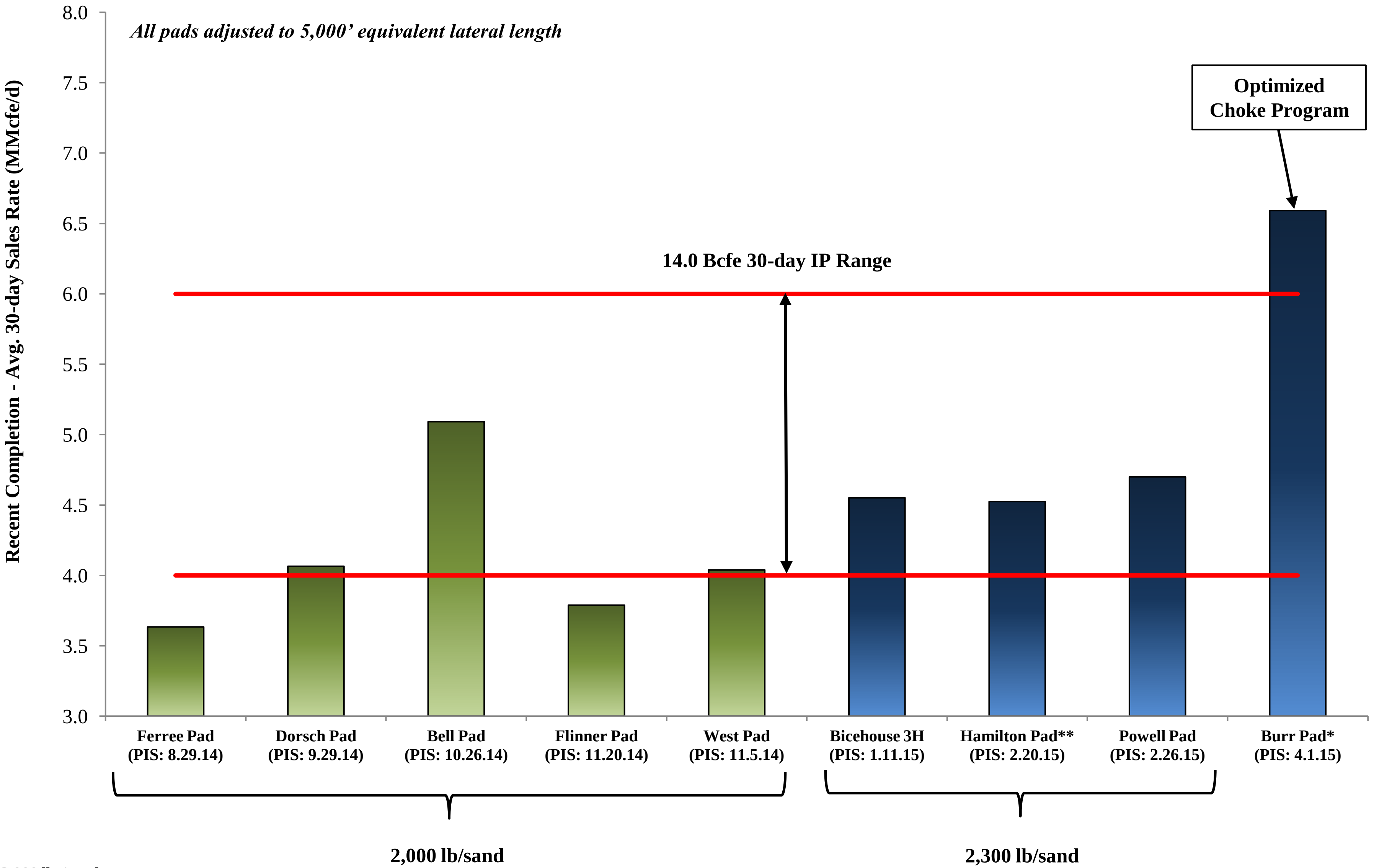
Total Net Acres	~62,600
Average Working Interest	~70%
Gross / Net Identified Potential Drilling Locations[(3)]	486 / 340
Current Well Spacing (Lateral Feet)	650'

2015 Drilling Plan

Rigs	1 (w/ Marcellus & Moraine East)
Wells Drilled	0
Wells Completed	2

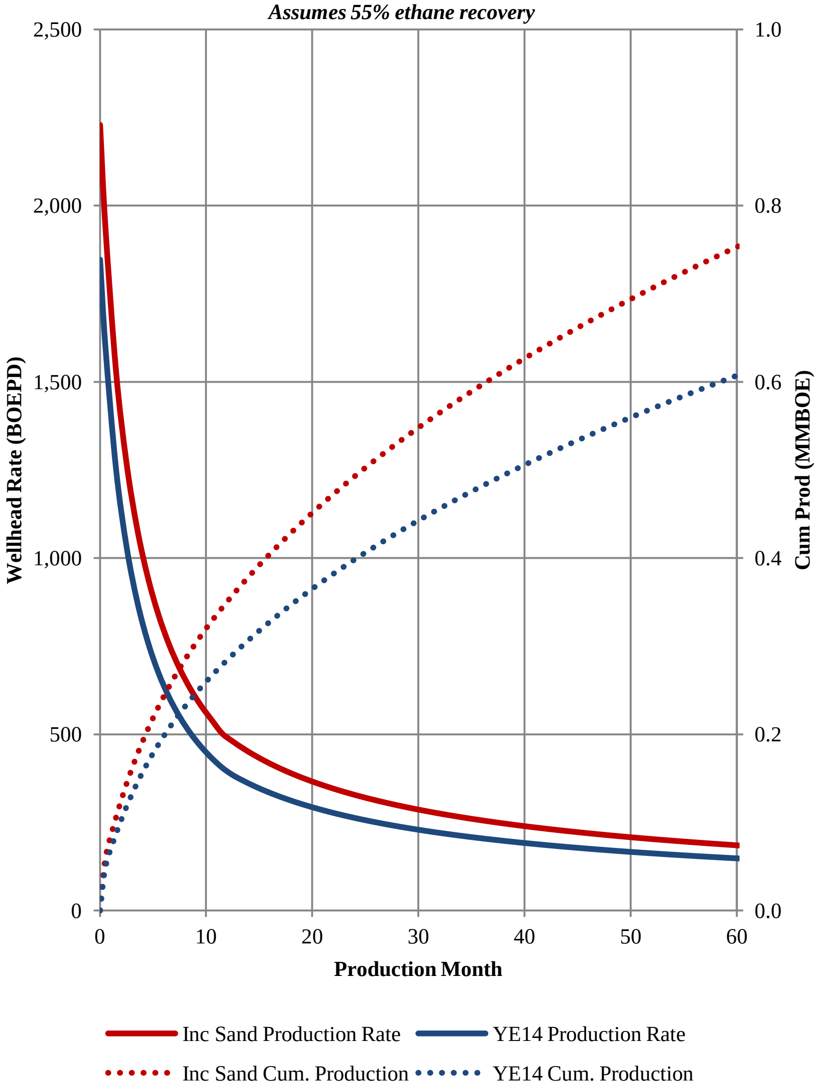
(1) All production results are on a per well basis
(2) Results include wells targeting both Marcellus and Upper Devonian
(3) See note on Potential Drilling Locations on page 3

Recent Marcellus Performance on High Sand Concentration Pads



* 2,000 lbs/sand
** Upper Devonian Burkett pad

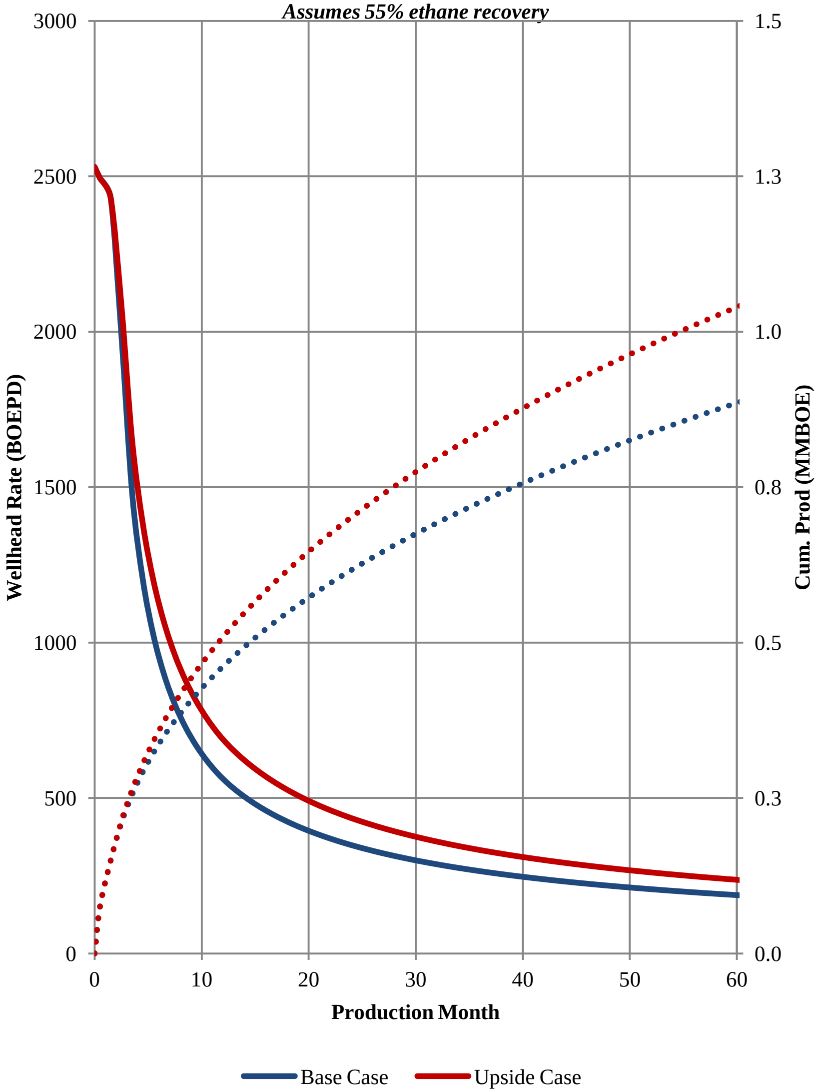
Warrior North Prospect Economics[1]



		YE14 Type Curve	Increased Sand Concentration
All-in Well Cost		$6.8 million	$7.4 million
Lateral Length		5,000 feet	6,500 feet
EUR		1.2 MMBOE	1.4 MMBOE
F&D Cost		$5.67/BOE	$5.29/BOE
IRR[(2),(3)]	$3.25 NYMEX $65.00 WTI	13%	25%
	$3.50 NYMEX $70.00 WTI	21%	36%
	$3.50 NYMEX $80.00 WTI	33%	57%
	Strip Pricing[(4)]	13%	21%
Avg. 30-day sales rate (MBOE/d)		1.2 – 1.4	1.8 – 1.9

(1) See note on Hydrocarbon Volumes and disclaimers at beginning of presentation.
(2) Basis price for C3+ NGLs is 50% of WTI Oil. Basis price for C2 is $0.24/gal in all cases.
(3) Historical price differentials applied to Condensate and C2+ NGL volumes. Gas price differential held at minus $0.80 per MMBtu, flat for life in all cases except strip cases, where the futures differential are applied.
(4) Strip pricing as of 2/9/2015

Warrior South Prospect Economics[1]



		YE14 Type Curve	Increased Sand Concentration
All-in Well Cost		$8.0 million	$8.0 million
Lateral Length		5,000 feet	5,000 feet
EUR		1.6 MMBOE	1.9 MMBOE
F&D Cost		$5.00/BOE	$4.21/BOE
IRR[(2),(3)]	$3.25 NYMEX $65.00 WTI	14%	23%
	$3.50 NYMEX $70.00 WTI	21%	33%
	$3.50 NYMEX $80.00 WTI	30%	44%
	Strip Pricing[(4)]	13%	21%
Avg. 30-day sales rate (MBOE/d)		2.0 – 2.7	2.0 – 2.7

(1) See note on Hydrocarbon Volumes at beginning of presentation.
(2) Basis price for C3+ NGLs is 50% of WTI Oil. Basis price for C2 is $0.24/gal in all cases.
(3) Historical price differentials applied to all volumes, flat for life in all cases except strip cases, where the futures differential are applied.
(4) Strip pricing as of 2/9/2015

QUESTION AND ANSWER