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) February 3, 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 2.02 Results of Operations and Financial Condition.

Attached hereto as Exhibit 99.1 is a press release (the "Press Release") issued by Matador Resources Company (the "Company") on February 3, 2016, announcing its 2015 proved oil and natural gas reserves and 2016 capital budget and guidance. The Press Release is incorporated by reference into this Item 2.02, and the foregoing description of the Press Release is qualified in its entirety by reference to this exhibit.

The Company is hosting an Analyst Day event on February 3, 2016 at which it intends to make a presentation concerning its 2016 capital investment plan and current operations. The materials to be utilized during the presentation (the "Materials") are furnished as Exhibit 99.2 hereto and incorporated herein by reference.

The information furnished pursuant to this Item 2.02, including Exhibits 99.1 and 99.2, shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended (the "Securities Act"), unless specifically identified therein as being incorporated therein by reference.

In the Press Release and the Materials, the Company has included as "non-GAAP financial measures," as defined in Item 10 of Regulation S-K of the Exchange Act, (i) 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") and (ii) present value discounted at 10% (pre-tax) of estimated total proved reserves ("PV-10"). In the Press Release and the Materials, the Company has provided reconciliations of the non-GAAP financial measures to the most directly comparable financial measures calculated and presented in accordance with generally-accepted accounting principles ("GAAP") in the United States. In addition, in the Press Release and the Materials, the Company has provided the reasons why the Company believes those non-GAAP financial measures provide useful information to investors.

Item 7.01 Regulation FD Disclosure.

Item 2.02 above is incorporated herein by reference.

The information furnished pursuant to this Item 7.01, including Exhibits 99.1 and 99.2, shall not be deemed to be "filed" for the purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any filing under the Securities Act 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	Press Release, dated February 3, 2016.
99.2	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: February 3, 2016	By:	/s/ Craig N. Adams
	Name:	Craig N. Adams
	Title:	Executive Vice President

Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Press Release, dated February 3, 2016.
99.2	Presentation Materials.

Exhibit 99.1

MATADOR RESOURCES COMPANY ANNOUNCES YEAR-END 2015 RESERVES AND 2016 CAPITAL BUDGET

DALLAS, February 3, 2016 – Matador Resources Company (NYSE: MTDR) (“Matador” or the “Company”), an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources, with an emphasis on oil and natural gas shale and other unconventional plays and with a current focus on its Delaware Basin operations in Southeast New Mexico and West Texas, today announced its 2015 year-end reserves and its 2016 capital budget and operating plan.

Year-End 2015 Proved Oil and Natural Gas Reserves

Matador is pleased to announce its proved oil and natural gas reserves were 85.1 million barrels of oil equivalent (“BOE”) at December 31, 2015, an all-time high for the Company and a 24% increase from 68.7 million BOE at December 31, 2014. The present value, discounted at 10%, of the estimated future net cash flows before income taxes (“PV-10”) of Matador’s total proved oil and natural gas reserves at December 31, 2015 was $541.6 million, as compared to a PV-10 of $1.04 billion at December 31, 2014, a 48% year-over-year decrease resulting from declines in oil and natural gas prices between the two periods. At December 31, 2015, Matador’s proved oil and natural gas reserves were 40% proved developed reserves, as compared to 45% at December 31, 2014.

For the year ended December 31, 2015, Matador’s proved oil and natural gas reserves were estimated using an average oil price of $46.79 per barrel and an average natural gas price of $2.59 per million British Thermal Unit (“MMBtu”), a decrease of 49% and 40%, respectively, as compared to an average oil price of $91.48 per barrel and an average natural gas price of $4.35 per MMBtu used to estimate Matador’s proved reserves for the year ended December 31, 2014.

Proved oil reserves increased 89% to 45.6 million barrels at December 31, 2015, as compared to 24.2 million barrels at December 31, 2014. Including Matador’s 2015 total oil production of approximately 4.5 million barrels, Matador effectively doubled its proved oil reserves year-over-year, despite an almost 50% year-over-year decline in the oil price required to be used to estimate proved oil reserves at December 31, 2015. Matador’s proved oil reserves in the Delaware Basin increased almost four-fold to 31.4 million barrels at December 31, 2015, as compared to 8.1 million barrels at December 31, 2014, resulting from the Company’s ongoing drilling and completion operations in the Delaware Basin. Proved oil reserves comprised 54% of the Company’s total proved reserves at December 31, 2015, as compared to 35% at December 31, 2014.

Proved natural gas reserves decreased 11% to 236.9 billion cubic feet at December 31, 2015, as compared to 267.1 billion cubic feet at December 31, 2014. The decline in year-over-year natural gas reserves resulted principally from the reclassification of proved undeveloped natural gas reserves to contingent resources, primarily in the Haynesville shale, as a result of the decline in natural gas prices during 2015. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by Matador or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

Matador's natural gas reserves comprised 46% of Matador's total proved reserves at December 31, 2015, as compared to 65% at December 31, 2014.

2016 Capital Budget, Operating Plan and Guidance

Matador is also pleased to announce its 2016 capital budget, operating plan and guidance. The Company's 2016 capital budget is based on running three operated drilling rigs in the Delaware Basin throughout 2016, although Matador will consider reducing its Delaware Basin program to two operated drilling rigs as early as the second quarter of 2016 should oil prices drop back and remain below $30 per barrel.

Key elements of the Company's 2016 capital budget, operating plan and guidance include the following:

- 2016 capital budget of $325 million, including $260 million for drilling, completions, facilities and infrastructure costs, $40 million for midstream activities in the Delaware Basin and $25 million for discretionary land and seismic data;

- 2016 oil production guidance of 4.9 to 5.1 million barrels, an increase of approximately 11% from 2015 actual oil production of 4.5 million barrels to the midpoint of 2016 production guidance;

- 2016 natural gas production guidance of 26.0 to 28.0 billion cubic feet, a decrease of approximately 3% from 2015 actual natural gas production of 27.7 billion cubic feet to the midpoint of 2016 production guidance;

- 2016 total oil equivalent production guidance of 9.2 to 9.8 million BOE, an increase of approximately 4% from 2015 actual oil equivalent production of 9.1 million BOE to the midpoint of 2016 production guidance; and

- 2016 Adjusted EBITDA guidance of $120 to $130 million, a decrease of approximately 44% from estimated 2015 Adjusted EBITDA of $220 to $225 million (final number pending completion of 2015 audited financial statements) based on estimated average realized prices for 2016 of $34.00 per barrel for oil (West Texas Intermediate oil price of $37.00 per barrel less $3.00 per barrel, based on the forward strip for oil prices in late January 2016) and $2.37 per thousand cubic feet for natural gas (NYMEX Henry Hub natural gas price, based on the forward strip for natural gas prices in late January 2016 and assuming regional differentials and uplifts from natural gas processing roughly offset). These estimated 2016 realized prices compare to estimated 2015 realized oil and natural gas prices received of $45.27 per barrel and $2.71 per thousand cubic feet, respectively.

Analyst Day Details

Management plans to provide its detailed 2016 operational plan, capital budget and forecasts, plus an update on its ongoing operations and continued improvements in each of its Delaware Basin focus areas, at the Company's Analyst Day scheduled to be held on Wednesday, February 3, 2016 at 9:00 a.m. Central Time in the Fort Worth Ballroom at the Westin Galleria Dallas hotel, 13340 Dallas Pkwy, Dallas, Texas 75240. The presentation will conclude with a question and answer session for those in attendance. Individuals who are unable to attend in person can participate in the live conference call or via virtual webcast. Following the presentation, lunch will be provided.

To access the Analyst Day conference call in a listen-only mode, domestic participants should dial (855) 875-8781 and international participants should dial (720) 634-2925. The participant passcode is 25027629. To access the virtual webcast, participants should use the following link: http://edge.media-server.com/m/p/gsoor954. All details can be accessed through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab.

A replay of the Analyst Day conference call will be made available through Friday, February 26, 2016 via webcast. A link to the replay webcast will be available through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab.

A copy of the Company's Analyst Day presentation will be available prior to the event through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab.

Analyst Day Follow-up Conference Call

Management also plans to host a live follow-up conference call at 3:30 p.m. Central Time on Wednesday, February 3, 2016 following the Company's Analyst Day presentation for anyone who has additional questions. To access the conference call, domestic participants should dial (855) 875-8781 and international participants should dial (720) 634-2925. The participant passcode is 25505768. To access the virtual webcast, participants should use the following link: http://edge.media-server.com/m/p/bshpb4om. All details can be accessed through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab.

A replay of the Analyst Day follow-up conference call will be made available through Friday, February 26, 2016 via webcast. A link to the replay webcast will be available through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab.

About Matador Resources Company

Matador is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Its current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. Matador also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

For more information, visit Matador Resources Company at www.matadorresources.com.

Forward-Looking Statements

This press release includes “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 financial and operational performance; general economic conditions; the Company’s ability to execute its business plan, including whether its 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; its ability to replace reserves and efficiently develop current reserves; costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; its ability to make acquisitions on economically acceptable terms; its ability to integrate acquisitions, including the HEYCO merger; availability of sufficient capital to execute its business plan, including from future cash flows, increases in its 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 press release, 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 press release. All forward-looking statements are qualified in their entirety by this cautionary statement.

Adjusted EBITDA

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, including stock option and grant expense and restricted stock and restricted stock units expense and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. 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.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from 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. References in this press release to Adjusted EBITDA are pro forma, forward-looking, preliminary or prospective in nature, and not based on historical fact. The Company could not provide reconciliations of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively, without undue hardship because the Adjusted EBITDA numbers included in this press release are estimations, approximations or ranges. In addition, it would be difficult for us to present a detailed reconciliation on account of many unknown variables for the reconciling items.

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 our 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. The PV-10 at December 31, 2014 may be reconciled to the Standardized Measure of discounted future net cash flows at such date by reducing PV-10 by the discounted future income taxes associated with such reserves. The PV-10 value at December 31, 2014 was $1.04 billion and the discounted future income taxes at December 31, 2014 were $130.1 million.

We have not provided a reconciliation of PV-10 to Standardized Measure at December 31, 2015. We could not provide such a reconciliation without undue hardship because we have not completed the audit of our December 31, 2015 financial statements. In addition, it would be difficult for us to present a detailed reconciliation on account of many unknown variables for the reconciling items.

Contact Information

Mac Schmitz
Investor Relations
(972) 371-5225
mschmitz@matadorresources.com

Exhibit 99.2

2016 Analyst Day Presentation

Managing 2016...

February 3, 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 the assets, employees and operations of Harvey E. Yates Company following its merger with one of Matador's wholly-owned subsidiaries on February 27, 2015; 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.

Estimated 2015 Results – Estimated 2015 results included herein are estimated at February 3, 2016 and subject to adjustments pending completion and release of the Company's 2015 audited financial statements.

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.



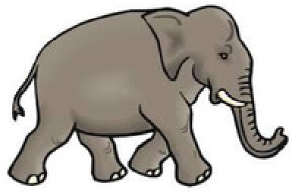
Welcome and Opening Remarks

Joseph Wm. Foran – Chairman and CEO

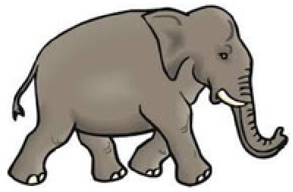
Today's Agenda

- **Welcome and Opening Remarks**
  - *Joseph Wm. Foran, Chairman and CEO*
- **2015 Summary and 2016 Capital Investment Plan**
  - *David E. Lancaster, Executive Vice President and CFO*
- **Morning Break**
- **Delaware Basin Operations Update**
  - *Matthew V. Hairford, President*
  - *David E. Lancaster, Executive Vice President and CFO*
- **Midstream Operations and 2016 Plans**
  - *Matthew V. Hairford, President*
  - *Matthew D. Spicer, Vice President and General Manager of Midstream*
- **Summary and Closing Remarks; Question and Answer Session**
  - *Joseph Wm. Foran, Chairman and CEO*
  - *Operating Committee Members*
- **Lunch**
  - *Austin Ballroom*
- **Afternoon Conference Call – 3:30 pm Central Time**

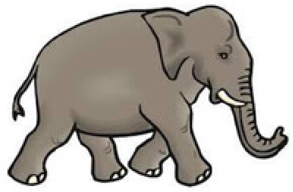
Managing 2016 – The Elephants in the Room Today



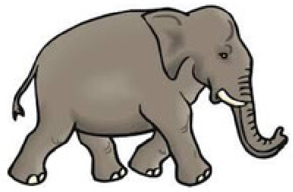
Continue with 3 rigs or drop a rig?



Outspend?



How to fund outspend?



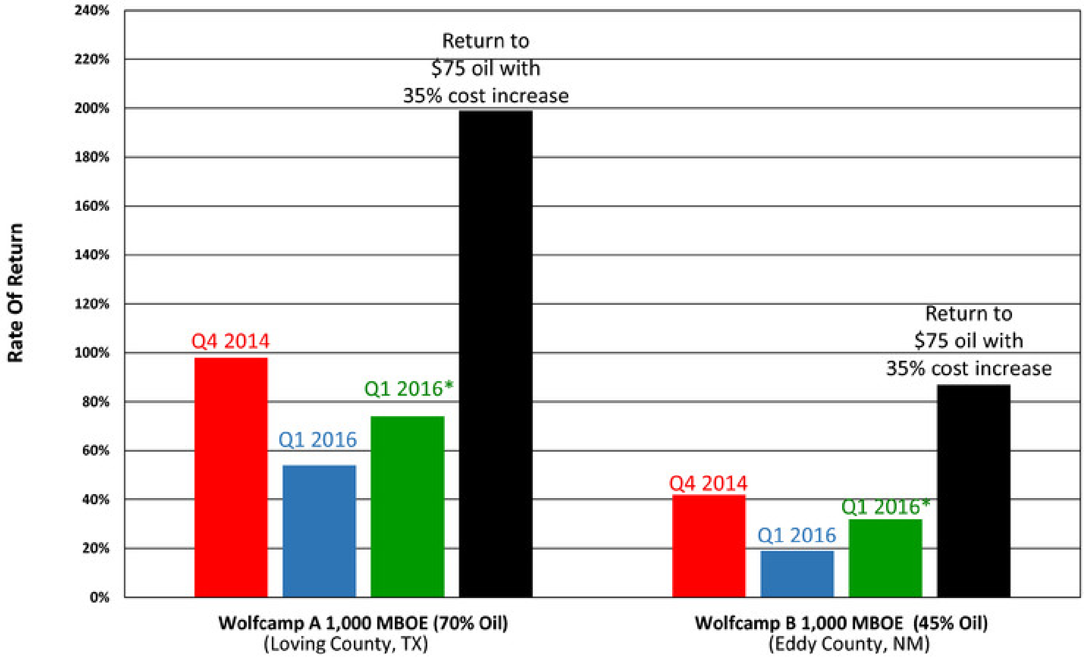
Maximizing shareholder value in a challenging environment?

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	~88,900 net acres[(3)]	+12-fold
Leverage[(4)]	1.5x[(5)]	1.5x	Flat
Share Price	$12.00[(6)]	$16.03[(6)]	+34%

(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 January 7, 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) As of February 7, 2012 at time of IPO.
(7) Closing share price as of January 29, 2016.

Attractive Wolfcamp Economics – Yesterday, Today and in the Future



Q4 2014 - $75 oil $3.50 natural gas, $11.0 million average cost per well
Q1 2016 - $35 oil $2.50 natural gas, $6.0 - $6.5 million average cost per well
Q1 2016* - $30-$40 oil (2016), $50 oil (2017), $60 oil (2018…)
Return to - $75 oil $3.50 natural gas, $8.5 million average cost per well

Note: Oil price is West Texas Intermediate. Natural gas price is Henry Hub. Differentials to these base prices applied to all cases. Well costs reflect estimated drilling, completions, production and facilities costs for typical development wells in Q1 2016.

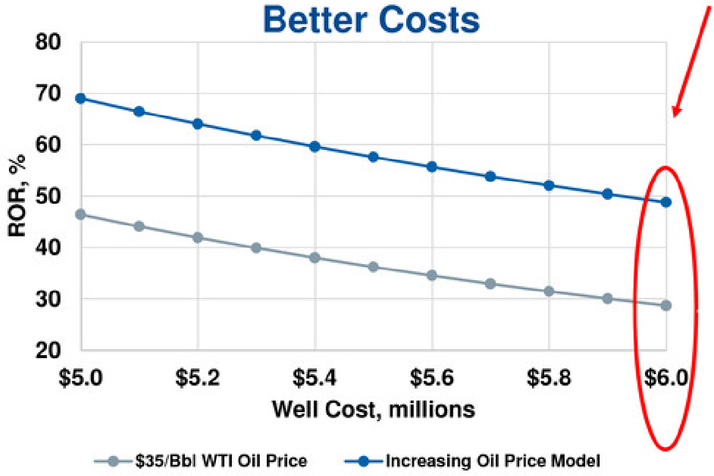
Q1 2016* is based upon projected hypothetical oil prices of $30-$40/Bbl in 2016, $50/Bbl in 2017 and $60/Bbl in 2018 and years thereafter, and $2.50/Mcf for natural gas. Such prices are for illustrative purposes only and are not intended to represent the Company's actual forecasts or expectations.

ROR Relationship to Well Cost(1) Savings and Improved EUR(2)

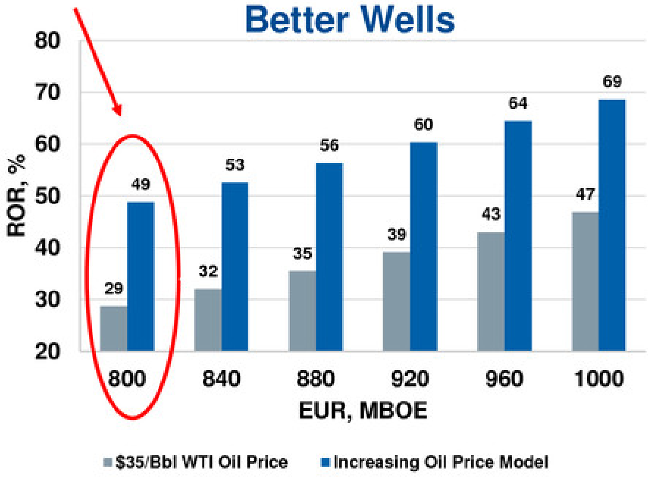
Increasing Oil Price Model	Year
$30	1st 6 mo. 2016
$40	2nd 6 mo. 2016
$50	2017
$60	2018 for life

Assumes $2.50/Mcf natural gas

Rustler Breaks
Wolfcamp A-X/Y
$6.0 million Well Cost



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



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

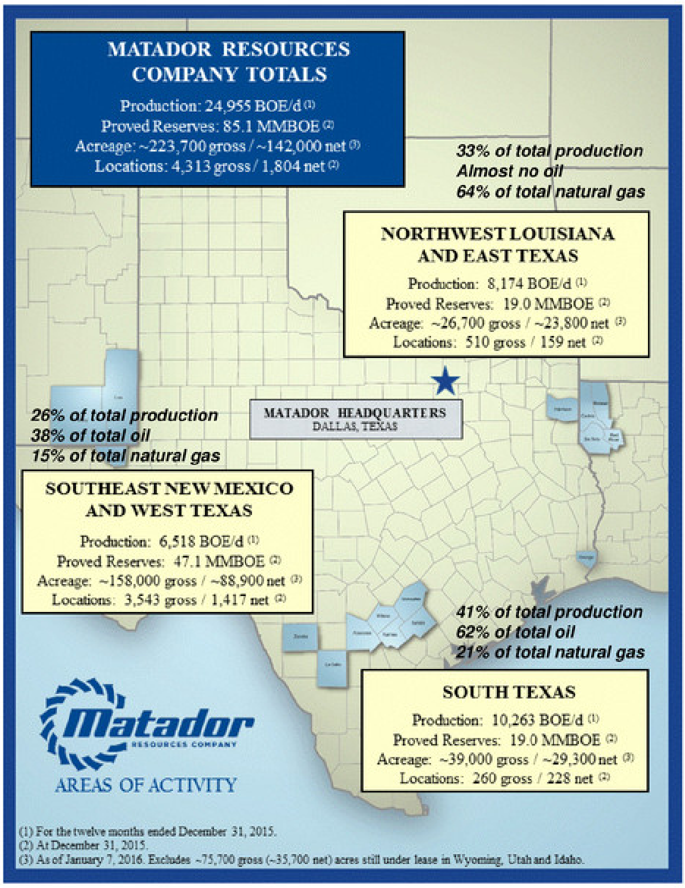
(1) Estimated well costs for a development well in Q1 2016, including drilling, completion, production and facilities costs.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.



2015 Summary and 2016 Capital Investment Plan

David E. Lancaster – Executive Vice President and CFO

Matador Resources Company – Operations Overview



Market Capitalization(1)	**~$1.4 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)	**~223,700 acres**	
Net Acreage(4)	**~142,000 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	510 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 January 29, 2016 and shares outstanding at December 31, 2015 as reported to the NYSE.
(2) Average daily production for the twelve months ended December 31, 2015.
(3) 2016 estimated capital expenditures, including all anticipated operations, midstream and land expenditures as of February 3, 2016, assuming a 3-rig program in the Delaware Basin in 2016.
(4) As of January 7, 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.

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 (72.3 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**

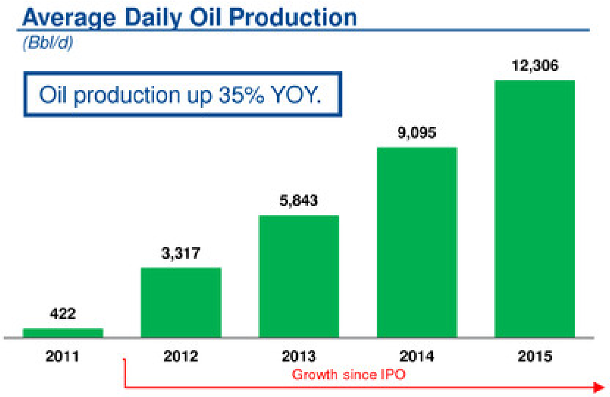
(1) At December 31, 2015.
(2) Includes any identified locations in which Matador's working interest is at least 25%.
(3) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria 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.

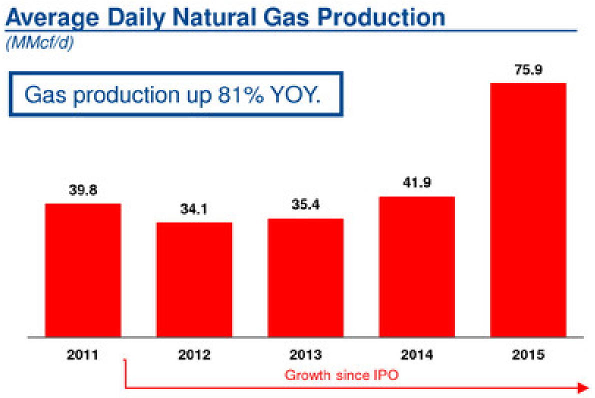
Despite Low Commodity Prices, 2015 Was an Excellent Year for Matador

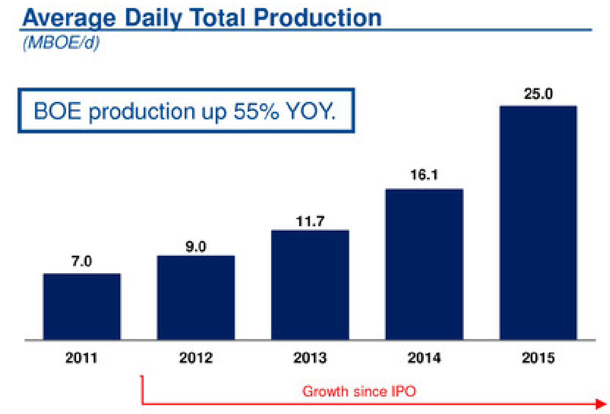
- **Four key transactions improved our asset base and kept our balance sheet strong**
  - **HEYCO merger in February 2015 added approximately 60,000 gross (20,000 net) acres in the Delaware Basin(1)**
    - *Initial non-operated well results across acreage have been very encouraging*
  - **Inaugural offering of $400 million in public bonds in April 2015**
  - **Follow-on equity offering in April 2015**
    - *7 million shares sold raising approximately $189 million*
    - *Combined bond and equity transactions raised almost $600 million in capital to strengthen balance sheet*
  - **Sold certain Loving County, Texas midstream assets to EnLink for ~$143 million(2)**
    - *Further strengthened balance sheet and reduced debt levels to among the best in the industry for small- and mid-cap E&P companies*
- **Matador begins 2016 from a position of strength – excellent properties, proven Board and staff and strong financial position**

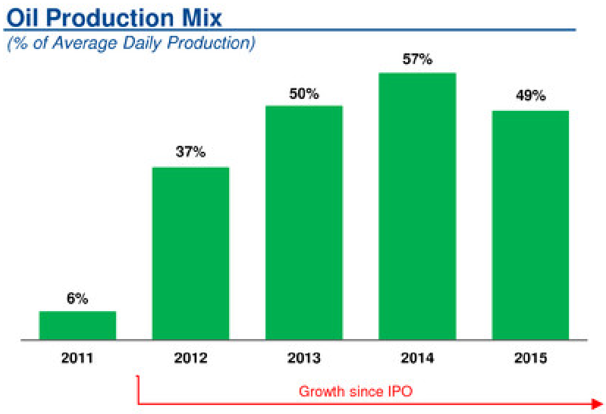
(1) Including additional acreage acquired through subsequent joint ventures with affiliates of HEYCO.
(2) Excluding customary purchase price adjustments.

Record Oil, Natural Gas and Total Production in 2015

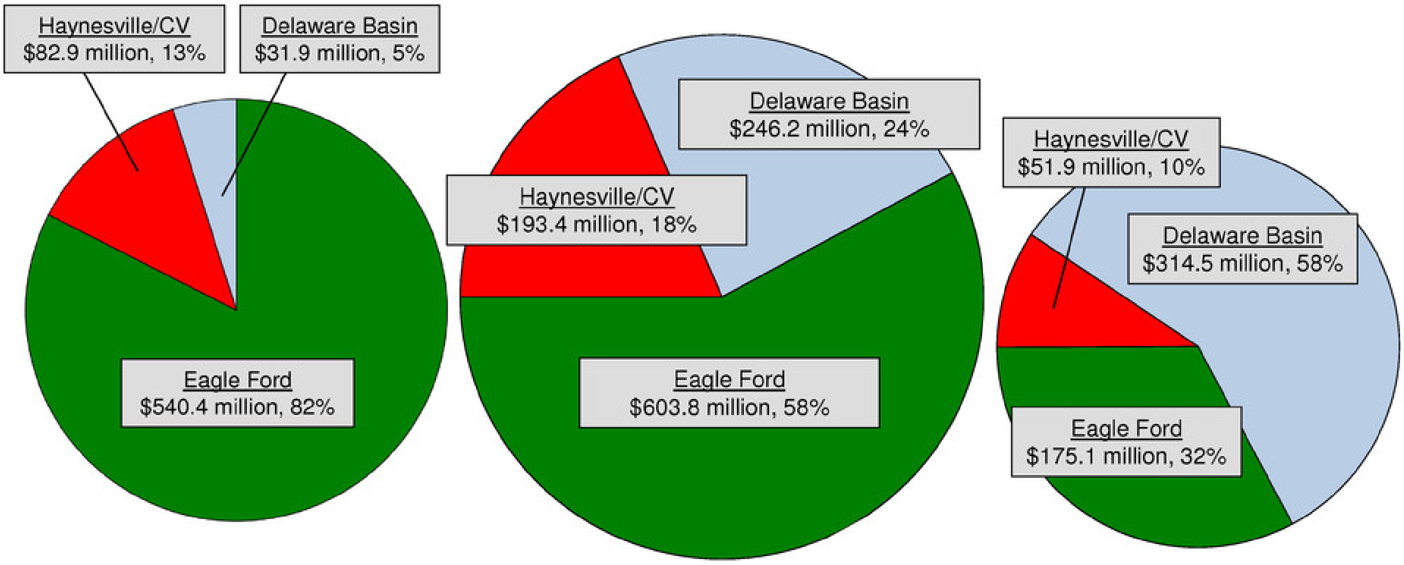








Matador's Reserves Volumes at an All-Time High at Year-End 2015

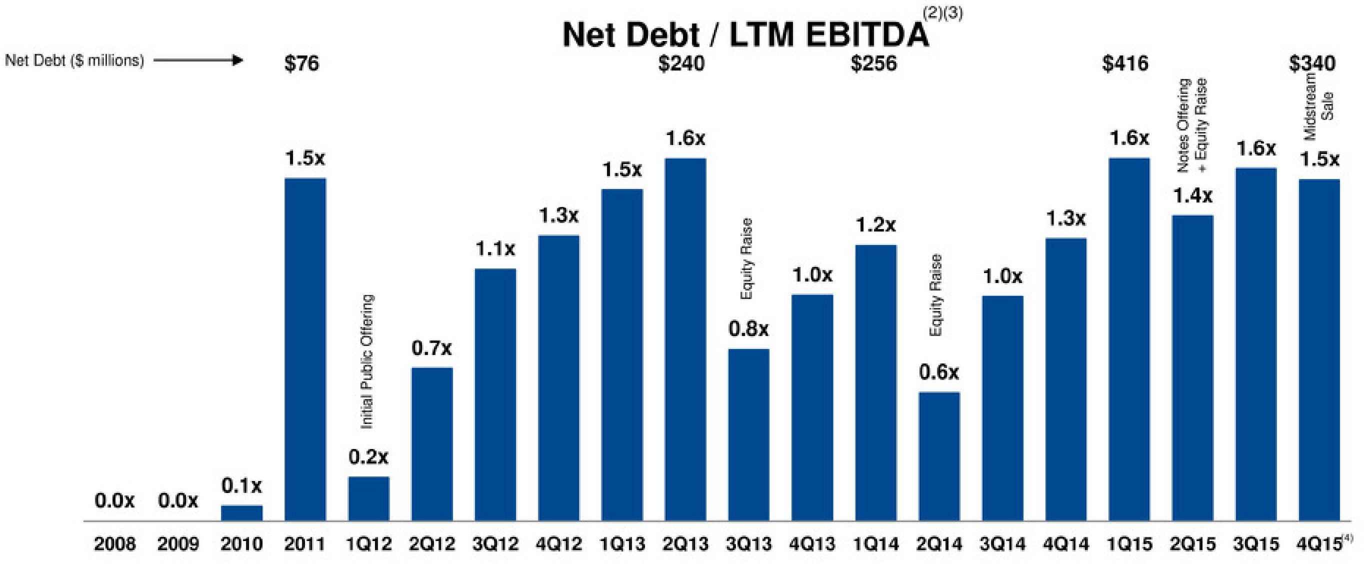


YE 2013	YE 2014	YE 2015
51.7 million BOE	68.7 million BOE	85.1 million BOE (24%)
16.4 million Bbl oil (32% oil)	24.2 million Bbl oil (35% oil)	45.6 million Bbl oil (54% oil) (89%)
PV-10(1): $655.2 million	PV-10(1): $1,043.4 million	PV-10(1): $541.6 million (48%)
$93.42 oil / $3.67 gas	$91.48 oil / $4.35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

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

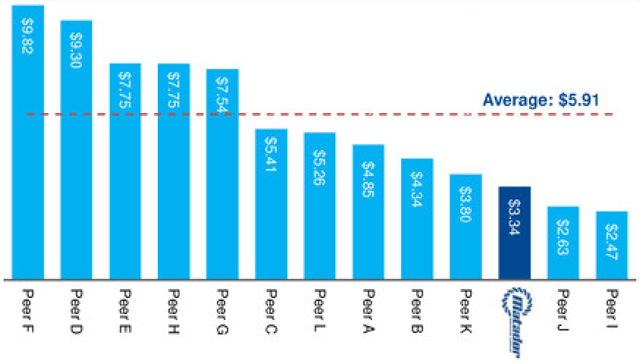
- Preserved and enhanced liquidity through April 2015 equity and Senior Notes offerings and sale of certain Loving County midstream assets for ~$143 million[1] in October 2015 – substantial liquidity to execute planned drilling program throughout 2016
- Strong financial position with YE 2015 Net Debt/LTM Adjusted EBITDA[2][3] of ~1.5x, well below peer average



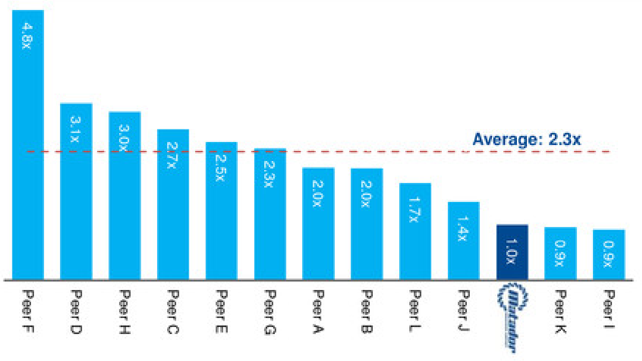
(1) Excluding customary purchase price adjustments.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Net Debt is equal to debt outstanding less available cash (including $43 million of restricted cash held in escrow at December 31, 2015).
(4) 4Q15 LTM Adjusted EBITDA and Net Debt are estimated at February 3, 2016 and subject to adjustment pending completion and release of 2015 audited financial statements.

Strong Balance Sheet Metrics Relative to Peers[1]

Q3 2015 Net Debt / Proved Reserves ($ / BOE)

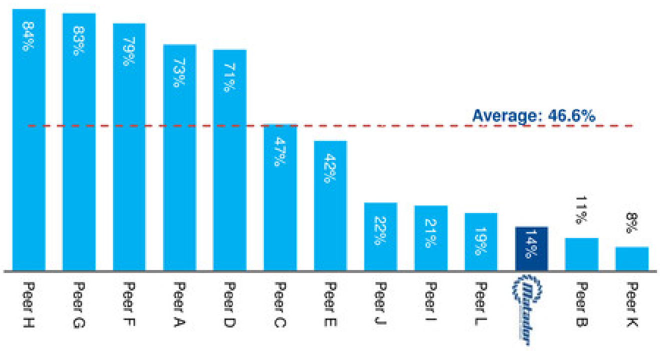


Q3 2015 Net Debt / LTM Adjusted EBITDA[2]



Proved PV-10[3] / Q3 2015 Net Debt

Q3 2015 Net Debt / Enterprise Value[4]



(1) Market analysis prepared by RBC Capital Markets. Average does not include Matador. Matador net debt figures are pro forma at September 30, 2015 for midstream sale on October 1, 2015. Peer group chosen by RBC includes BCEI, CRZO, CWEI, EGN, EPE, FANG, LPI, PDCE, PE, RSPP, SM, SN. Source: Company filings, metrics pro forma for announced acquisitions, capital markets transactions and divestitures. Market data as of January 29, 2016.
(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) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.
(4) Enterprise value equals market capitalization plus net debt outstanding.

2015 Anticipated Results vs. 2015 Guidance (As Updated Nov. 4, 2015)

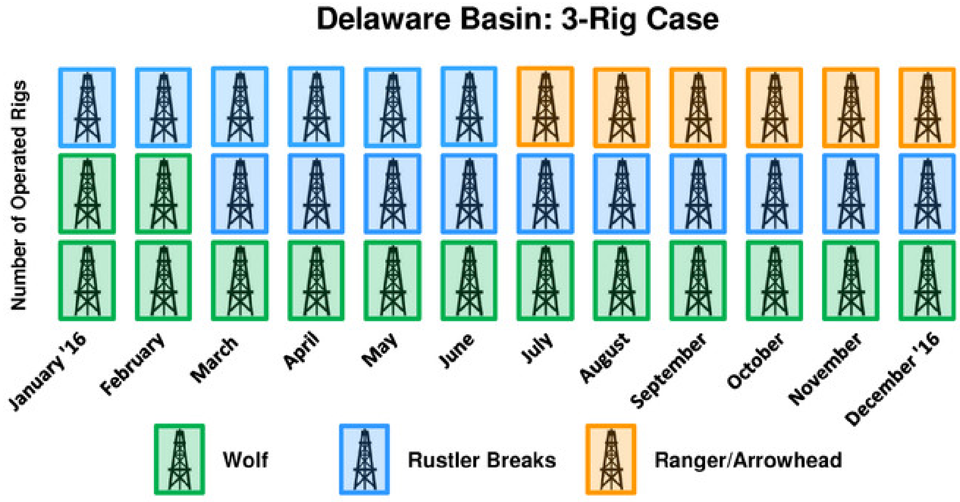
Exchange: Ticker	NYSE: MTDR
Shares Outstanding[(1)]	85.6 million common shares
Share Price[(1)]	$16.03/share
Market Capitalization[(1)]	$1.4 billion

	Actual 2014	*Original 2015 Guidance*	*Updated 2015 Guidance*[(2)]	*Estimated 2015 Results*[(3)]	*% Change*
Capital Spending	$610 million	$350 million	$425 million	~$480 million[(4)]	- 21%
Total Oil Production	3.3 million Bbl	4.0 to 4.2 million Bbl	4.4 to 4.5 million Bbl	4.5 million Bbl	+ 35%
Total Natural Gas Production	15.3 Bcf	24.0 to 26.0 Bcf	27.0 to 28.0 Bcf	27.7 Bcf	+ 81%
Oil and Natural Gas Revenues	$367.7 million	$270 to $290 million	$290 to $300 million[(5)]	~$275 to $280 million	- 24%
Adjusted EBITDA[(6)]	$262.9 million	$200 to $220 million	$220 to $230 million[(5)]	~$220 to $225 million	- 15%

(1) Market capitalization based on closing share price as of January 29, 2016 and shares outstanding at December 31, 2015 as reported to the NYSE.
(2) The Company raised certain of its full-year 2015 guidance estimates on August 4 and November 4, 2015.
(3) Estimated 2015 financial results are estimated at February 3, 2016 and subject to adjustment pending completion and release of 2015 audited financial statements.
(4) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(5) Oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 2015 guidance range as revised on November 4, 2015 and actual production results through October 31, 2015. Prices for oil and natural gas used in these estimates were $50.00/Bbl (WTI oil price of $55.00/Bbl less $5.00/Bbl differentials and transportation costs) and $3.00/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period October through December 2015 and weighted average realized prices for the period January through September 2015 of $47.36/Bbl and $2.83/Mcf.
(6) 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.

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 back 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*



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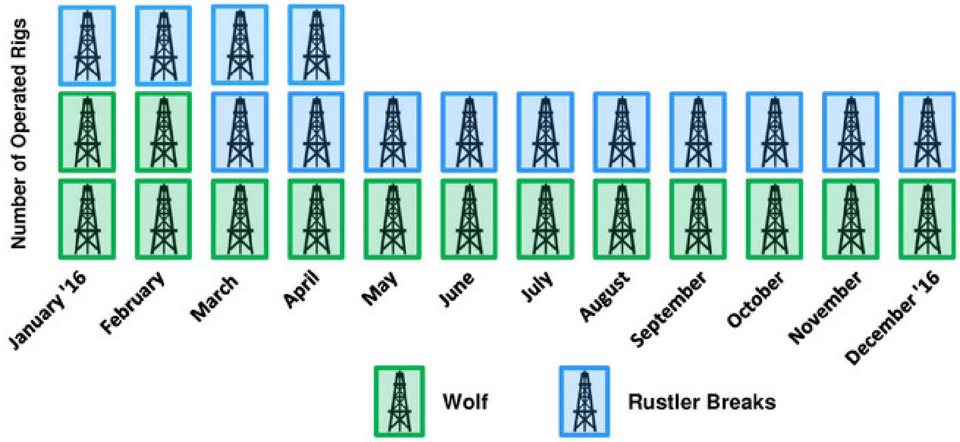
  - *Continue to invest in Delaware midstream assets, particularly the cryogenic natural gas processing plant and gathering assets we are building in the Rustler Breaks prospect area in Eddy County, NM*

Delaware Basin: 2-Rig Case

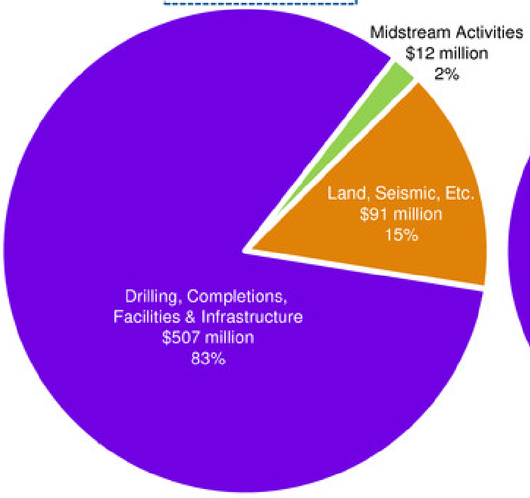


2016 Capital Investment Plan – Summary

- **We estimate our capital budget in 2016 to be approximately $325 million for the 3-rig case (down 32% from 2015[(1)]), declining to $277 million for the 2-rig case (down 42% from 2015[(1)])**
  - *We expect to have sufficient liquidity to fund our 2016 capital investments - ~$60 million in cash and $375 million in undrawn revolving credit facility at December 31, 2015*

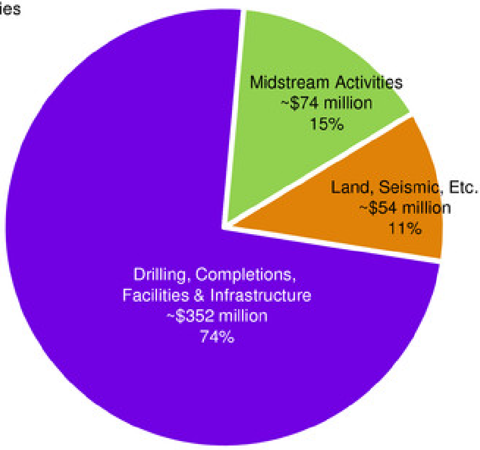
2014 CapEx

$610 million



2015 CapEx

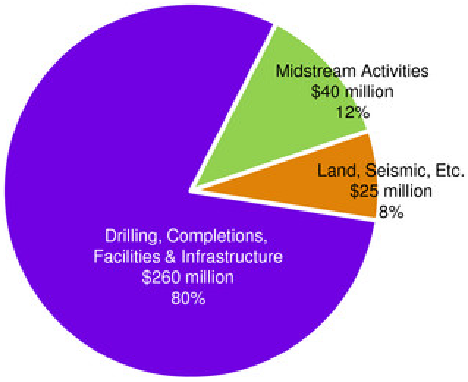
~$480 million(1) 21%



2016E CapEx – 3-Rig Scenario

3 Delaware Basin rigs throughout 2016

$325 million 32%

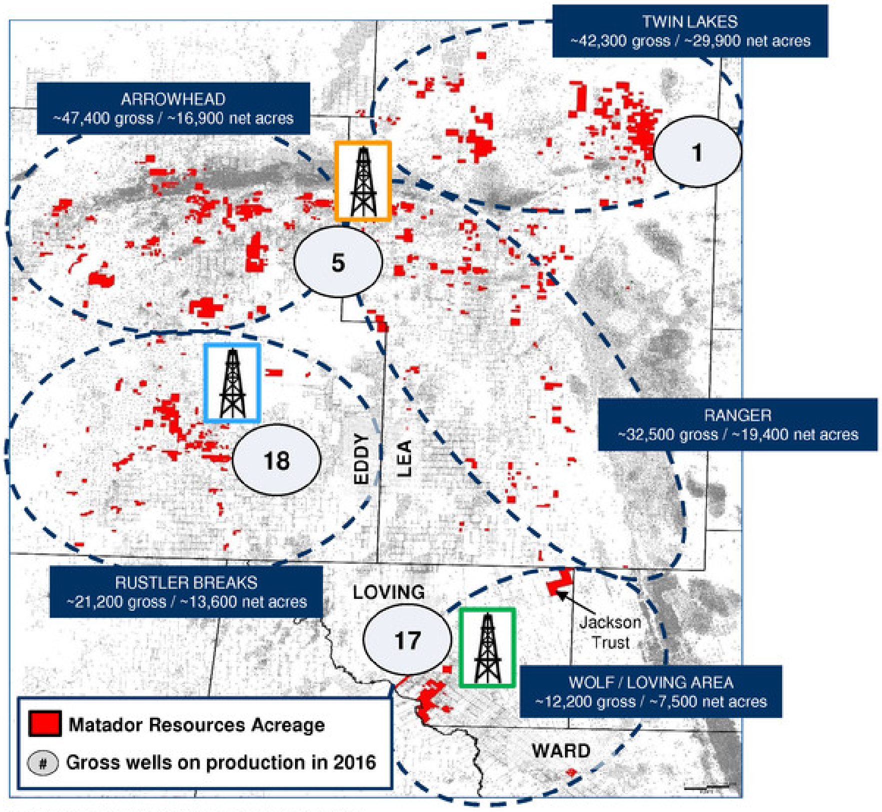


(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures. 2015 CapEx and related components are estimated at February 3, 2016 and are subject to adjustment pending the completion and release of 2015 audited financial statements.

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, as and if needed*
  - *Additional borrowings under our undrawn credit facility*

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



Note: All acreage at January 7, 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*

Detail of 2016E Capital Expenditures

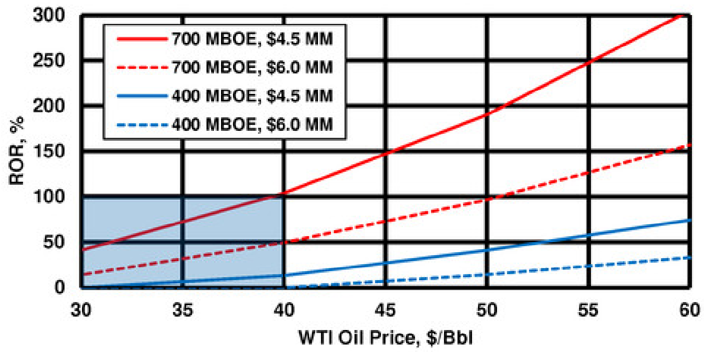
	2015 Drilled, 2016 Anticipated Completion(1)		2016 Anticipated Drilling & Completion		2016 Anticipated Drilling, 2017 Anticipated Completion(2)		2016 Anticipated First Sales(2)		2016E CapEx	
	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	*(in millions)*	
Delaware Basin										
Operated Activity										
Operated Activity - 3 Rig Scenario	*-*	*-*	*41*	*34.6*	*8*	*5.8*	*41*	*34.6*	*$246.6*	*75.9%*
Operated Activity - 2 Rig Scenario	*-*	*-*	*33*	*28.2*	*6*	*4.8*	*33*	*28.2*	*$198.6*	
Non-Operated Activity	5	0.7	8	1.2	-	-	13	1.9	$5.4	1.7%
Midstream Activities	-	-	-	-	-	-	-	-	$40.0	12.3%
Land/Seismic/Etc.	-	-	-	-	-	-	-	-	$23.0	7.1%
Area Total										
3 Rig Scenario	*5*	*0.7*	*49*	*35.8*	*8*	*5.8*	*54*	*36.5*	*$315.0*	*96.9%*
2 Rig Scenario	*5*	*0.7*	*41*	*29.4*	*6*	*4.8*	*46*	*30.1*	*$267.0*	
Eagle Ford										
Non-Operated Activity	2	0.0	-	-	-	-	2	0.0	$0.1	0.0%
Facilities/Pipelines/Etc.	-	-	-	-	-	-	-	-	$3.5	1.1%
Land/Seismic/Etc.	-	-	-	-	-	-	-	-	$2.0	0.6%
Area Total	2	0.0	-	-	-	-	2	0.0	$5.6	1.7%
Haynesville / Cotton Valley										
Haynesville Non-Op Activity	12	2.0	5	0.6	-	-	17	2.6	$4.4	1.4%
Total - 3 Rig Scenario	**19**	**2.7**	**54**	**36.4**	**8**	**5.8**	**73**	**39.1**	**$325.0**	**100.0%**
Total - 2 Rig Scenario	***19***	***2.7***	***46***	***30.0***	***6***	***4.8***	***65***	***32.7***	***$277.0***	

- ***97% of our 2016 capital investments directed toward the Delaware Basin***

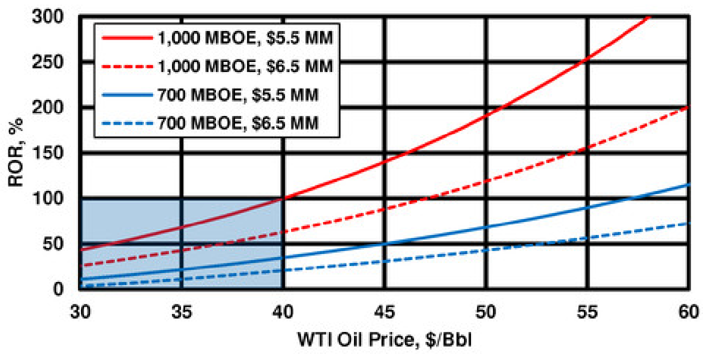
(1) A portion of the CapEx associated with some of these wells was incurred in 2015, as some wells were waiting on completion or were already being completed at December 31, 2015.
(2) Some wells drilled in late 2016 will not be completed and turned to sales until early 2017. As a result, they do not contribute to our estimated oil and natural gas production volumes for 2016.
(3) Includes Matador operated and non-operated wells.

Delaware Basin – Sensitivities to Oil Price[1] and Cost Savings

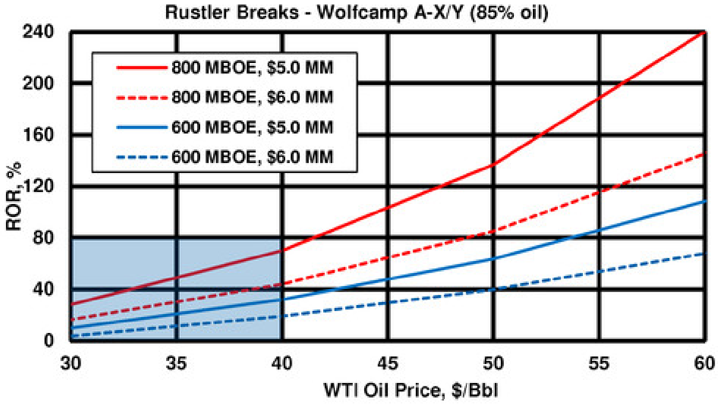
Ranger/Arrowhead - 2nd Bone Spring (90% oil)



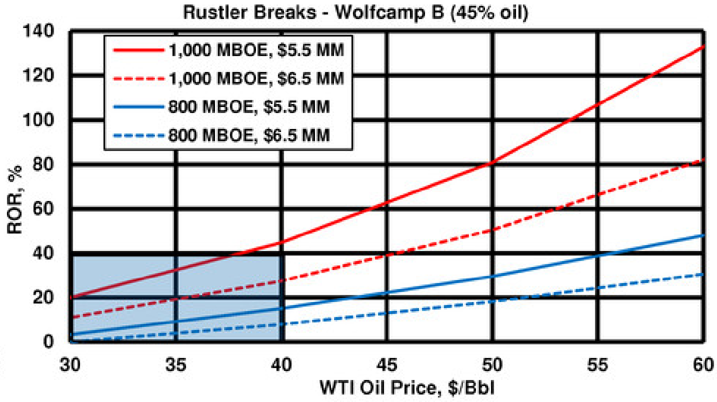
Wolf - Wolfcamp A-X/Y (70% oil)



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



Rustler Breaks - Wolfcamp B (45% oil)

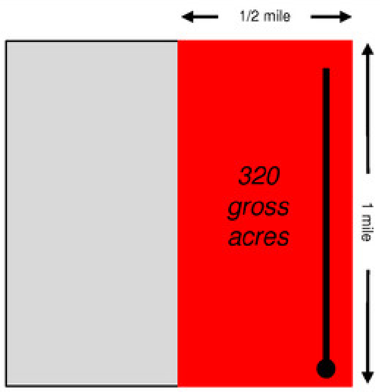


Note: $2.50/Mcf natural gas price used in all graphs, less differentials. Costs include total estimated drilling, completion, production and facilities costs for a typical development well in each area.
Note: High end of cost range reflects Q1 2016 estimated costs; low end of cost range reflects 2016 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.

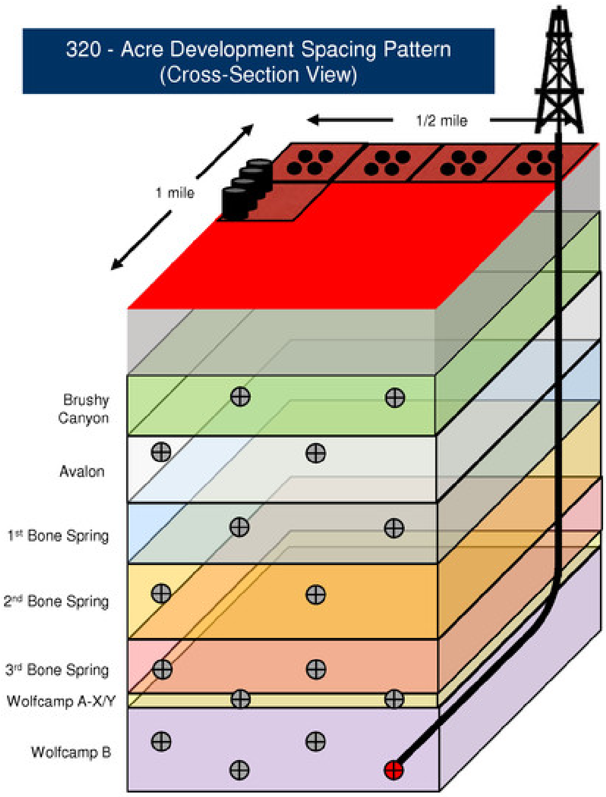
Single Wolfcamp B Well at Rustler Breaks Holds Up To 15 Potential Locations

- *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)

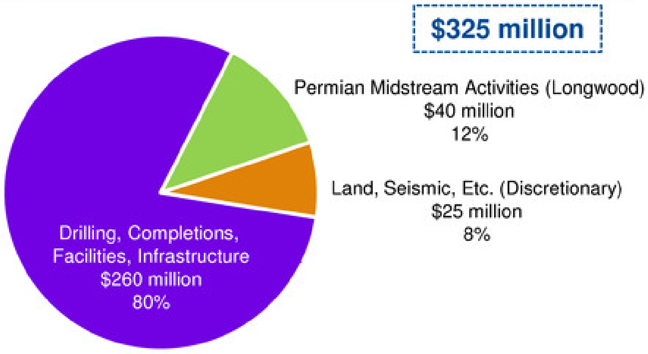


Additional Locations Held With Wolfcamp B well
2
2
2
2
2
2
3
15

2016 Capital Investment Plan Summary – 3 Delaware Basin Rigs

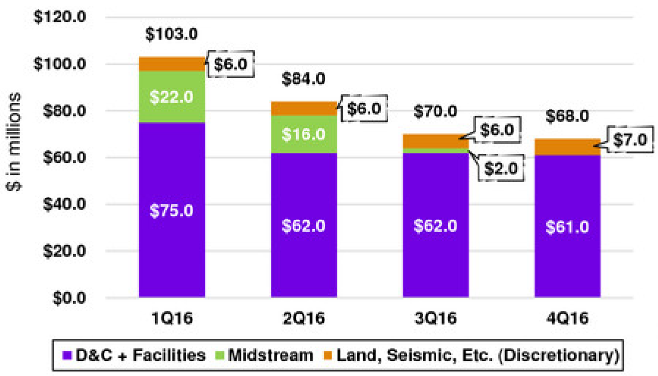
2016E CapEx – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



2016E CapEx by Quarter – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



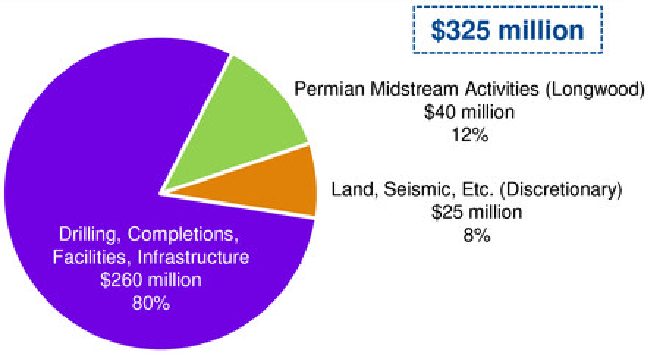
- **2016E CapEx of ~$325 million**
  - *Decrease of ~32% from 2015 estimated capital expenditures of ~$480 million(1)*
  - *Includes estimated efficiency and cost savings of 15 to 20% throughout 2016, but additional savings may be realized*
- Delaware Basin focus on Wolfcamp development at Wolf and Rustler 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 – over 90% 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. 2015 CapEx and related components are estimated at February 3, 2016 and are subject to adjustment pending the completion and release of 2015 audited financial statements.
(2) At December 31, 2015.

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

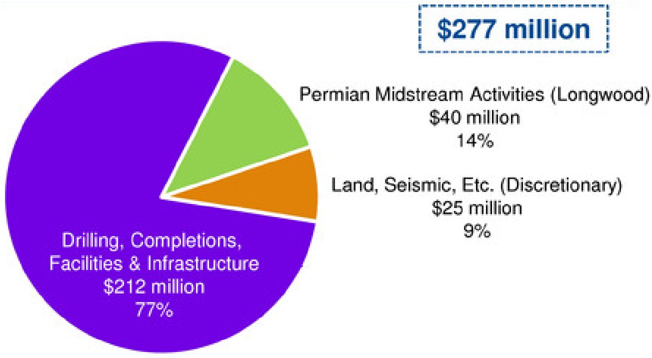
2016E CapEx – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



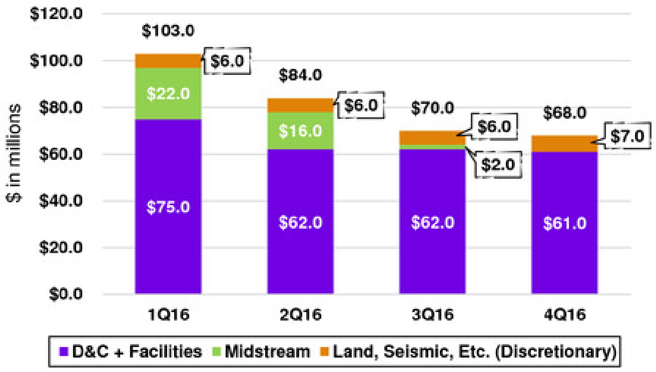
2016E CapEx – 2-Rig Case

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



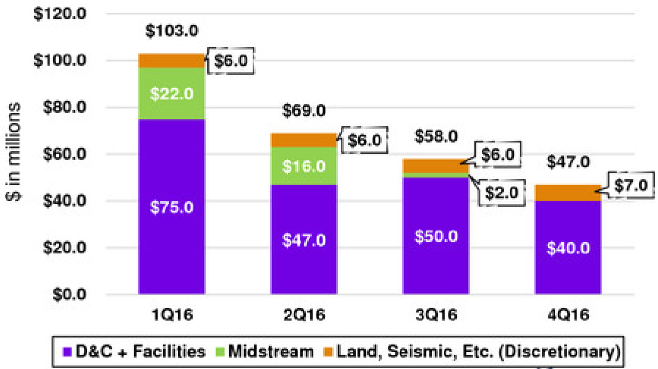
2016E CapEx by Quarter – 3-Rig Case

(3 rigs in the Delaware Basin throughout 2016)



2016E CapEx by Quarter – 2-Rig Case

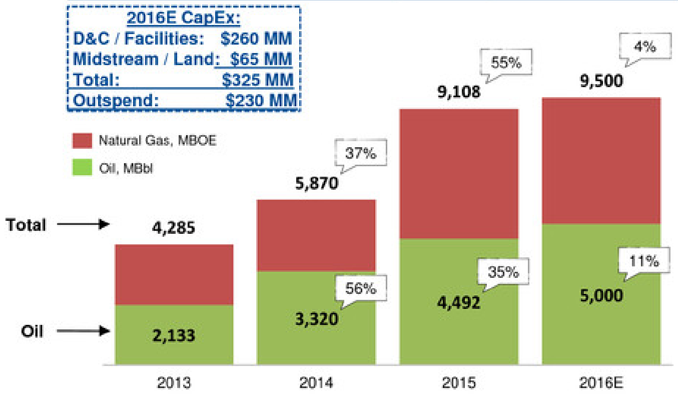
(3 rigs in the Delaware Basin in Q1 2016; 2 rigs in Q2-Q4 2016)



2016 Oil and Natural Gas Production Estimates

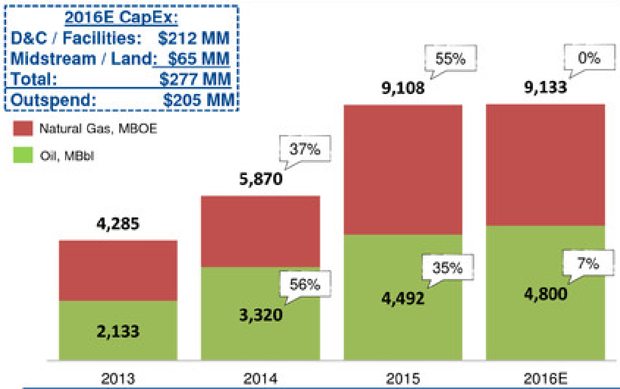
Oil and Natural Gas Production – 3-Rig Case

(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*

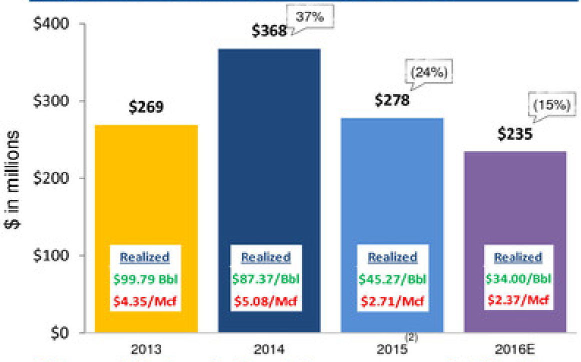
2016E Natural Gas Production – 3-Rig Case

- 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

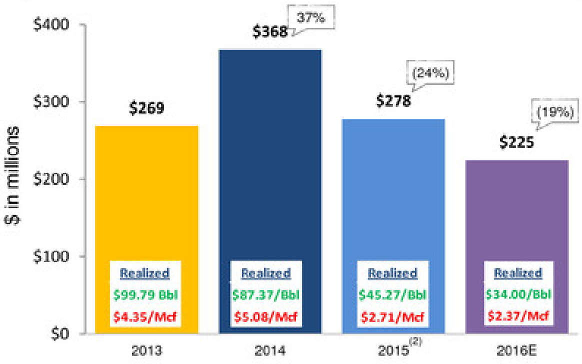
Oil and Natural Gas Revenues – 3-Rig Case

(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

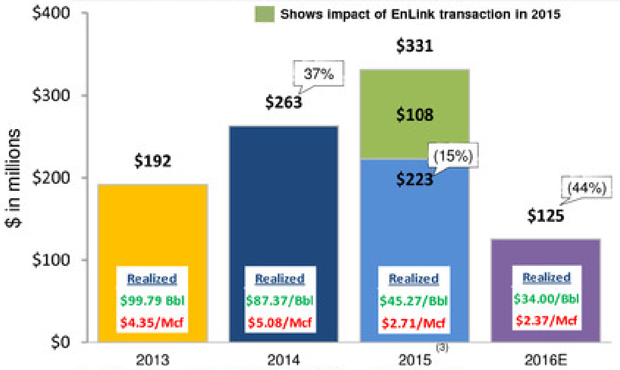
- Revenues impacted by lower estimated 2016 realized oil and natural gas prices – forecasts use strip commodity prices in late January 2016
  - *2016E realized oil price of $34/Bbl vs ~$45/Bbl realized in 2015*
  - *2016E realized natural gas price of $2.37/Mcf vs $2.71/Mcf in 2015*
  - *Assuming $3.00/Bbl 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 ~15% from estimated $275 to $280 million[2] in 2015*
  - *Oil and natural gas hedges estimated to contribute $20 million[3] 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[2]

(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 differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.
(2) 2015E oil and natural gas revenues are estimated at February 3, 2016 and subject to adjustment pending completion and release of 2015 audited financial statements.
(3) At strip oil and natural gas prices in late January 2016.

2016 Adjusted EBITDA Estimates

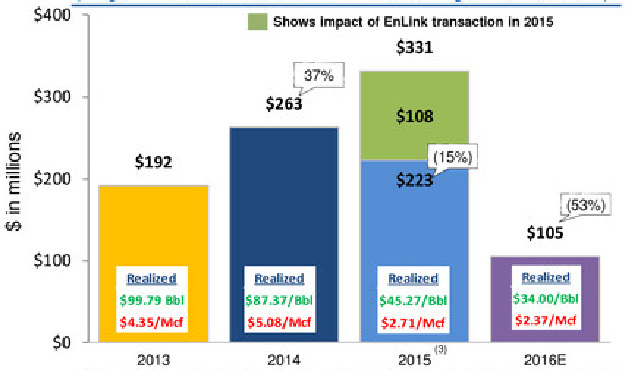
Adjusted EBITDA[1][2] – 3-Rig Case

(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 estimated $220 to $225 million[3] 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)[3]

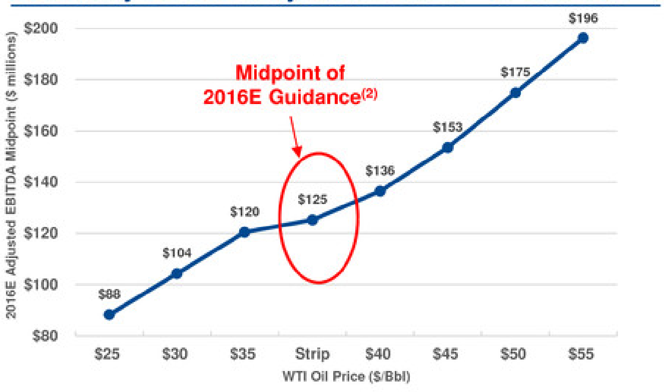
(unit costs per BOE)	Operating Cost Estimates	
	2016E	2015
Production taxes and marketing	$4.25	$3.90
Lease operating	$6.00	$6.40
General and administrative	$5.25	$5.50
Operating cash costs, excluding interest	*$15.50*	*$15.80*
Depletion, depreciation and amortization	$16.25	$19.60

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

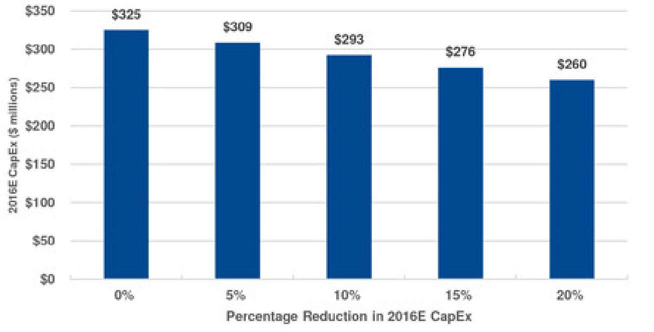
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) 2016E oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 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 differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.
(3) 2015E Adjusted EBITDA and operating costs are estimated at February 3, 2016 and subject to adjustment pending completion and release of 2015 audited financial statements.

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 differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.

Hedging Profile

2016 Hedges[1]

- **Oil:** ~1.6 million barrels of oil hedged for 2016 at weighted average floor and ceiling prices of $47/Bbl and $75/Bbl, respectively – Approximately 31% of oil hedged for 2016
- **Natural Gas**: 11.7 Bcf of natural gas hedged for 2016 at weighted average floor and ceiling of $2.61/MMBtu and $3.54/MMBtu, respectively – Approximately 43% of natural gas hedged for 2016

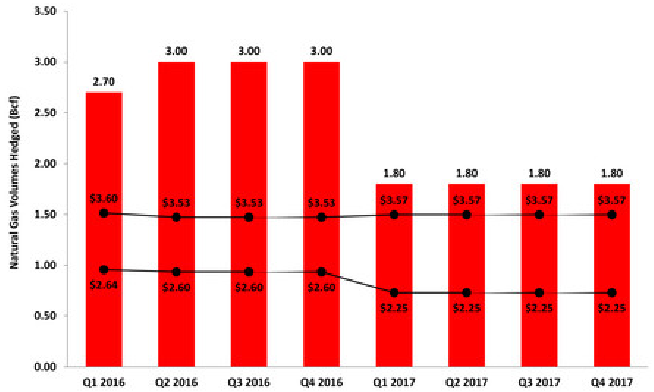
2017 Hedges[1]

- **Oil:** No hedges in place for 2017
- **Natural Gas**: 7.2 Bcf of natural gas ($2.25/MMBtu floor and $3.57/MMBtu ceiling)

- *Oil and natural gas hedges estimated to add $20 million[2] to projected oil and natural gas revenues in 2016*

Oil Hedges (Costless Collars)

Natural Gas Hedges (Costless Collars)



(1) At February 3, 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) of 1.5x 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) Estimated Net Debt and LTM Adjusted EBITDA at December 31, 2015 are estimated at February 3, 2016 and subject to adjustments pending completion of 2015 audited financial statements. 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.

Summary and Initial 2016 Guidance

- **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 back 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**

	Estimated 2015 Results(1)	*2016 Guidance*(2)	*% Change*
Capital Spending	~$480 million(3)	$325 million	- 32%
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%
Adjusted EBITDA(4)	~$220 to 225 million(1)	$120 to $130 million(2)	- 44%

(1) Estimated 2015 financial results are estimated at February 3, 2016 and subject to adjustment pending completion and release of 2015 audited financial statements.
(2) 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) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period January through December 2016.
(3) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(4) 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.



Delaware Basin Operations Update

Matthew V. Hairford – President
David E. Lancaster – Executive Vice President and CFO

Understanding the Opportunities

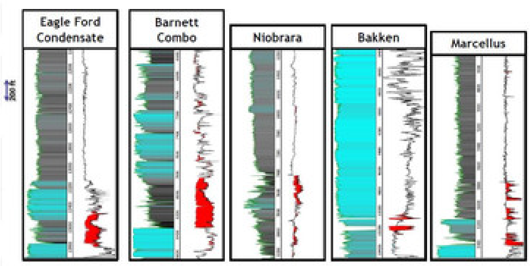
Most current unconventional plays target one or two zones across a trend area.

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

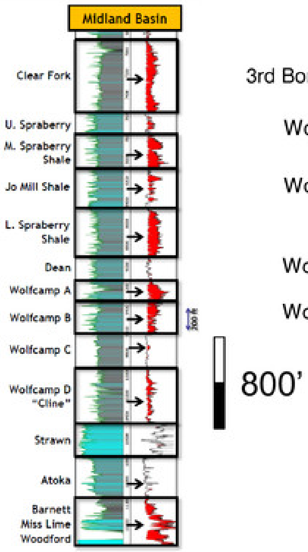
Challenge: To identify the best targets within multiple prospective intervals across a geologically complex basin

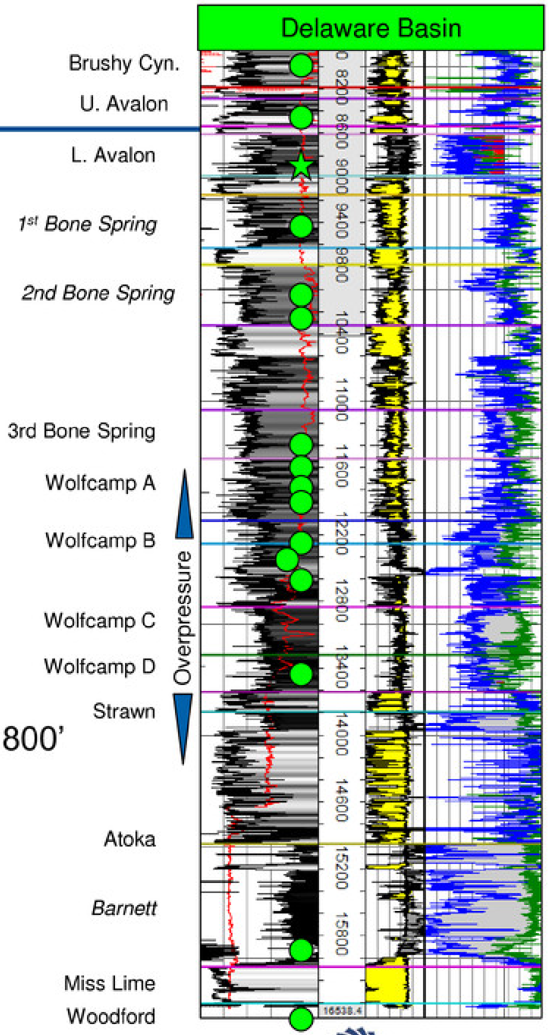
Matador's geoscience staff is committed to bringing the best targets forward!



Source: PXD

All logs plotted at same scale

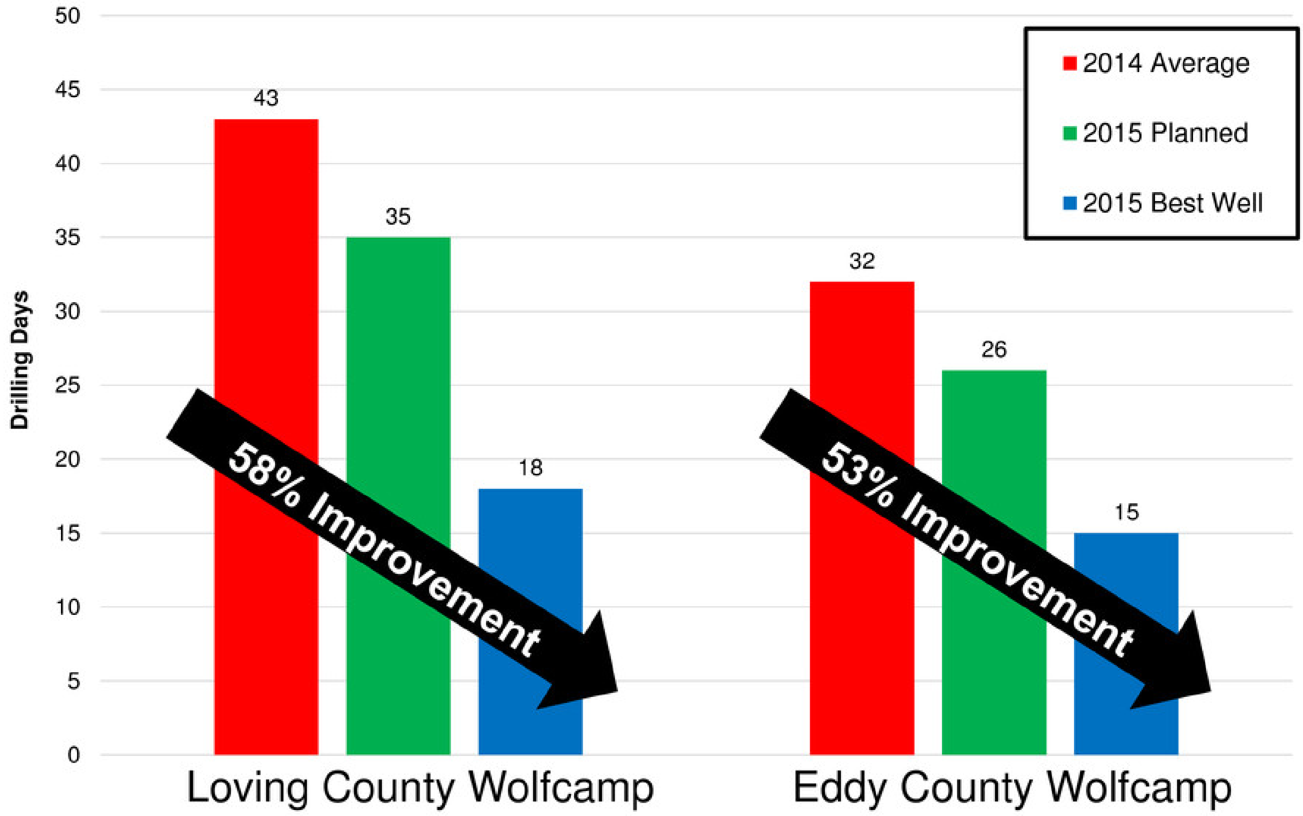




Tested by MTDR

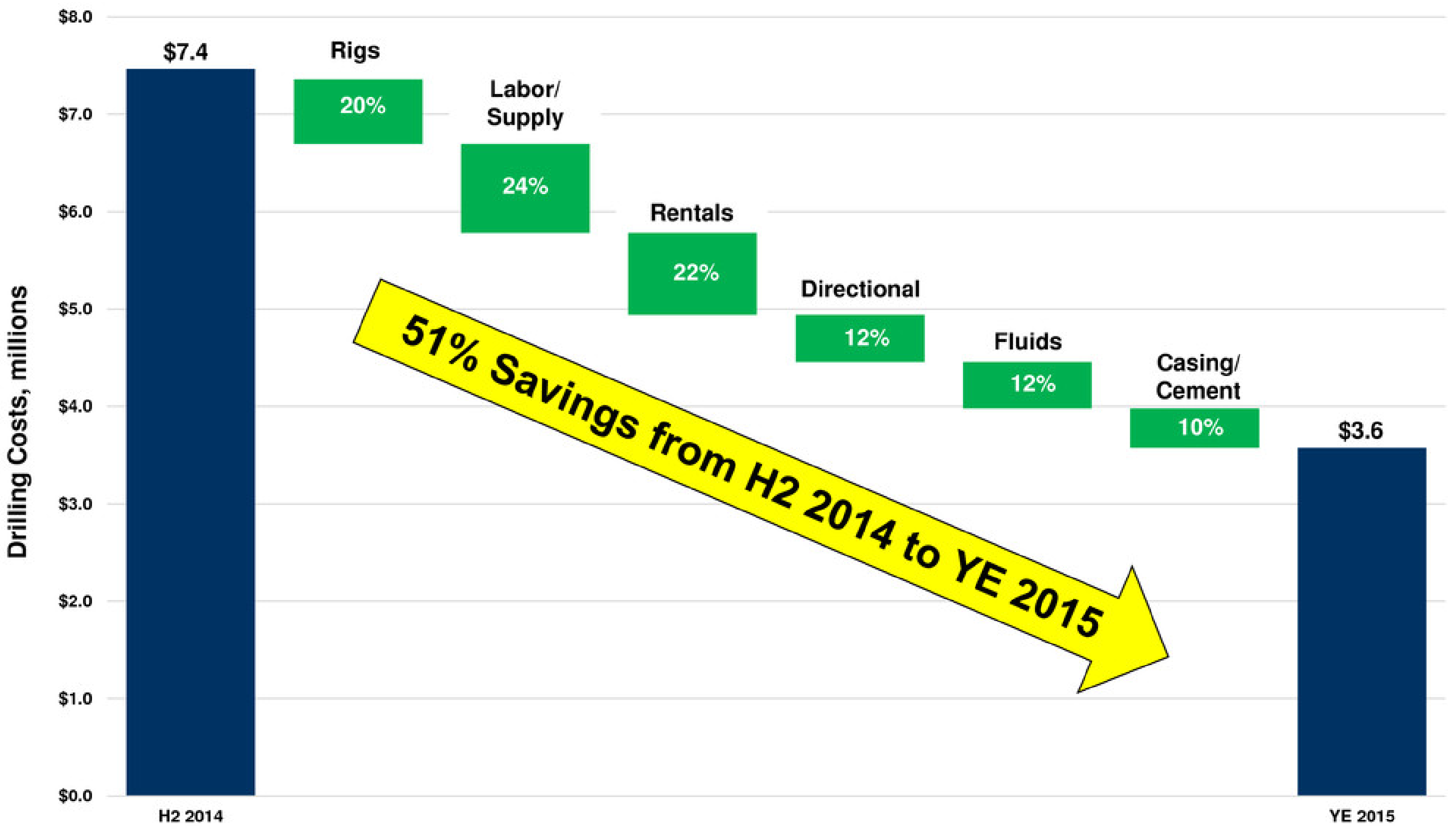
Tested by others

Improved Wolfcamp Drilling Times Significantly in 2015

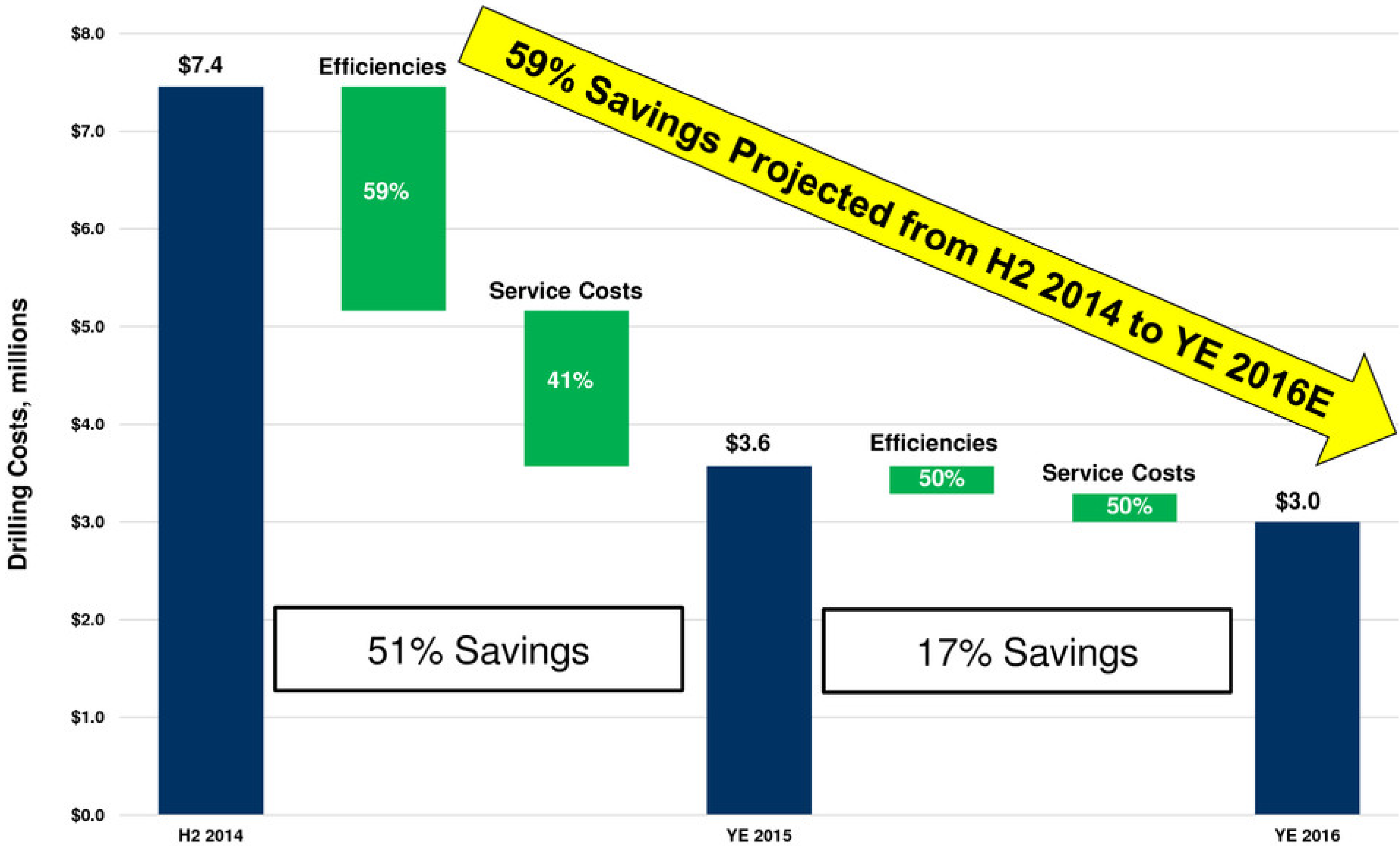


Note: Best wells are Johnson 44-02S-B53 #206H in Loving County (Wolfcamp) and Tiger 14-24S-28E RB #204H in Eddy County (Wolfcamp).

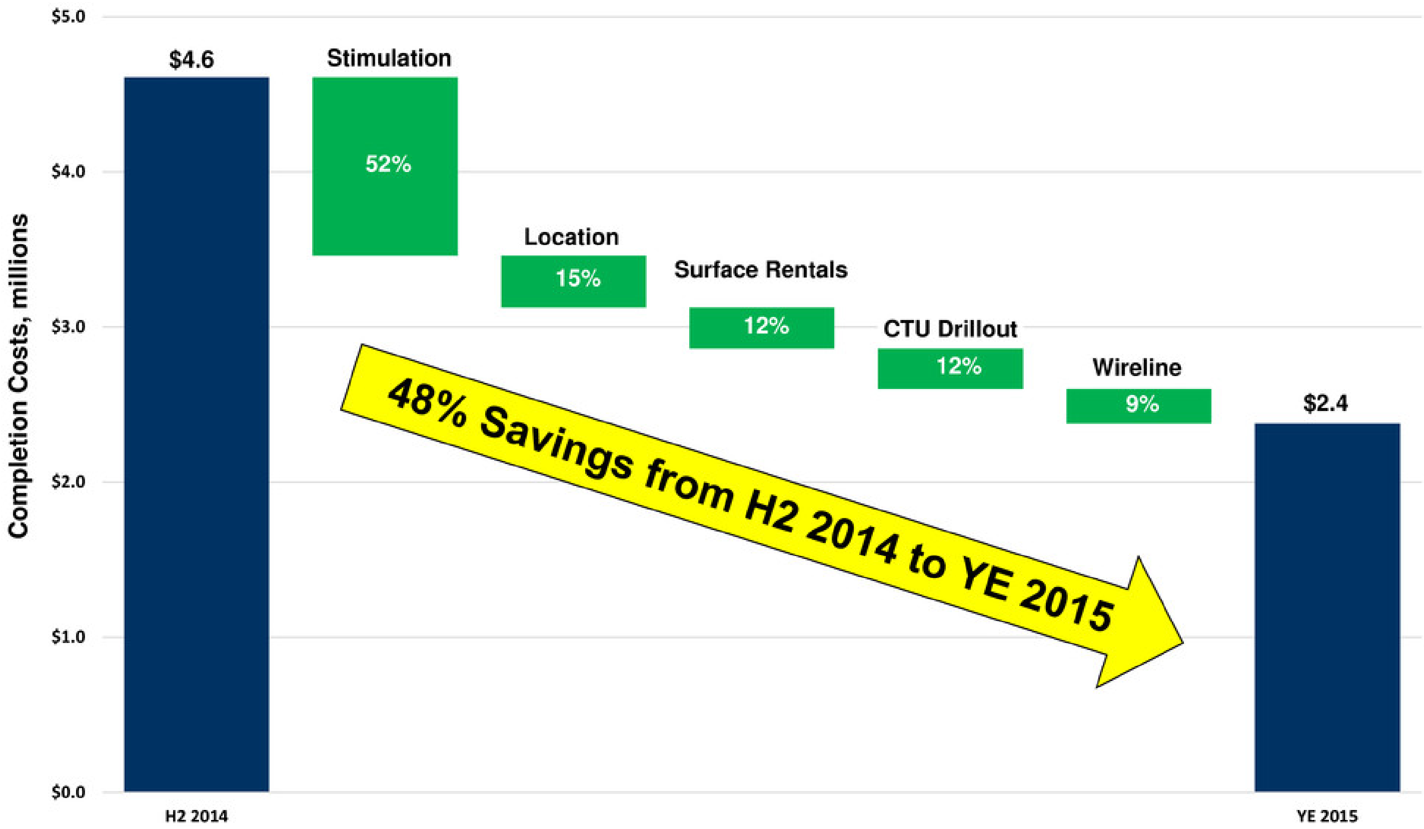
2015 Wolf Area Drilling Cost Improvements



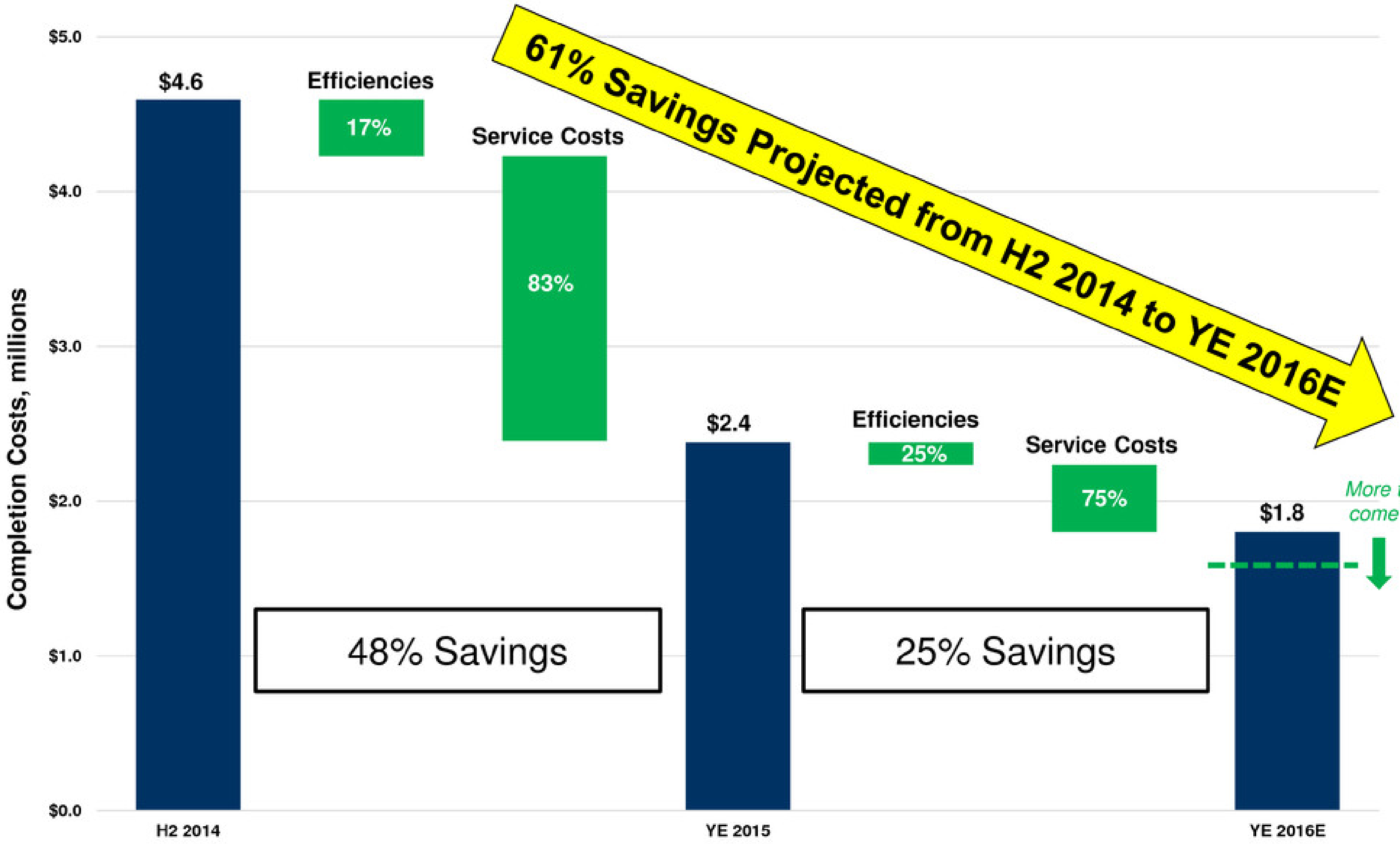
2016 Anticipated Wolf Area Drilling Cost Improvements



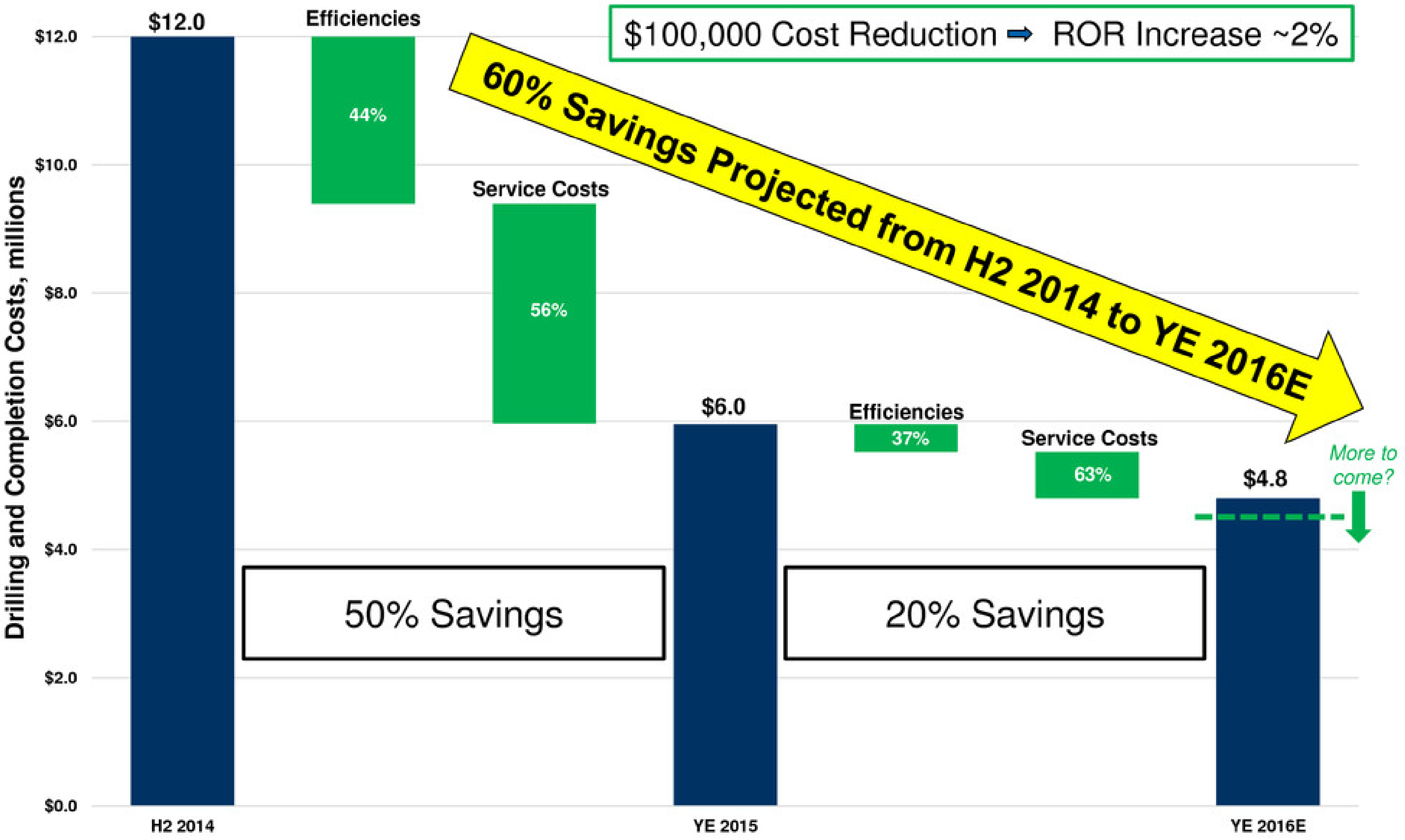
2015 Wolf Area Completion Cost Improvements



2016 Anticipated Wolf Area Completion Cost Improvements

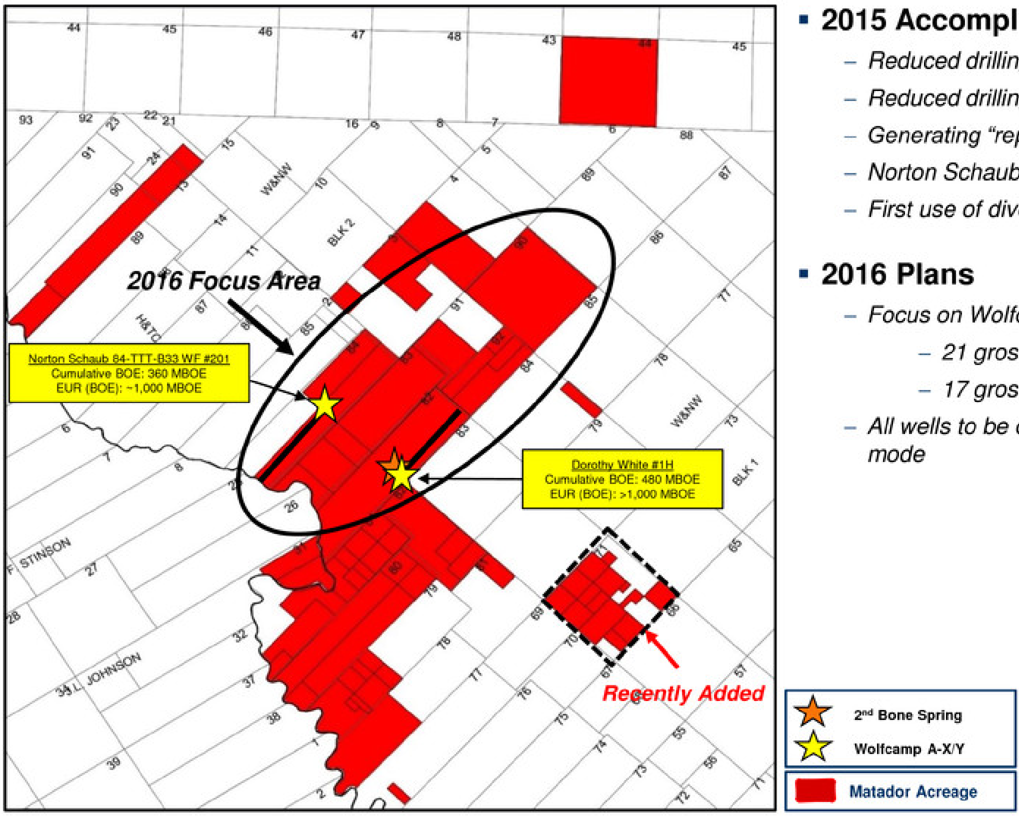


2016 Anticipated Wolf Area Total Drilling and Completion Cost Improvements



Note: Does not include production and facilities costs.

Wolf Prospect Area – Continued Focus on Wolfcamp Development in 2016

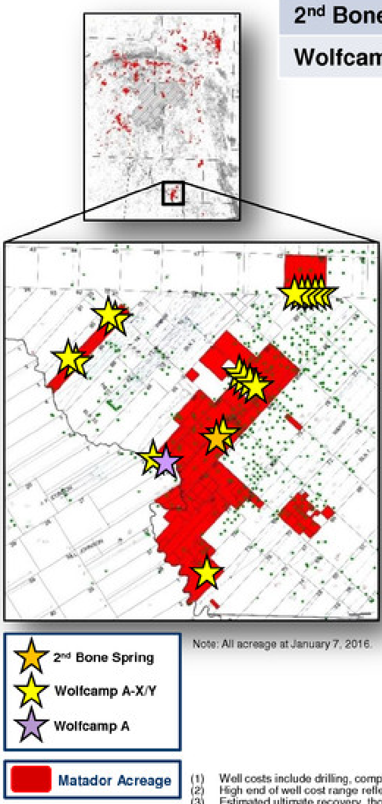


- **2015 Accomplishments**
  - *Reduced drilling times by 58%*
  - *Reduced drilling and completion costs by 50%*
  - *Generating "repeatable" results*
  - *Norton Schaub ESP test a success*
  - *First use of diverting technology encouraging*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *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*

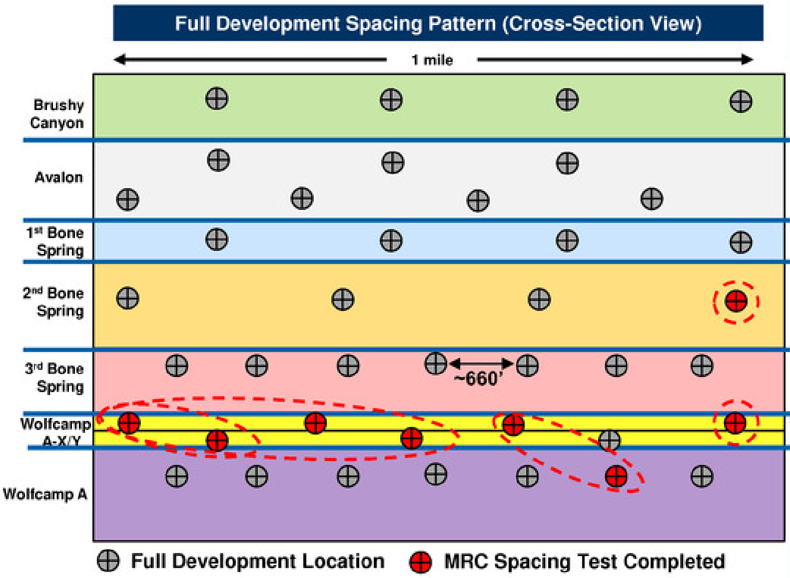
Note: All acreage at January 7, 2016.

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 January 7, 2016.

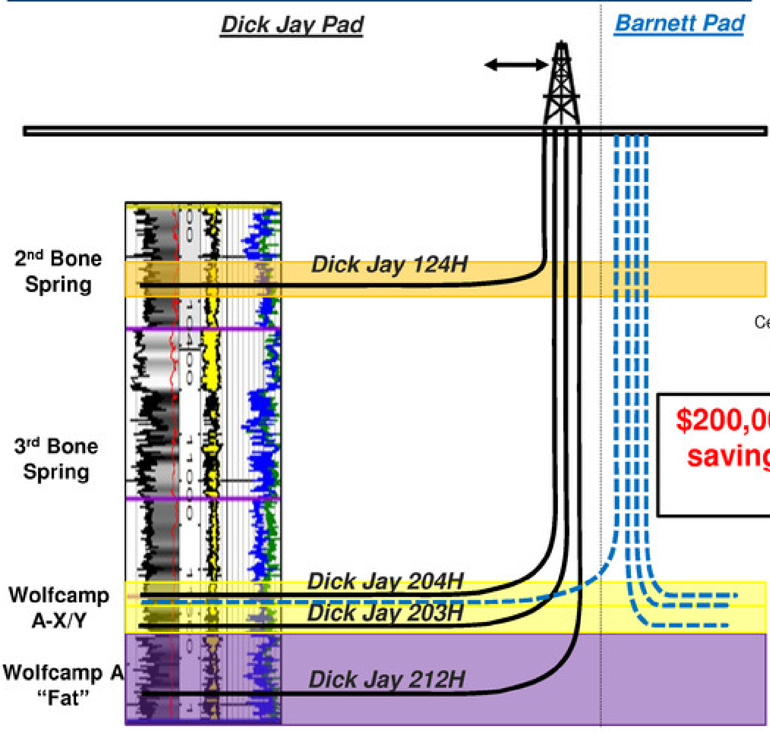


Formation	Total Gross Locations[4]	Est. Operated Locations[5]
Brushy Canyon	4	4
Avalon	72	68
1st Bone Spring	Eval. Ongoing	Eval. Ongoing
2nd Bone Spring	70	66
3rd Bone Spring	72	68
Wolfcamp A-X/Y	51	47
Wolfcamp A	70	66
	339	319

(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%.

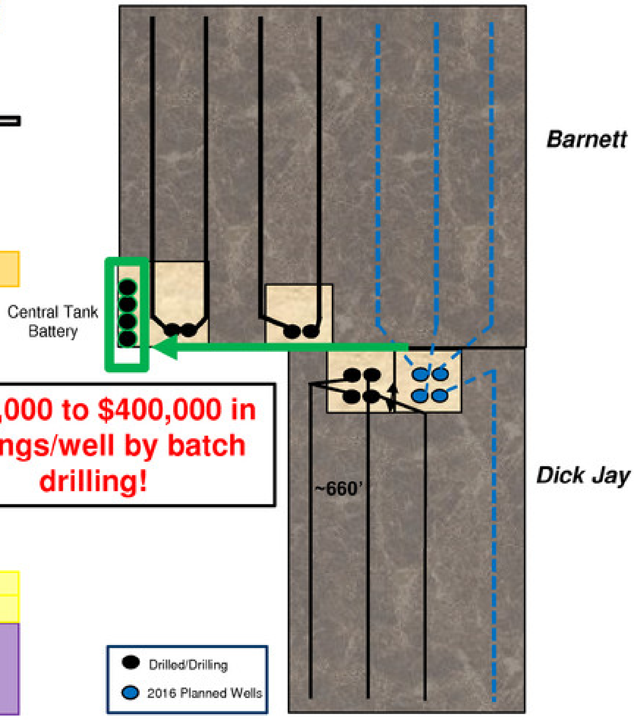
Drilling Wells in Batch Mode / Central Production Facilities

Dick Jay / Barnett Development (Cross-Section View)

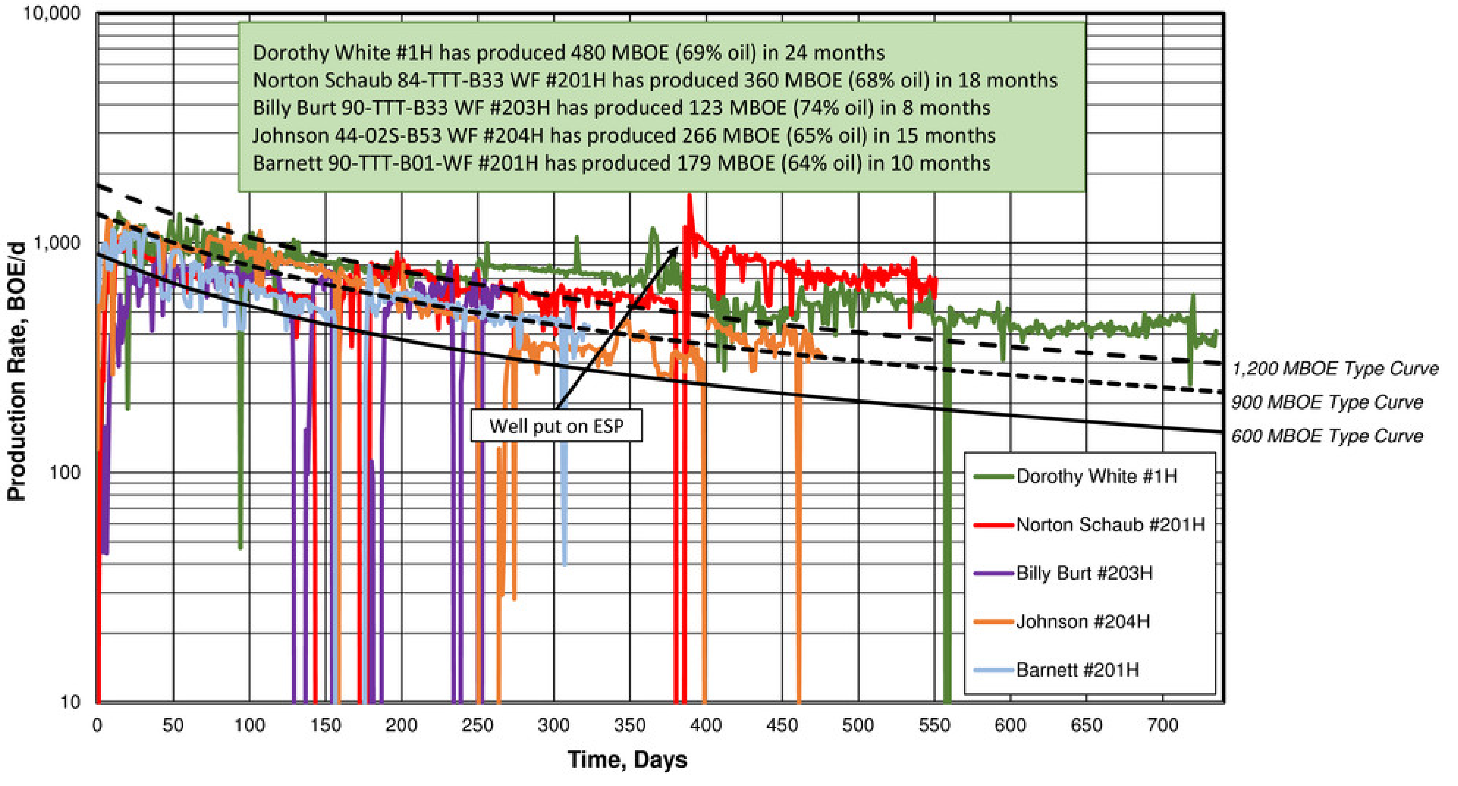


$200,000 to $400,000 in savings/well by batch drilling!

Dick Jay / Barnett Development (Top-Down View)



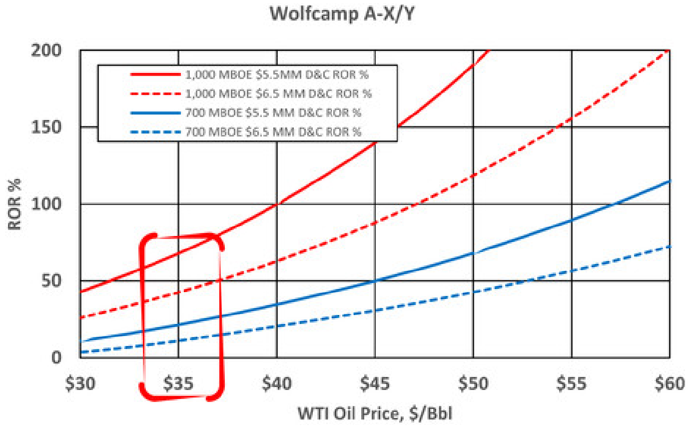
Wolf Area Wolfcamp A-X/Y Wells Continue Strong Performance Across Acreage

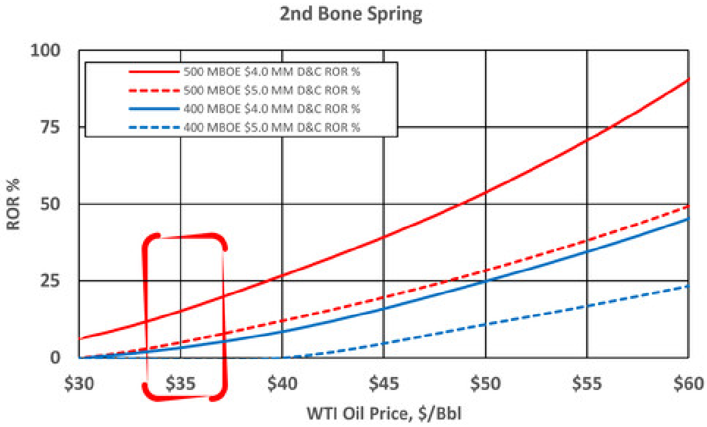


Note: Production from selected Wolfcamp A-X/Y wells in Wolf prospect area as of January 2016.

Wolf – Estimated Returns by Formation

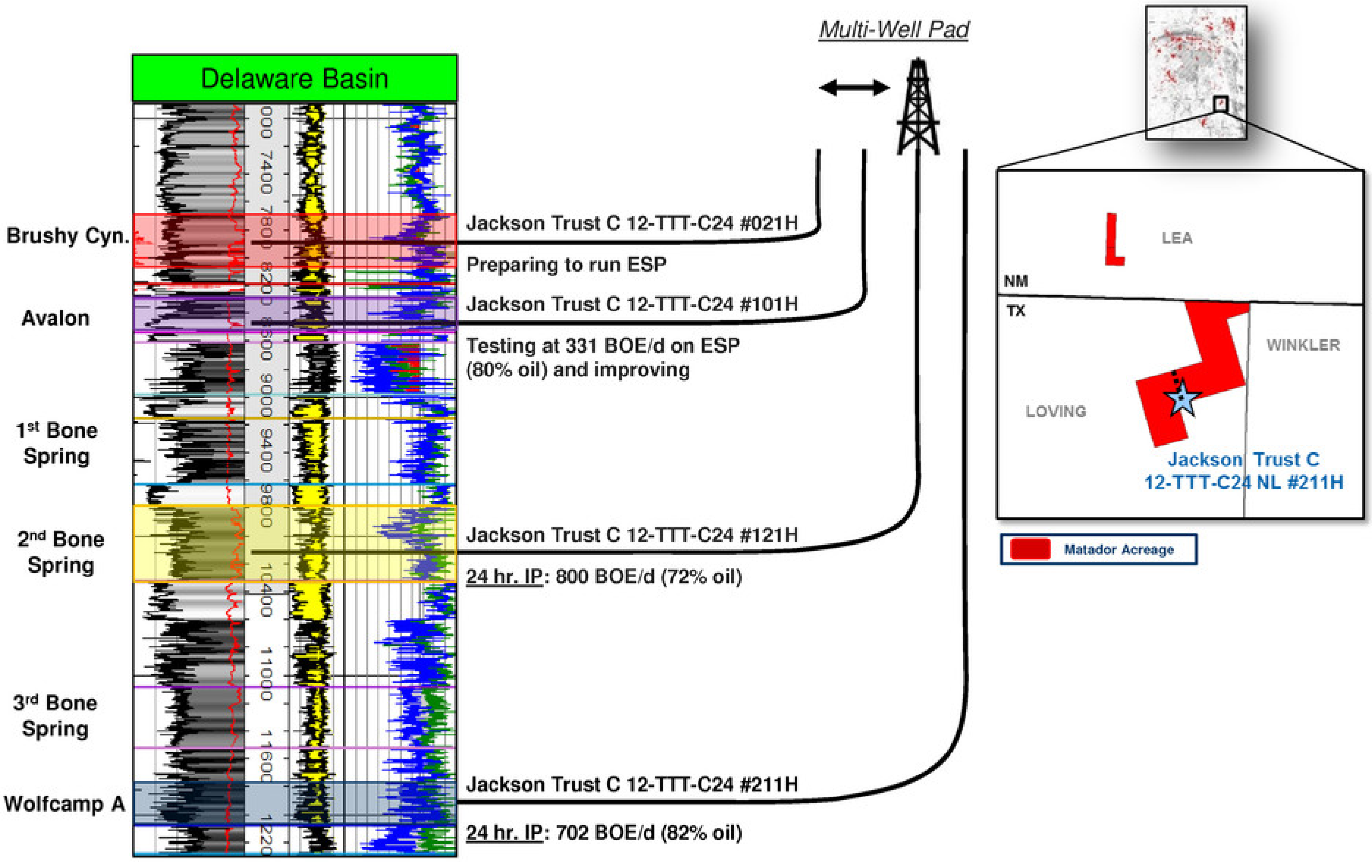
Formation	Development Well Cost[(1)(2)] (millions)	EUR[(3)] (MBOE)	% Oil
2nd Bone Spring	$4.0 - $5.0	400 – 500	50 – 65%
Wolfcamp A-X/Y	$5.5 - $6.5	650 – 1,100	65 – 80%





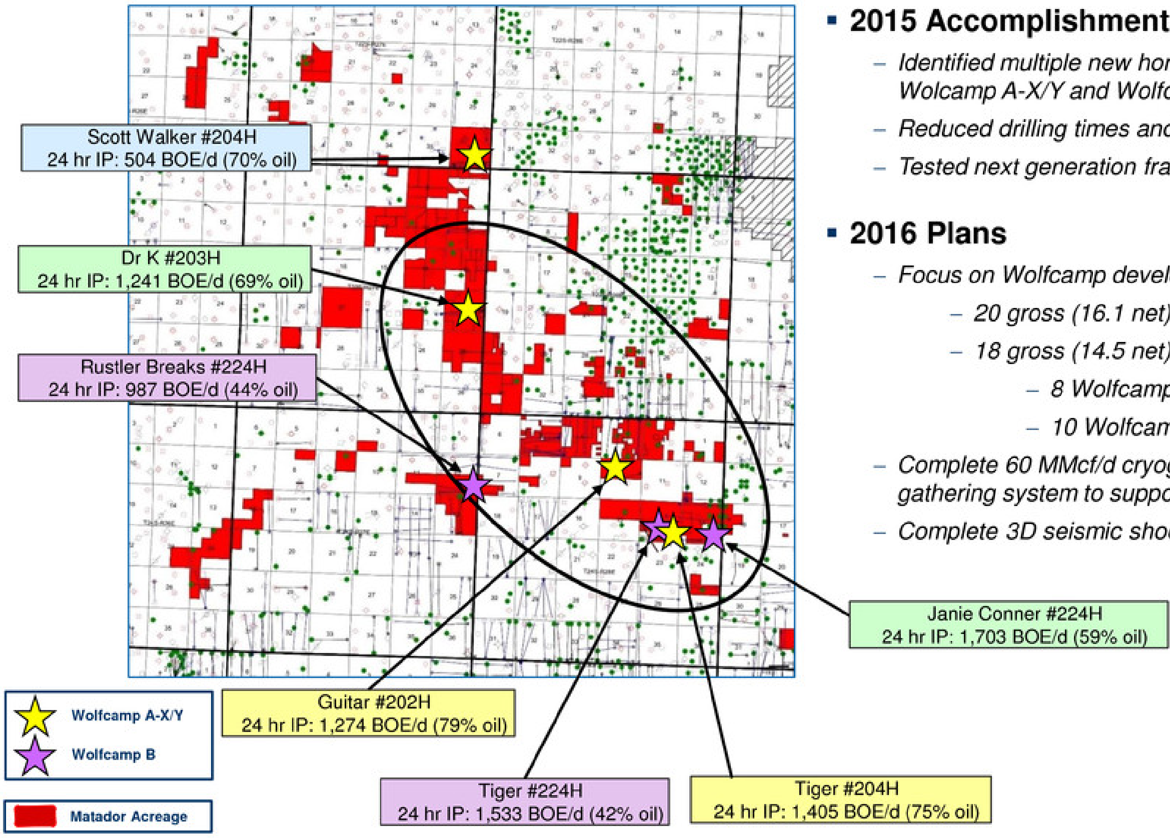
Note: Assumes $2.50/Mcf flat natural gas price with -$0.73/Mcf natural gas differential and -$1.75/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects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

Stacked Horizon Test at Jackson Trust



Note: All acreage at January 7, 2016.

Rustler Breaks – Focus on Wolfcamp Development in 2016

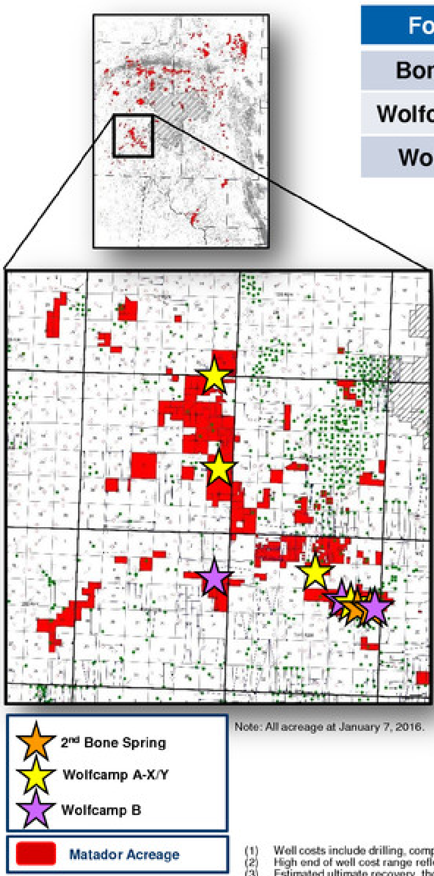


- **2015 Accomplishments**
  - *Identified multiple new horizons, particularly in the Wolcamp A-X/Y and Wolfcamp B*
  - *Reduced drilling times and well costs significantly*
  - *Tested next generation frac design up to 3,000 lbs/ft*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *20 gross (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*

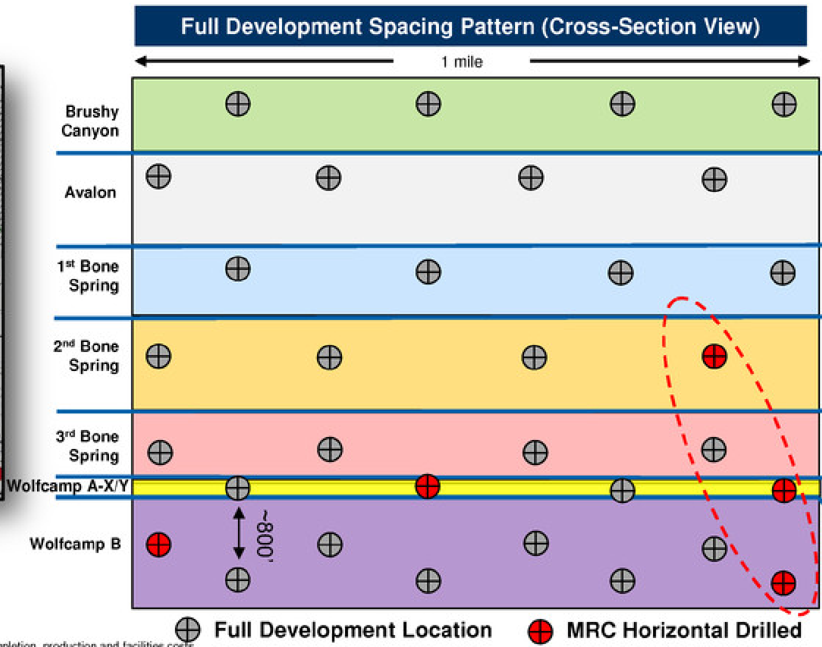
Note: All acreage at January 7, 2016.

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%



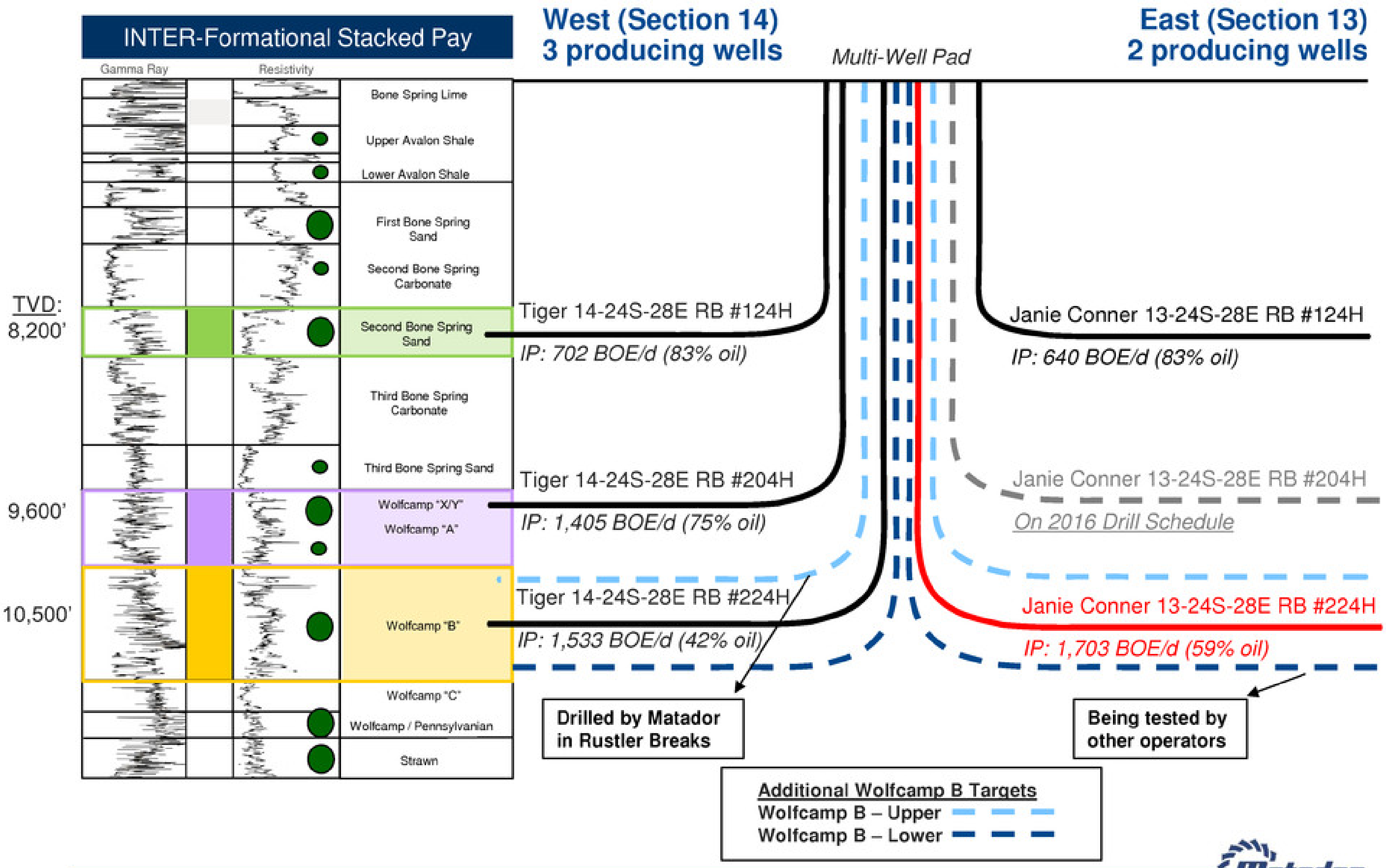
Note: All acreage at January 7, 2016.



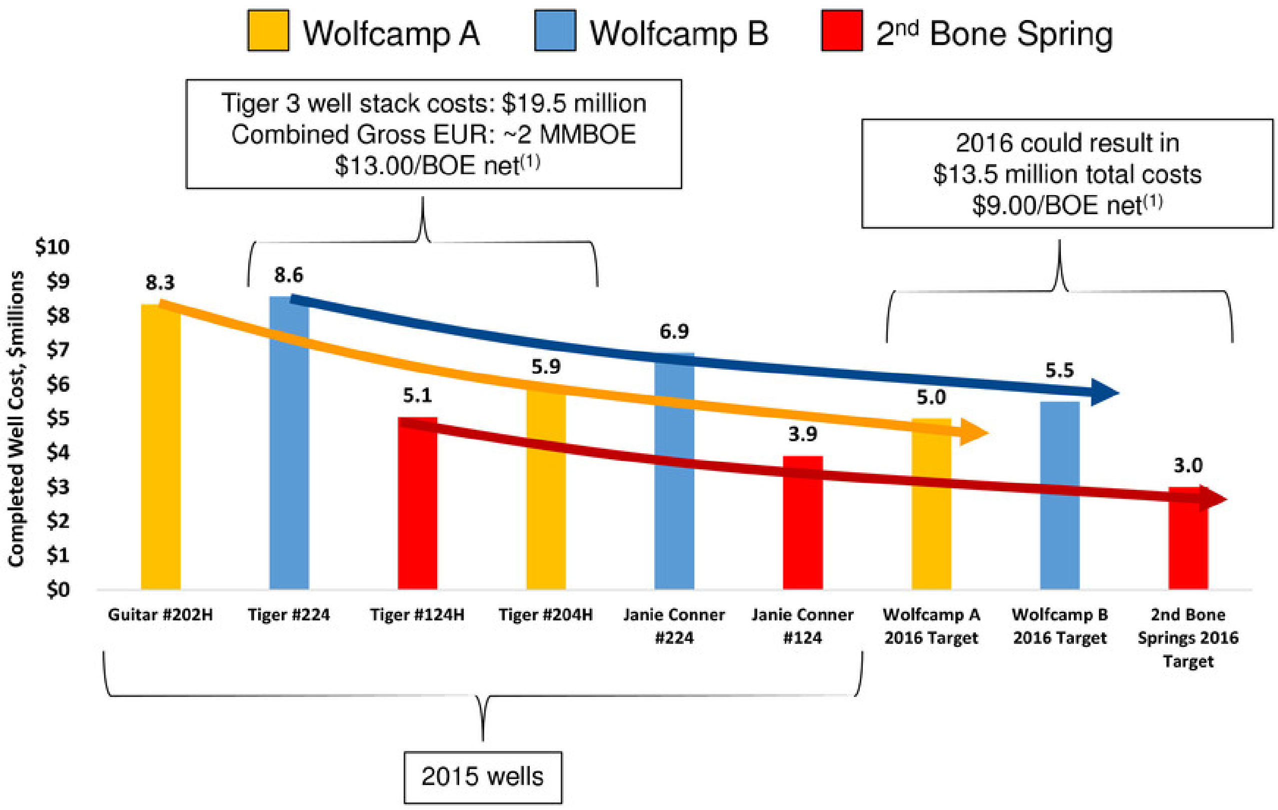
Formation	Total Gross Locations(4)	Est. Operated Locations(5)
Brushy Canyon	171	115
Avalon	178	123
1st Bone Spring	183	125
2nd Bone Spring	188	127
3rd Bone Spring	173	120
Wolfcamp A-X/Y	167	114
Wolfcamp B	235	177
	1,637	1,135

(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 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

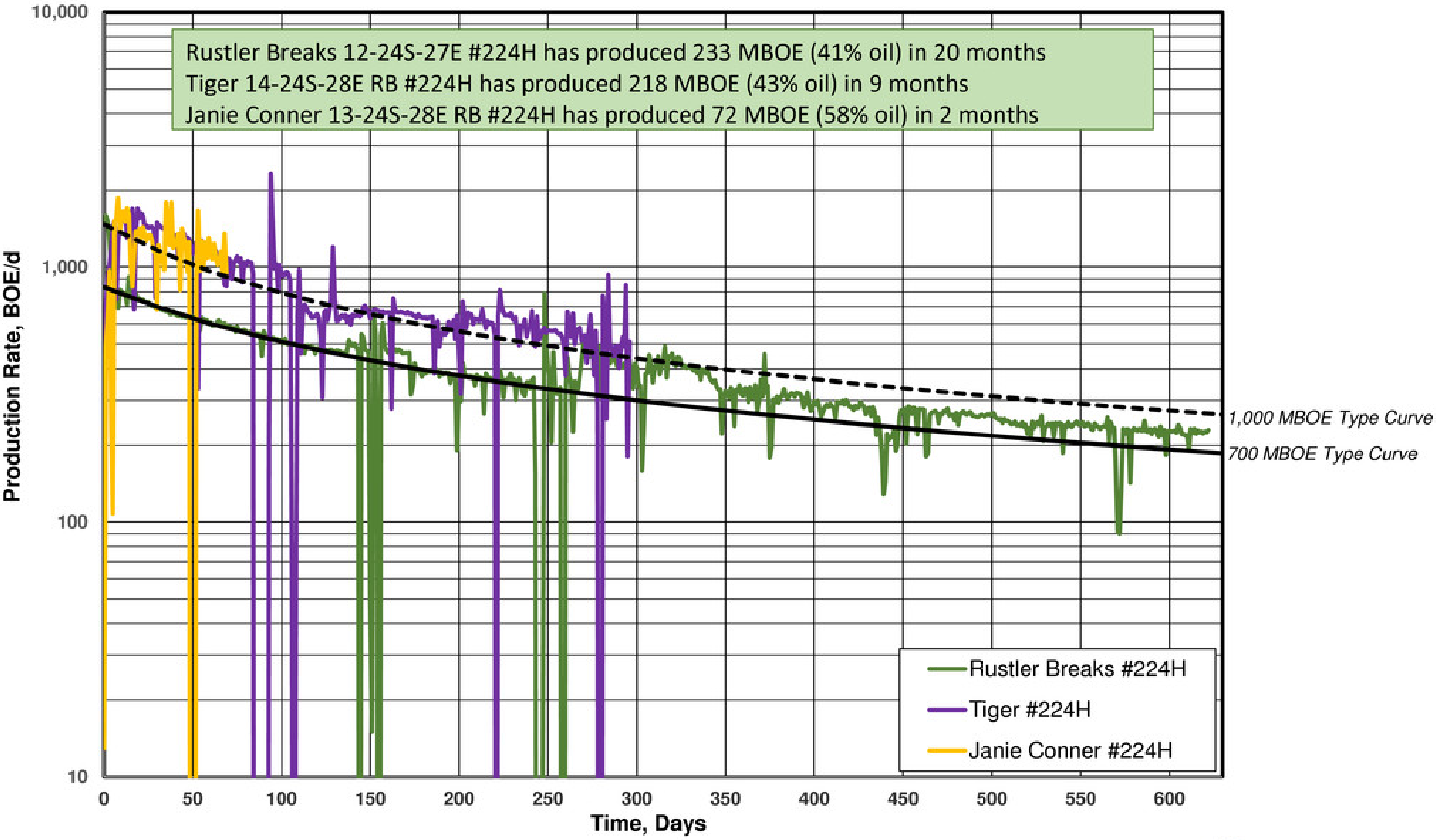


Rustler Breaks Well Cost Achievements



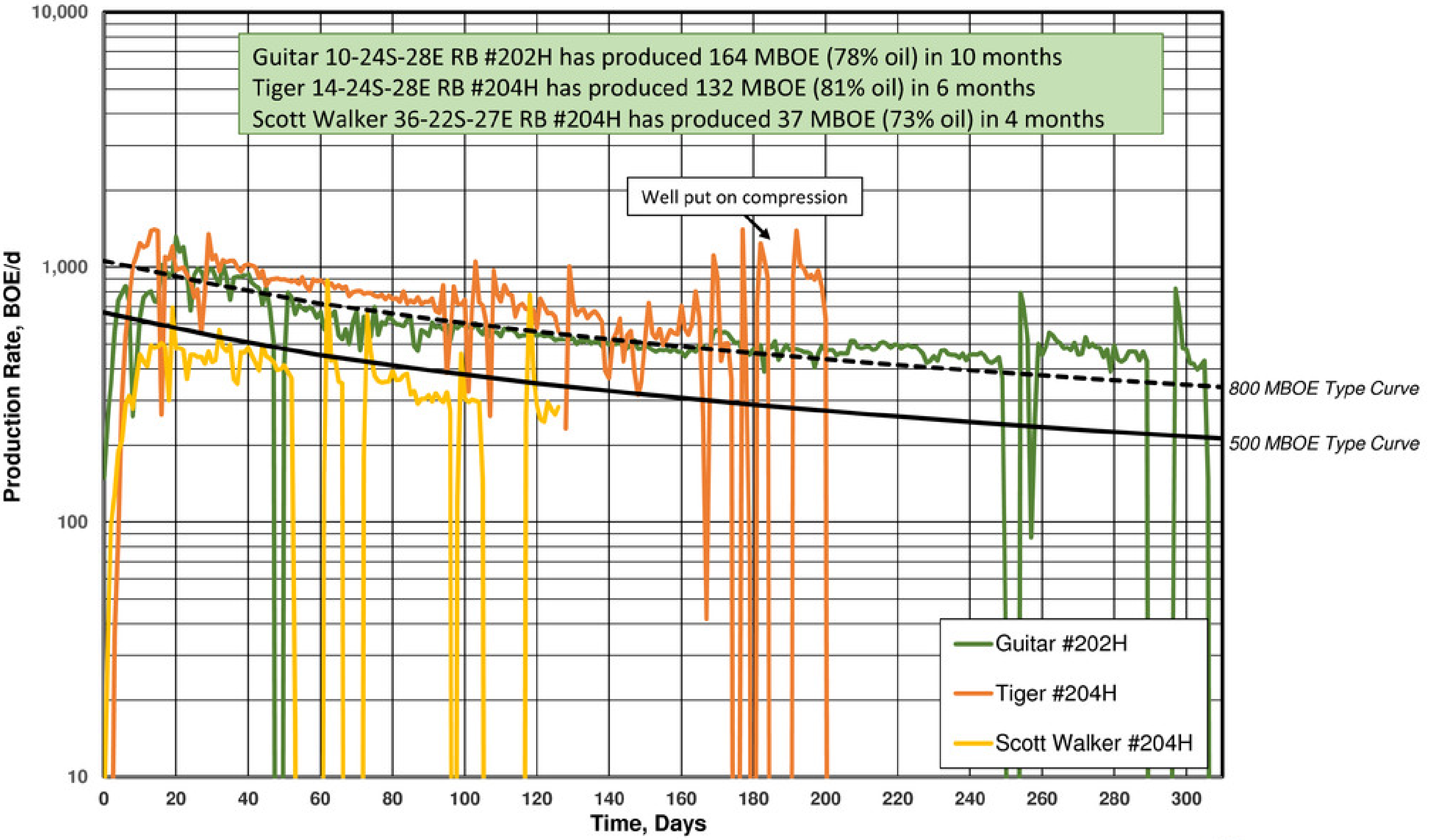
(1) Assumes 75% NRI (net revenue interest) for each well.

Rustler Breaks Wolfcamp B Wells Performing Above Expectations



Note: Production as of January 2016.

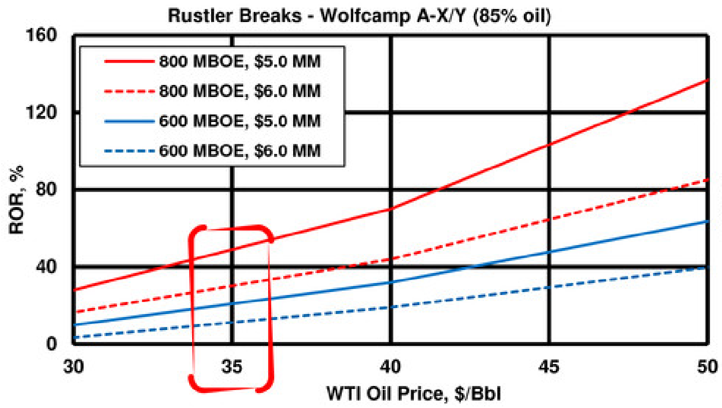
Rustler Breaks Wolfcamp A-X/Y Wells Performing Above Expectations

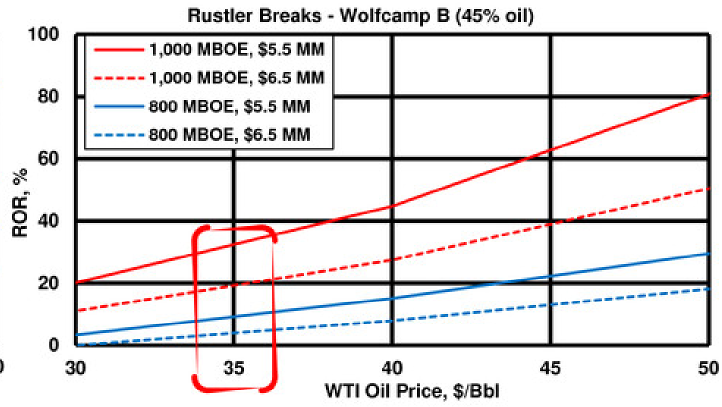


Note: Production as of January 2016.

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%

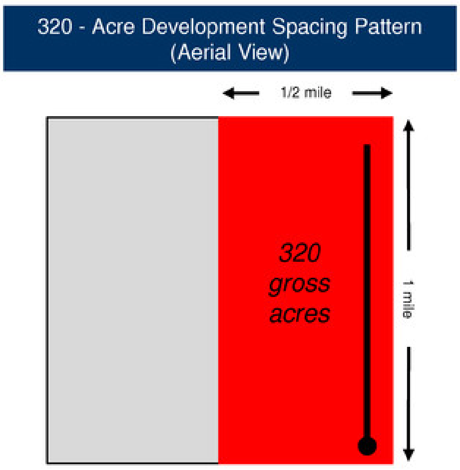


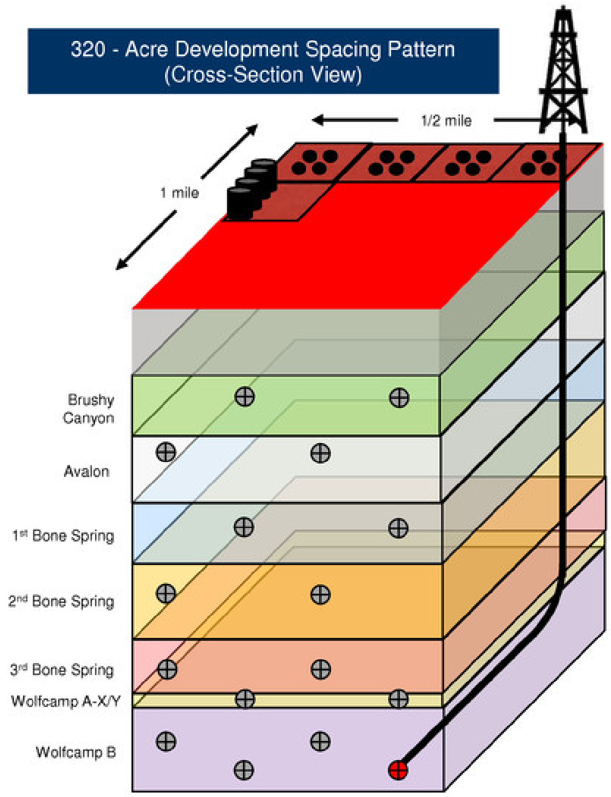


Note: Assumes $2.50/Mcf flat natural gas price with -$0.70/Mcf natural gas differential and -$3.26/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects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

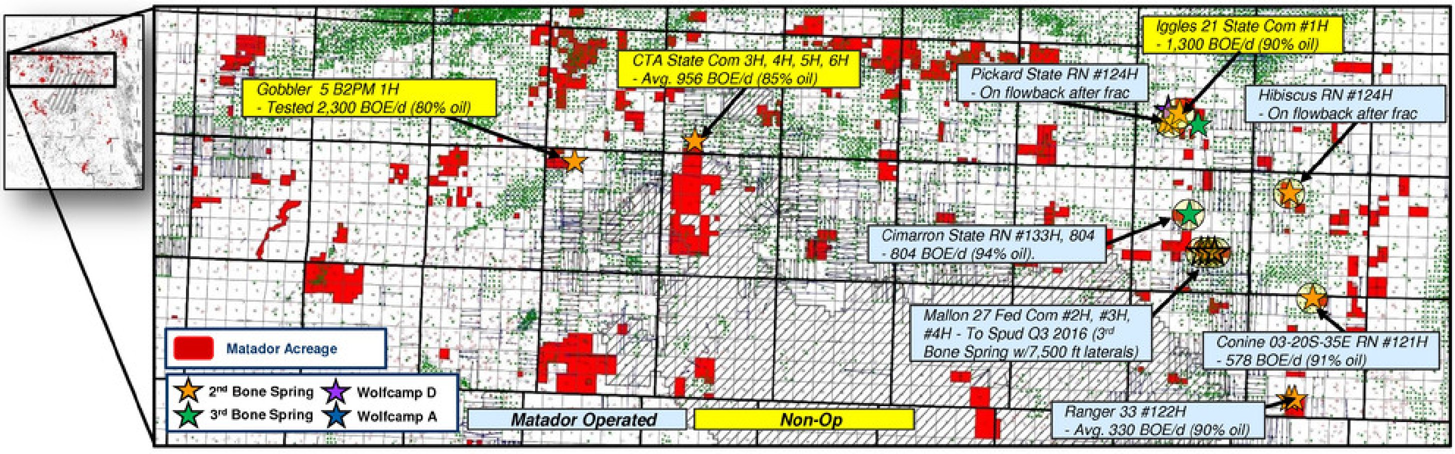
- *One producing Wolfcamp B well holds 320 surface acres and up to 15 additional potential locations for future development*





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

Ranger/Arrowhead – Bone Spring and Wolfcamp Development in 2016

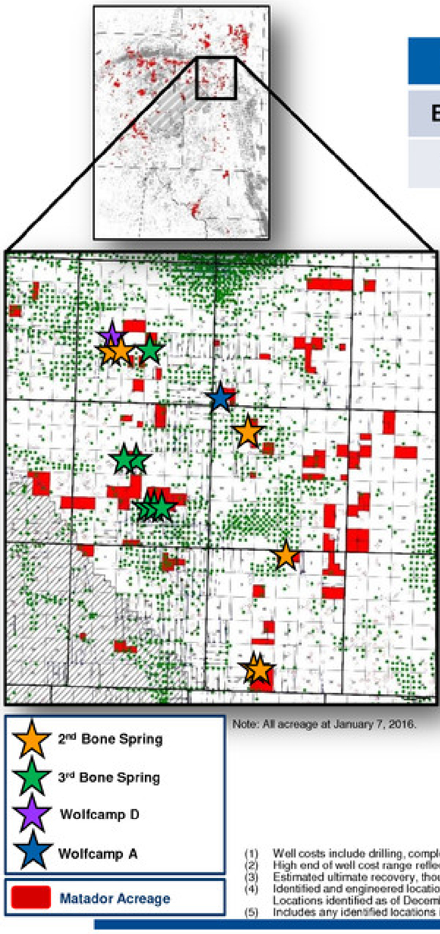


- **2015 Accomplishments**
  - *Merged with HEYCO adding ~60,000 gross and ~20,000 net acres[(1)]*
  - *12 gross (4.5 net) wells*
  - *Drilled Twin Lakes vertical data well*
  - *Applied for 10 new Federal drilling permits*

- **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*

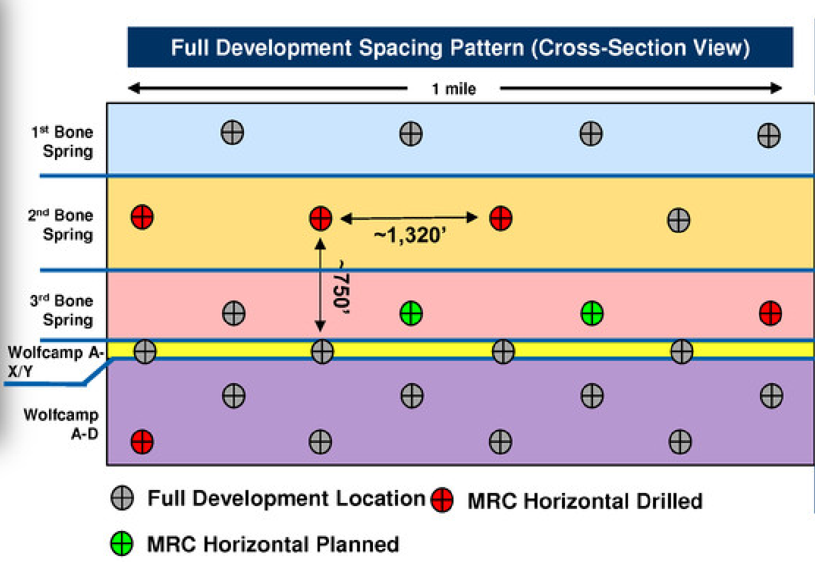
Note: All acreage at January 7, 2016.
(1) Including additional acreage acquired through subsequent joint ventures with affiliates of HEYCO.

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%

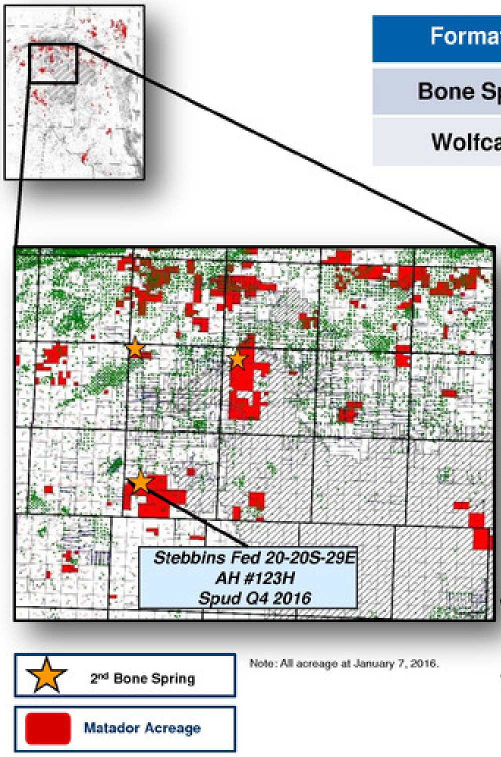
* Based on Volumetrics and 4-8% Recovery Factor



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

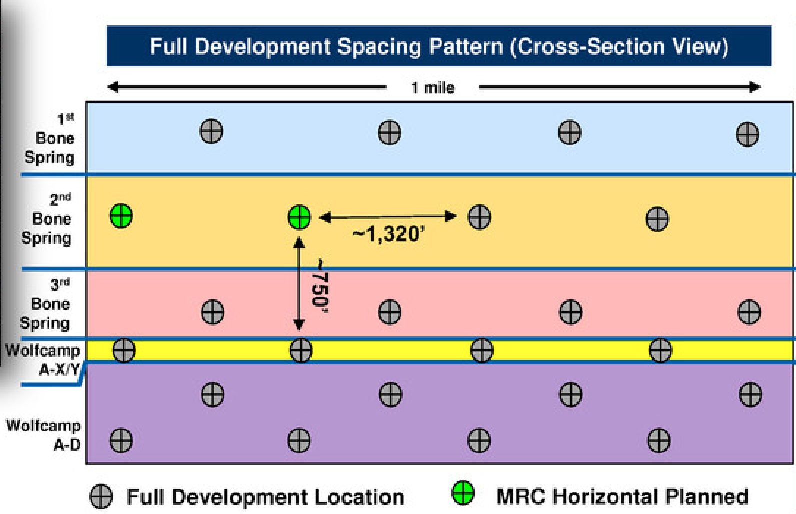
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations 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%

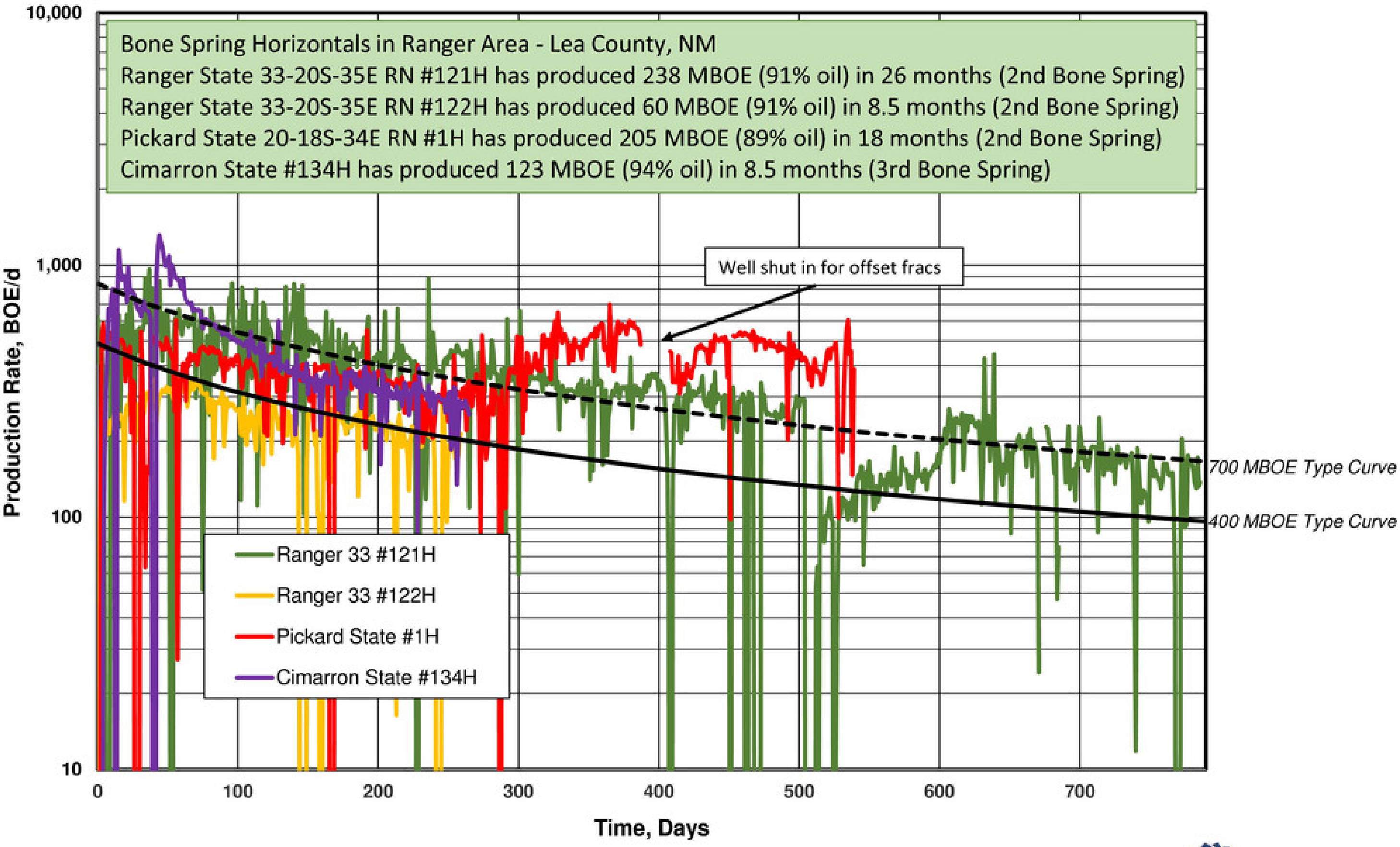
* Based on Volumetrics and 4-8% Recovery Factor



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

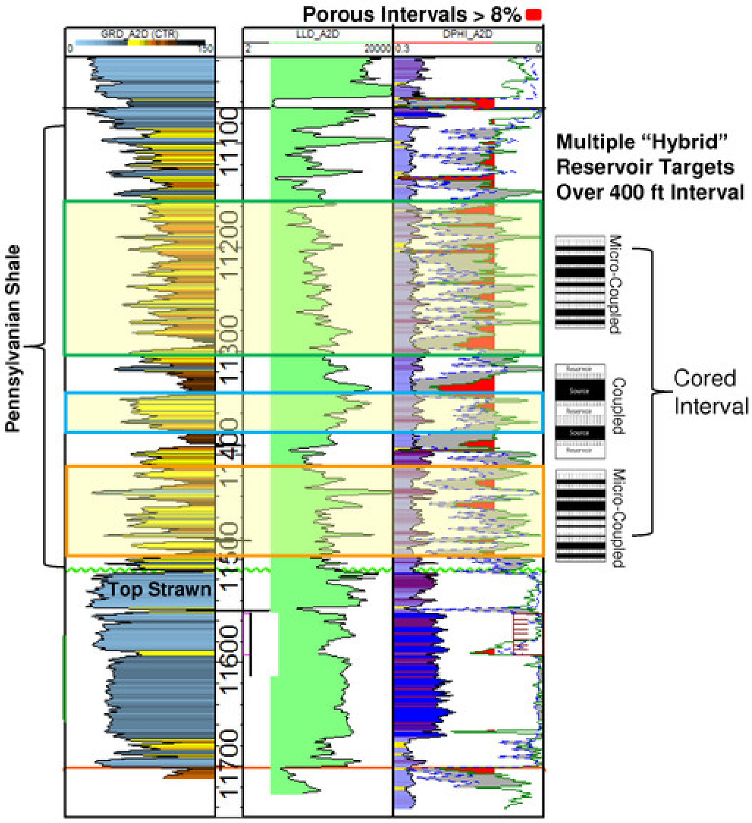
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Gross locations identified as of 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

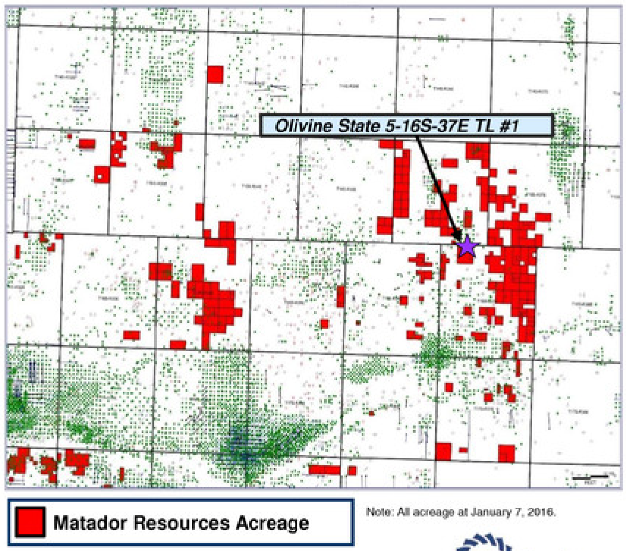


Note: Production as of January 2016.

Testing New Oil Shale Play in Twin Lakes Prospect

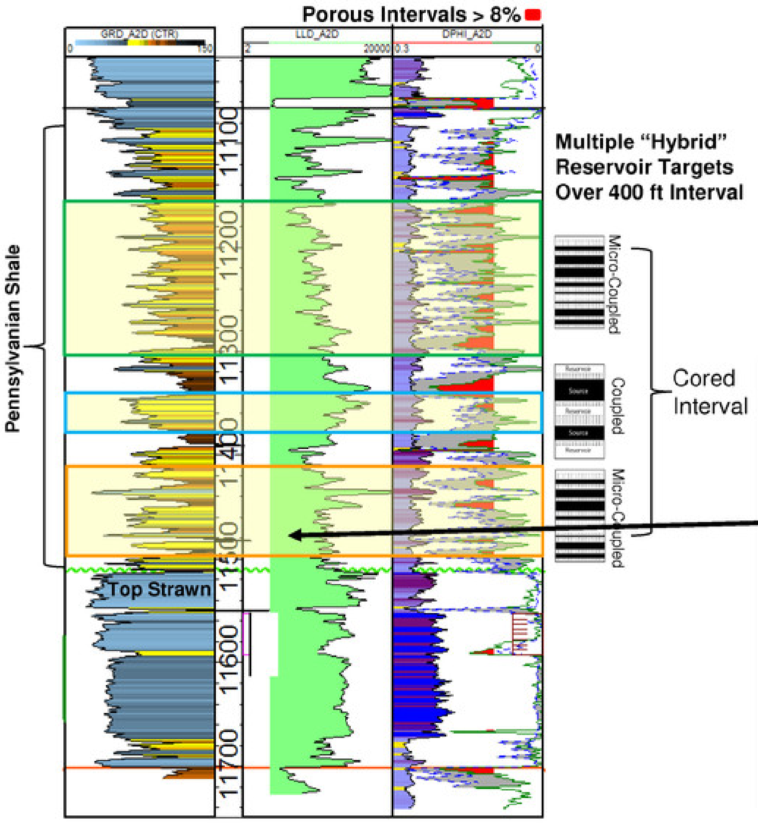


- **Pennsylvanian-Lower Wolfcamp D Oil Shale**
  - One of the primary source rocks for Twin Lakes prospect area (~42,300 gross and ~29,900 net acres)
  - Super-charged area having produced 1.3 billion Bbl oil and 2.2 trillion cubic feet natural gas
  - Drilled initial data collection well (Olivine State #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

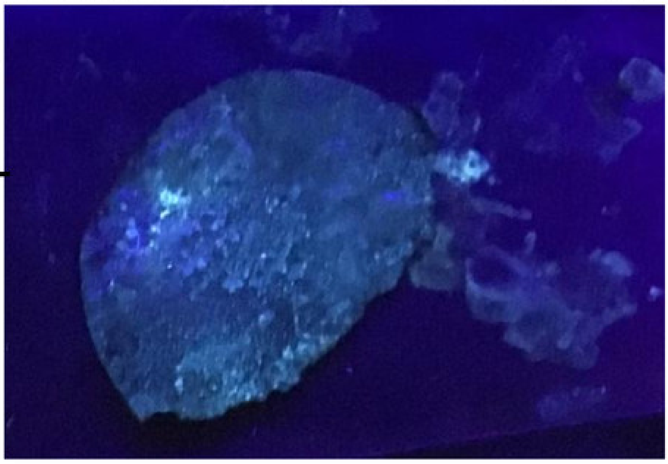


Note: All acreage at January 7, 2016.

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
- **Core chip from Wolfcamp D Shale with oil fluorescence**



Matador RESOURCES COMPANY



Midstream Operations and 2016 Plans

Matthew D. Spicer – Vice President and General Manager of Midstream
Matthew V. Hairford – President

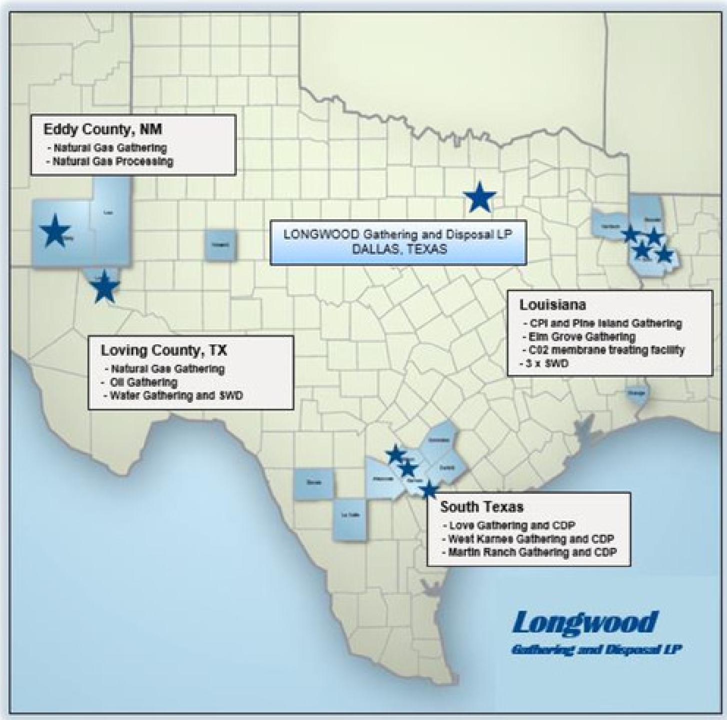
NYSE: MTDR

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

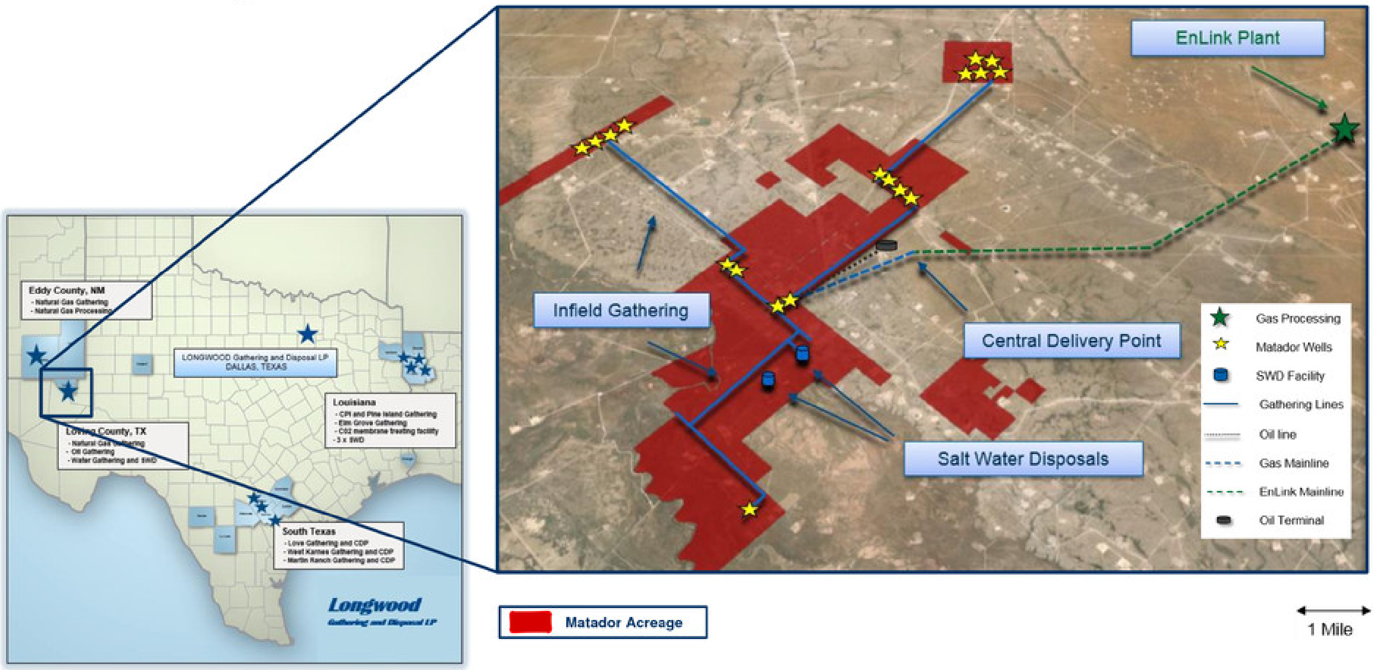
- *Eddy County, NM*
  - Gas gathering and compression
  - Cryogenic gas processing plant
  - Water gathering (under evaluation)
  - Salt water disposal (under evaluation)



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

Wolf - Loving County, TX – Significant Midstream Footprint

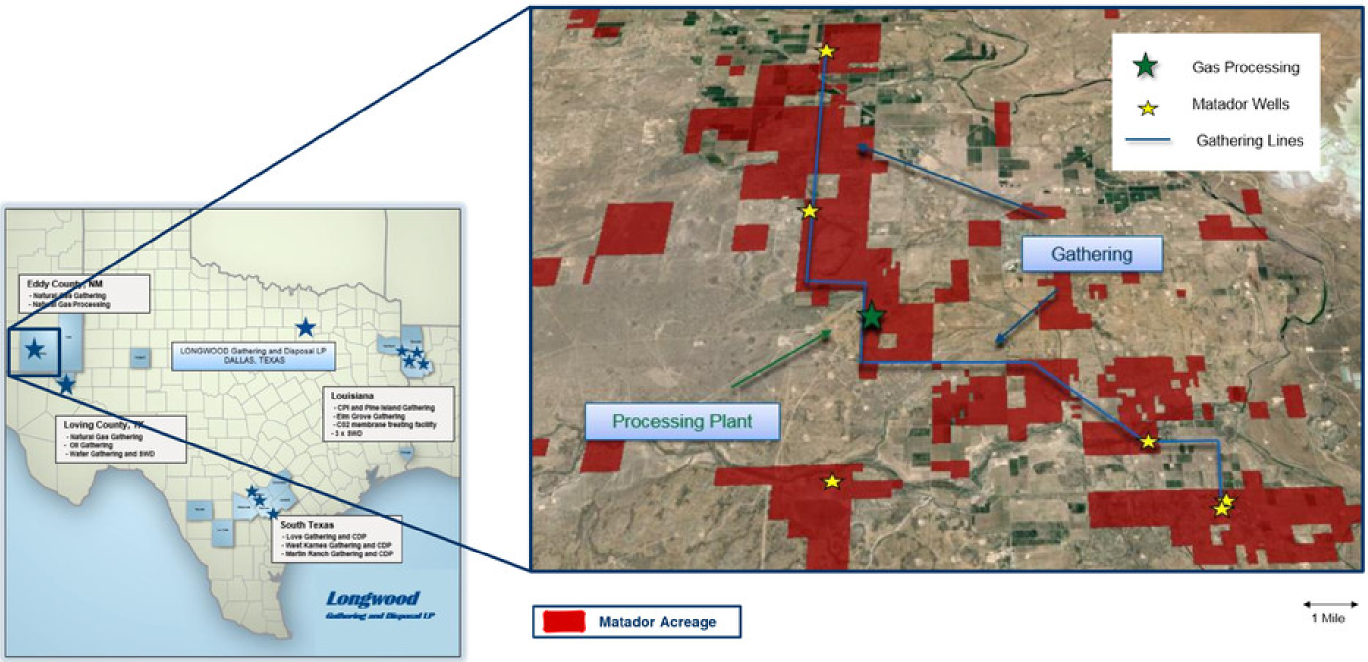
- Gas Gathering
- Water Gathering
- Salt Water Disposal
- Oil Gathering



Note: All acreage at January 7, 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 January 7, 2016.

Midstream Initiatives Growing into Respectable Business

- Expect to spend ~$40 million on midstream initiatives in the Delaware Basin in 2016
- Matador expects Longwood to be able to support its own sources of financing
- Monetization of midstream assets could be a significant source of funding for Matador in 2016
- Projected 2016 cash flow for Midstream is expected to be approximately $20 million(1)

(1) Estimated cash flow excludes allocations for general and administrative and certain other expenses. Cash flow presented is not necessarily incremental to Matador's other businesses.



Summary; Q&A

NYSE: MTDR

Matador RESOURCES COMPANY

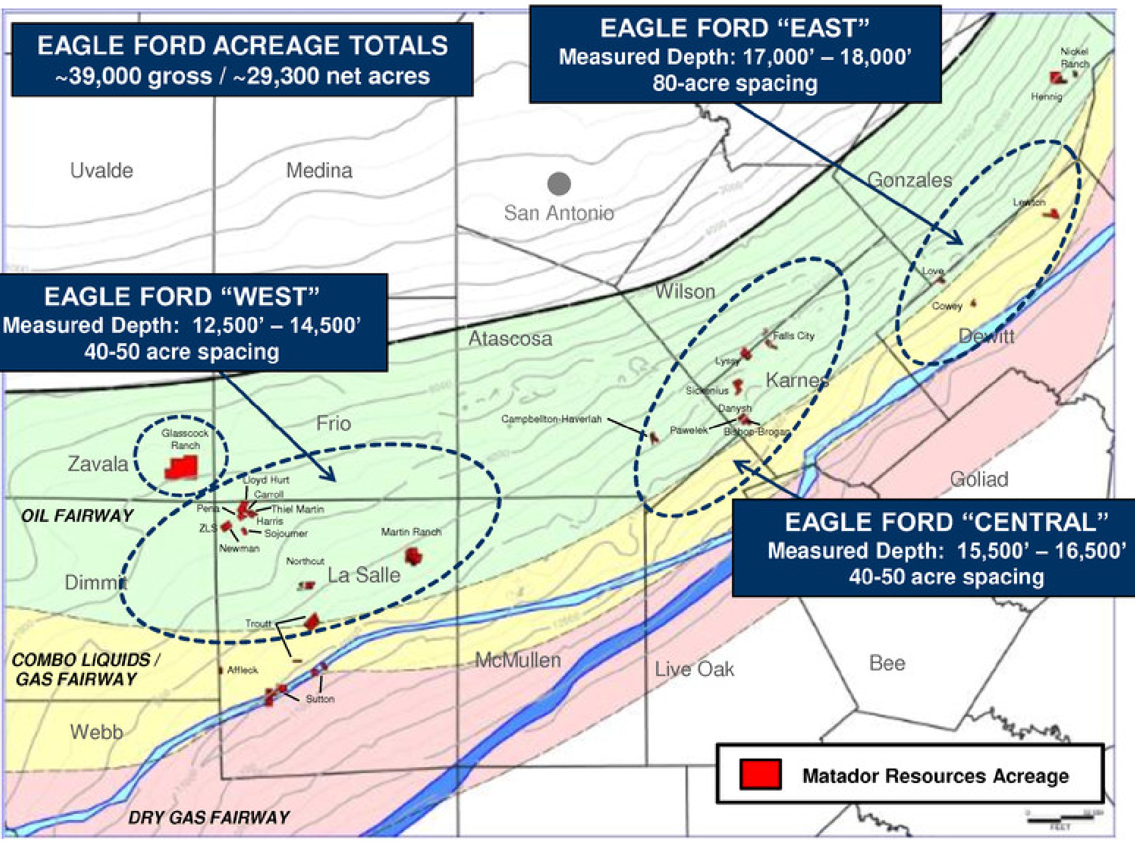
2016 Analyst Day Presentation

February 3, 2016 **NYSE: MTDR**



Appendix

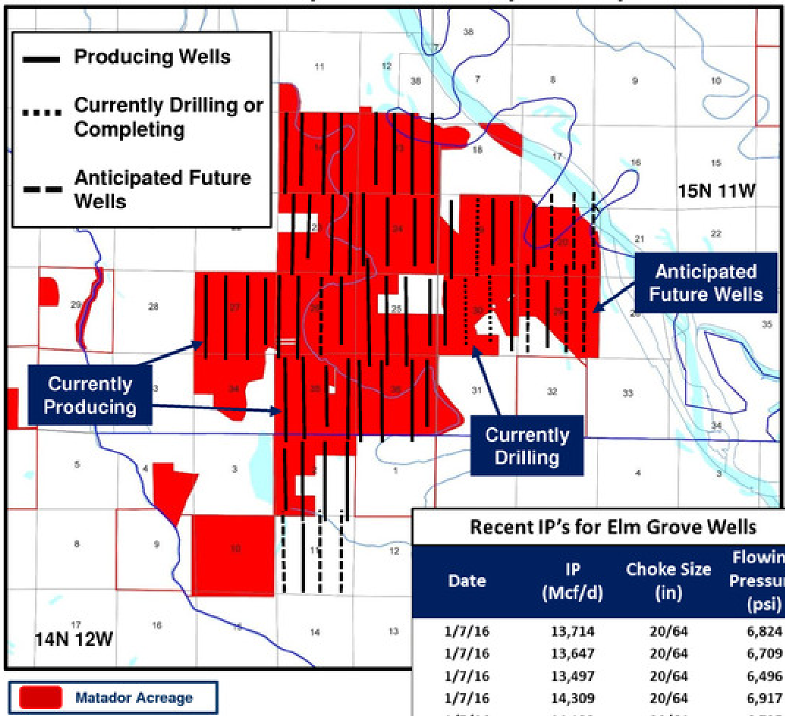
Eagle Ford – "Oil Bank"



Note: All acreage at January 7, 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

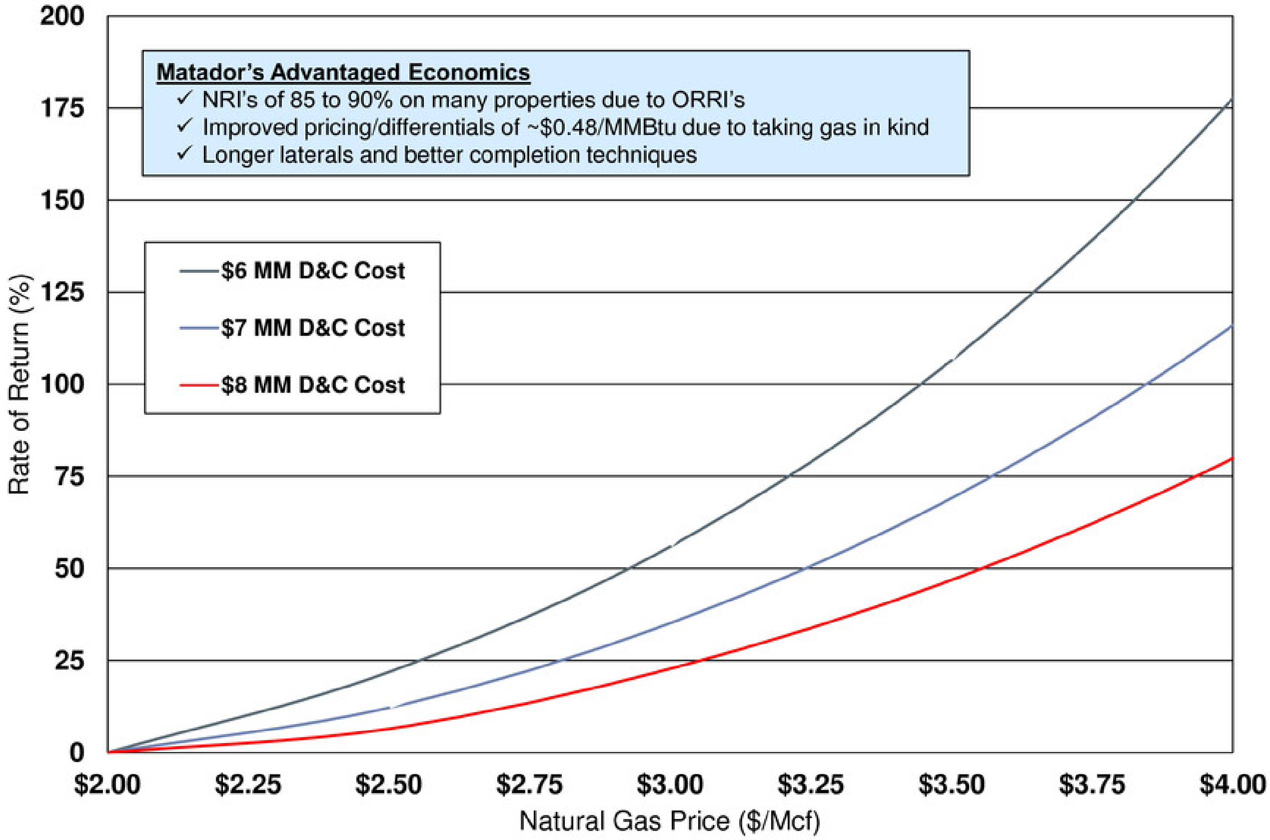
- 22 gross (1.9 net) wells turned to sales throughout Tier 1 Haynesville in 2015
- Includes 9 gross (1.6 net) wells turned to sales on Elm Grove properties operated by Chesapeake in 2015 (shown on map at left)
  - *Chesapeake deferred first production on 9 gross (1.9 net) wells drilled and completed 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 January 7, 2016.
(1) As of January 31, 2016.

Economics of Tier 1 Haynesville Well (10 Bcf) in Elm Grove



Note: Individual well economics only. Excludes costs prior to drilling (i.e. acquisition or acreage costs). Economics use a NRI / WI of 85% but actual interests vary. D&C cost = drilling and completion cost.

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
W.J. "Jack" Sleeper, Jr.	- Retired President, DeGolyer and MacNaughton (Worldwide Petroleum Consultants)	Oil and Gas Executive Management

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 VP – Reservoir Engineering and CTO	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	38 years	Since Inception
Billy E. Goodwin VP – Drilling	- Samson, Conoco	31 years	Since 2010
G. Gregg Krug VP 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
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)
Interest expense	1,396	1,616	673	1,649	2,070	5,869	7,229
Total income tax provision (benefit)	9,536	10,634	16,504	27,701	(26,390)	(89,350)	(33,305)
Depletion, depreciation and amortization	24,030	31,797	35,143	43,767	46,470	51,768	45,237
Accretion of asset retirement obligations	117	123	130	134	112	132	182
Full-cost ceiling impairment	-	-	-	-	67,127	229,026	285,721
Unrealized (gain) loss on derivatives	3,108	5,234	(16,293)	(50,351)	8,557	23,532	(6,733)
Stock-based compensation expense	1,795	1,834	1,038	857	2,337	2,794	1,755
Net loss on asset sales and inventory impairment	-	-	-	-	97	-	-
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**

(In thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 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
Net change in operating assets and liabilities	21,729	(15,221)	(586)	56	(45,234)	40,843	(20,846)
Interest expense, net of non-cash portion	1,396	1,616	673	1,649	2,070	5,869	6,678
Current income tax (benefit) provision	1,275	1,539	(156)	(2,525)	-	-	(295)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	17	(36)	(75)	(45)
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**

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,							LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	2014	9/30/2015
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	($402,821)
Interest expense	-	-	3	683	1,002	5,687	5,334	16,817
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	64,375	(121,344)
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	134,737	187,242
Accretion of asset retirement obligations	92	137	155	209	256	348	504	560
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	-	581,874
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	(58,302)	(24,995)
Stock-based compensation expense	665	656	898	2,406	140	3,897	5,524	7,743
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	-	97
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$245,173**

	Year Ended December 31,							LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	2014	9/30/2015
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	$257,047
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	5,978	(25,181)
Interest expense, net of non-cash portion	-	-	3	683	1,002	5,687	5,334	16,266
Current income tax (benefit) provision	$10,448	($2,324)	(1,411)	(46)	-	404	133	(2,820)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	17	(139)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$245,173**

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.

We have not provided a reconciliation of PV-10 to Standardized Measure at December 31, 2015. We could not provide such a reconciliation without undue hardship because we have not completed the audit of our December 31, 2015 financial statements. In addition, it would be difficult for us to present a detailed reconciliation on account of many unknown variables for the reconciling items.

	At December 31, 2013	At December 31, 2014	At September 30, 2015
PV-10 *(in millions)*	$655.2	$1,043.4	$692.7
Discounted Future Income Taxes *(in millions)*	$(76.5)	$(130.1)	$(18.9)
Standardized Measure *(in millions)*	$578.7	$913.3	$673.8