UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of Earliest Event Reported) March 21, 2016

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas	**001-35410**	**27-4662601**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

5400 LBJ Freeway, Suite 1500, Dallas, Texas	**75240**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (972) 371-5200

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

Matador Resources Company expects to make presentations concerning its business to potential investors. The materials to be utilized during the presentations are furnished as Exhibit 99.1 hereto and incorporated herein by reference.

The information furnished pursuant to this Item 7.01, including Exhibit 99.1, shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

MATADOR RESOURCES COMPANY

Date: March 21, 2016	By:	/s/ Craig N. Adams
	Name:	Craig N. Adams
	Title:	Executive Vice President

Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.

Exhibit 99.1

Investor Presentation

March 2016 **NYSE: MTDR**

Disclosure Statements

Safe Harbor Statement – This presentation and statements made by representatives of Matador Resources Company ("Matador" or the "Company") during the course of this presentation include "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. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project," "hypothetical," "forecasted," and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements, and such forward-looking statements may not prove to be accurate. These forward-looking statements involve certain risks and uncertainties, including, but not limited to, the following risks related to Matador's financial and operational performance: general economic conditions; Matador's ability to execute its business plan, including whether Matador's drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; Matador's ability to replace reserves and efficiently develop its current reserves; Matador's costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; Matador's ability to integrate acquisitions, including the merger with Harvey E. Yates Company; Matador's ability to make other acquisitions on economically acceptable terms; availability of sufficient capital to execute Matador's business plan, including from its future cash flows, increases in Matador's borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.

Cautionary Note – The Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. Potential resources are not proved, probable or possible reserves. The SEC's guidelines prohibit Matador from including such information in filings with the SEC.

Definitions – Proved oil and natural gas reserves are the estimated quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Matador's production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where Matador produces liquids-rich natural gas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. Estimated ultimate recovery (EUR) is a measure that by its nature is more speculative than estimates of proved reserves prepared in accordance with SEC definitions and guidelines and is accordingly less certain. Type curves shown in this presentation are used to compare actual well performance to a range of potential production results calculated without regard to economic conditions; actual recoveries may vary from these type curves based on individual well performance and economic conditions.

Company Summary

Matador History

Predecessor Entities

Foran Oil & Matador Petroleum

- Founded by Joe Foran in 1983 – most participants are still shareholders today
- Foran Oil funded with $270,000 in contributed capital from 17 friends and family members; evolved into Matador Petroleum Corporation
- Sold Matador Petroleum Corporation to Tom Brown, Inc.(1) in June 2003 for an enterprise value of $388 million in an all-cash transaction

Matador Today

Matador Resources Company Timeline

Matador has grown almost entirely through the drill bit, with a focus on unconventional reservoir plays

Pre – IPO

2003 | 2008 | 2009 | 2010 | 2011 | 2012

2003
Founded by Joe Foran with $6 million, a proven management and technical team and board of directors

2008
Sold Haynesville rights in ~9,000 net acres to CHK for ~$180 million; retained 25% participation interest, carried working interest and overriding royalty interest

2010-2011
Redeployed capital into the Eagle Ford early in the play, acquiring over 30,000 net acres for ~$100 million

2012, 2013 and 2014 capital spending focused primarily on developing Eagle Ford and transitioning to oil

Assembling Permian acreage position; begin delineation drilling program

Post – IPO

2012 | 2013 | 2014 | 2015 | 2016

February 2012
IPO at $12.00; net cash proceeds of ~$136 million

September 2013
Follow-on Offering at $15.25; net cash proceeds of ~$142 million

May 2014
Follow-on Offering at $25.00; net cash proceeds of ~$181 million

February 2015
HEYCO Combination

April 2015
Inaugural High-Yield Offering of $400 million;
Follow-on Offering at ~$27.00; net cash proceeds of ~$187 million

October 2015
Sale of certain Loving County midstream assets for ~$143 million(2)

March 2016
Follow-on Offering at ~$19.00; net cash proceeds of ~$142 million

(1) Tom Brown acquired by Encana in 2004.
(2) Excluding customary purchase price adjustments.

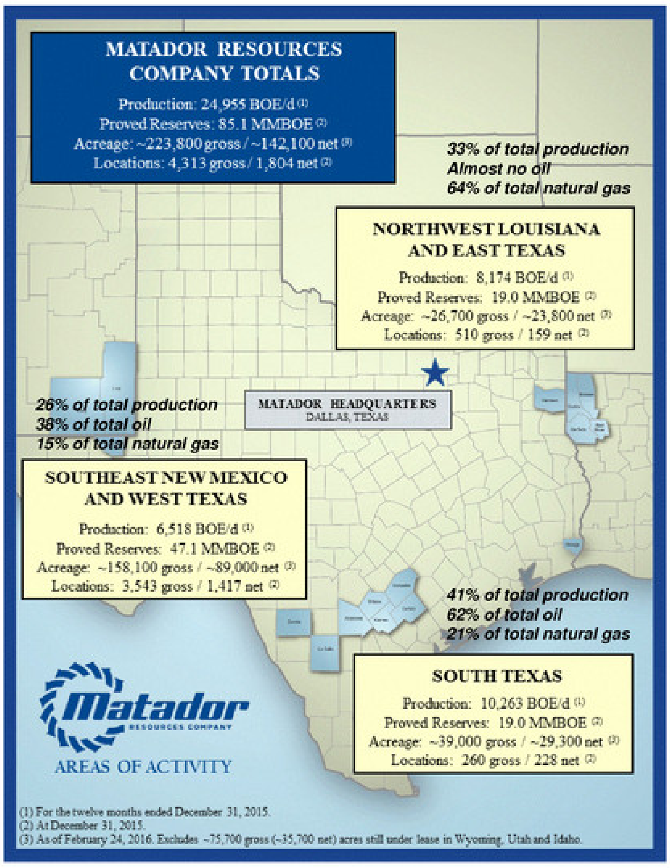
Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	93.3 million common shares
Share Price(1)	$20.43/share
Market Capitalization(1)	~$1.9 billion

	Actual 2014 Results	*Actual 2015 Results*	*2016 Guidance*	*% YoY Change*
Capital Spending	$610 million	$482 million(2)	$325 million	- 33%
Total Oil Production	3.3 million Bbl	4.5 million Bbl	4.9 to 5.1 million Bbl	+ 11%
Total Natural Gas Production	15.3 Bcf	27.7 Bcf	26.0 to 28.0 Bcf	- 3%
Total Oil Equivalent Production	5.9 million BOE	9.1 million BOE	9.2 to 9.8 million BOE	+ 4%
Adjusted EBITDA(3)	$263 million	$223 million	$120 to $130 million(4)	- 44%

(1) Market capitalization based on closing share price as of March 17, 2016 and shares outstanding as reported in the Form 10-K at February 25, 2016 plus 7.5 million shares issued in March 2016 equity offering.
(2) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(4) Estimated 2016 Adjusted EBITDA is based upon the midpoint of 2016 production guidance range as provided on February 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $34.00/Bbl (WTI oil price of $37.00/Bbl less $3.00/Bbl of estimated price differentials) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional price differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.

Matador Resources Company – Operations Overview



Market Capitalization(1)	**~$1.9 billion**	
Avg Daily Production – YE 2015(2)	**24,955 BOE/d**	↑ 55%*
Oil (% total)	12,306 Bbl/d (49%)	
Natural Gas (% total)	75.9 MMcf/d (51%)	
Proved Reserves @ 12/31/2015	**85.1 million BOE**	↑ 24%*
% Proved Developed	40%	
% Oil	54%	
2016E CapEx(3)	**$325 million**	
% Delaware Basin	~97%	
Gross Acreage(4)	**~223,800 acres**	
Net Acreage(4)	**~142,100 acres**	
Engineered Drilling Locations(5)	**4,313 gross / 1,804 net**	↑ 32%*
Delaware Basin	3,543 gross / 1,417 net	↑ 48%*
Eagle Ford	260 gross / 228 net	
Haynesville/Cotton Valley	519 gross / 159 net	

* Note: Represents increase as compared to each respective figure at or for the year ended December 31, 2014.

(1) Market capitalization based on closing share price as of March 17, 2016 and shares outstanding as reported in the Form 10-K at February 25, 2016 plus 7.5 million shares issued in March 2016 equity offering.

(2) Average daily production for the twelve months ended December 31, 2015.

(3) 2016 estimated capital expenditures, including all anticipated operations, midstream, land and non-operated well expenditures as of February 3, 2016, assuming a 3-rig program in the Delaware Basin in 2016.

(4) As of February 24, 2016. Excludes ~75,700 gross (~35,700 net) acres still under lease in Wyoming, Utah and Idaho.

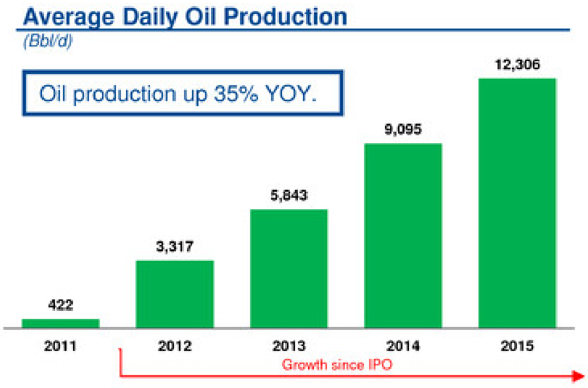
(5) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015, but including no locations at Twin Lakes. Includes all identified locations where Matador has an operated or non-operated working interest.

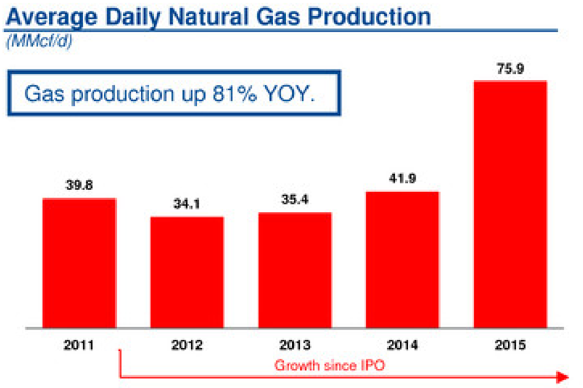
Matador Has Made Tremendous Progress Since its IPO

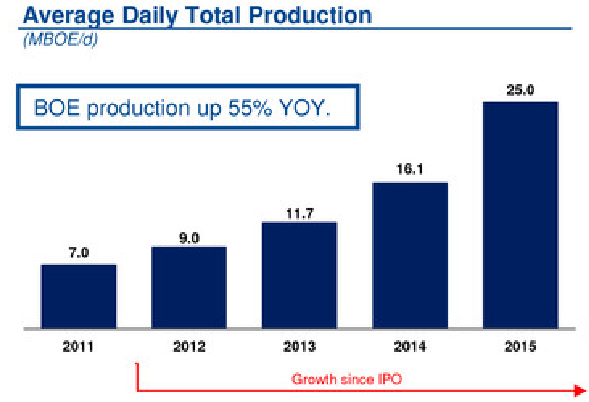
	At IPO(1): February 7, 2012	*Today(2)*	*Difference*
Oil Production	414 Bbl/d (6% oil)	11,547 Bbl/d (49% oil)	↑ +28-fold
Proved Reserves	27 MMBOE (4% oil)	85 MMBOE (54% oil)	↑ +3-fold
Proved Oil Reserves	1.1 MMBbl	45.6 MMBbl	↑ +41-fold
Delaware Acreage	~7,500 net acres	~89,000 net acres(3)	↑ +12-fold
Leverage(4)	1.5x(5)	0.9x(6)	↓ -40%
Share Price	$12.00(7)	$20.43(8)	↑ +70%

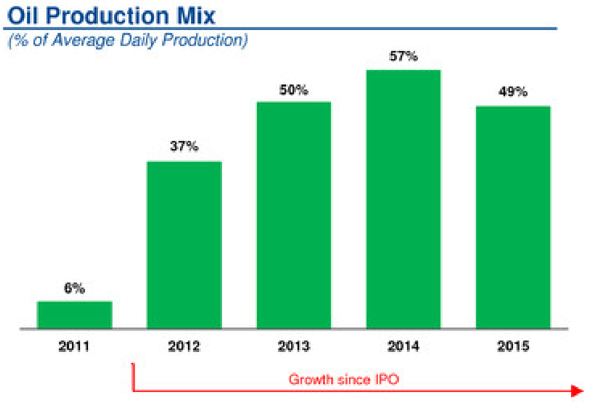
(1) Unless otherwise noted, at or for the nine months ended September 30, 2011.
(2) Unless otherwise noted, at or for the three months ended December 31, 2015.
(3) As of February 24, 2016.
(4) Calculated as net debt divided by LTM Adjusted EBITDA. Net debt is equal to debt outstanding less available cash (including $43 million of restricted cash held in escrow at December 31, 2015). Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(5) At December 31, 2011.
(6) Pro forma at December 31, 2015 after giving effect to the March 2016 equity offering.
(7) As of February 7, 2012 at time of IPO.
(8) Closing share price as of March 17, 2016.

Record Oil, Natural Gas and Total Production in 2015

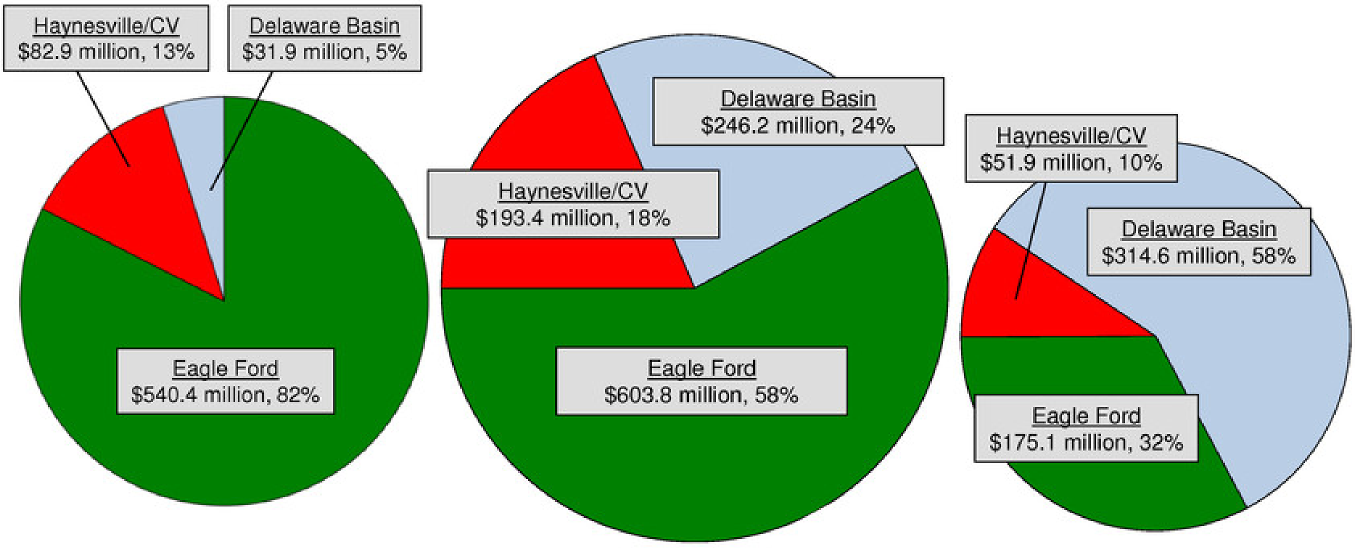








Matador's Proved Reserves and PV-10(1): 2013 – 2015

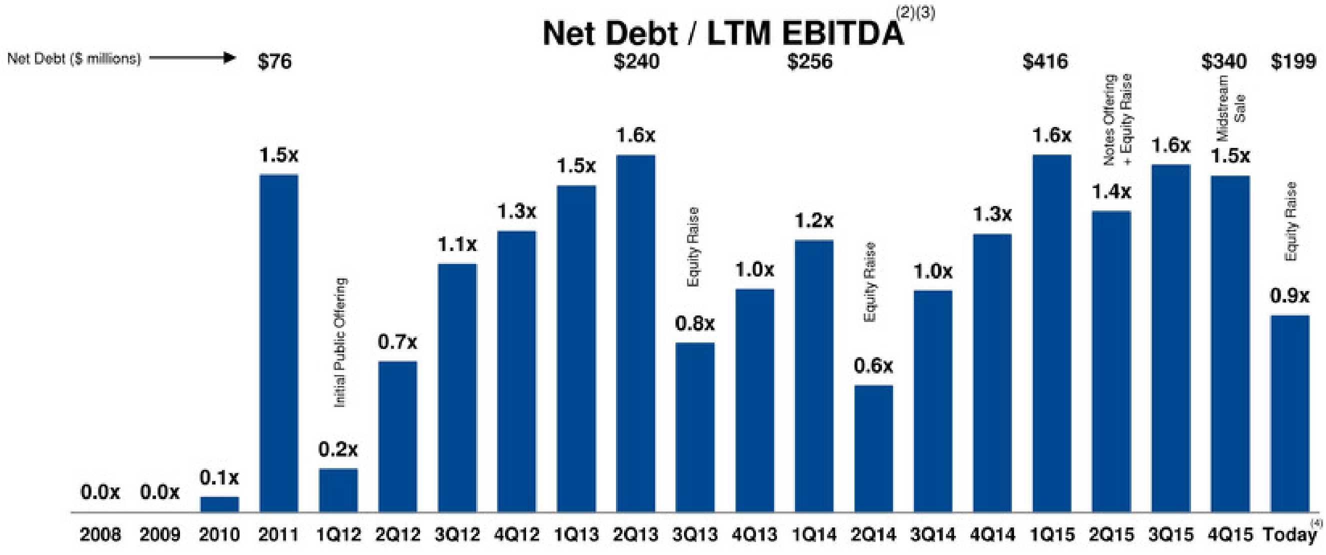


YE 2013	YE 2014	YE 2015
51.7 million BOE	68.7 million BOE	85.1 million BOE (24% up)
16.4 million Bbl oil (32% oil)	24.2 million Bbl oil (35% oil)	45.6 million Bbl oil (54% oil) (89% up)
PV-10(1): $655.2 million	PV-10(1): $1,043.4 million	PV-10(1): $541.6 million (48% down)
$93.42 oil / $3.67 gas	$91.48 oil / $4.35 gas	$46.79 oil (49% down) / $2.59 gas (40% down)

Note: Oil and natural gas prices noted are in $/Bbl and $/MMBtu, respectively. Prices reflect the arithmetic average of first-day-of-month oil and natural gas prices for the 12-month periods January 1 to December 31, 2013, 2014 and 2015, respectively, as per SEC guidelines for reserves estimation.
(1) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.

Committed to Maintaining Strong Balance Sheet

- Preserved and enhanced liquidity through April 2015 equity and Senior Notes offerings, sale of certain Loving County midstream assets for ~$143 million[1] in October 2015 and May 2016 equity offering
- Substantial liquidity to execute planned drilling program throughout 2016, including proceeds from March 2016 equity offering of ~$142 million and $375 million in undrawn borrowing capacity at March 11, 2016
- Strong financial position with pro forma YE 2015 Net Debt/LTM Adjusted EBITDA[2][3][4] of ~0.9x, well below peer average

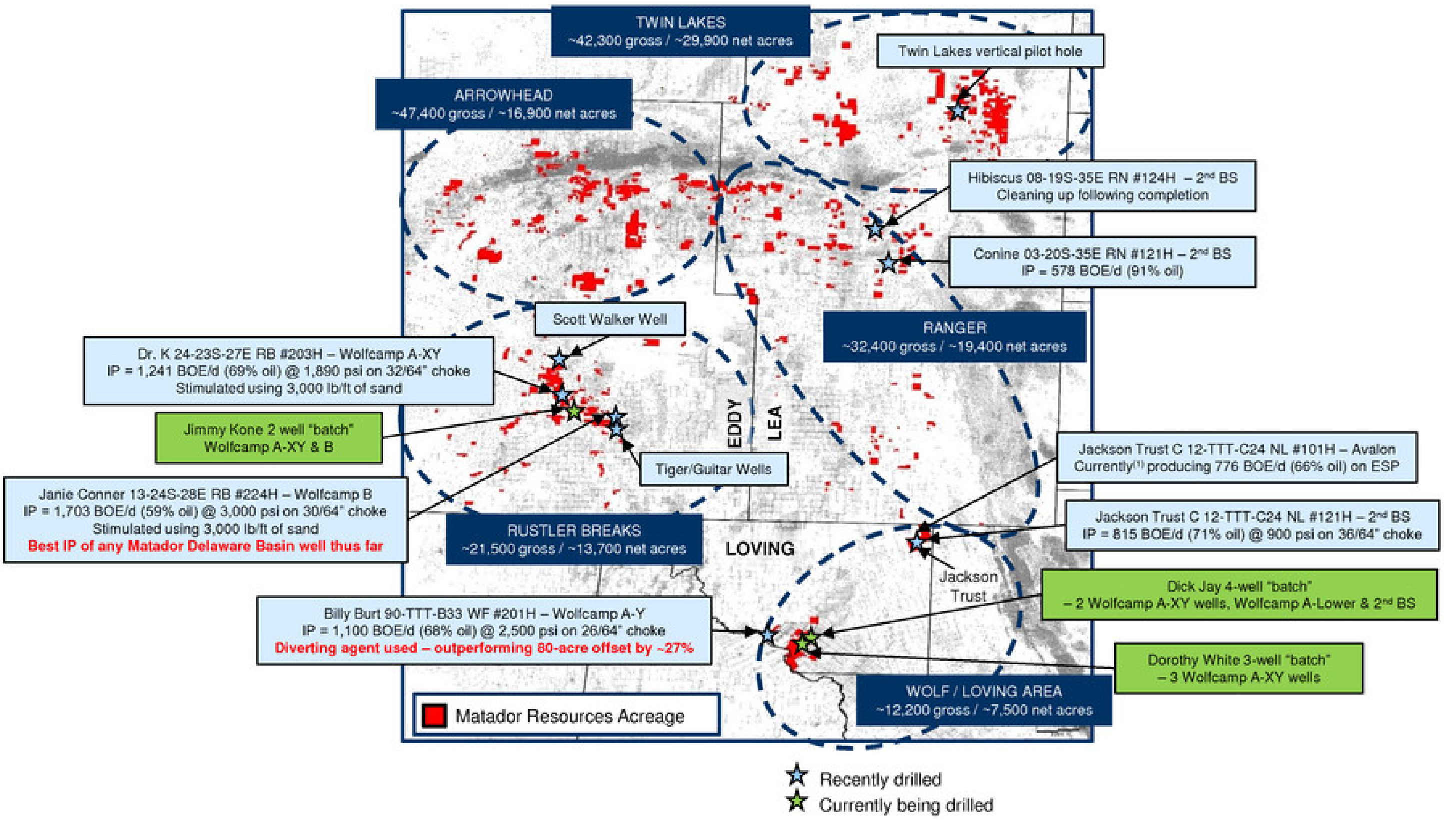


(1) Excluding customary purchase price adjustments.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Net Debt is equal to debt outstanding less available cash (including $43 million of restricted cash held in escrow at December 31, 2015).
(4) LTM EBITDA at December 31, 2015 and Net Debt pro forma at December 31, 2015 after giving effect to the March 2016 equity offering.

Delaware Basin

Southeast New Mexico and West Texas

Delaware Basin Acreage Position and Recent Test Results



Note: All acreage at February 24, 2016. Some tracts not shown on map.
(1) As of late February 2016.

Understanding the Opportunities

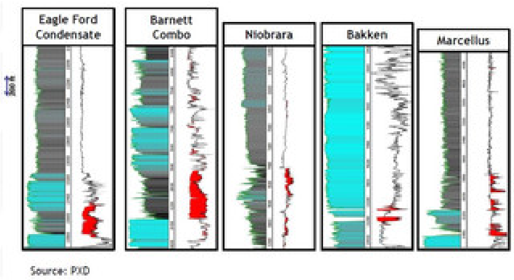
Most current unconventional plays target one or two zones across a trend area.

The Delaware Basin has over a dozen unique targets between the top of the Brushy Canyon and the Woodford.

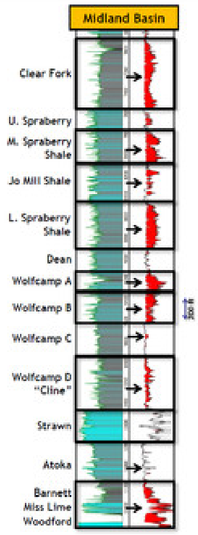
Objective: To drill and complete better wells for less money

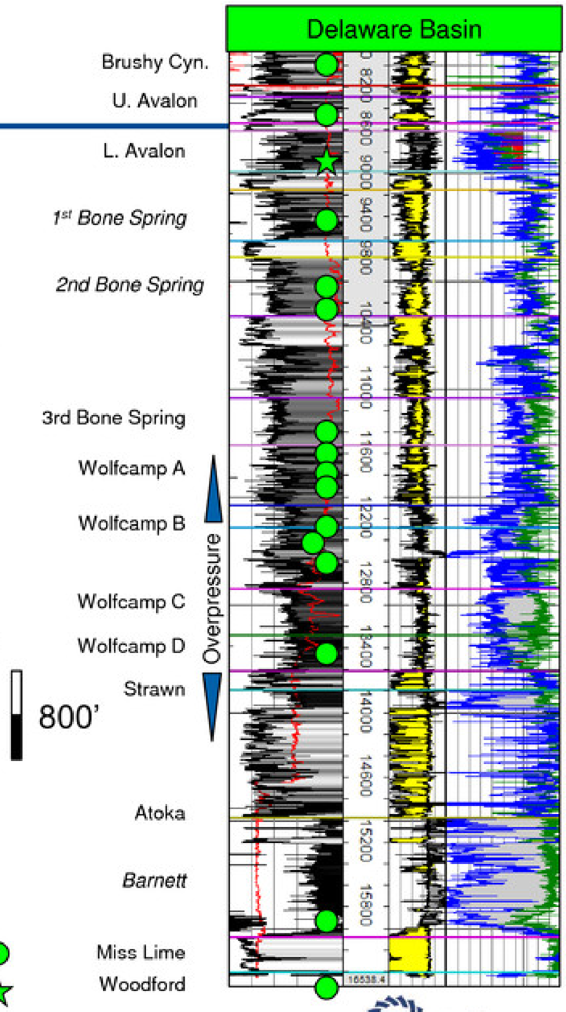
Challenge: To identify the best targets within multiple prospective intervals across a geologically complex basin

Matador's geoscience staff is committed to bringing the best targets forward!



All logs plotted at same scale





Matador Resources Company

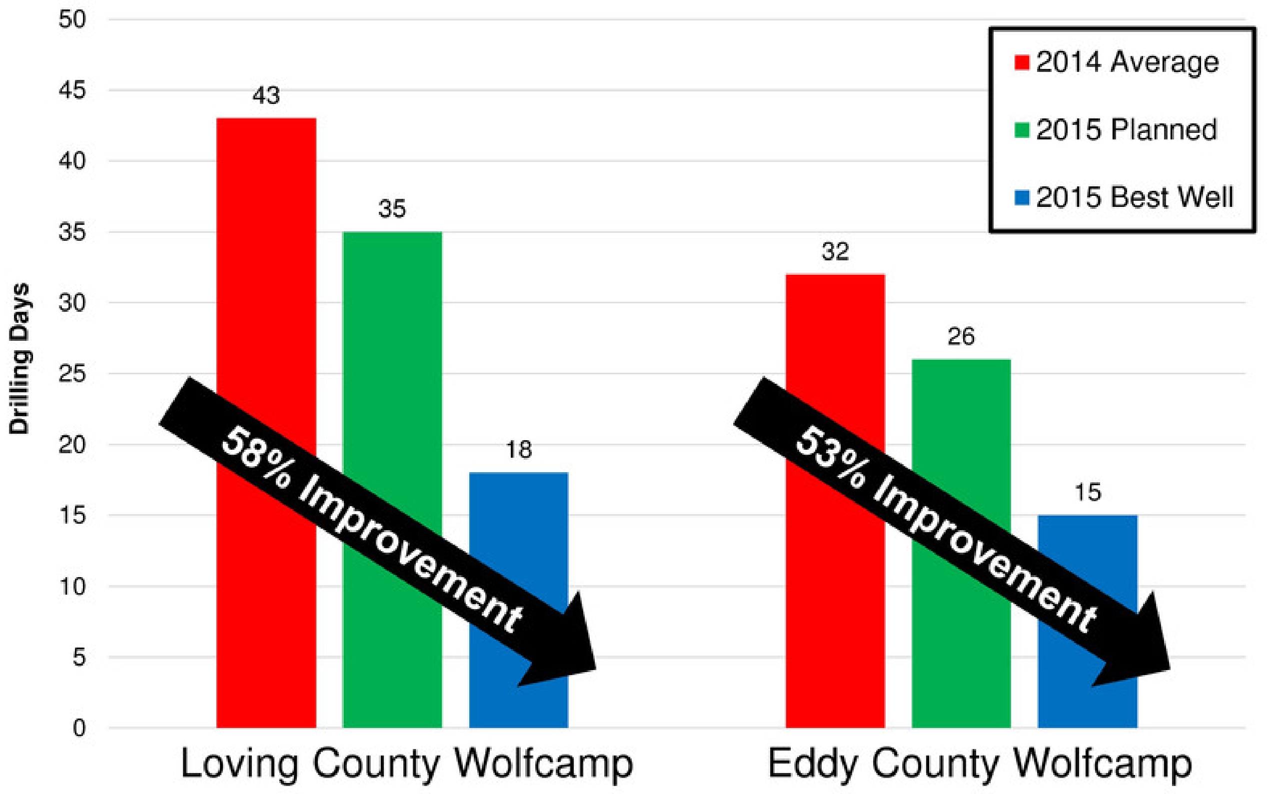
Delaware Basin Inventory Continues to Increase

- Matador has identified up to 3,543 gross (1,417 net) potential locations(1) for future drilling on its Delaware Basin acreage
  - *Only 118 gross (71.1 net) locations are PUD locations at December 31, 2015*
- Matador anticipates operating up to 2,263 gross (1,284 net) of these potential locations(2)
- Inventory does not yet include any locations for Twin Lakes prospect area

	Total Locations Identified(1)(3)		Potential Matador Operated Locations(1)(2)	
Formation	**Gross**	**Net**	**Gross**	**Net**
Delaware Group	276	100	178	90
Avalon	322	144	233	136
1st Bone Spring	556	177	290	152
2nd Bone Spring	657	243	381	215
3rd Bone Spring	489	203	325	186
Wolfcamp A-XY	280	122	187	111
Lower Wolfcamp A	339	164	256	154
Wolfcamp B	275	123	191	113
Wolfcamp D	349	140	222	126
TOTAL	**3,543**	**1,417**	**2,263**	**1,284**

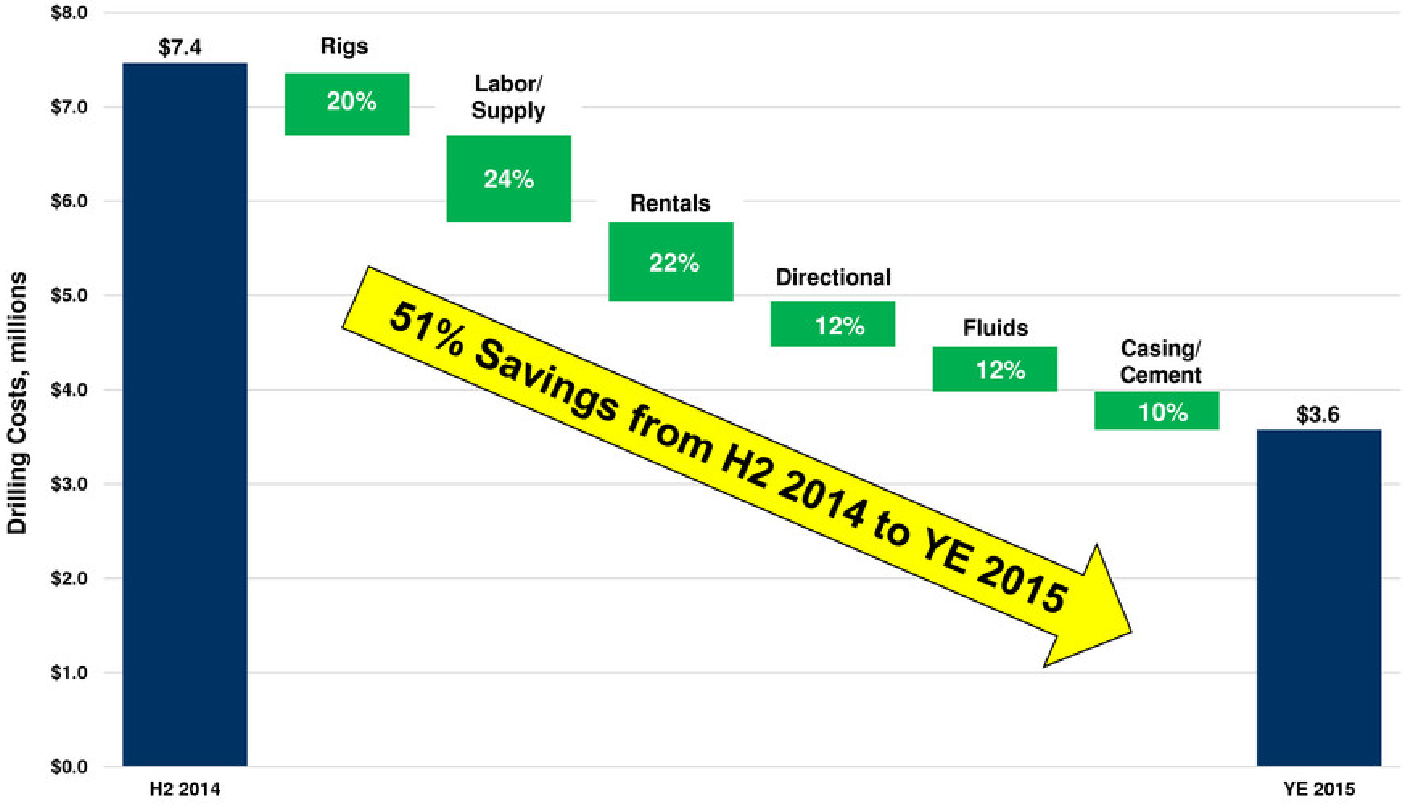
(1) At December 31, 2015.
(2) Includes any identified locations in which Matador's working interest is at least 25%.
(3) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015, but including no locations at Twin Lakes. Includes all identified locations where Matador has an operated or non-operated working interest.

Improved Wolfcamp Drilling Times Significantly in 2015

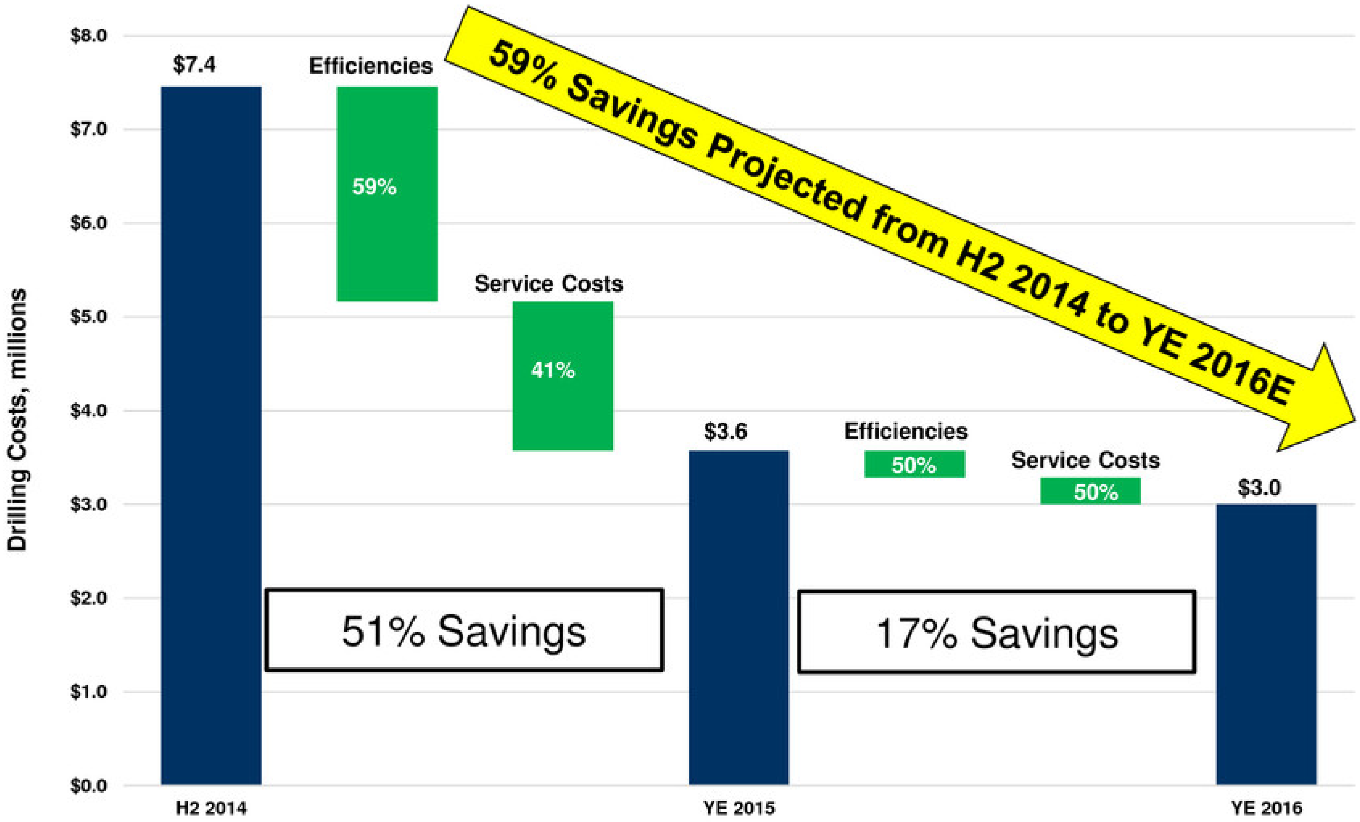


Note: Best wells are Johnson 44-02S-B53 #206H in Loving County (Wolfcamp) and Tiger 14-24S-28E RB #204H in Eddy County (Wolfcamp).

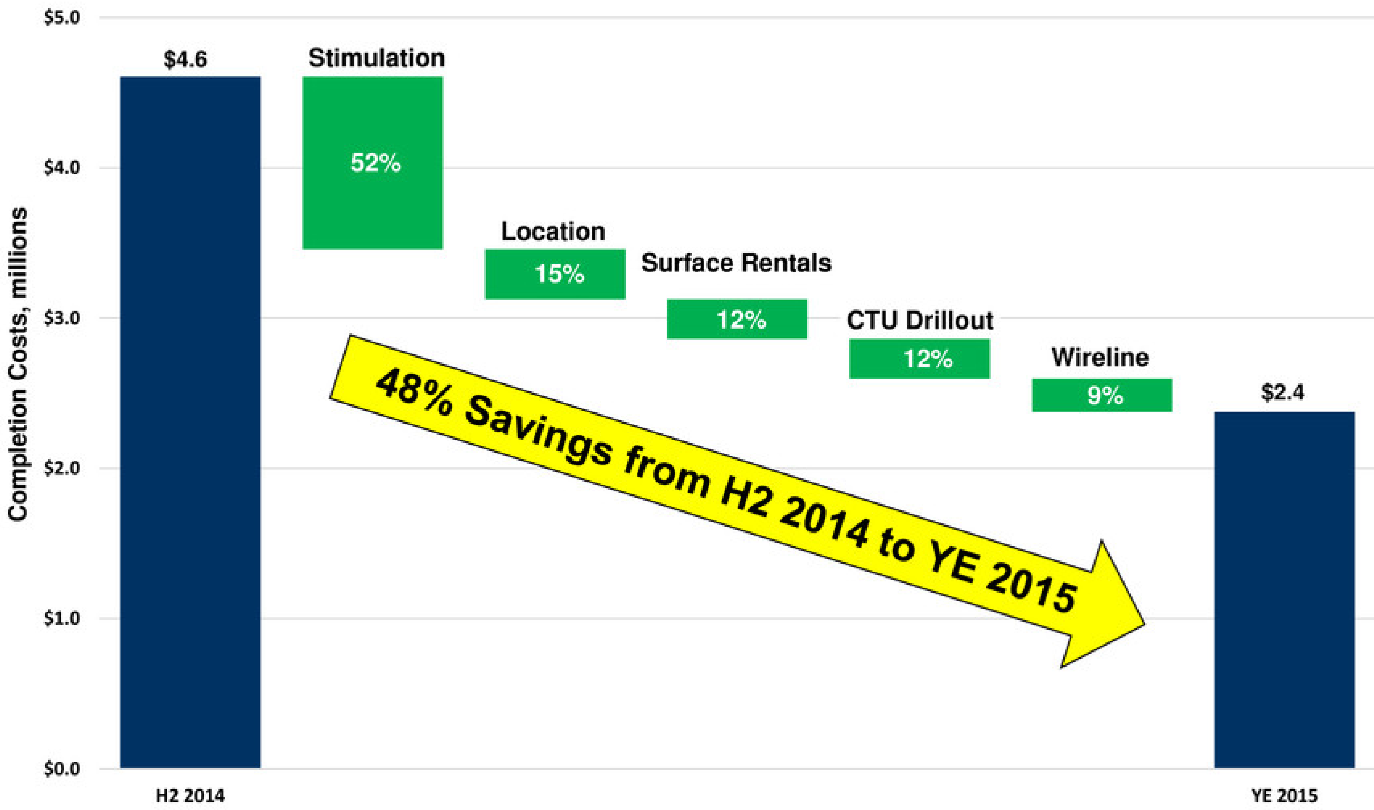
2015 Wolf Area Drilling Cost Improvements



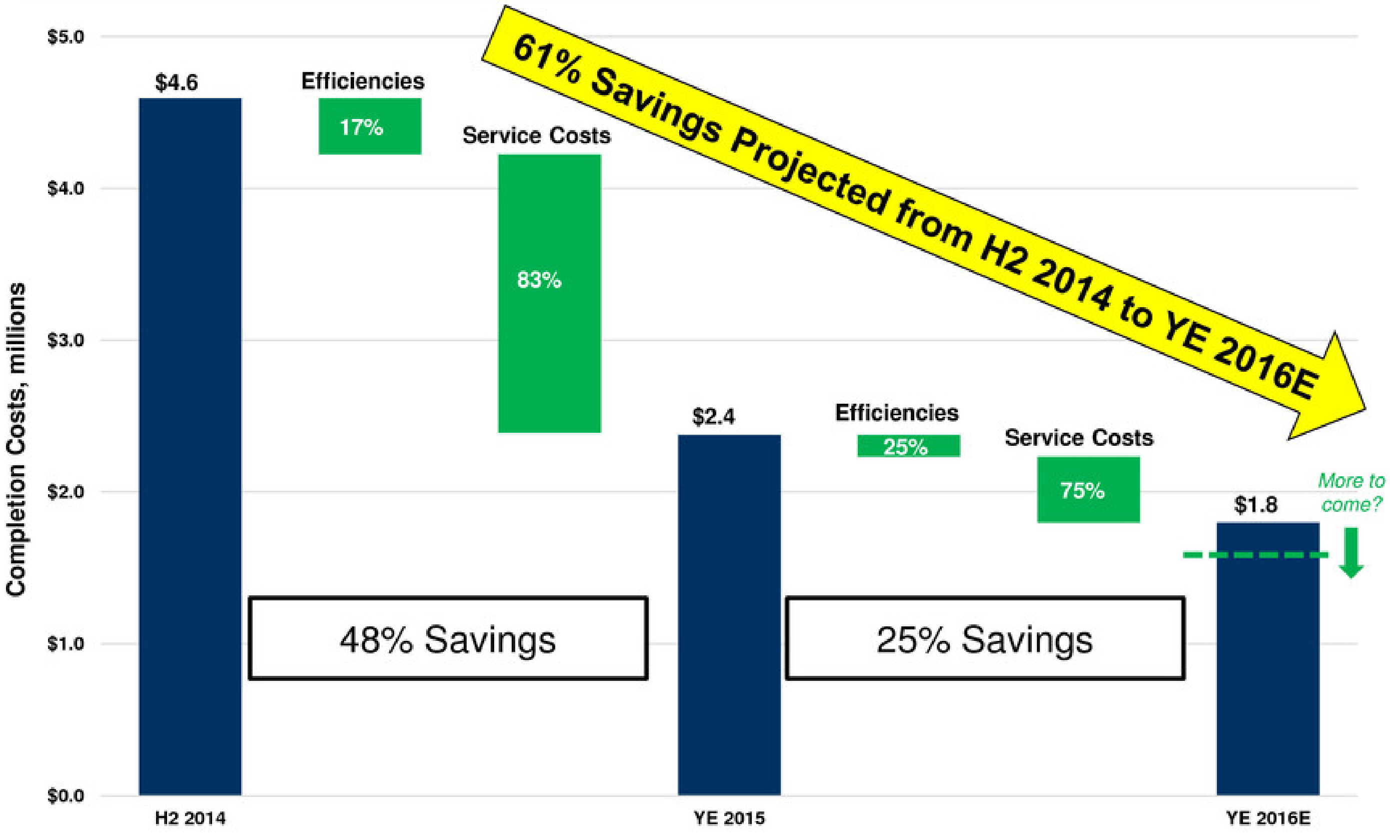
2016 Anticipated Wolf Area Drilling Cost Improvements



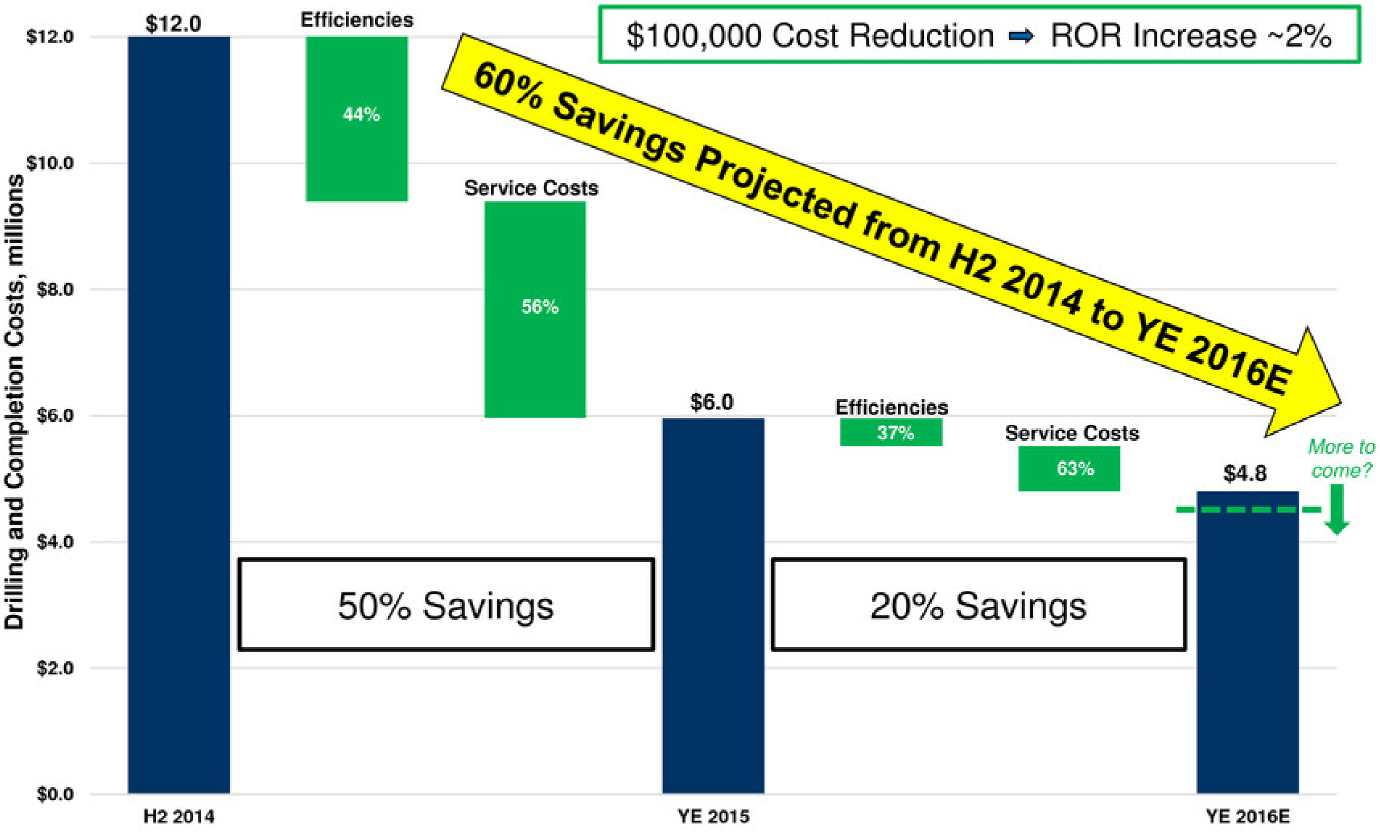
2015 Wolf Area Completion Cost Improvements



2016 Anticipated Wolf Area Completion Cost Improvements

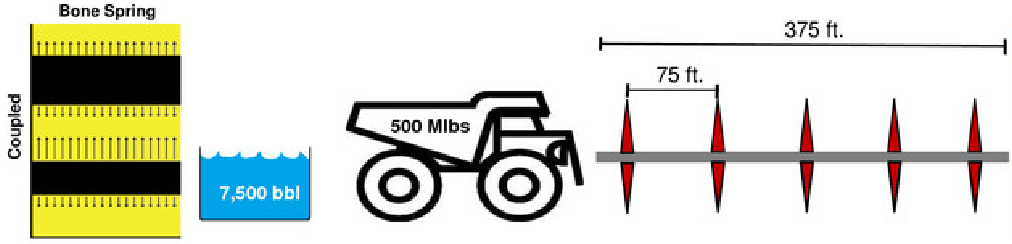


2016 Anticipated Wolf Area Total Drilling and Completion Cost Improvements

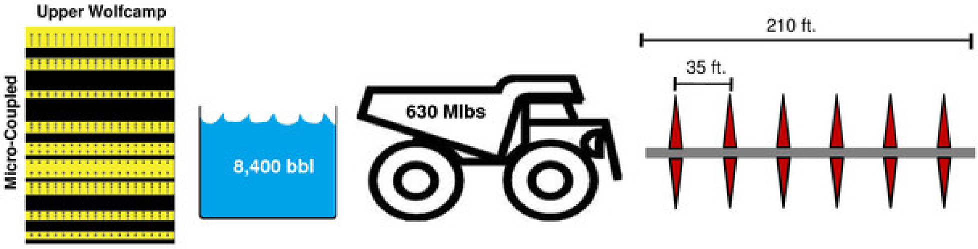


Note: Does not include production and facilities costs.

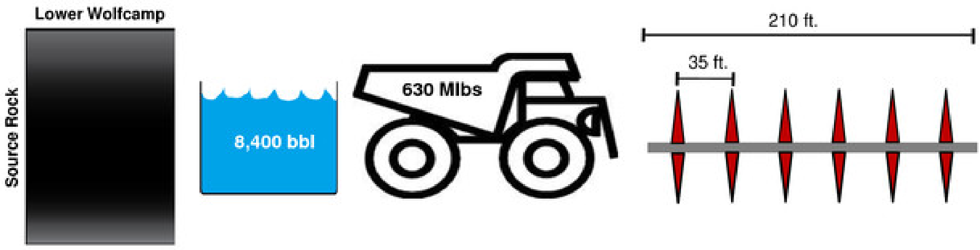
Evolution of Permian Basin Frac Design – Reservoir Specific



Gen 1	Gen 2
2,000 lbs/ft	1,333 lbs/ft
40 Bbl/ft	20 Bbl/ft
50' cluster spacing	75' cluster spacing
4 wells	6 wells

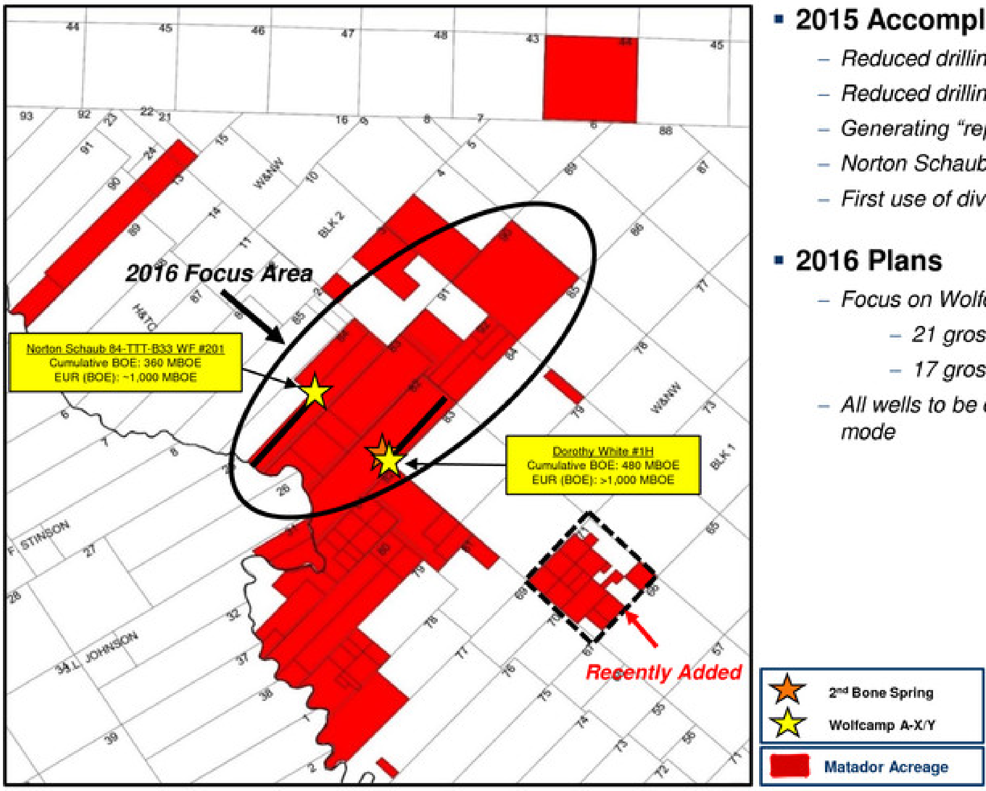


Gen 1	Gen 2	Testing
2,000 lbs/ft	2,000 lbs/ft	3,000 lbs/ft
40 Bbl/ft	30 Bbl/ft	40 Bbl/ft
35' cluster spacing	50' cluster spacing	35' cluster Spacing
10 wells	13 wells	1 well



Gen 1	Testing
2,000 lbs/ft	3,000 lbs/ft
40 Bbl/ft	40 Bbl/ft
35' cluster spacing	35' cluster Spacing
1 well	1 well

Wolf Prospect Area – Continued Focus on Wolfcamp Development in 2016

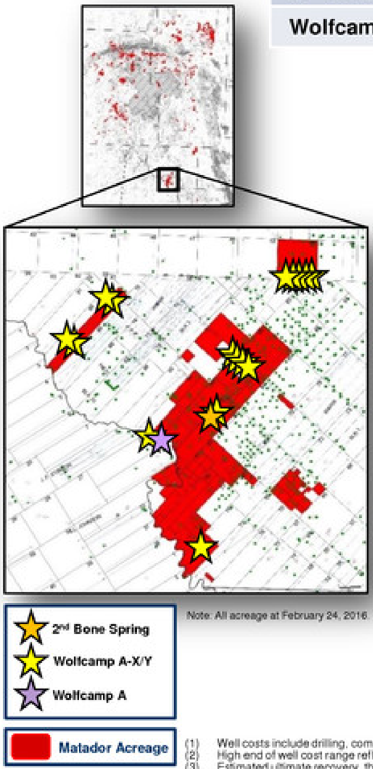


- **2015 Accomplishments**
  - *Reduced drilling times by 58%*
  - *Reduced drilling and completion costs by 50%*
  - *Generating "repeatable" results*
  - *Norton Schaub ESP test a success*
  - *First use of diverting technology encouraging*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *21 gross (18.4 net) wells planned for 2016*
    - *17 gross (15.2 net) wells on production*
  - *All wells to be drilled from multi-well pads in batch mode*

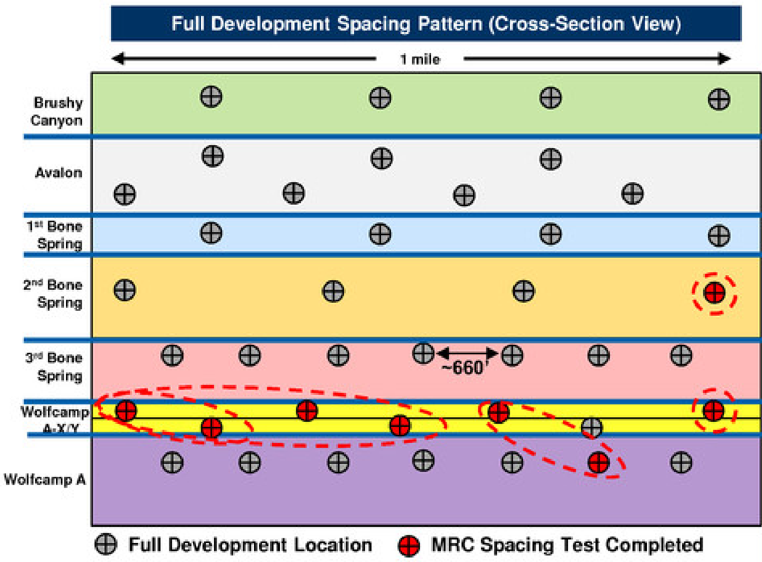
Note: All acreage at February 24, 2016.

Wolf Inventory – Multi-Pay Development Potential

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
2nd Bone Spring	$4.0 – $5.0	400 – 500	50 – 65%
Wolfcamp A-X/Y	$5.5 – $6.5	650 – 1,100	65 – 80%



Note: All acreage at February 24, 2016.

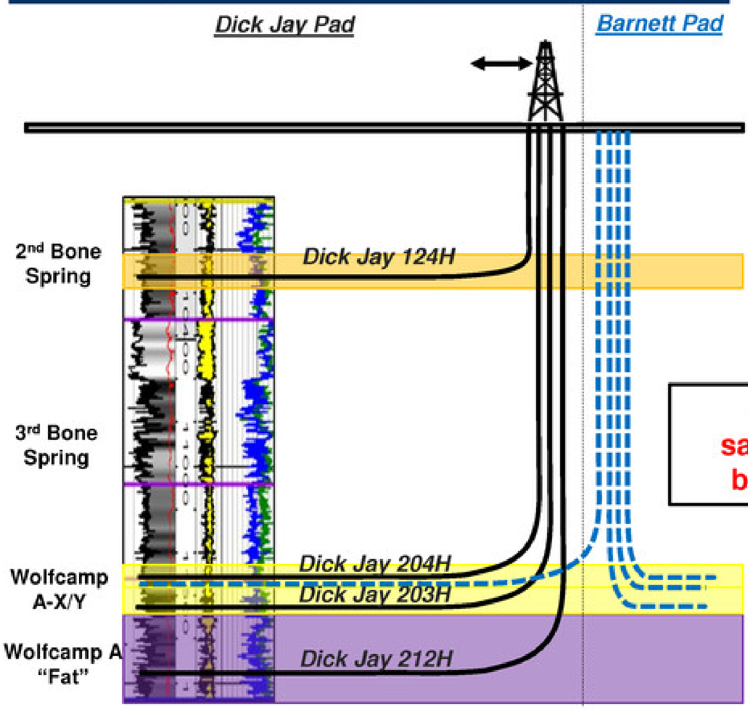


Formation	Total Gross Locations(4)	Est. Operated Locations(5)
Brushy Canyon	4	4
Avalon	72	68
1st Bone Spring	Eval. Ongoing	Eval. Ongoing
2nd Bone Spring	70	66
3rd Bone Spring	72	68
Wolfcamp A-X/Y	51	47
Wolfcamp A	70	66
	339	319

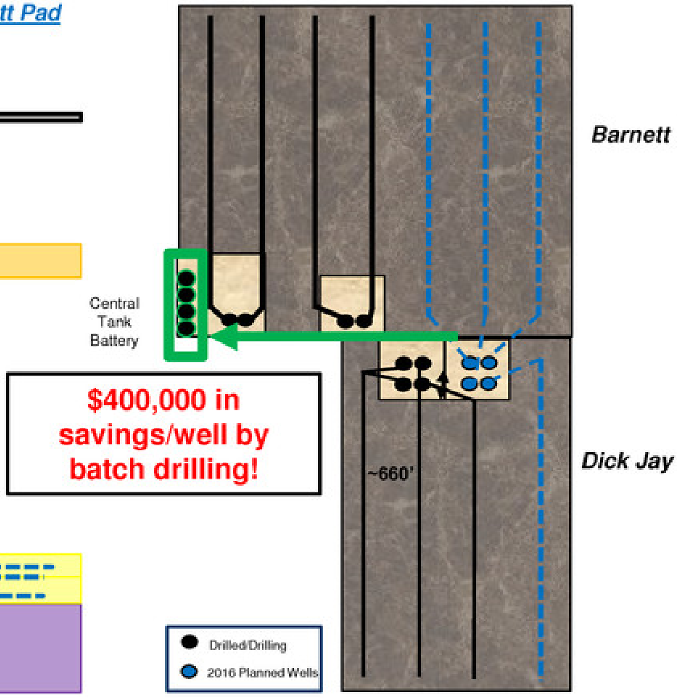
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

Drilling Wells in Batch Mode / Central Production Facilities

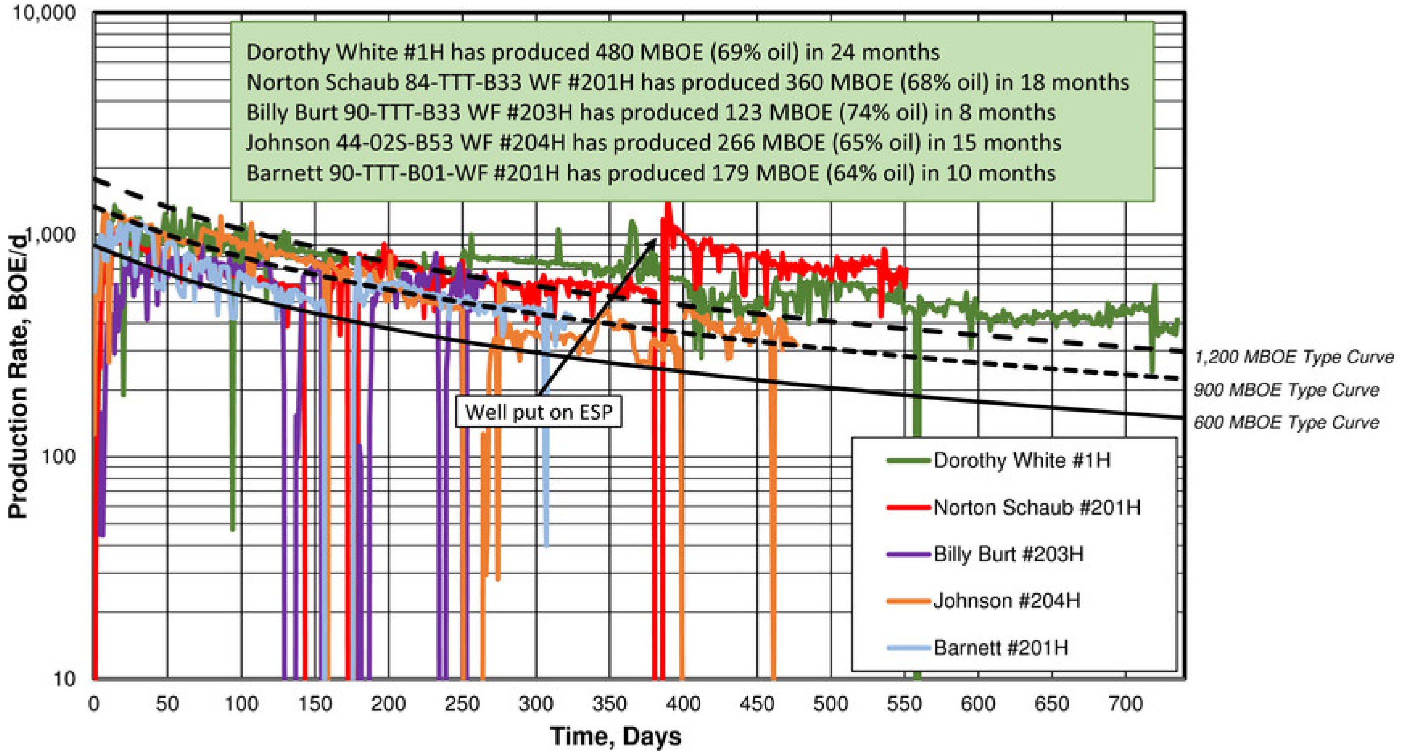
Dick Jay / Barnett Development (Cross-Section View)



Dick Jay / Barnett Development (Top-Down View)



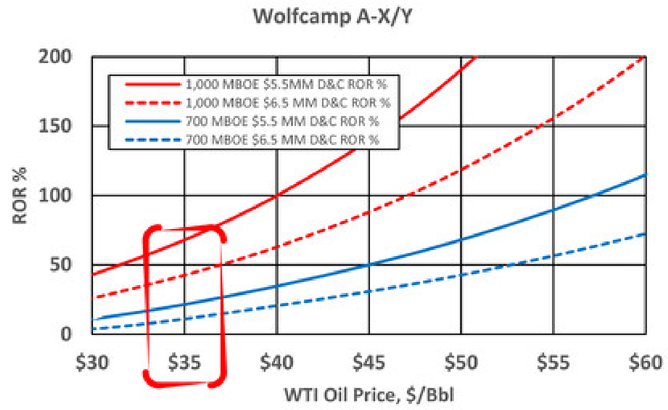
Wolf Area Wolfcamp A-X/Y Wells Continue Strong Performance Across Acreage

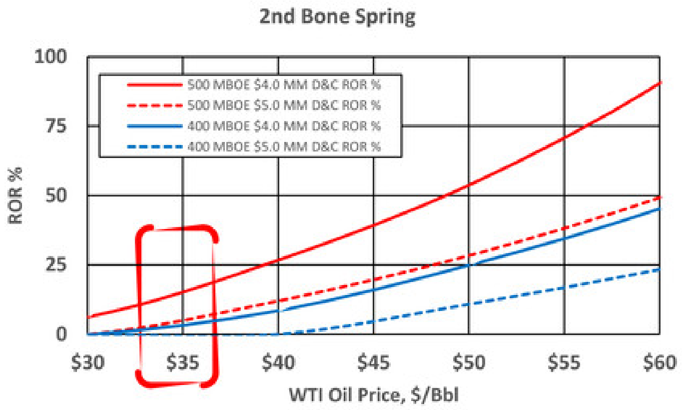


Note: Production from selected Wolfcamp A-X/Y wells in Wolf prospect area as of January 2016.

Wolf – Estimated Returns by Formation

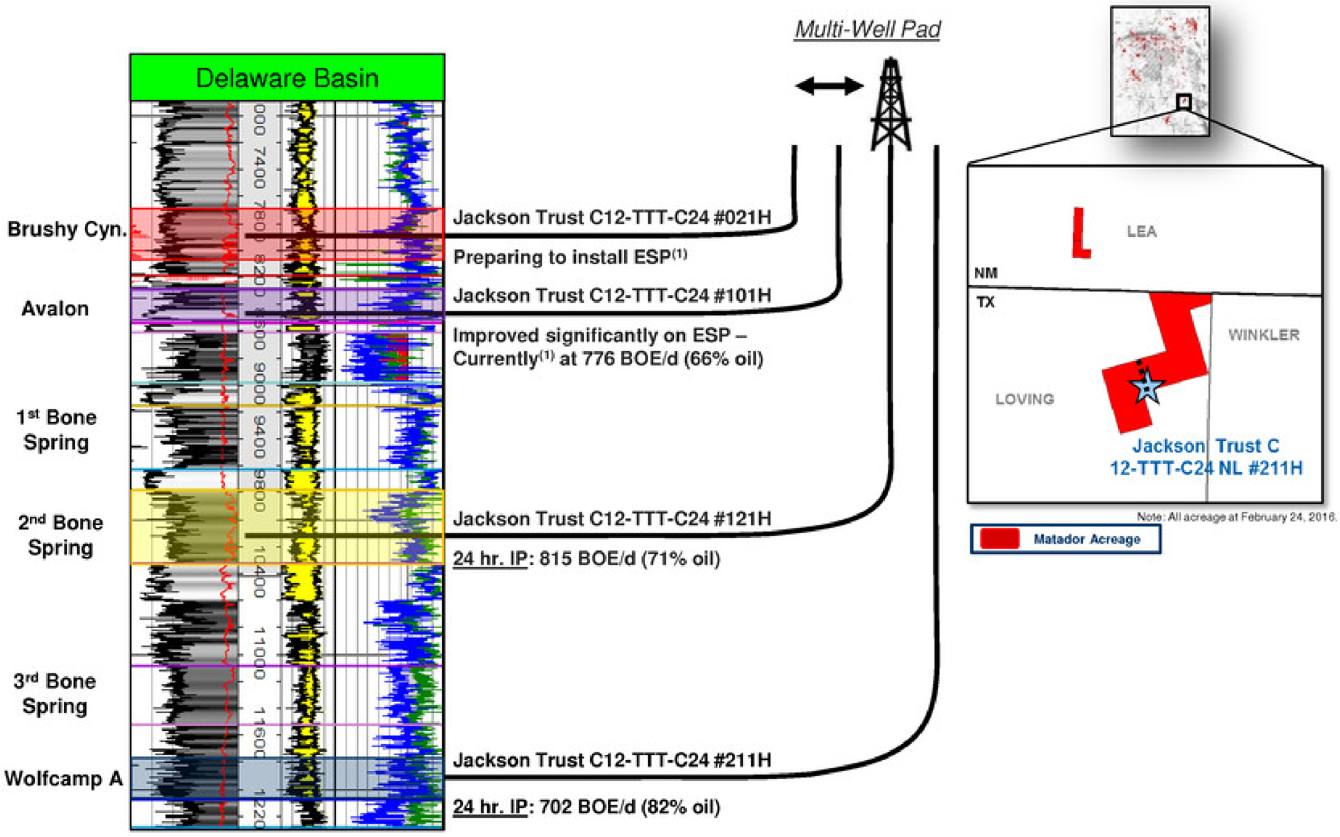
Formation	Development Well Cost(1)(2) (millions)	EUR(3) (MBOE)	% Oil
2nd Bone Spring	\$4.0 - \$5.0	400 – 500	50 – 65%
Wolfcamp A-X/Y	\$5.5 - \$6.5	650 – 1,100	65 – 80%





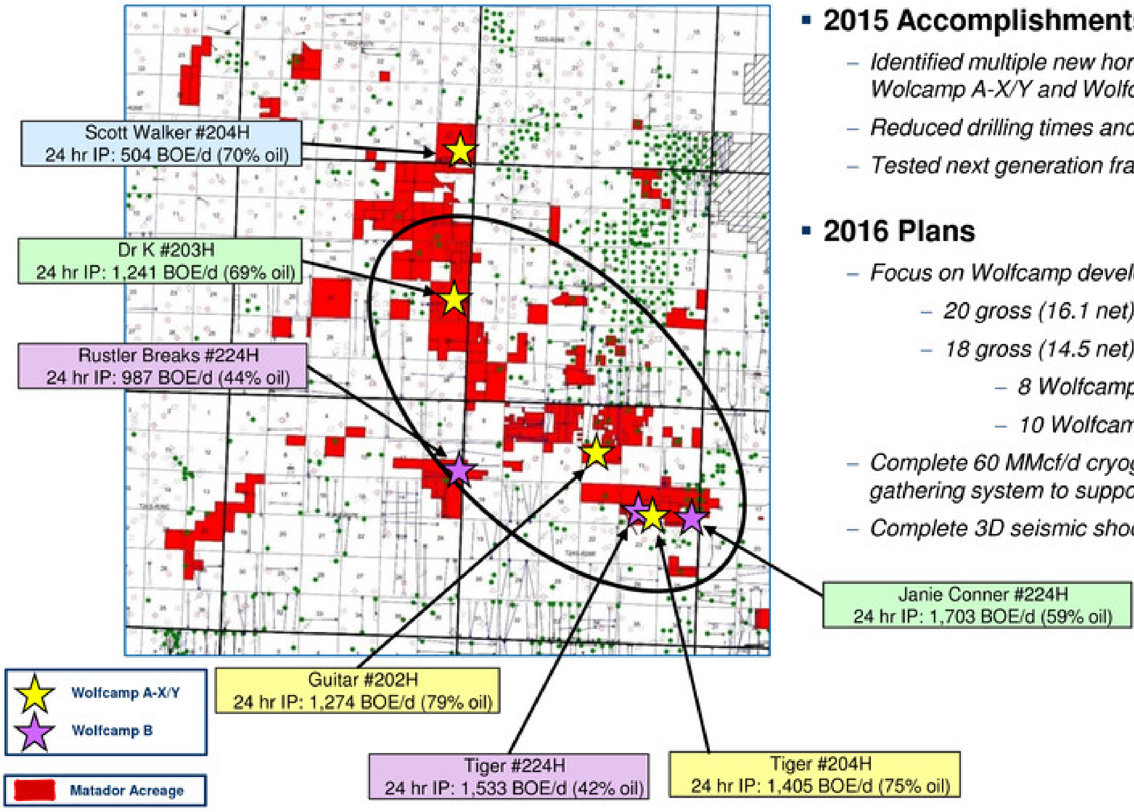
Note: Assumes \$2.50/Mcf flat natural gas price with -\$0.73/Mcf natural gas differential and -\$1.75/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Stacked Horizon Test at Jackson Trust



(1) As of late February 2016.

Rustler Breaks – Focus on Wolfcamp Development in 2016

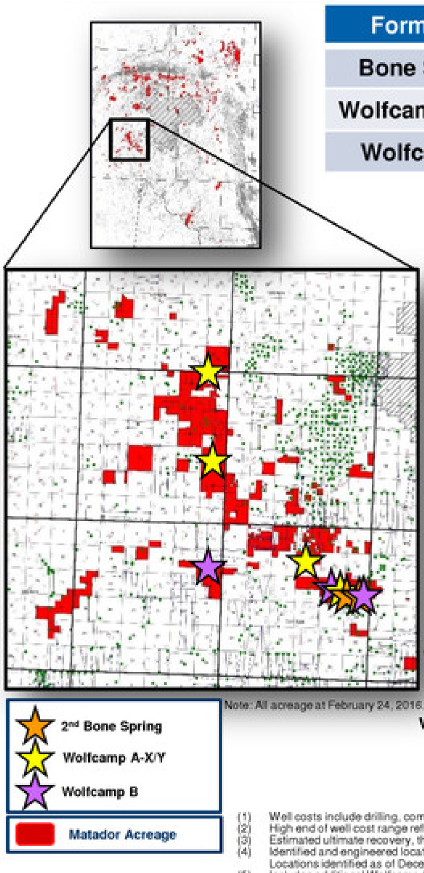


- **2015 Accomplishments**
  - *Identified multiple new horizons, particularly in the Wolcamp A-X/Y and Wolfcamp B*
  - *Reduced drilling times and well costs significantly*
  - *Tested next generation frac design up to 3,000 lbs/ft*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *20 gross (16.1 net) wells planned for 2016*
    - *18 gross (14.5 net) wells on production*
      - *8 Wolfcamp A-X/Y*
      - *10 Wolfcamp B*
  - *Complete 60 MMcf/d cryogenic processing plant and gathering system to support operations*
  - *Complete 3D seismic shoot across prospect area*

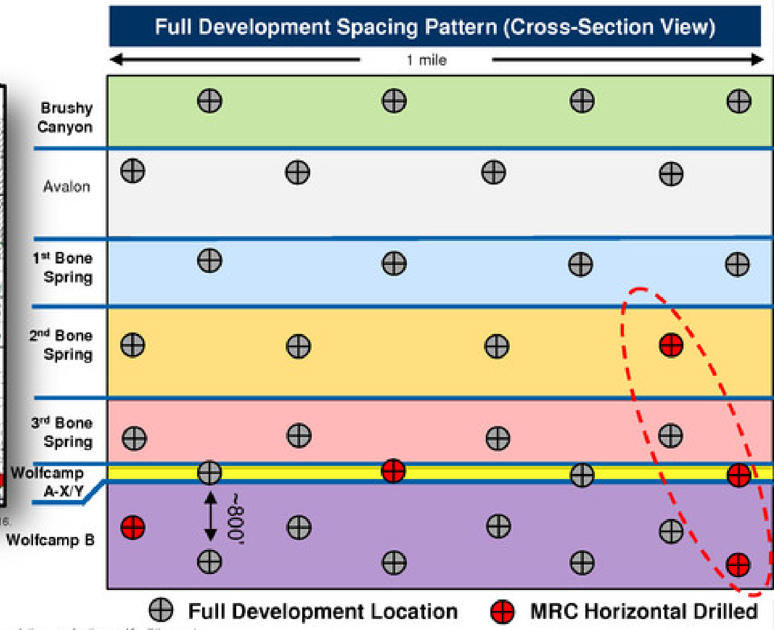
Note: All acreage at February 24, 2016.

Rustler Breaks Inventory – Multi-Pay Development Potential

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Bone Spring	$3.0 – $4.0	300 – 600	80 – 85%
Wolfcamp A-X/Y	$5.0 – $6.0	600 – 800	80 – 85%
Wolfcamp B	$5.5 – $6.5	800 – 1,000	40 – 50%



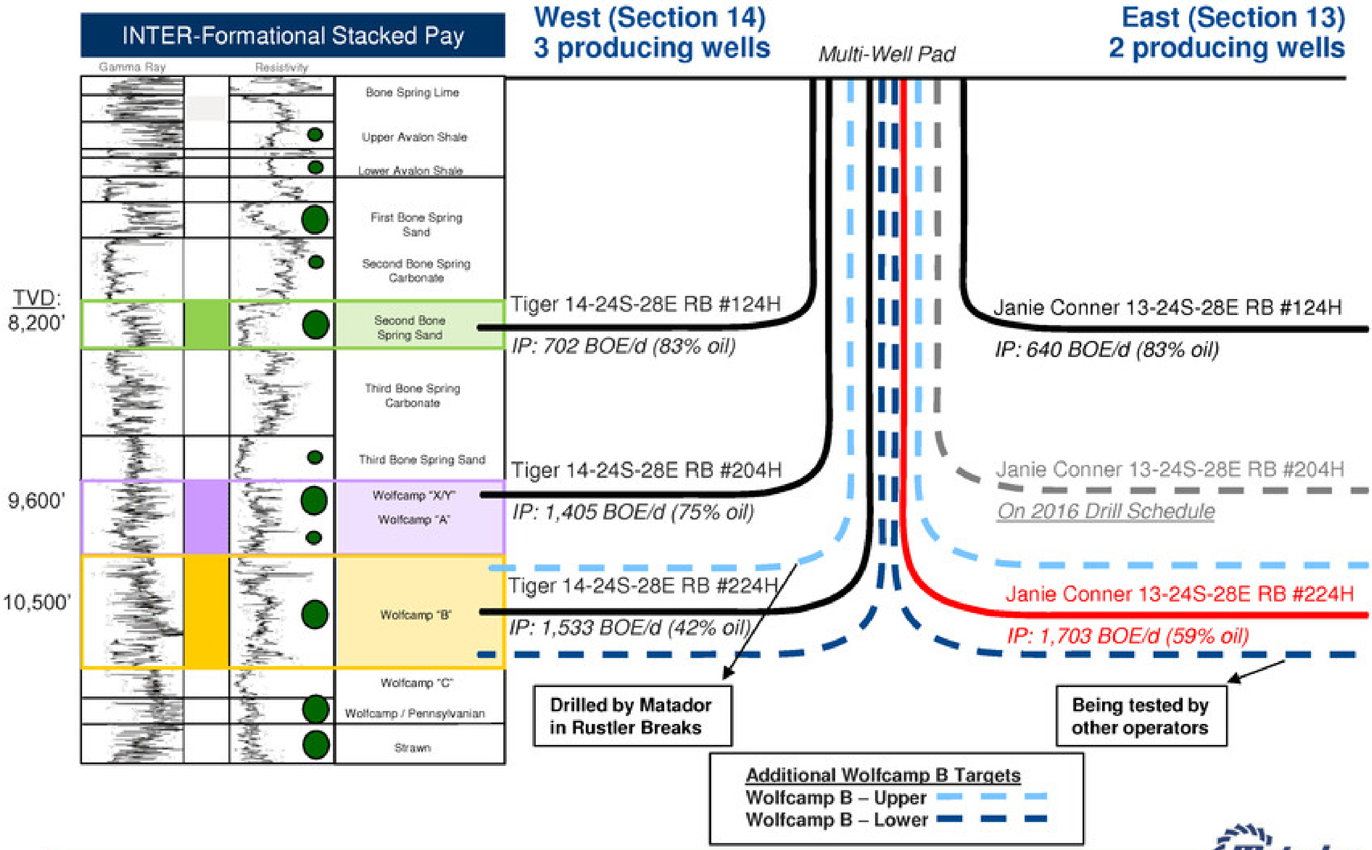
Note: All acreage at February 24, 2016.



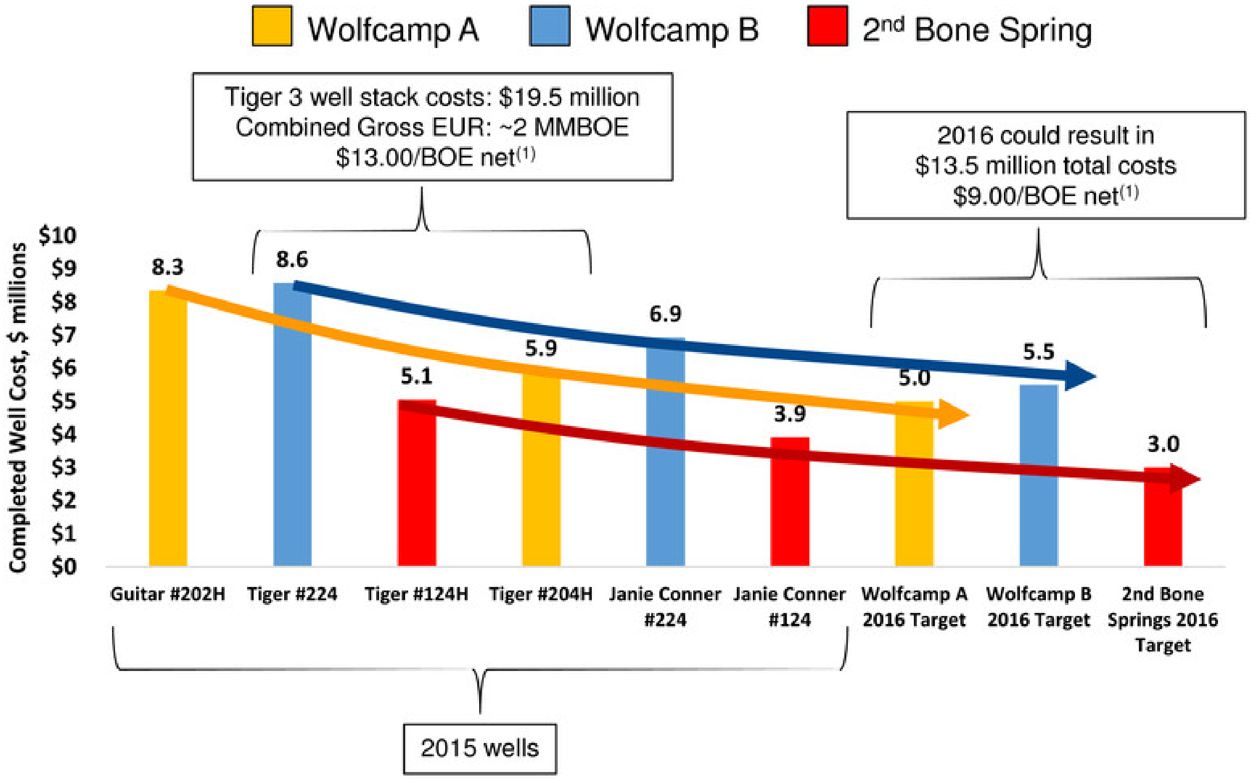
Formation	Total Gross Locations(4)(5)	Est. Operated Locations(5)(6)
Brushy Canyon	171	115
Avalon	178	123
1st Bone Spring	183	125
2nd Bone Spring	188	127
3rd Bone Spring	173	120
Wolfcamp A-X/Y	167	114
Wolfcamp B	235	177
	1,637	1,135

(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes additional Wolfcamp A lower and Wolfcamp D locations not depicted in chart. As a result, total gross locations and estimated operated locations do not sum.
(6) Includes any identified locations in which Matador's working interest is at least 25%.

Rustler Breaks – 5 Wells Producing From 3 Zones on Multi-Well Pad

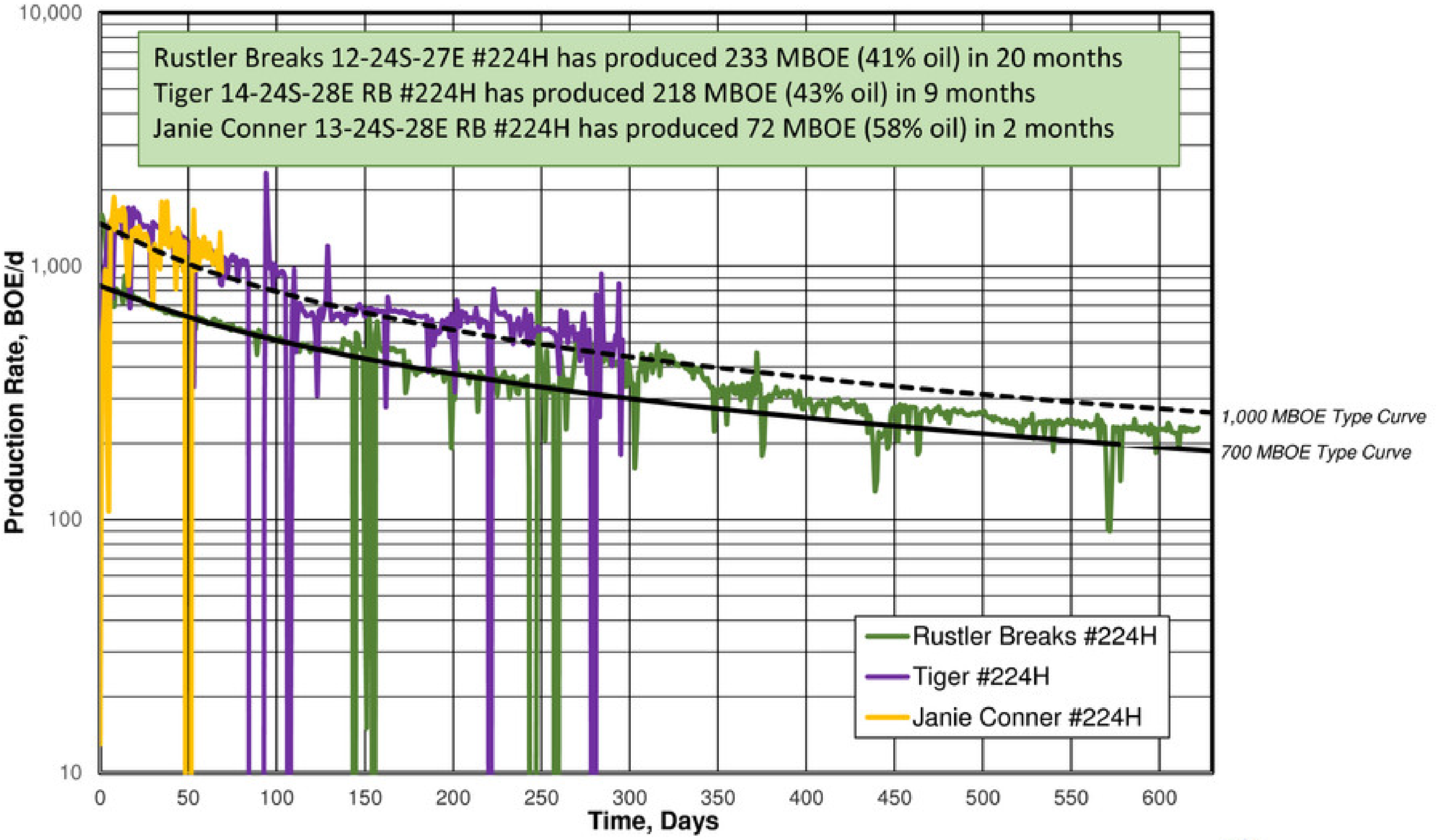


Rustler Breaks Well Cost Achievements



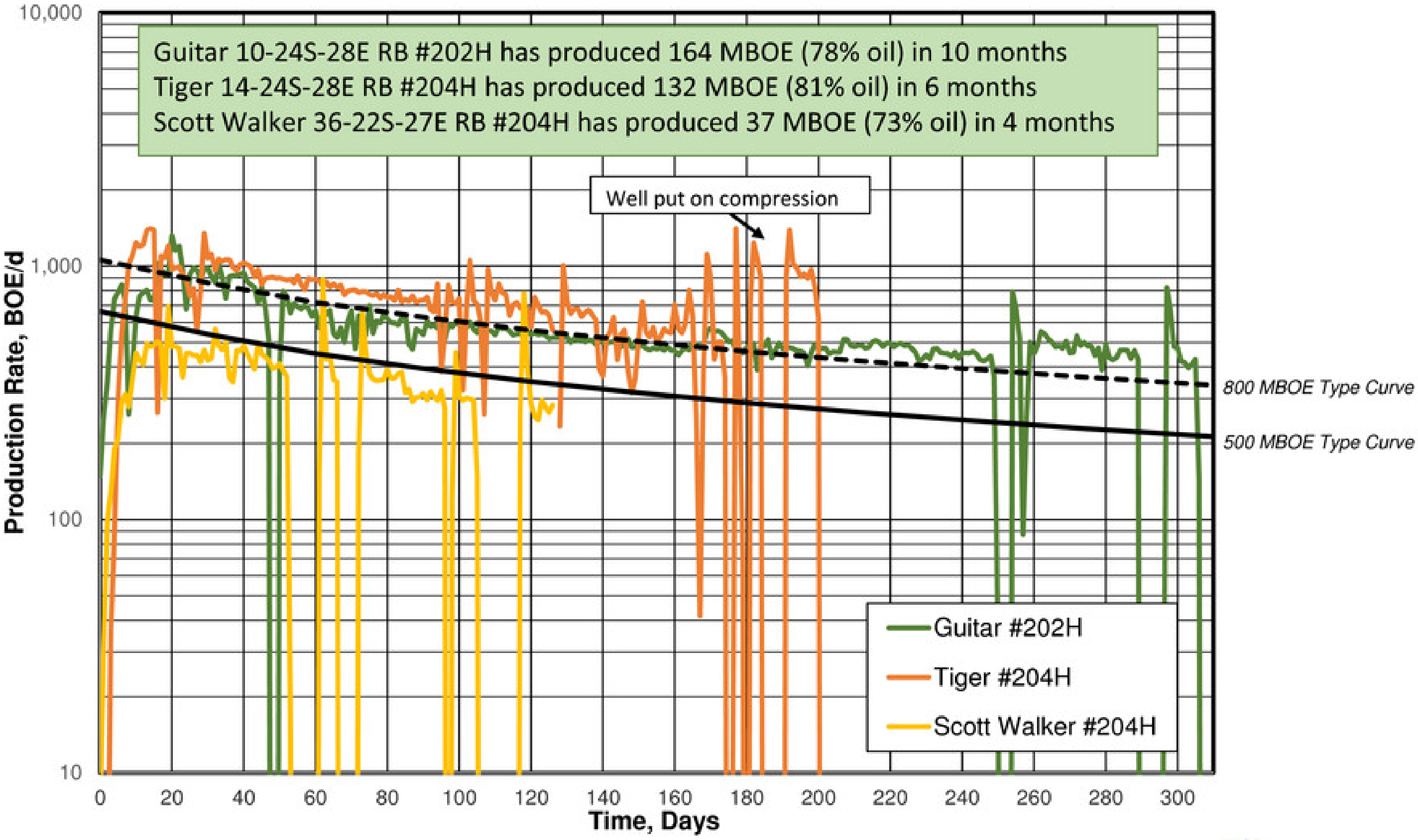
(1) Assumes 75% NRI (net revenue interest) for each well; 2016 well costs are estimates for year-end 2016.

Rustler Breaks Wolfcamp B Wells Performing Above Expectations



Note: Production as of January 2016.

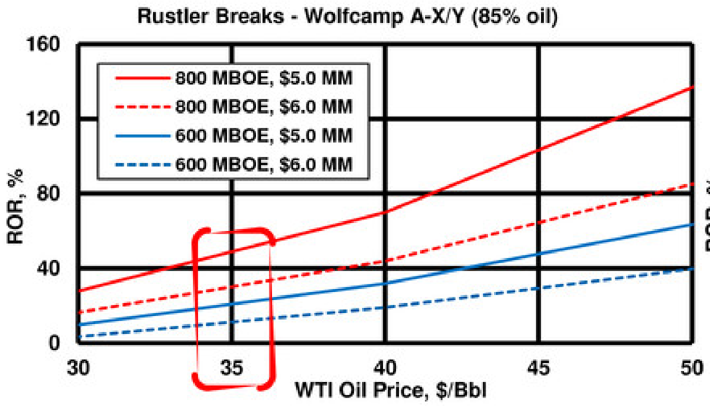
Rustler Breaks Wolfcamp A-X/Y Wells Performing Above Expectations

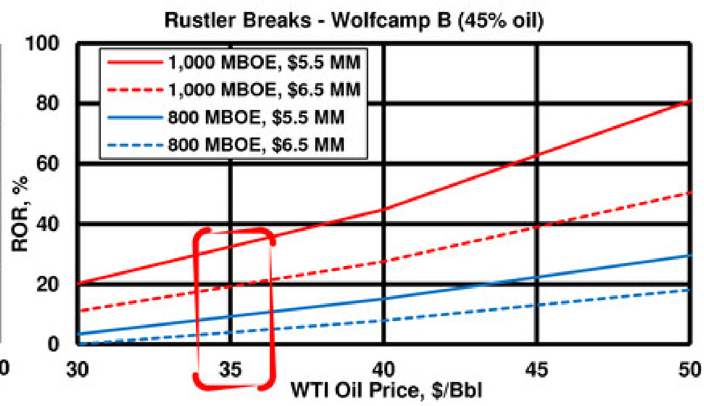


Note: Production as of January 2016.

Rustler Breaks – Estimated Returns by Formation

Formation	Development Well Cost[1][2] (millions)	EUR[3] (MBOE)	% Oil
Wolfcamp A-X/Y	$5.0 – $6.0	600 – 800	80 – 85%
Wolfcamp B	$5.5 – $6.5	800 – 1,000	40 – 50%



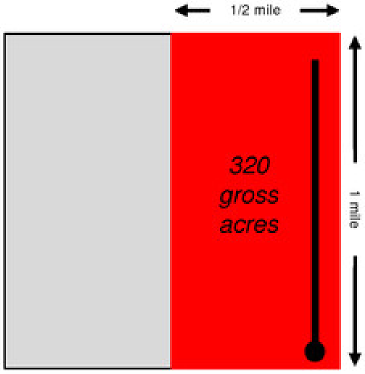


Note: Assumes $2.50/Mcf flat natural gas price with -$0.70/Mcf natural gas differential and -$3.26/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.

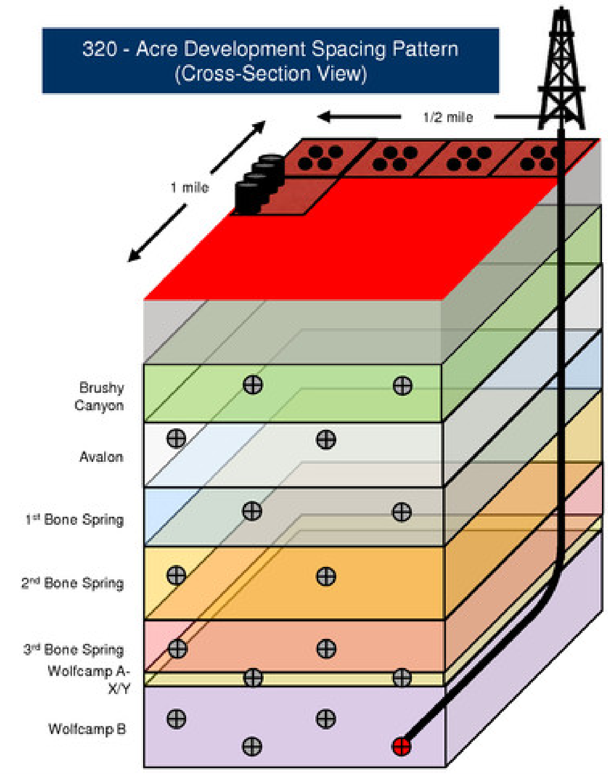
Single Wolfcamp B Well at Rustler Breaks Holds Up To 15 Potential Locations

- *One producing Wolfcamp B well holds 320 surface acres and up to 15 additional potential locations for future development*

320 - Acre Development Spacing Pattern (Aerial View)

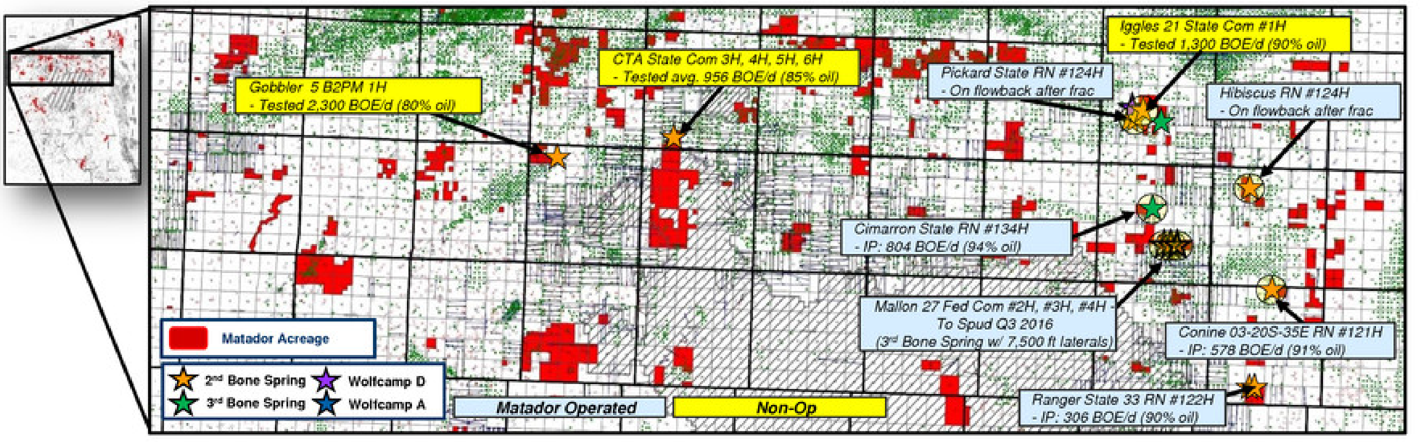


320 - Acre Development Spacing Pattern (Cross-Section View)



Additional Locations Held With Wolfcamp B well
2
2
2
2
2
2
3
15

Ranger/Arrowhead – Bone Spring and Wolfcamp Development in 2016

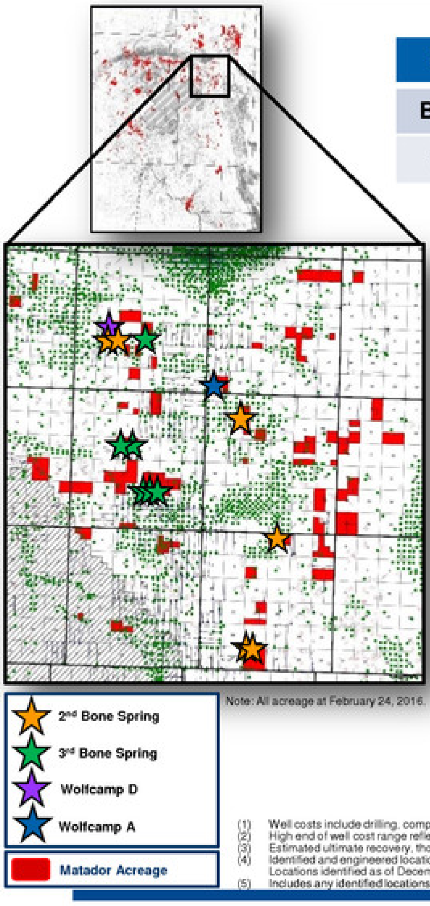


- **2015 Accomplishments**
  - Merged with HEYCO adding ~60,000 gross and ~20,000 net acres(1)
  - 12 gross (4.5 net) wells
  - Drilled Twin Lakes vertical data well
  - Applied for 10 new Federal drilling permits

- **2016 Plans**
  - Further delineate and develop Bone Spring
    - 7 gross (4.9 net) wells with 5 gross (3.9 net) wells on production
  - Drill and complete horizontal in Wolfcamp D at Twin Lakes
  - Submit 50 to 75 Federal drilling permits for approval and future development

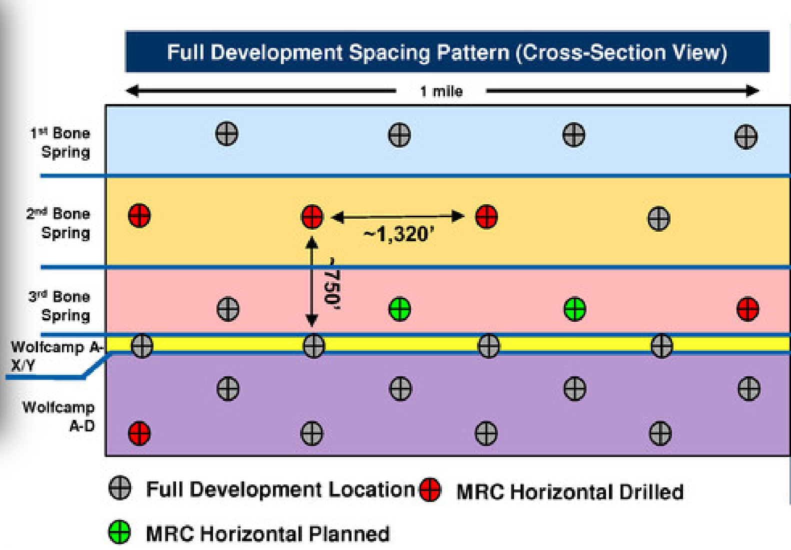
Note: All acreage at February 24, 2016.
(1) Including additional acreage acquired through subsequent joint ventures with affiliates of HEYCO.

Ranger Inventory – Multi-Well Development Potential



Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Bone Spring	\$4.5 – \$6.0	400 – 700	90 – 95%
Wolfcamp	\$6.5 – \$8.0	200 – 800*	80 – 85%

* Based on Volumetrics and 4-8% Recovery Factor



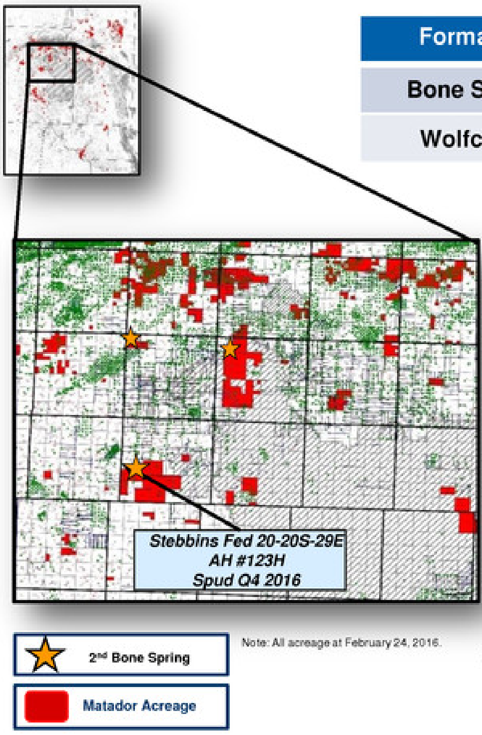
Formation	Total Gross Locations(4)	Est. Operated Locations(5)
1st Bone Spring	155	80
2nd Bone Spring	169	90
3rd Bone Spring	89	43
Wolfcamp A-X/Y	48	15
Wolfcamp A-D	194	114
	655	342

(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

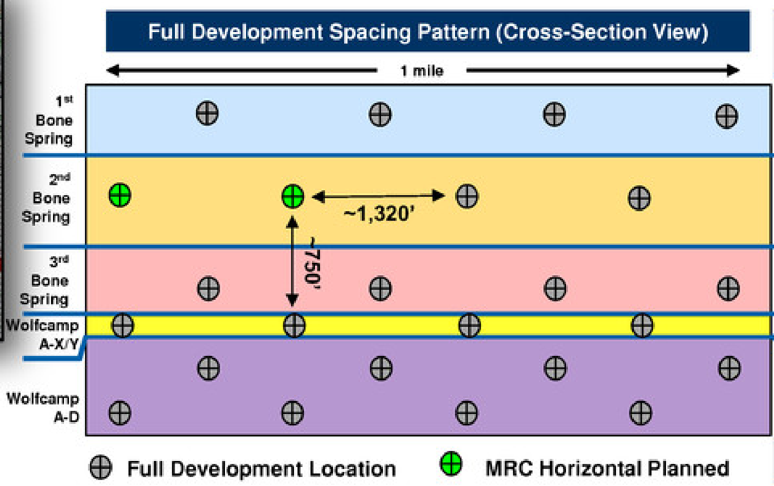
Arrowhead Inventory – Multi-Well Development Potential

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Bone Spring	\$4.5 – \$6.0	400 – 700	80 – 90%
Wolfcamp	\$6.5 – \$8.0	200 – 800*	80 – 85%

* Based on Volumetrics and 4-8% Recovery Factor



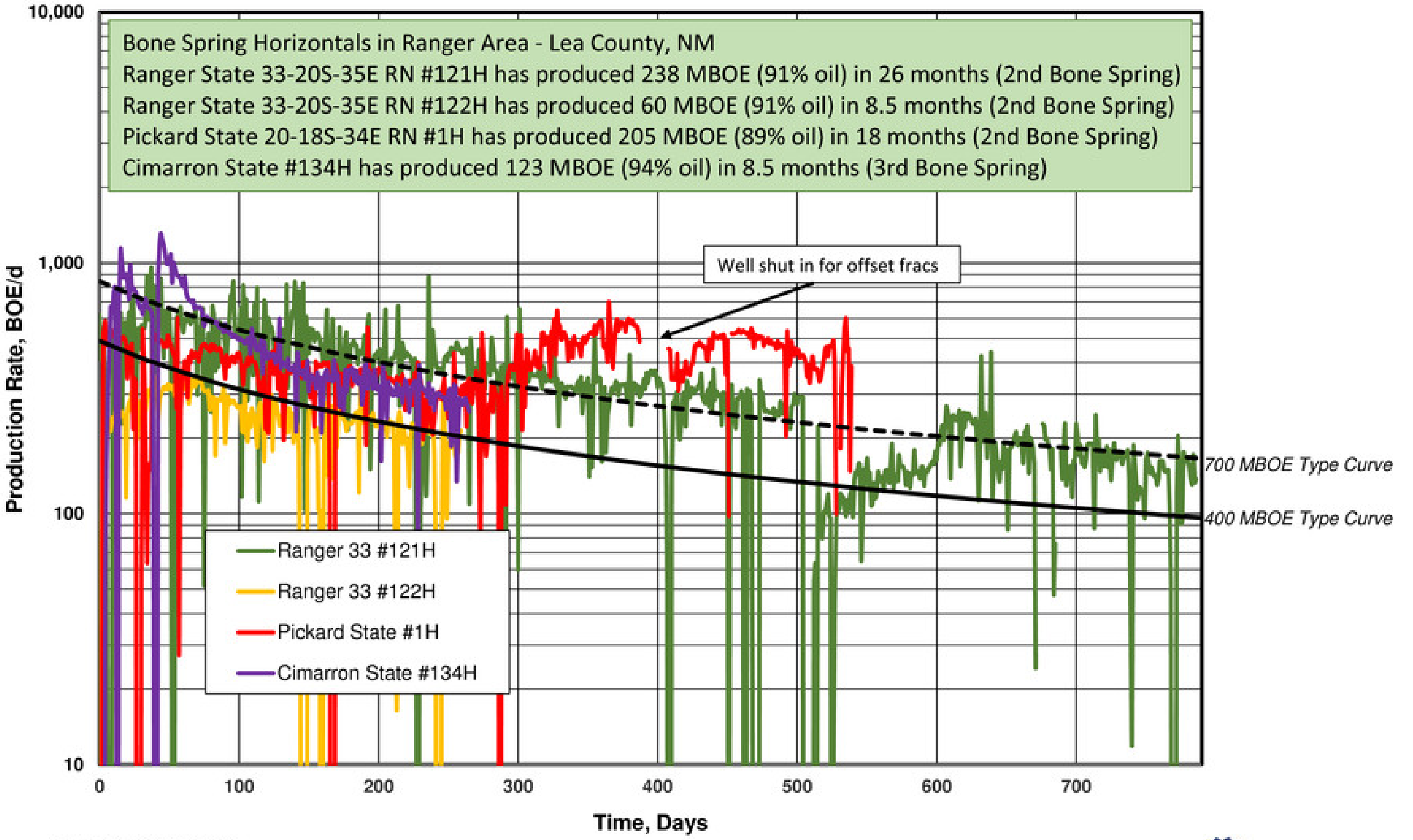
Note: All acreage at February 24, 2016.



Formation	Total Gross Locations(4)	Est. Operated Locations(5)
1st Bone Spring	210	77
2nd Bone Spring	210	78
3rd Bone Spring	120	59
Wolfcamp A-X/Y	14	11
Wolfcamp A-D	88	44
	642	269

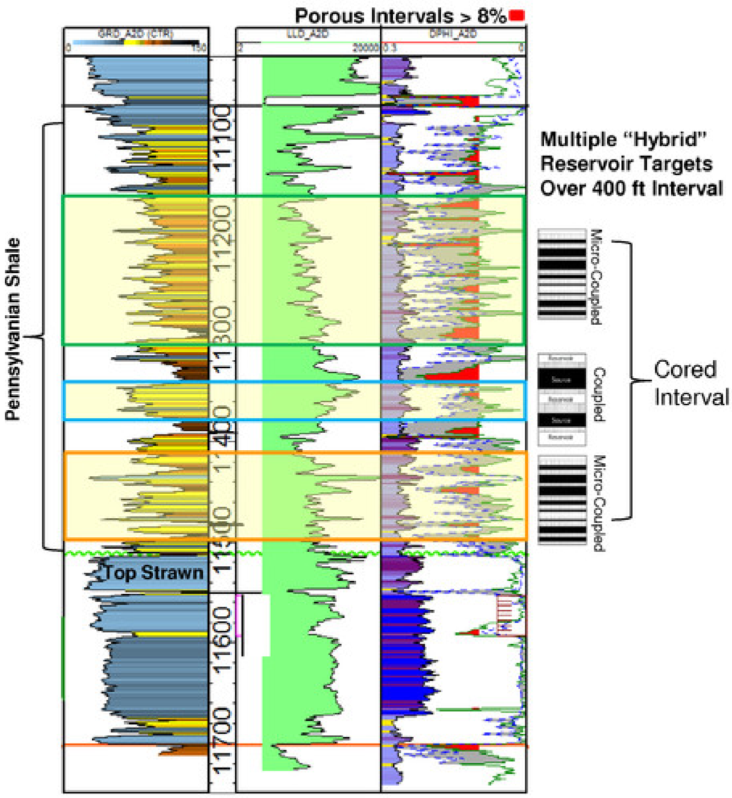
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Gross locations identified as of December, 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

Ranger Area Bone Spring Wells Continued Strong Performance

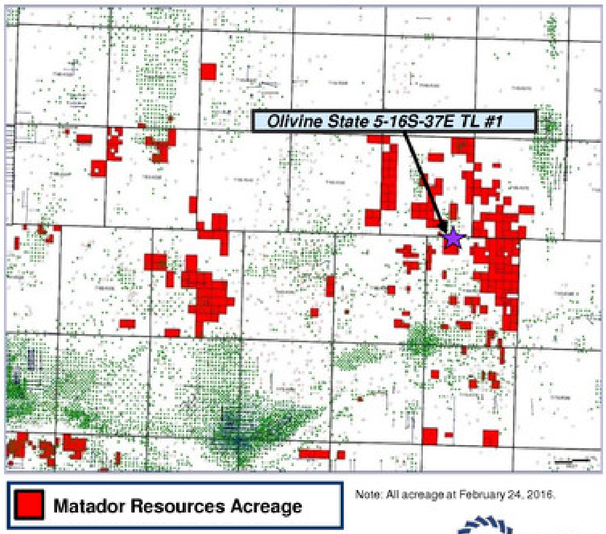


Note: Production as of January 2016.

Testing New Oil Shale Play in Twin Lakes Prospect



- **Pennsylvanian-Lower Wolfcamp D Oil Shale**
  - One of the primary source rocks for Twin Lakes prospect area (~42,300 gross and ~29,900 net acres)
  - Super-charged area having produced 1.3 billion Bbl oil and 2.2 trillion cubic feet natural gas
  - Drilled initial data collection well (Olivine State #1) to obtain full set of whole cores and geophysical logs
  - Horizontal well to test Wolfcamp D planned in Q4 2016 after analyzing data for optimal landing target



Note: All acreage at February 24, 2016.



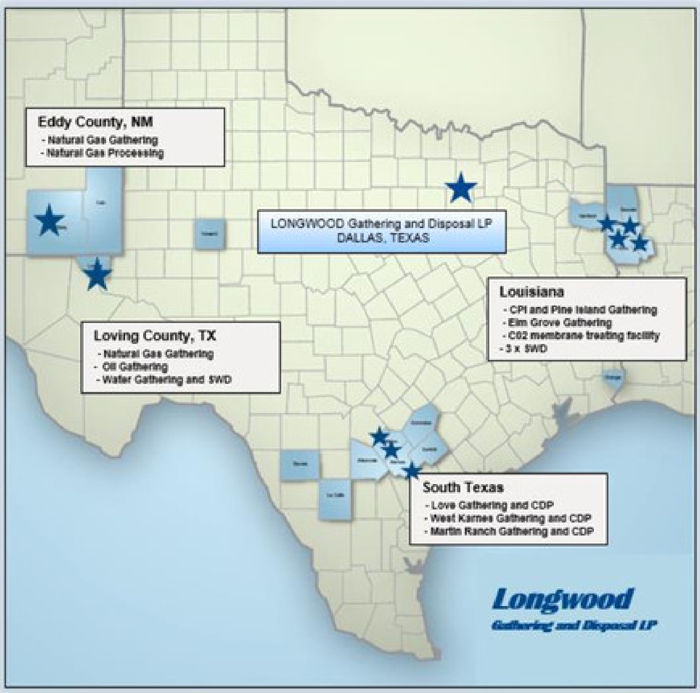
Midstream

Longwood Gathering and Disposal Systems[(1)] in Delaware Basin

- *Loving County, TX*
  - Gas gathering
  - Water gathering
  - Salt water disposal
  - Oil gathering
  - Cryogenic gas processing plant

Sold to EnLink

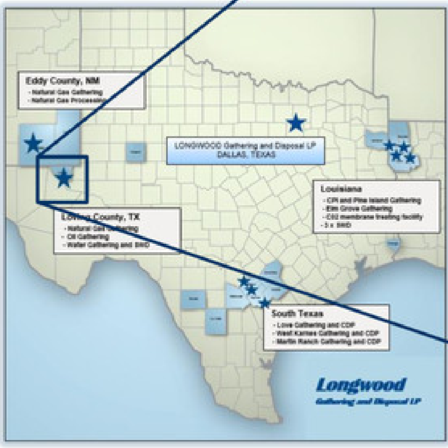
- *Eddy County, NM*
  - Gas gathering and compression
  - Cryogenic gas processing plant
  - Water gathering (under evaluation)
  - Salt water disposal (under evaluation)

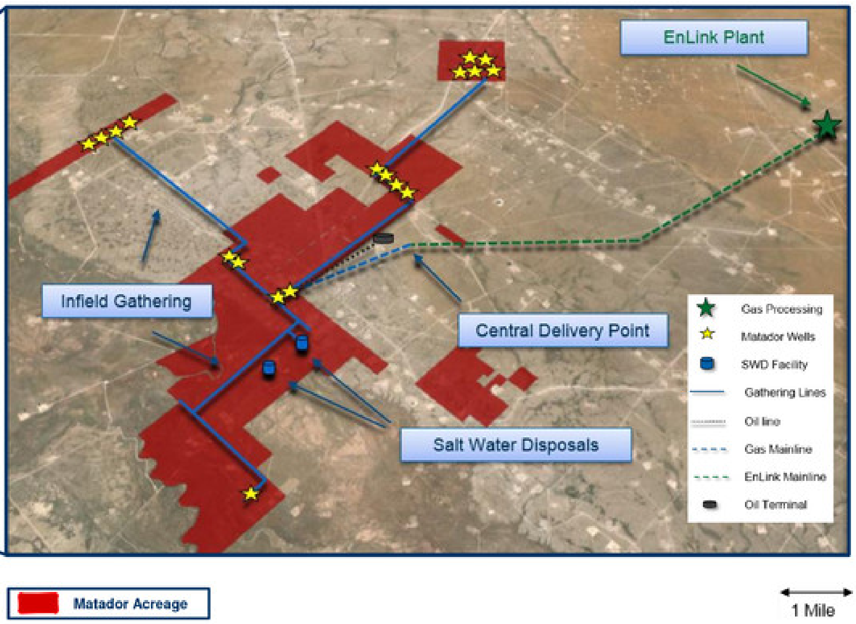


(1) Longwood Gathering and Disposal Systems, LP is an indirect wholly owned subsidiary of Matador Resources Company.

Wolf - Loving County, TX – Significant Midstream Footprint

- Gas Gathering
- Water Gathering
- Salt Water Disposal
- Oil Gathering

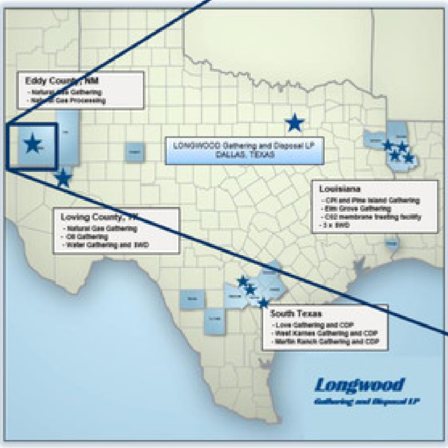


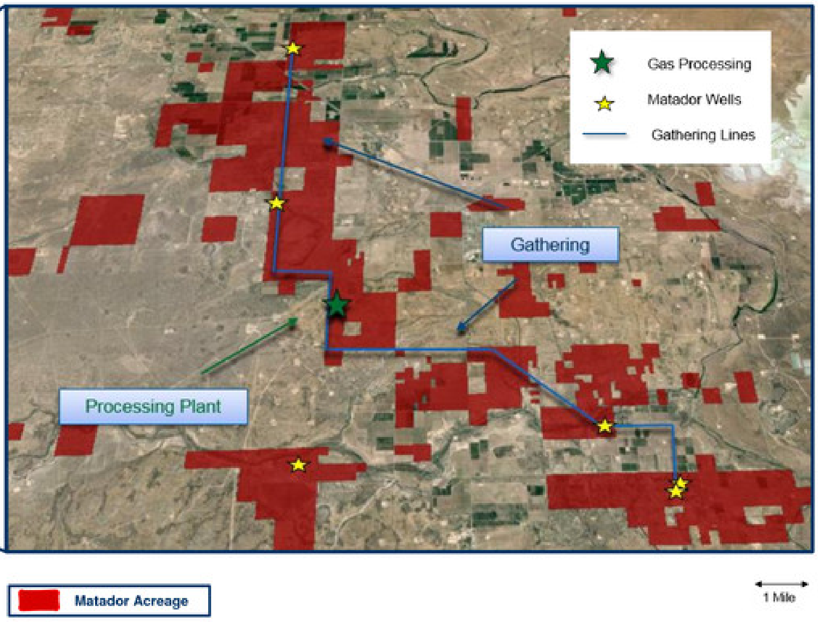


Note: All acreage at February 24, 2016.

Rustler Breaks - Eddy County, NM – Repeating the Proven Wolf Model

- Gas gathering and compression
- Cryogenic gas processing plant
- Water gathering (under evaluation)
- Salt water disposal (under evaluation)





Note: All acreage at February 24, 2016.

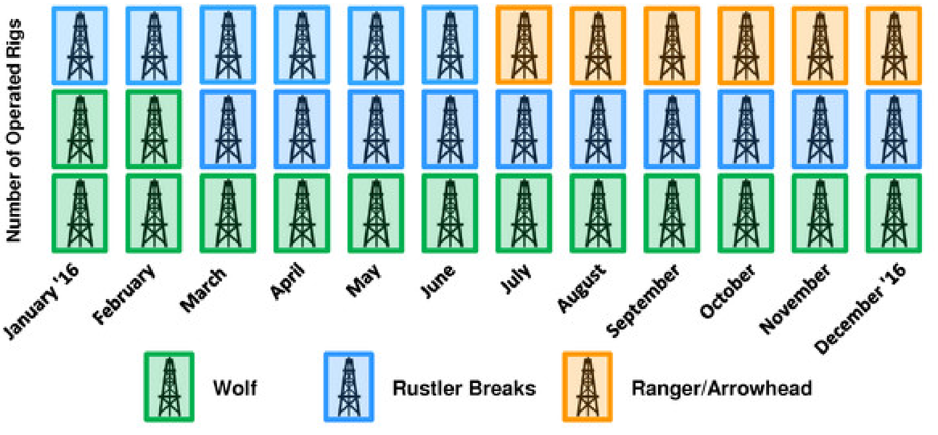
Matador
RESOURCES COMPANY

2016 Capital Investment Plan

2016 Capital Investment Plan – Summary

- **We will keep the focus on our Delaware Basin assets and opportunities with the intent of creating and preserving long-term shareholder value**
  - *Plan to run 3 rigs in 2016, but will consider dropping to 2 rigs as early as Q2 2016 if oil prices drop and remain below $30 per barrel*
  - *Continue to improve drilling and completion efficiencies, lower costs, improve well recoveries and returns and upgrade our acreage position*
  - *Continue to invest in Delaware midstream assets, particularly the cryogenic natural gas processing plant and gathering assets we are building in the Rustler Breaks prospect area in Eddy County, NM*

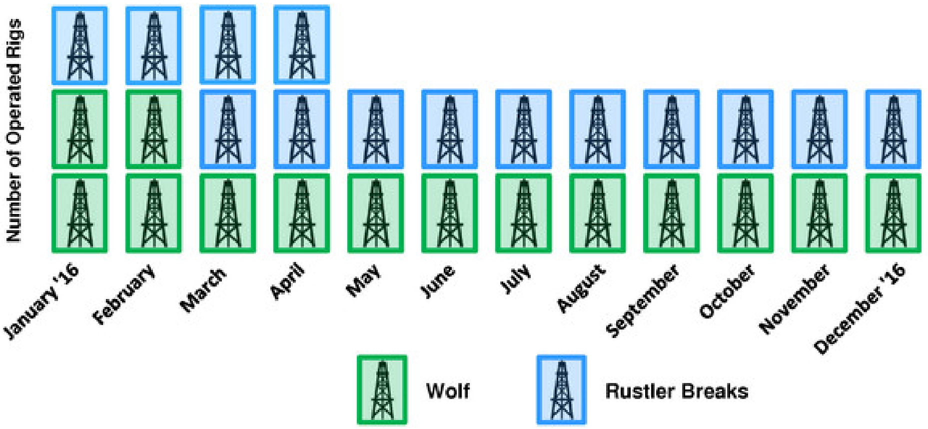
Delaware Basin: 3-Rig Case



2016 Capital Investment Plan – Summary

- **We will keep the focus on our Delaware Basin assets and opportunities with the intent of creating and preserving long-term shareholder value**
  - *Plan to run 3 rigs in 2016, but will consider dropping to 2 rigs as early as Q2 2016 if oil prices drop and remain below $30 per barrel*
  - *Continue to improve drilling and completion efficiencies, lower costs, improve well recoveries and returns and upgrade our acreage position*
  - *Continue to invest in Delaware midstream assets, particularly the cryogenic natural gas processing plant and gathering assets we are building in the Rustler Breaks prospect area in Eddy County, NM*

Delaware Basin: 2-Rig Case

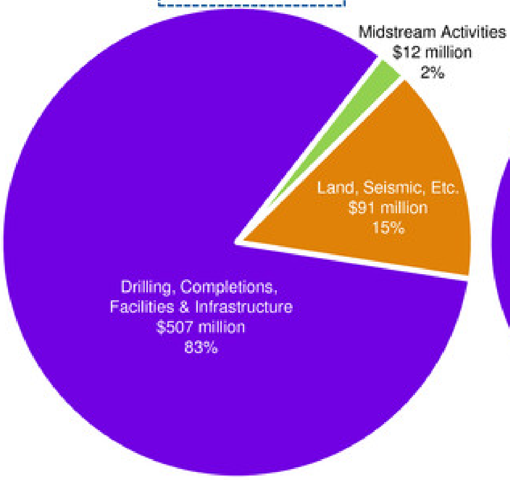


2016 Capital Investment Plan – Summary

- **We estimate our capital budget in 2016 to be approximately $325 million for the 3-rig case (down 33% from 2015[(1)]), declining to $277 million for the 2-rig case (down 43% from 2015[(1)])**
  - *We expect to have sufficient liquidity to fund our 2016 capital investments - $61 million in cash and $375 million in undrawn revolving credit facility at December 31, 2015*

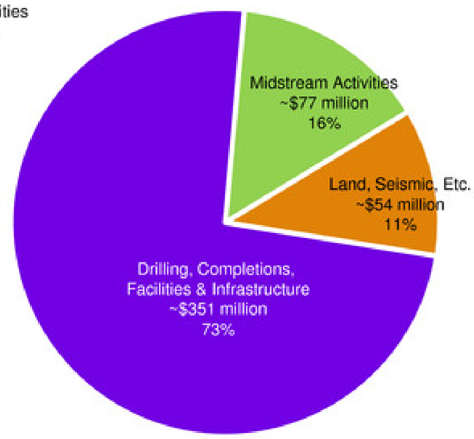
2014 CapEx

$610 million



2015 CapEx

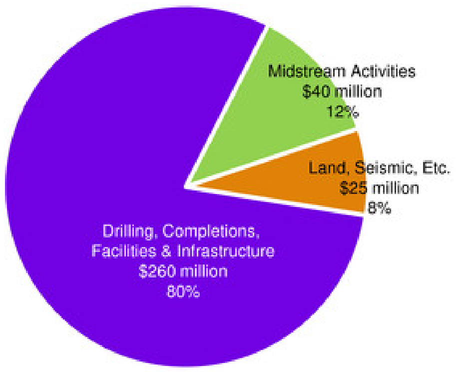
$482 million[(1)] 21%



2016E CapEx – 3-Rig Scenario

3 Delaware Basin rigs throughout 2016

$325 million 32%

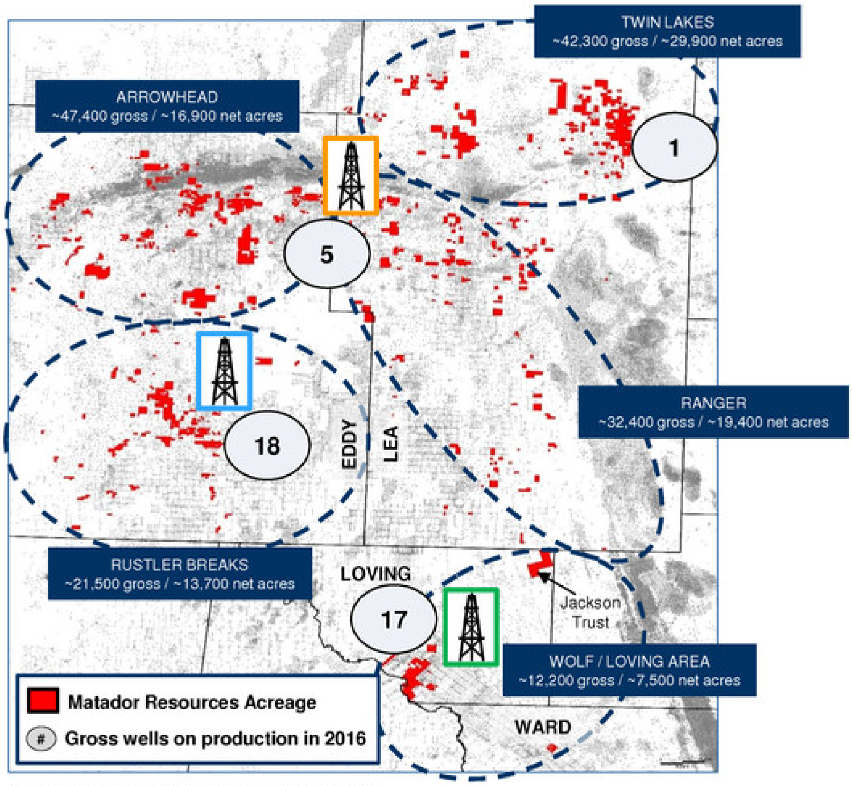


(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.

2016 Capital Investment Plan – Summary

- We expect to grow oil production by about 11% and keep natural gas production close to flat; total BOE production growth of about 4% in the 3-rig program as compared to 2015
- We expect to outspend cash flow by ~$205 million (2-rig) to ~$230 million (3-rig) in 2016, including outspend associated with midstream and land, but anticipate funding most or all of this outspend without incurring significant additional debt by year-end
- We anticipate funding most or all of this outspend through a combination of:
  - *Additional operational efficiencies and cost savings*
  - *Improved well performance*
  - *Potential rise in oil and natural gas prices throughout the year*
  - *Certain asset sales, including midstream assets and other non-strategic properties*
  - *Joint ventures and creative land deals*
  - *Additional equity*
  - *Additional borrowings under our undrawn credit facility*
- We raised ~$142 million in a March 2016 follow-on equity offering covering most of the 2016 projected outspend

Matador's 2016 Delaware Basin Operated Drilling Plan: 3-Rig Case



Note: All acreage at February 24, 2016. Some tracts not shown on map.

Wolf/Loving Area

- *21 gross (18.4 net) wells planned for 2016*
- *17 gross (15.2 net) wells on production, including 14 Wolfcamp A-XY, 1 Wolfcamp A-Lower and 2 2nd Bone Spring wells*

Rustler Breaks

- *20 gross (16.1 net) wells planned for 2016*
- *18 gross (14.5 net) wells on production, including 8 Wolfcamp A-XY and 10 Wolfcamp B wells*

Ranger/Arrowhead

- *7 gross (4.9 net) wells planned for 2016*
- *5 gross (3.9 net) wells on production, including 2 2nd Bone Spring and 3 3rd Bone Spring wells*

Twin Lakes

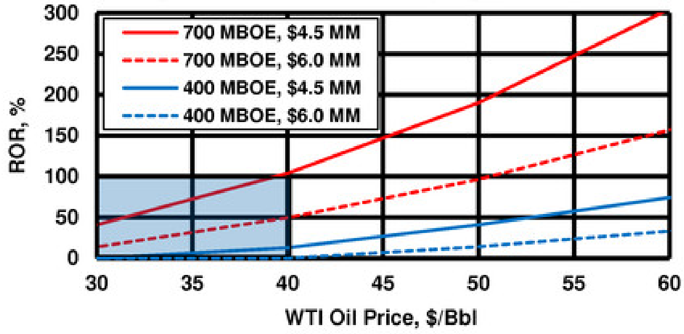
- *1 gross (1.0 net) well planned for 2016 and on production*
- *Initial Wolfcamp D horizontal well*

Total 3-Rig Program

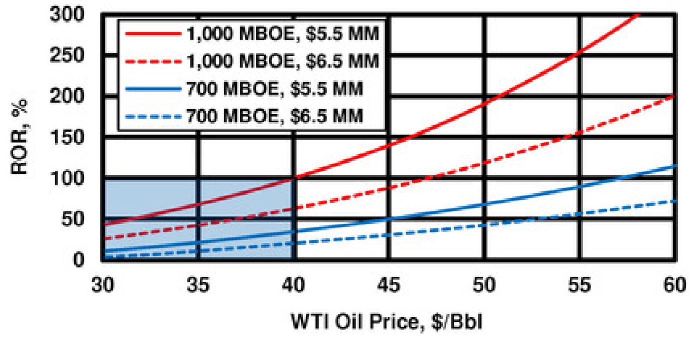
- *49 gross (40.4 net) wells planned for 2016*
- *41 gross (34.6 net) wells on production, including 34 Wolfcamp wells and 7 Bone Spring wells*

Delaware Basin – Sensitivities to Oil Price(1) and Cost Savings

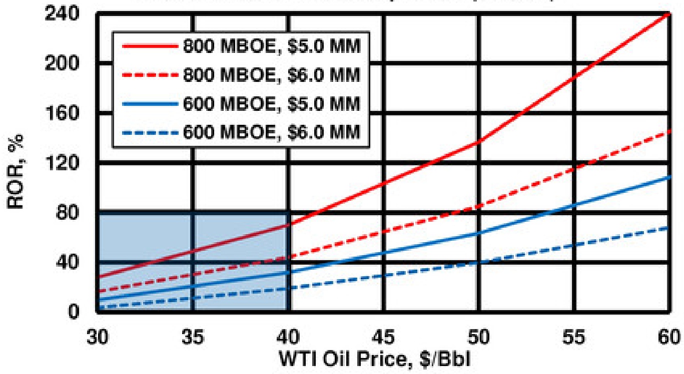
Ranger/Arrowhead - 2nd Bone Spring (90% oil)



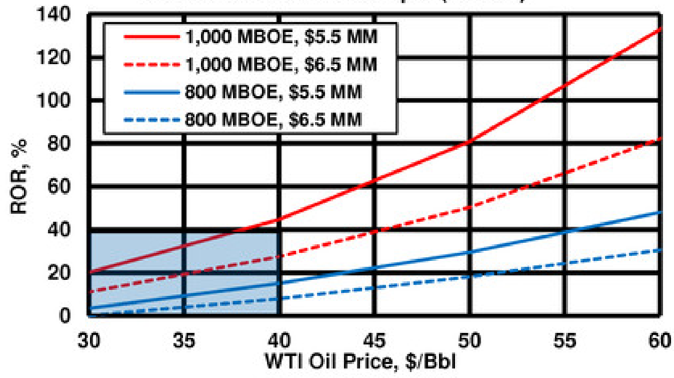
Wolf - Wolfcamp A-X/Y (70% oil)



Rustler Breaks - Wolfcamp A-X/Y (85% oil)



Rustler Breaks - Wolfcamp B (45% oil)

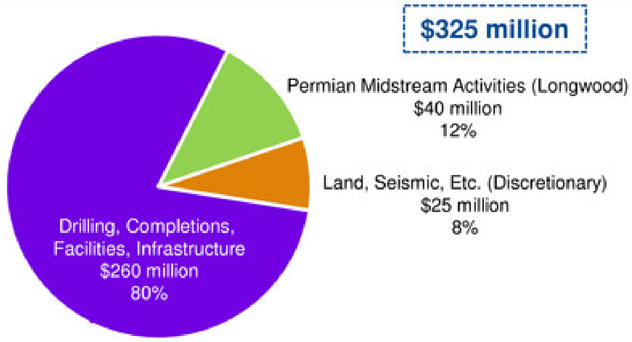


Note: $2.50/Mcf natural gas price used in all graphs, less differentials. Costs include total estimated drilling, completion, production and facilities costs for a typical development well in each area.
Note: High end of cost range reflects Q1 2016 estimated costs; low end of cost range reflects 2016 target.
(1) Oil price shown is West Texas Intermediate oil price (WTI). Differentials to WTI oil price are included in all graphs for each area.

2016 Capital Investment Plan Summary – 3 Delaware Basin Rigs

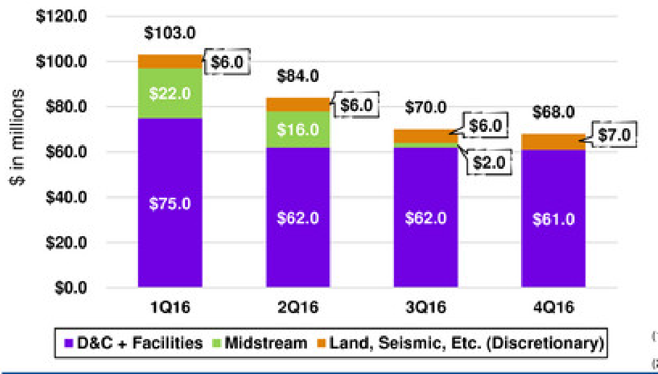
2016E CapEx – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



2016E CapEx by Quarter – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



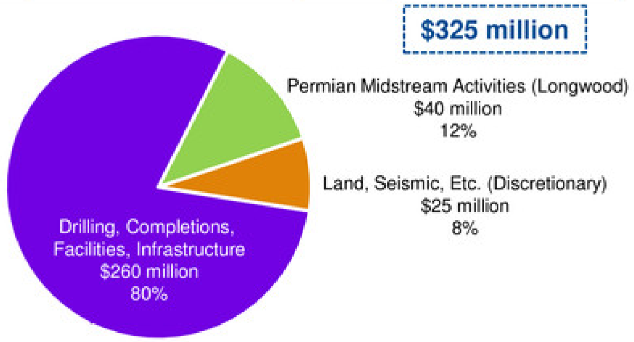
- 2016E CapEx of ~$325 million
  - *Decrease of ~33% from 2015 capital expenditures of $482 million[(1)]*
  - *Includes estimated efficiency and cost savings of 15 to 20% throughout 2016, but additional savings may be realized*
- Delaware Basin focus on Wolfcamp development at Wolf and Rustler Breaks, plus additional delineation of Ranger and Arrowhead prospect areas
  - *Includes ~$40 million for midstream initiatives and ~$25 million for land and seismic - almost all in the Delaware Basin*
  - *Includes ~$5.5 million for anticipated non-op well participation*
- 2016E CapEx highest in Q1 2016 – falls quickly thereafter
  - *Almost all midstream CapEx incurred in first half of 2016*
- No operated Eagle Ford drilling activity in 2016 – 92% of acreage HBP or not subject to near-term expirations[(2)]
  - *Includes ~$6 million CapEx, primarily for rod pump installations and some lease extensions*
- Haynesville development includes selective participation in non-operated wells, primarily Chesapeake drilling at Elm Grove; Haynesville acreage ~100% held by production
  - *Includes ~$4 million in 2016 as we expect only 5 gross (0.6 net) wells in 2016*

(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(2) At December 31, 2015.

2016 Capital Investment Plan Summary – 3-Rig and 2-Rig Cases

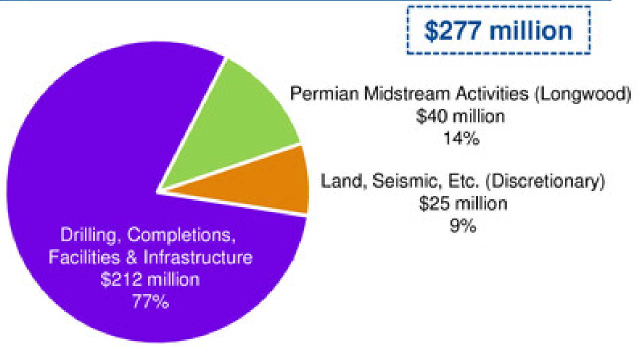
2016E CapEx – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



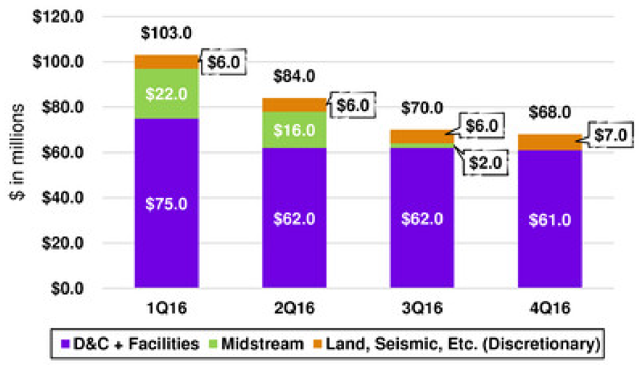
2016E CapEx – 2-Rig Case

(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



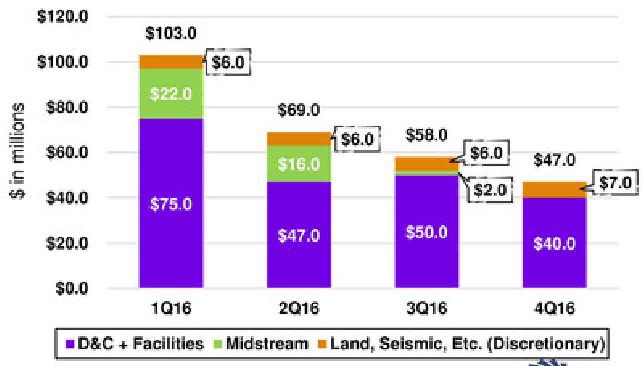
2016E CapEx by Quarter – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



2016E CapEx by Quarter – 2-Rig Case

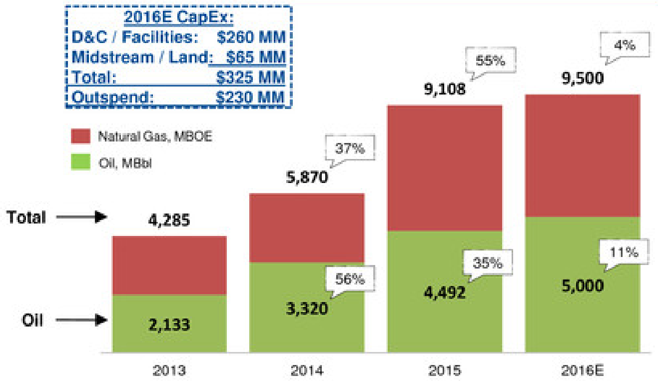
(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



2016 Oil and Natural Gas Production Estimates

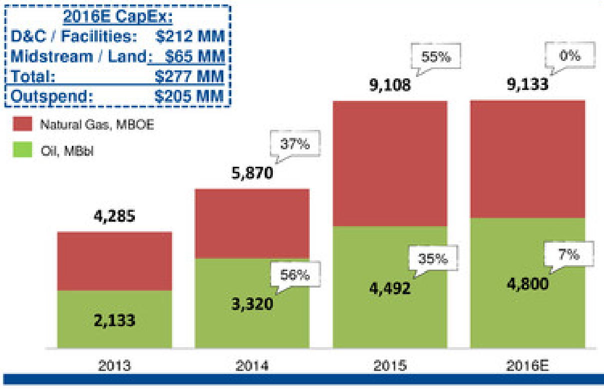
Oil and Natural Gas Production – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



Oil and Natural Gas Production – 2-Rig Case

(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



2016E Oil Production – 3-Rig Case

- Estimated oil production of 4.9 to 5.1 million barrels
  - *11% increase from 2015 to midpoint of 2016 range*
  - *Declines about 200,000 barrels in 2-rig case*
- Average daily oil production of 13,700 Bbl/d, up from 12,300 Bbl/d in 2015
  - *Delaware Basin ~9,600 Bbl/d (70%)*
  - *Eagle Ford ~4,100 Bbl/d (30%)*
- Quarterly oil production more "lumpy" in 2016 due to additional multi-well pads
  - *Q1 2016 down ~3% sequentially due to 3-well and 4-well pad drilling at Wolf; Q4 2016 up 34% over Q4 2015*

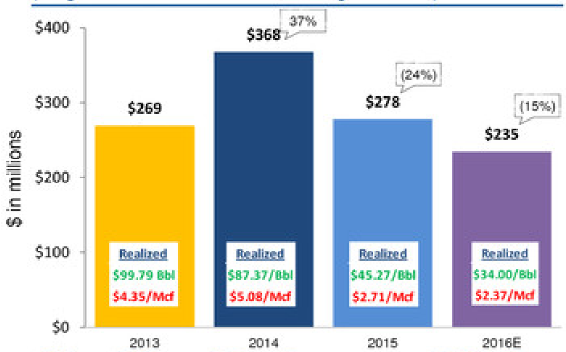
2016E Natural Gas Production – 3-Rig Case

- Estimated natural gas production of 26.0 to 28.0 Bcf
  - *3% decrease from 2015 to midpoint of 2016 range*
  - *Declines about 1 Bcf in 2-rig case*
- Average daily natural gas production of 74.0 MMcf/d, compared to 75.9 MMcf/d in 2015
  - *Haynesville/Cotton Valley ~33.4 MMcf/d (45%)*
  - *Delaware Basin ~29.6 MMcf/d (40%)*
  - *Eagle Ford ~11.0 MMcf/d (15%)*
  - *Q4 2016 up 5% over Q4 2015*

2016 Oil and Natural Gas Revenue Estimates[1]

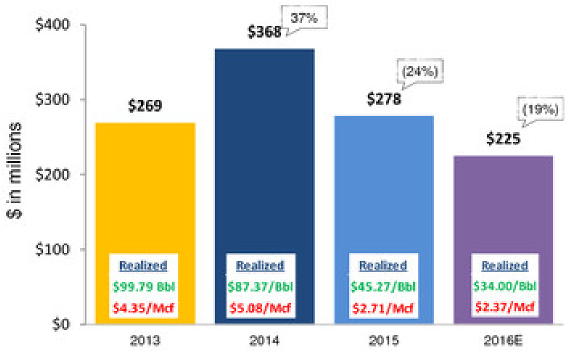
Oil and Natural Gas Revenues – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



Oil and Natural Gas Revenues – 2-Rig Case

(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



2016E Oil and Natural Gas Revenues

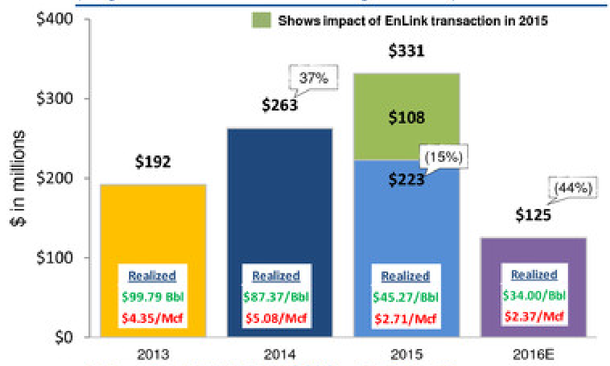
- Revenues impacted by lower estimated 2016 realized oil and natural gas prices – forecasts use strip commodity prices in late January 2016
  - *2016E realized oil price of $34/Bbl vs ~$45/Bbl realized in 2015*
  - *2016E realized natural gas price of $2.37/Mcf vs $2.71/Mcf in 2015*
  - *Assuming $3.00/Bbl average price differential from WTI for oil and Henry Hub for natural gas, assuming price differentials and processing revenues offset*
  - *Realized prices are unhedged*
- Estimated oil and natural gas revenues of $230 to $240 million in 3-rig case
  - *Decrease of ~16% from $278 million in 2015*
  - *Oil and natural gas hedges estimated to contribute $20 million[2] in additional revenues in 2016, as compared to $77 million in 2015*
- Estimated oil and natural gas revenues decline by about $10 million in 2-rig case
- ~53% oil by volume, ~73% oil by revenue in 2016[1]; compared to ~49% oil by volume, ~73% oil by revenue in 2015

(1) 2016E oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 2016 production guidance range as provided on February 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $34.00/Bbl (WTI oil price of $37.00/Bbl less $3.00/Bbl) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional price differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.
(2) At strip oil and natural gas prices in late January 2016.

2016 Adjusted EBITDA Estimates

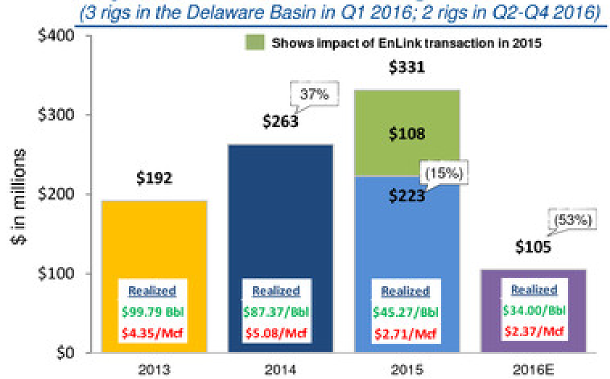
Adjusted EBITDA[(1)(2)] – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



Adjusted EBITDA[(1)(2)] – 2-Rig Case

(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



2016E Adjusted EBITDA[(1)(2)]

- Estimated Adjusted EBITDA[(1)(2)] of $120 to $130 million in 3-rig case
  - *Decrease of ~44% from $223 million in 2015*
- Estimated Adjusted EBITDA[(1)(2)] of $100 to $110 million in 2-rig case
  - *Includes estimated rig release penalty*

2016E Operating Cost Estimates (Unit Costs per BOE)

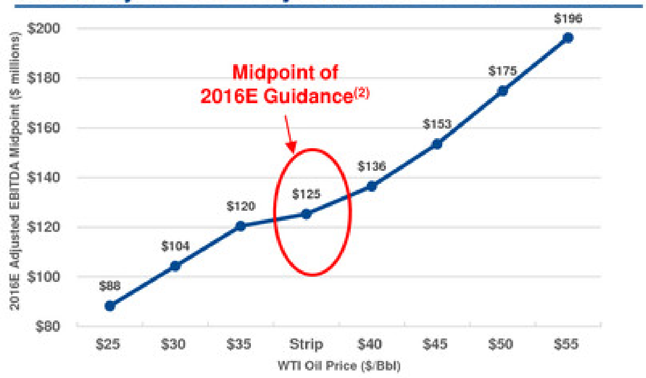
(unit costs per BOE)	Operating Cost Estimates	
	2016E	2015
Production taxes and marketing	$4.25	$3.90
Lease operating	$6.00	$6.39
General and administrative	$5.25	$5.50
Operating cash costs, excluding interest	*$15.50*	*$15.79*
Depletion, depreciation and amortization	$16.25	$19.63

Projected to decline from $6.50 in Q1 to $5.50 in Q4

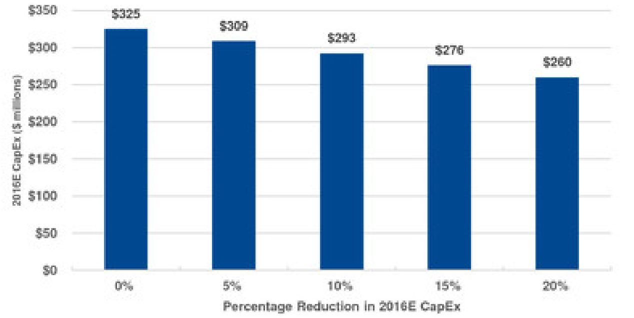
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) 2016E oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 2016 production guidance range as provided on February 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $34.00/Bbl (WTI oil price of $37.00/Bbl less $3.00/Bbl) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional price differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.

Commodity Price and CapEx Estimates Significantly Impact Forecasts

Sensitivity of 2016E Adjusted EBITDA[1] to Oil Price



Sensitivity of 2016E CapEx to Additional Cost Savings



- *Relatively small improvements in oil price and service cost reductions can significantly improve financial forecasts and reduce estimated CapEx*
- *$10/Bbl increase in oil price improves Adjusted EBITDA[1] by ~$33 million*
- *10 to 15% decrease in well costs due to further drilling efficiencies and service cost savings reduces CapEx by $33 to $50 million*
- *$10/Bbl increase in oil price and additional 10% in CapEx reductions reduce operating cash outspend by ~$66 million – about 30% of estimated outspend in 3-rig case*
- *Matador technical teams focused on continuing to reduce both operating costs and capital expenditures in 2016 and continuing to improve well performance*

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) Estimated 2016 oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 2016 production guidance range as provided on February 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $34.00/Bbl (WTI oil price of $37.00/Bbl less $3.00/Bbl) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional price differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.

Hedging Profile

Remainder of 2016 Hedges(1)

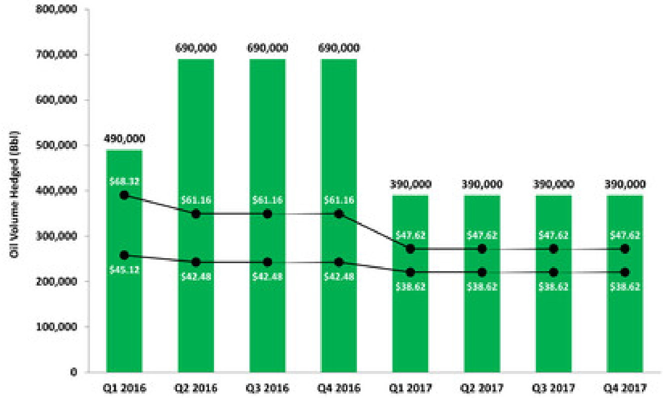
- **Oil**: ~2.3 million barrels of oil hedged for remainder of 2016 at weighted average floor and ceiling prices of $42/Bbl and $61/Bbl, respectively – Over 50% of oil hedged for remainder of 2016
- **Natural Gas**: 10.0 Bcf of natural gas hedged for remainder of 2016 at weighted average floor and ceiling of $2.60/MMBtu and $3.53/MMBtu, respectively – Approximately 44% of natural gas hedged for remainder of 2016

2017 Hedges(1)

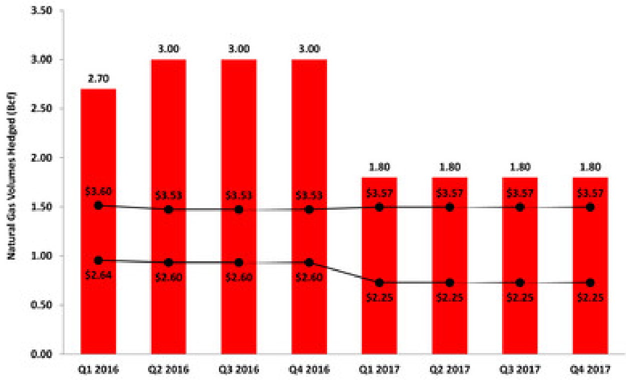
- **Oil**: ~1.6 million barrels of oil hedged for 2017 ($38/Bbl floor and $48/Bbl ceiling)
- **Natural Gas**: 7.2 Bcf of natural gas hedged for 2017 ($2.25/MMBtu floor and $3.57/MMBtu ceiling)

- *Oil and natural gas hedges estimated to add over $20 million(2) to projected oil and natural gas revenues in 2016*

Oil Hedges (Costless Collars)



Natural Gas Hedges (Costless Collars)



(1) At March 17, 2016.
(2) At strip oil and natural gas prices in late January 2016.

Credit Agreement Status

- **Strong, supportive bank group led by Royal Bank of Canada**
- **Borrowing base reaffirmed on October 16, 2015 at $375 million based on June 30, 2015 reserves**
  - *Maturity of credit facility extended from December 2016 to October 2020*
  - *Bank group unanimous in supporting borrowing base affirmation and maturity extension*
- **No borrowings outstanding at December 31, 2015**
- **Net Debt/Adjusted EBITDA(1)(2)(3) of 0.9x at December 31, 2015**

TIER	Conforming Borrowing Base Utilization	LIBOR Margin	BASE Margin	Commitment Fee
Tier One	x < 25%	150 bps	50 bps	37.5 bps
Tier Two	25% < or = x < 50%	175 bps	75 bps	37.5 bps
Tier Three	50% < or = x < 75%	200 bps	100 bps	50 bps
Tier Four	75% < or = x < 90%	225 bps	125 bps	50 bps
Tier Five	90% < or = x < 100%	250 bps	150 bps	50 bps

- **Financial covenants**
  - *Maximum Total Debt to Adjusted EBITDA(2) Ratio of not more than 4.25:1.00*

(1) Net debt is equal to debt outstanding less available cash (including $43 million of restricted cash held in escrow at December 31, 2015).
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA an a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) LTM EBITDA at December 31, 2015 and Net Debt pro forma at December 31, 2015 after giving effect to the March 2016 equity offering.

Summary and Initial 2016 Guidance (As Provided February 3, 2016)

- **Plan to run 3 rigs in the Delaware Basin throughout 2016, but will reduce to 2 rigs as early as Q2 2016 if oil prices drop and remain below $30 per barrel**
- **Delaware Basin drilling focused on Wolf and Rustler Breaks Wolfcamp development and further delineation of Ranger, Arrowhead and Twin Lakes prospect areas**
- **No Eagle Ford and minimal Haynesville non-operated drilling activity in 2016**
- **Initial 2016 guidance based on assumption of running 3 rigs throughout 2016**

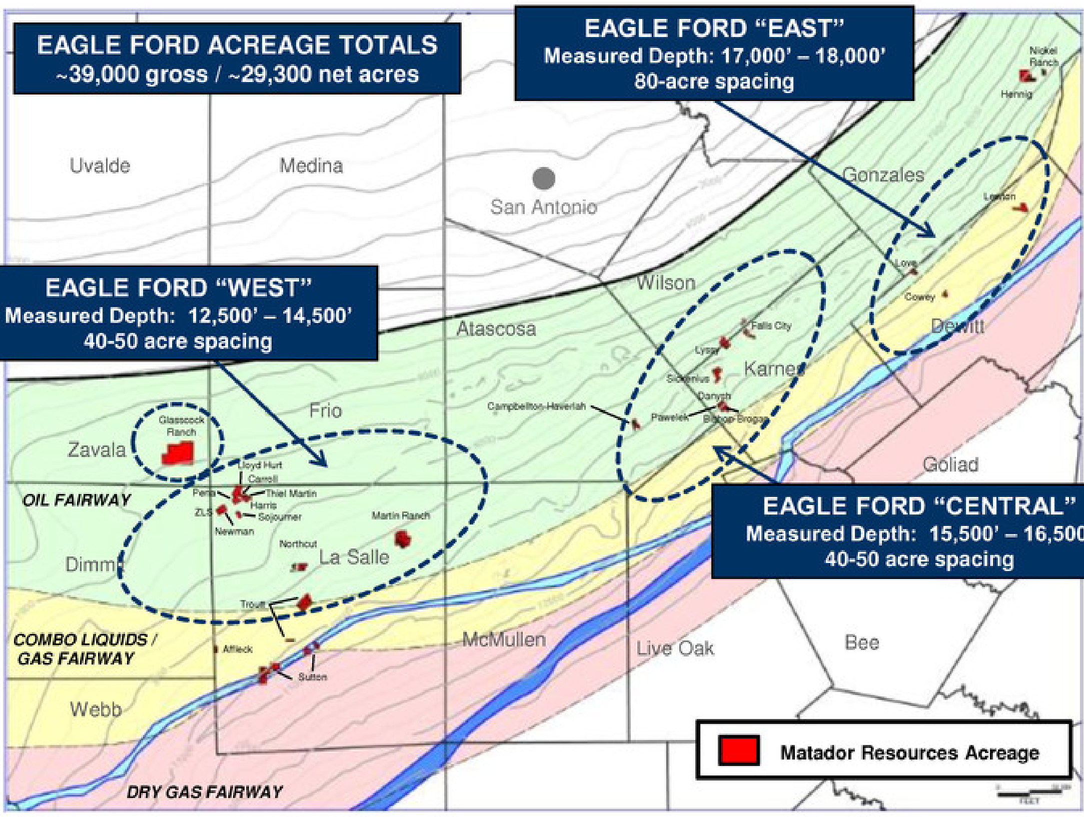
	Actual 2015 Results	*2016 Guidance*	*% Change*
Capital Spending	$482 million[(1)]	$325 million	- 33%
Total Oil Production	4.5 million Bbl	4.9 to 5.1 million Bbl	+ 11%
Total Natural Gas Production	27.7 Bcf	26.0 to 28.0 Bcf	- 3%
Total Oil Equivalent Production	9.1 million BOE	9.2 to 9.8 million BOE	+ 4%
Adjusted EBITDA[(2)]	$223 million	$120 to $130 million[(3)]	- 44%

(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Estimated 2016 Adjusted EBITDA is based upon the midpoint of 2016 production guidance range as provided on February 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $34.00/Bbl (WTI oil price of $37.00/Bbl less $3.00/Bbl of estimated price differentials) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional price differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.



Appendix

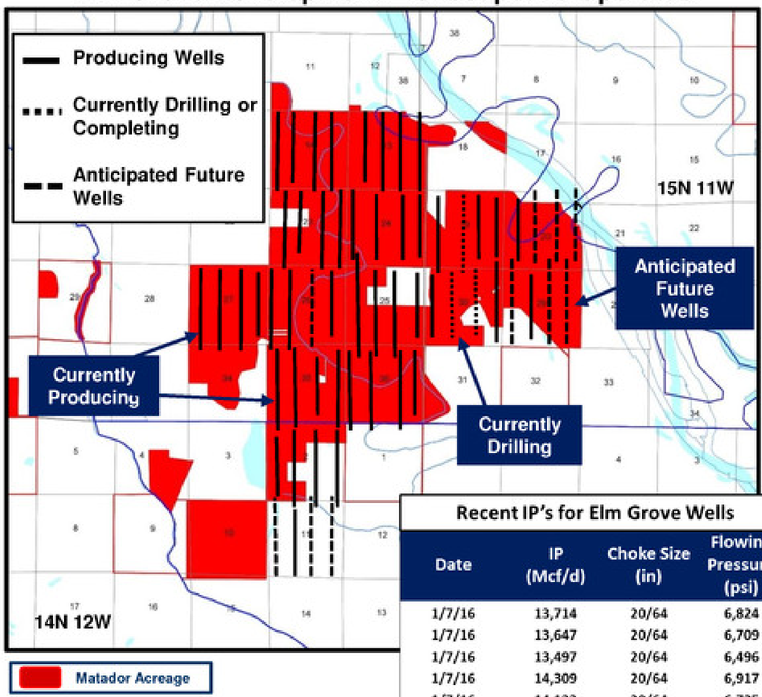
Eagle Ford – "Oil Bank"



Note: All acreage at February 24, 2016. Some tracts not shown on map.

Haynesville Operations

Elm Grove Development – Chesapeake Operated



Recent IP's for Elm Grove Wells

Date	IP (Mcf/d)	Choke Size (in)	Flowing Pressure (psi)
1/7/16	13,714	20/64	6,824
1/7/16	13,647	20/64	6,709
1/7/16	13,497	20/64	6,496
1/7/16	14,309	20/64	6,917
1/7/16	14,123	20/64	6,725
1/7/16	12,632	18/64	6,959
1/14/16	13,497	20/64	6,798
1/14/16	14,374	20/64	6,907
1/15/16	11,884	18/64	7,186

2015 Haynesville Non-Op Program

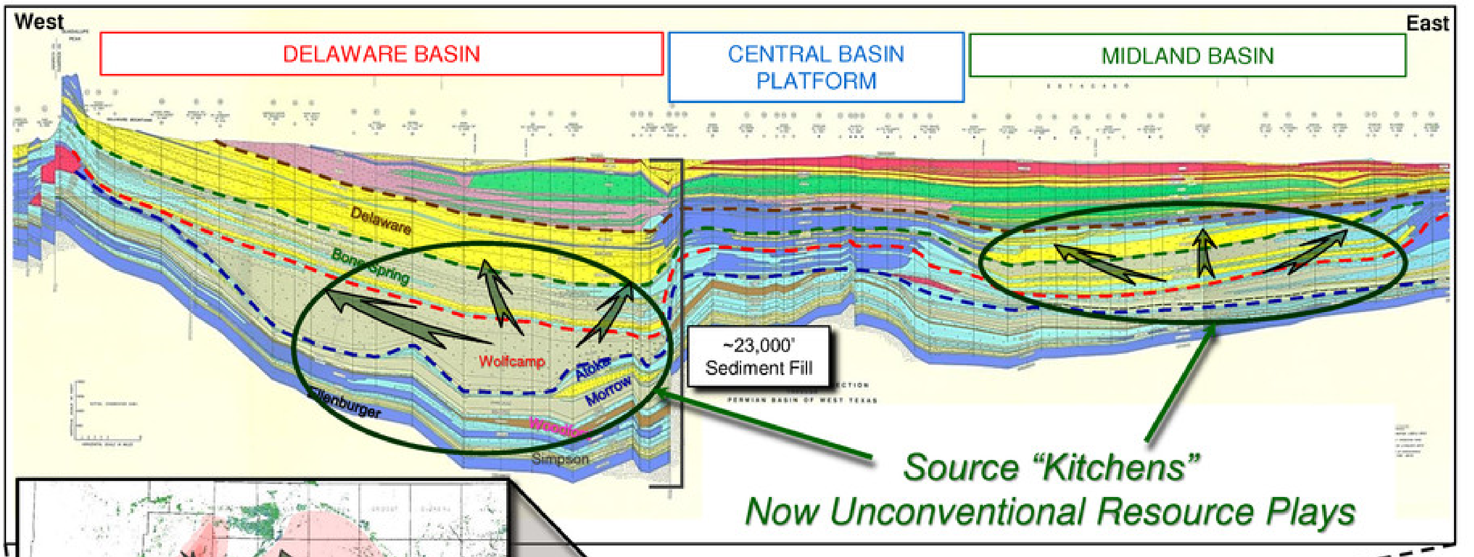
- 22 gross (1.9 net) wells turned to sales throughout Tier 1 Haynesville in 2015
- Includes 9 gross (1.6 net) wells turned to sales on Elm Grove properties operated by Chesapeake in 2015 (shown on map at left)
  - *Chesapeake deferred first production on 9 gross (1.9 net) Elm Grove wells drilled and completed in 2015 until early Q1 2016*

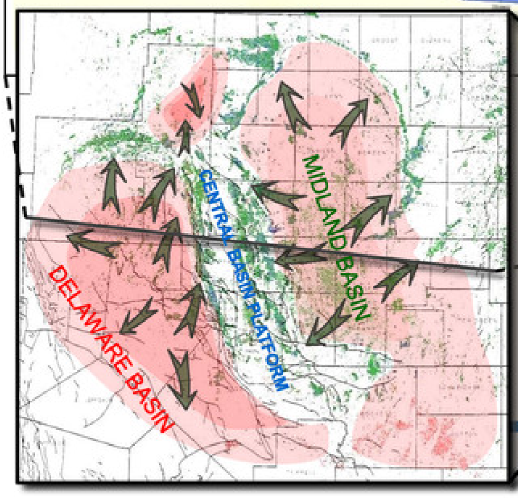
2016 Haynesville Non-Op Program

- 5 gross (0.6 net) wells expected to be drilled and completed in the Haynesville in 2016
- Estimated capital expenditures of ~$4 million
- 9 gross (1.9 net) Elm Grove wells operated by Chesapeake turned to sales in early 2016
  - *Initial rates of ~13 MMcf/d of natural gas with drilling and completion costs of ~$7 million per well*
- Haynesville and Cotton Valley average daily natural gas production currently ~50 MMcf/d(1) with recent well additions

Note: All acreage at February 24, 2016.
(1) As of January 31, 2016.

Delaware Basin – A "World Class" Hydrocarbon System





- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 <u>conventional</u> reservoirs with cumulative production >1.0 million Bbl each
- Cumulative production from 1,500 conventional reservoirs, as of year 2000 (pre-horizontal drilling) <u>>30.0 billion Bbl</u>[(1)]

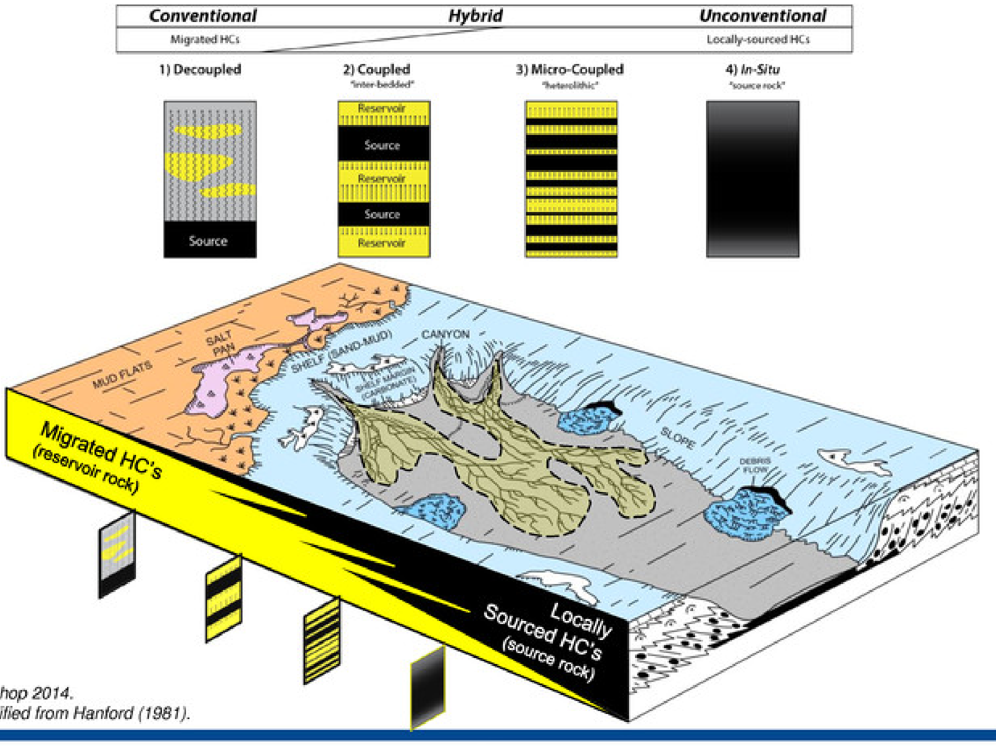
(1) Dutton et al, AAPG 2005.

Spectrum of Unconventional Play Types

In general there is no consensus on the what an "unconventional" reservoir is…

At Matador, we think of an unconventional reservoir as a spectrum of play types.

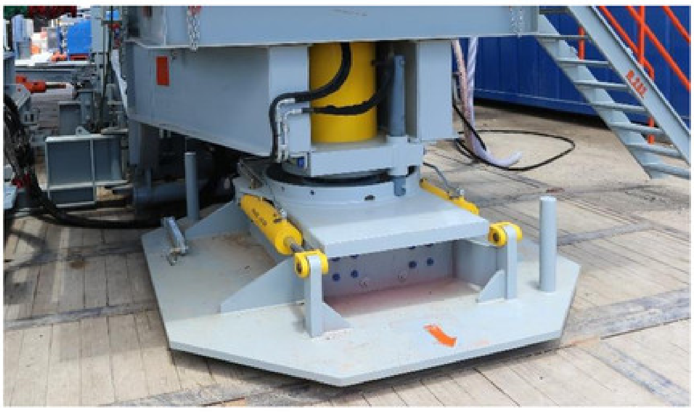
The distribution and quality of these play types are both spatially and temporally variable.



Play types from Bishop 2014.
Block diagram modified from Hanford (1981).

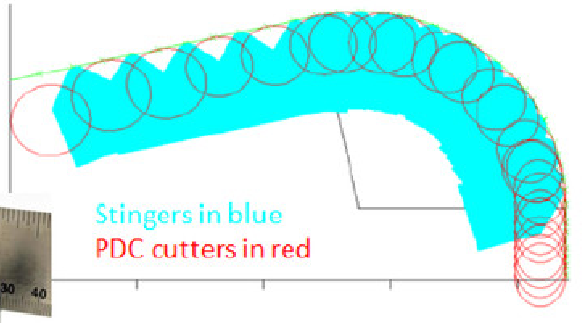
New Rig Technology for Horizontal Drilling – Saving Time and Money!

- **7,500 psi Pressure Rating**
  - Estimated reduction in drilling time of 20 to 25% in the lateral on Wolfcamp wells
- **Telescoping Flex-joint**
  - Estimated reduction in drilling time of 12 to 18 hours per well
- **Integrated Mud-Gas Separator**
  - Estimated savings of 50% compared to rental separator
- **BOP Wrangler**
  - Estimated reduction in drilling time of 12 hours per well
- **Walking System & V-door turned 90°**
  - Allows for batch-drilling and simultaneous operations
- **Reduced Downtime**



Future Bit Technology – The Evolution of the PDC bit

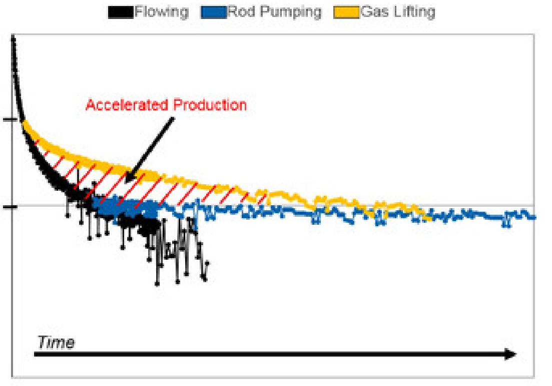
- Matador continues to be at the forefront of new bit technology
- Smith Bits latest technology StingBlade design
- StingBlade design features
  - *Alternating Stinger/PDC cutters*
  - *Stinger cutters cut troughs in the formation with the PDC cutters coming behind and removing the ridges*
  - *Stinger cutters do the hard work, PDC cutters keep the speed*
  - *Ultimate combination of speed, durability and steerability*



Optimizing Artificial Lift Operations Across the Permian Basin

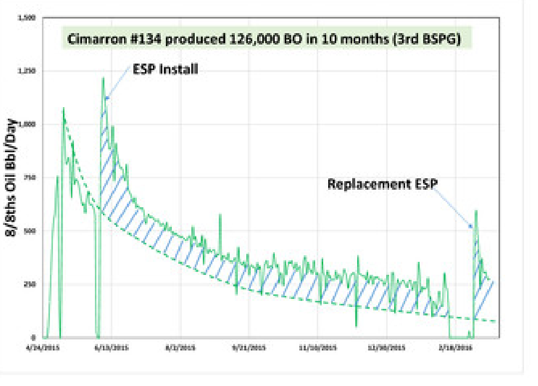
Optimizing Gas Lift Operations

- Numerous 2nd Bone Spring wells on gas lift
- Accelerates production while reducing LOE
- Lower maintenance costs than beam pump
- Helps wells recover faster from offset fracs
- Very efficient with high GOR wells



Using ESP's to Optimize Production

- Accelerated production while maintaining a controlled drawdown of bottomhole pressure
- BHP gauges aid in analyzing 3rd Bone Spring reservoir properties
- Quick startup after shut in for maintenance = minimal downtime
- Quiet operation in environmentally sensitive areas
- Able to unload offset frac water even more effectively than gas lift in wells with lower GOR and high reservoir deliverability

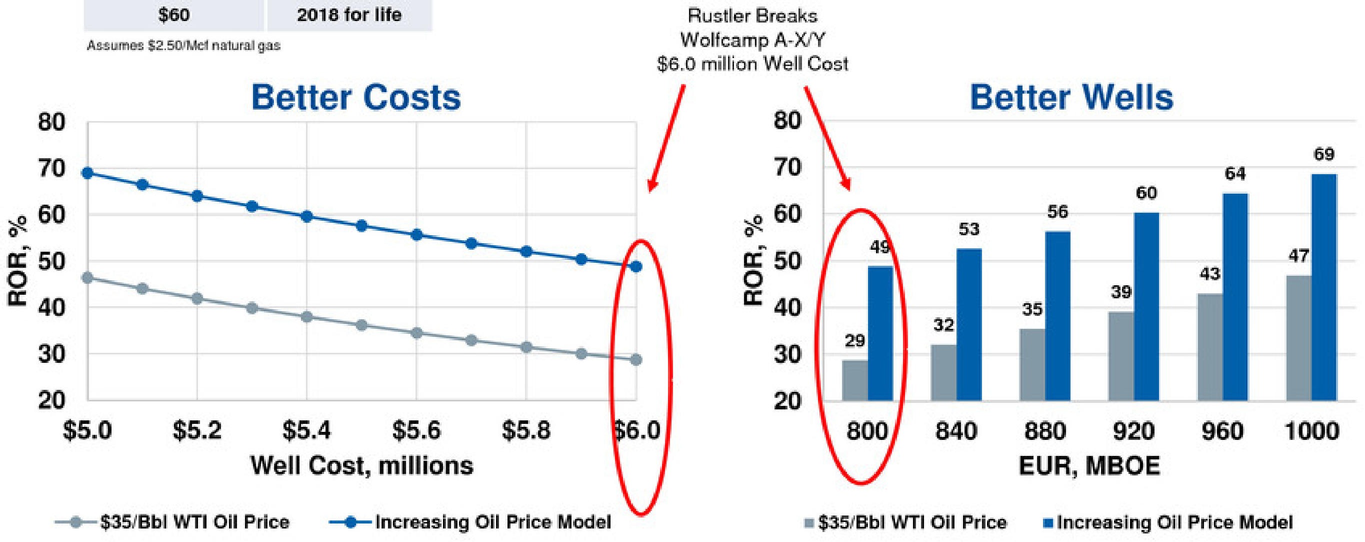


Note: Graph and data in gas lift figure above is for illustrative purposes only and not meant to reflect historical or forecasted data from actual well.

Delaware Basin: ROR Relationship to Well Cost[1] Savings and Improved EUR[2]

Increasing Oil Price Model	Year
$30	1st 6 mo. 2016
$40	2nd 6 mo. 2016
$50	2017
$60	2018 for life

Assumes $2.50/Mcf natural gas



Every $100,000 saved increases ROR by 2% on average

Every 5% increase in EUR increases ROR by 4% on average

(1) Estimated well costs for a development well in Q1 2016, including drilling, completion, production and facilities costs.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Board of Directors – Expertise and Stewardship

Board Members	Professional Experience	Business Expertise
David M. Laney Lead Director	- Past Chairman, Amtrak Board of Directors - Former Partner, Jackson Walker LLP	Law and Investments
Reynald A. Baribault Director	- Vice President / Engineering and Co-founder, North Plains Energy, LLC - President and CEO, IPR Energy Partners, LLC - Former Vice President, Netherland, Sewell & Associates, Inc.	Oil and Gas Exploration & Development
Gregory E. Mitchell Director	- President and CEO, Toot'n Totum Food Stores	Petroleum Retailing
Dr. Steven W. Ohnimus Director	- Retired Vice President and General Manager, Unocal Indonesia	Oil and Gas Operations
Carlos M. Sepulveda, Jr. Director	- Executive Chairman of the Board, Triumph Bancorp, Inc. - Retired President and CEO, Interstate Battery System International, Inc. - Director and Audit Chair, Cinemark Holdings, Inc.	Business and Finance
Margaret B. Shannon Director	- Retired Vice President and General Counsel, BJ Services Co. - Former Partner, Andrews Kurth LLP	Law and Corporate Governance
Don C. Stephenson Director	- Retired Partner, Baker Botts L.L.P.	Law and Tax Strategy
George M. Yates Director	- Chairman & CEO of HEYCO Energy Group, Inc.	Oil and Gas Exploration & Development

Special Board Advisors – Expertise and Stewardship

Special Board Advisors	Professional Experience	Business Expertise
Ronney F. Coleman	- Retired President – North America, Archer - Former Vice President North America Pumping, BJ Services Co.	Oilfield Services
Marlan W. Downey	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil and Gas Exploration
John R. Gass	- VP, Eastern Hemisphere Operations, Nabors Drilling International Limited based in Dubai, UAE - Previously spent 28 years with Parker Drilling Company in various management roles	Oil and Gas Drilling
David F. Nicklin	- Retired Executive Director of Exploration, Matador Resources Company	Oil and Gas Exploration
Wade I. Massad	- Managing Member, Cleveland Capital Management, LLC - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Greg L. McMichael	- Retired Vice President and Group Leader – Energy Research of A.G. Edwards	Capital Markets
Dr. James D. Robertson	- Retired VP Exploration, Chief Geophysicist, ARCO International	Oil and Gas Exploration
Michael C. Ryan	- Partner, Berens Capital Management - Former Director, Matador Resources Company	International Business and Finance

Proven Management Team – Experienced Leadership

Management Team	Background and Prior Affiliations	Industry Experience	Matador Experience
Joseph Wm. Foran Founder, Chairman and CEO	- Matador Petroleum Corporation, Foran Oil Company, James Cleo Thompson Jr.	35 years	Since Inception
Matthew V. Hairford President, Chair of Operating Committee	- Samson, Sonat, Conoco	31 years	Since 2004
David E. Lancaster EVP and CFO	- Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	36 years	Since 2003
Craig N. Adams EVP – Land, Legal & Administration	- Baker Botts L.L.P., Thompson & Knight LLP	22 years	Since 2012
Van H. Singleton, II EVP – Land	- Southern Escrow & Title, VanBrannon & Associates	19 years	Since 2007
Bradley M. Robinson SVP of Reservoir Engineering and CTO	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	38 years	Since Inception
Billy E. Goodwin SVP of Operations	- Samson, Conoco	31 years	Since 2010
G. Gregg Krug SVP and Head of Marketing and Midstream	- Williams Companies, Samson, Unit Corporation	32 years	Since 2005
Matthew D. Spicer VP and General Manager of Midstream	- Matador Resources Company	2 years	Since 2014
Trent W. Green VP – Production	- HEYCO, Bass Enterprises, Schlumberger, S.A. Holditch & Associates, Inc., Amerada Hess	26 years	Since 2015
Robert T. Macalik VP and CAO	- Pioneer Natural Resources, PricewaterhouseCoopers (PwC)	13 years	Since 2015
Kathryn L. Wayne Controller and Treasurer	- Matador Petroleum Corporation, Mobil	31 years	Since Inception

Adjusted EBITDA Reconciliation

This investor presentation includes the non-GAAP financial measure of Adjusted EBITDA. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. "GAAP" means Generally Accepted Accounting Principles in the United States of America. The Company believes Adjusted EBITDA helps it evaluate its operating performance and compare its results of operations from period to period without regard to its financing methods or capital structure. The Company defines Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or net cash provided by operating activities as determined by GAAP.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as an indicator of the Company's operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents the calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively, that are of a historical nature. Where references are pro forma, forward-looking, preliminary estimates or prospective in nature, and not based on historical fact, the table does not provide a reconciliation. The Company could not provide such reconciliations without undue hardship because such Adjusted EBITDA numbers are estimations, approximations and/or ranges. In addition, it would be difficult for the Company to present a detailed reconciliation on account of many unknown variables for the reconciling items.

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(In thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net (loss) Income:												
Net (loss) income	$ (27,596)	$ 7,153	$ 6,194	$ 3,941	$ 3,801	$ (6,676)	$ (9,197)	$ (21,188)	$ (15,505)	$ 25,119	$ 20,105	$ 15,374
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Total income tax provision (benefit)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056
Depletion, depreciation and amortization	7,111	8,180	7,287	9,176	11,205	19,914	21,680	27,655	28,232	20,234	26,127	23,802
Accretion of asset retirement obligations	39	57	62	51	53	58	59	86	81	80	86	100
Full-cost ceiling impairment	35,673	-	-	-	-	33,205	3,596	26,674	21,230	-	-	-
Unrealized (gain) loss on derivatives	1,668	(332)	(2,870)	(3,604)	3,270	(15,114)	12,993	3,653	4,825	(7,526)	9,327	606
Stock-based compensation expense	53	128	1,234	991	(363)	191	(51)	363	492	1,032	1,239	1,134
Net loss on asset sales and inventory impairment	-	-	-	154	-	60	-	425	-	192	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(In thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:												
Net cash provided by operating activities	$ 12,732	$ 6,799	$ 14,912	$ 27,425	$ 5,110	$ 46,416	$ 28,799	$ 43,903	$ 32,229	$ 51,684	$ 43,280	$ 52,278
Net change in operating assets and liabilities	(2,690)	8,386	(3,004)	(15,286)	15,920	(18,491)	(500)	(6,235)	7,126	(12,553)	15,265	(3,630)
Interest expense, net of non-cash portion	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Current income tax (benefit) provision	-	(45)	(1)	-	- -		188	(188)	46	32	902	(576)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(In thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015	4Q 2015
Unaudited Adjusted EBITDA reconciliation to Net (loss) Income:								
Net (loss) income	$ 16,363	$ 18,226	$ 29,619	$ 46,563	$ (50,234)	$ (157,091)	$ (242,059)	$ (230,401)
Interest expense	1,396	1,616	673	1,649	2,070	5,869	7,229	6,586
Total income tax provision (benefit)	9,536	10,634	16,504	27,701	(26,390)	(89,350)	(33,305)	1,677
Depletion, depreciation and amortization	24,030	31,797	35,143	43,767	46,470	51,768	45,237	35,370
Accretion of asset retirement obligations	117	123	130	134	112	132	182	307
Full-cost ceiling impairment	-	-	-	-	67,127	229,026	285,721	219,292
Unrealized (gain) loss on derivatives	3,108	5,234	(16,293)	(50,351)	8,557	23,532	(6,733)	13,909
Stock-based compensation expense	1,795	1,834	1,038	857	2,337	2,794	1,755	2,564
Net loss on asset sales and inventory impairment	-	-	-	-	97	-	-	(1,005)
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**	**$ 48,299**

(In thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015	4Q 2015
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:								
Net cash provided by operating activities	$ 31,945	$ 81,530	$ 66,883	$ 71,123	$ 93,346	$ 20,043	$ 72,535	$ 22,611
Net change in operating assets and liabilities	21,729	(15,221)	(586)	56	(45,234)	40,843	(20,846)	16,254
Interest expense, net of non-cash portion	1,396	1,616	673	1,649	2,070	5,869	6,678	6,285
Current income tax (benefit) provision	1,275	1,539	(156)	(2,525)	-	-	(295)	3,254
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	17	(36)	(75)	(45)	(105)
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**	**$ 48,299**

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Year Ended December 31,							
(In thousands)	2008	2009	2010	2011	2012	2013	2014	2015
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):								
Net income (loss)	$103,878	($14,425)	$6,377	($10,309)	($33,261)	$45,094	$110,771	($679,785)
Interest expense	-	-	3	683	1,002	5,687	5,334	21,754
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	64,375	(147,368)
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	134,737	178,847
Accretion of asset retirement obligations	92	137	155	209	256	348	504	734
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	-	$801,166
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	(58,302)	39,265
Stock-based compensation expense	665	656	898	2,406	140	3,897	5,524	9,450
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	-	($908)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$223,155**

	Year Ended December 31,							
(In thousands)	2008	2009	2010	2011	2012	2013	2014	2015
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:								
Net cash provided by operating activities	$25,851	$1,791	$27,273	$61,868	$124,228	$179,470	$251,481	$208,535
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	5,978	(8,980)
Interest expense, net of non-cash portion	-	-	3	683	1,002	5,687	5,334	20,902
Current income tax (benefit) provision	$10,448	($2,324)	(1,411)	(46)	-	404	133	2,959
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	17	(261)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$223,155**

Note: LTM is last 12 months.

PV-10 Reconciliation

PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of the Company's properties. Matador and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. PV-10 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing PV-10 by the discounted future income taxes associated with such reserves.

	At December 31, 2013	At December 31, 2014	At December 31, 2015
PV-10 *(in millions)*	**$655.2**	**$1,043.4**	**$541.6**
Discounted Future Income Taxes *(in millions)*	**$(76.5)**	**$(130.1)**	**$(12.4)**
Standardized Measure *(in millions)*	**$578.7**	**$913.3**	**$529.2**