

2013 Analyst Day Presentation

December 12, 2013

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" 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 our financial and operational performance: general economic conditions; our ability to execute our business plan, including whether our 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; our ability to replace reserves and efficiently develop our current reserves; our costs of operations, delays and other difficulties related to producing oil, natural gas and natural gas liquids; our ability to make acquisitions on economically acceptable terms; availability of sufficient capital to execute our business plan, including from our future cash flows, increases in our borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.

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

Definitions – Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which 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 estimate 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.



Welcome and Opening Remarks

Company Overview

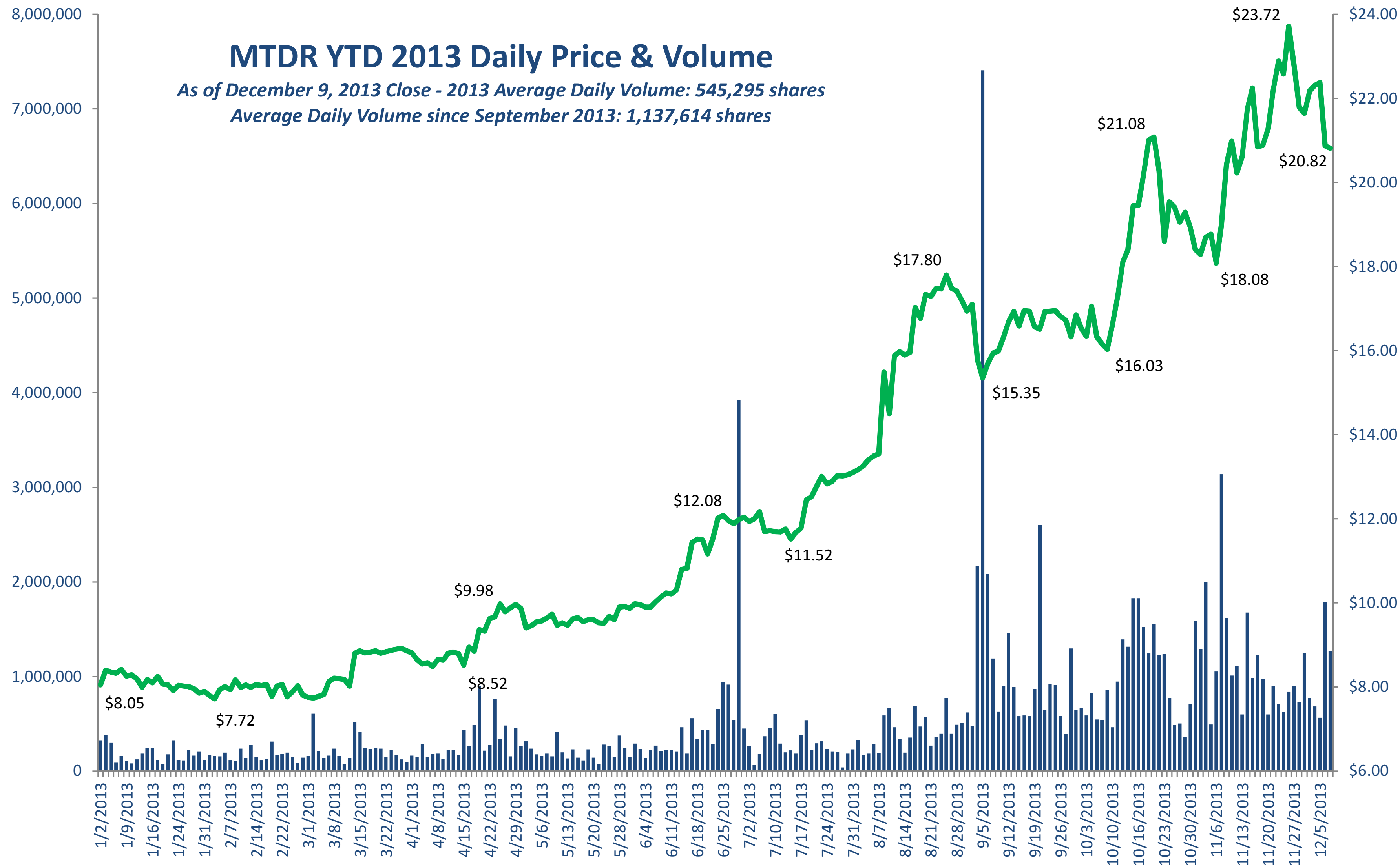
Completed IPO of 14,883,334 shares (12,209,167 primary) including overallotment at $12.00/share in March 2012 and Follow-on Offering of 9,775,000 shares including overallotment at $15.25/share in September 2013

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	65.6 million common shares
Share Price(2)	$20.82/share
Market Capitalization(2)	~$1.4 billion

	2012 Actual	***2013 Guidance***
Capital Spending	$335 million	$370 million
Total Oil Production	1.214 million barrels	2.0 to 2.1 million barrels
Total Natural Gas Production	12.5 billion cubic feet	12.0 to 13.0 billion cubic feet
Oil and Natural Gas Revenues	$156.0 million	$250 to $270 million(3)
Adjusted EBITDA(4)	$115.9 million	$180 to $190 million(3)

(1) As reported in the Form 10-Q for the quarter ended September 30, 2013 filed on November 8, 2013.
(2) As of December 9, 2013.
(3) Estimated 2013 oil and natural gas revenues and Adjusted EBITDA based upon production guidance range as updated on November 6, 2013. Guidance includes actual results for the nine months ended September 30, 2013 and estimated results for the remainder of 2013. Estimated average realized prices for oil and natural gas used in these estimates were $96.00/Bbl and $4.30/Mcf, respectively, for the period October through December 2013.
(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.

MTDR up 154% Year to Date



Keys to Matador’s Success

- **People**
  - We have a strong, committed technical and financial team in place and we continue to make additions and improvements to our staff and our capabilities
  - Board and Special Advisor additions have strengthened Board skills and stewardship

- **Properties**
  - Matador’s acreage positions and multi-year drilling inventory are significant and located in three of the industry’s best plays – Eagle Ford, Permian and Haynesville
  - Our property mix provides us with a balanced opportunity set for both oil and natural gas

- **Process**
  - Continuous improvement in all aspects of our business leading to better production and financial results and increased shareholder value
  - Gaining experience in being a publicly-held company

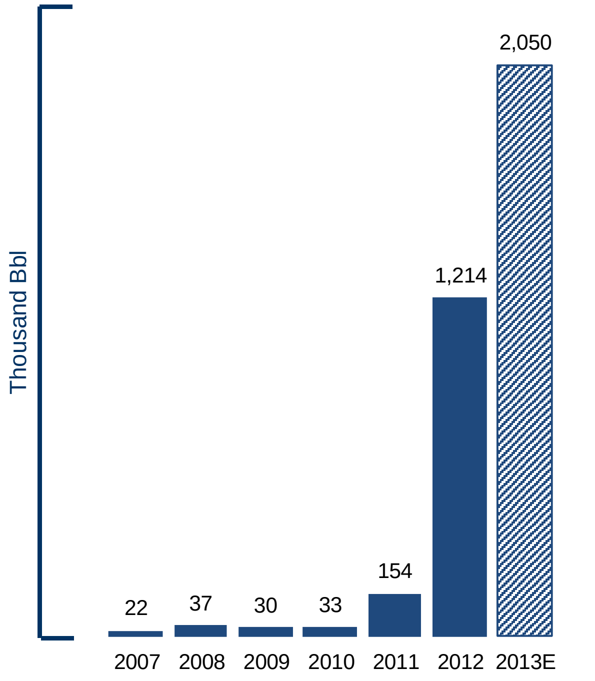
Matador Execution History – IPO (February 7, 2012) vs. Today

What we said at IPO	Metric	At IPO[1]	What we've done	Today[7]
Grow with a focus on the Eagle Ford to create a more balanced portfolio	*Production*	▪ 7.1 MBOE/d ▪ 414 Bbl/d of oil ▪ 6% oil	16x growth in oil production	▪ 13.5 MBOE/d ▪ 6,700 Bbl/d of oil ▪ 50% oil
	Proved Reserves	▪ 27 MMBOE ▪ 1.1 MMBbl of oil ▪ 4% oil	Over 12x growth in oil reserves	▪ 44 MMBOE ▪ 13.9 MMBbl of oil ▪ 31% oil
	PV-10[2]	▪ $155.2 million ▪ 24% of PV-10 value in the Eagle Ford	3.5x growth in PV-10	▪ $538.6 million ▪ 89% of PV-10 value in the Eagle Ford
	LTM Adjusted EBITDA[3]	▪ $50 million[4]	~260% growth	▪ $181 million
Identify and develop additional oil opportunities	*Acreage*	▪ ~7,500 net acres in the Permian	Increased Permian leasehold position by over 5x	▪ ~40,800 net acres in the Permian[8]
Create value for stakeholders	*Enterprise Value[5]*	▪ $0.65 billion[6]	More than doubled Enterprise Value	▪ Over $1.5 billion[9]

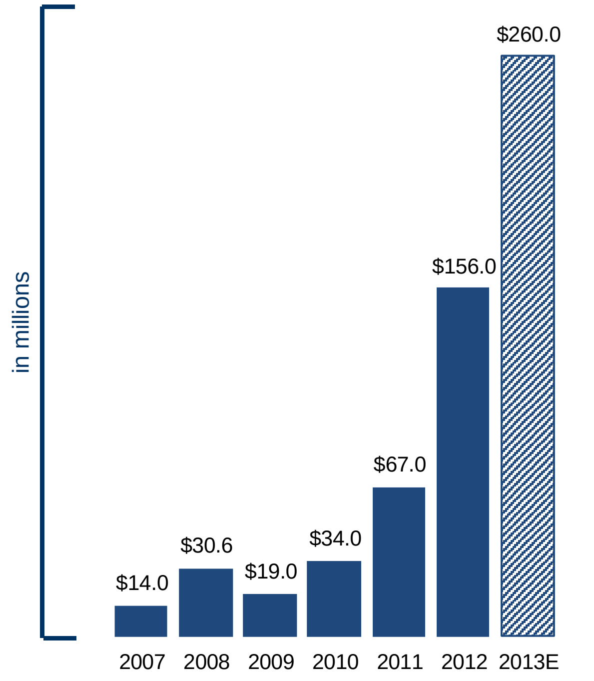
(1) Unless otherwise noted, at or for the nine months ended September 30, 2011.
(2) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.
(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(4) For the twelve months ended December 31, 2011.
(5) Enterprise value equals market capitalization plus borrowings under our revolving credit agreement.
(6) As of February 7, 2012 at time of IPO.
(7) Unless otherwise noted, at or for the three months ended September 30, 2013.
(8) As of November 30, 2013.
(9) As of December 9, 2013.

Matador's Continued Growth

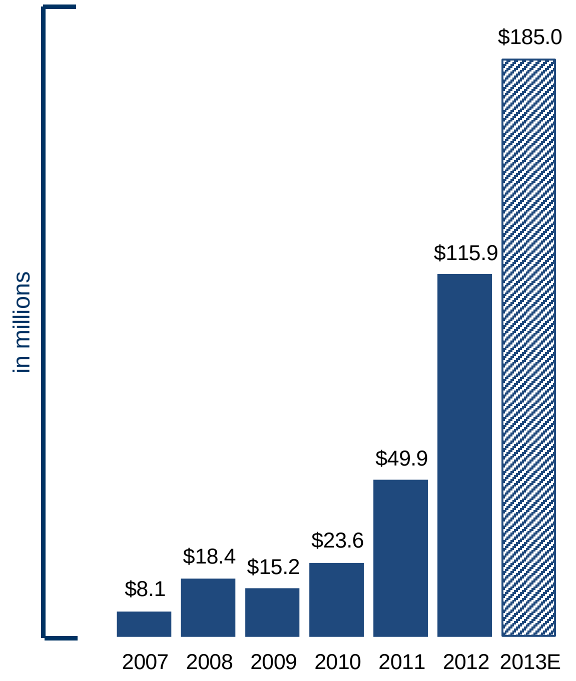
TOTAL OIL PRODUCTION[1]



TOTAL OIL AND NATURAL GAS REVENUES[1]



ADJUSTED EBITDA[1][2]



Growth Since the IPO

(1) 2013 estimates at midpoint of guidance range as updated on November 6, 2013. Guidance includes actual results for the nine months ended September 30, 2013 and estimated results for the remainder of 2013. Estimated average realized prices for oil and natural gas used in these estimates were $96.00/Bbl and $4.30/Mcf, respectively, for the period October through December 2013.
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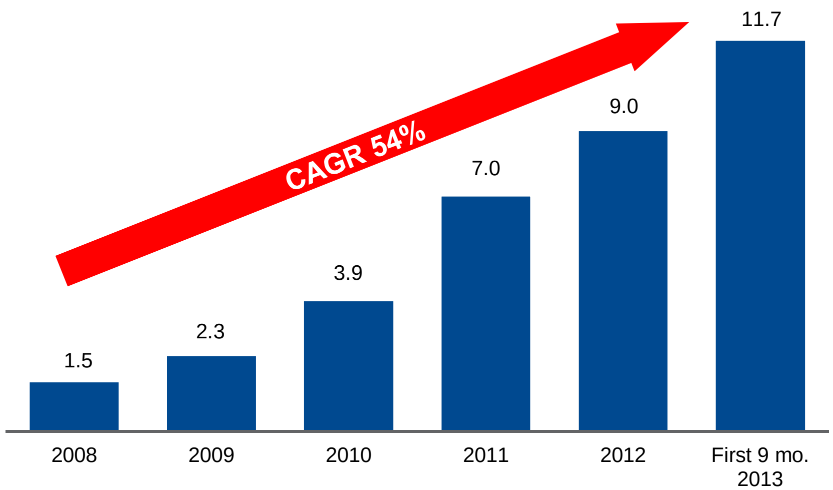
2013 Has Been an Excellent Year for Matador!

- **Technical improvements in all aspects of our Eagle Ford operations resulting in better wells for less money!**
  - Drilling times and costs per well decreased significantly
  - Improved hydraulic fracture treatment designs yielding better EURs per well
  - Flowback and production (gas-lift) operations resulting in better early well performance
  - Began initial downspacing tests and early results are encouraging
- **Built a significant acreage position in the emerging Permian Basin play and initiated exploration and operations**
  - Increased Permian acreage position to ~65,000 gross (~40,800 net) acres during 2013
  - Initial drilling results encouraging; running one rig continuously and plan to do so throughout 2014
- **Expected oil production growth of ~70%**
  - Estimated 2.0 to 2.1 million barrels in 2013 from 1.2 million barrels in 2012
- **Expected Adjusted EBITDA(1) growth of ~60%**
  - Estimated $180 to $190 million in 2013 from $115.9 million in 2012
- **Completed a successful equity offering of 9.775 million shares in September 2013**
  - Strong balance sheet and simple capital structure; no high-yield debt or convertibles
  - Current debt outstanding of $175 million less than 1x estimated 2013 Adjusted EBITDA(1)
- **MTDR share price up 154% year-to-date**
  - One of the top performers in the Russell 2000 Energy Index in 2013
  - Recent equity offering has resulted in significant increase in trading liquidity

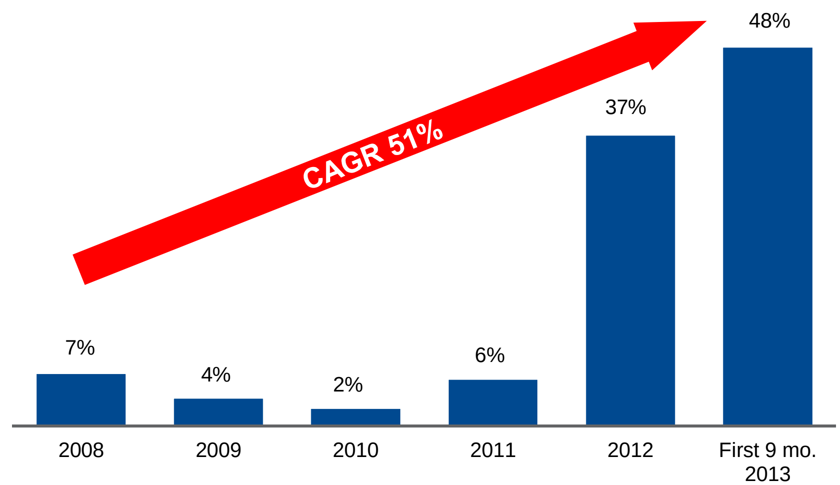
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Matador's Continued Growth

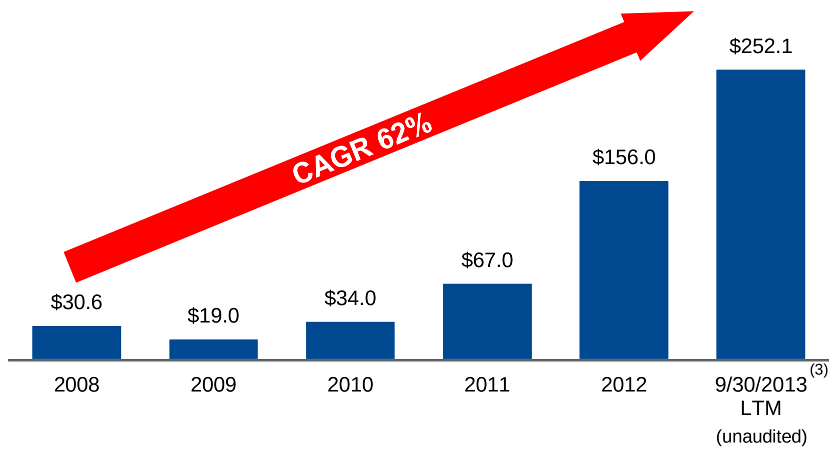
Average Daily Production(1)
(MBOE/d)



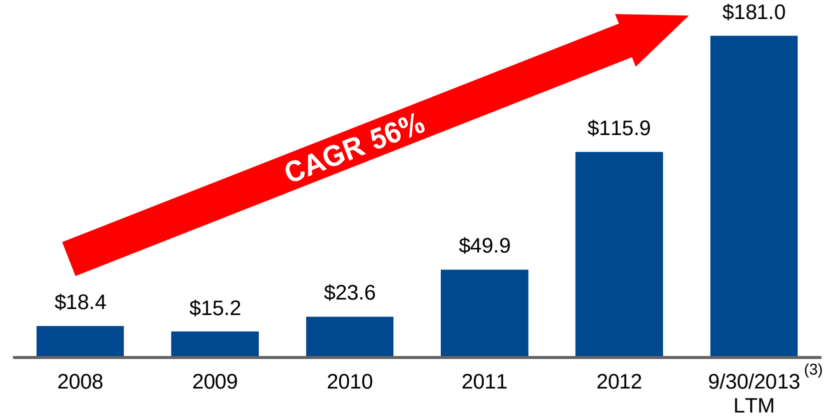
Oil Production Mix(1)
(% of Average Daily Production)



Oil & Natural Gas Revenues
($ in millions)



Adjusted EBITDA(2)
($ in millions)



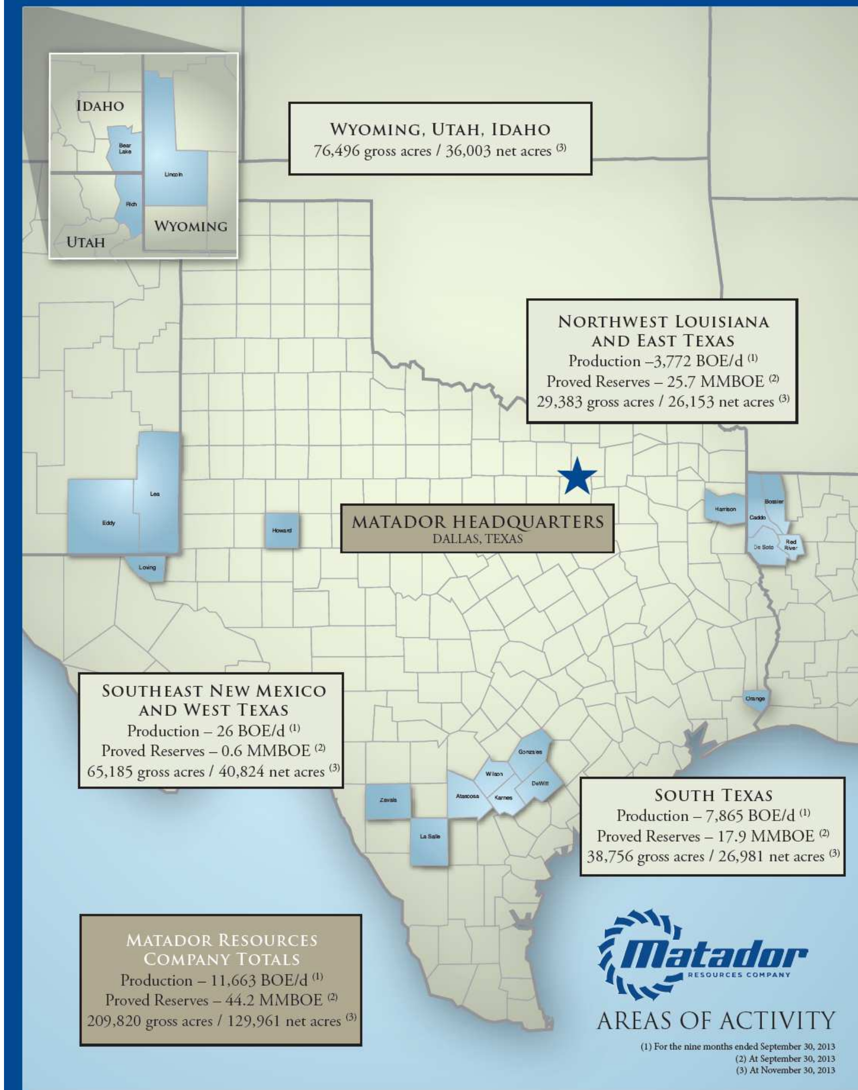
(1) Nine months ended September 30, 2013 reflects average daily production for the first nine months of 2013. 2008 – 2012 average daily production reflects average for each respective year.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) LTM is last twelve months through September 30, 2013.

Today's Agenda

- **Welcome and Opening Remarks**
  - Joseph Wm. Foran, Chairman and CEO
  - Matthew V. Hairford, President
- **2014 Capital Investment Plan**
  - David E. Lancaster, Executive Vice President, COO and CFO
- **Eagle Ford Operations and Development**
  - Ryan C. London, Vice President and General Manager
- **Permian Exploration and Operations**
  - David F. Nicklin, Executive Director of Exploration
  - Ryan C. London, Vice President and General Manager
- **Haynesville and Other Natural Gas Operations**
  - Bradley M. Robinson, Vice President – Reservoir Engineering and CTO
- **Summary and Closing Remarks/Q&A**
  - Joseph Wm. Foran, Chairman and CEO
- **Buffet Lunch**

2014 Capital Investment Plan

Matador Resources Company Overview



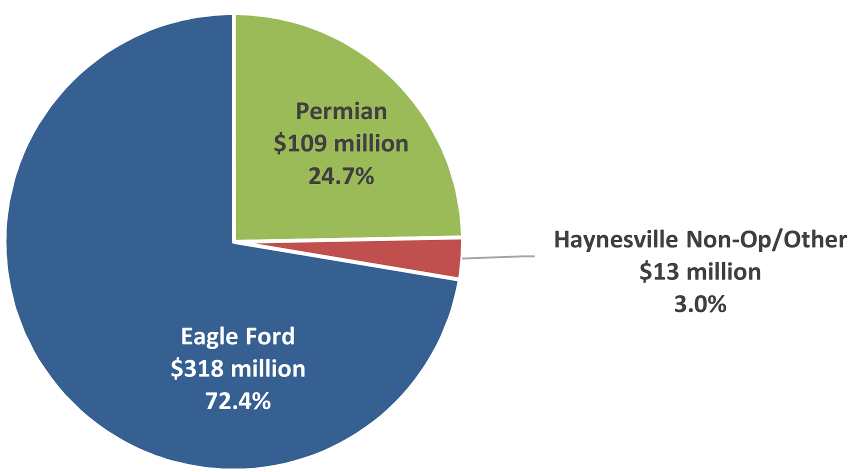
Market Capitalization(1)	**~$1.4 billion**
Average Daily Production(2)	**11,663 BOE/d**
Oil (% total)	5,584 Bbl/d (48%)
Natural Gas (% total)	36.5 MMcf/d (52%)
Proved Reserves @ 9/30/2013	**44.2 million BOE**
% Proved Developed	37%
% Oil	31%
2013E CapEx	**$370 million**
% South Texas	~72%
% Oil and Liquids	~97%
Gross Acreage(3)	**209,820 acres**
Net Acreage(3)	**129,961 acres**
Engineered Drilling Locations(3)(4)	**1,105 gross / 558.6 net**
Eagle Ford	270 gross / 222.7 net
Permian	235 gross / 171.8 net
Haynesville/Cotton Valley	600 gross / 164.1 net

(1) Market capitalization based on shares outstanding and closing share price as of December 9, 2013.
(2) Average daily production for the nine months ended September 30, 2013.
(3) Presented as of November 30, 2013.
(4) Identified and engineered Tier 1 and Tier 2 locations identified for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation.

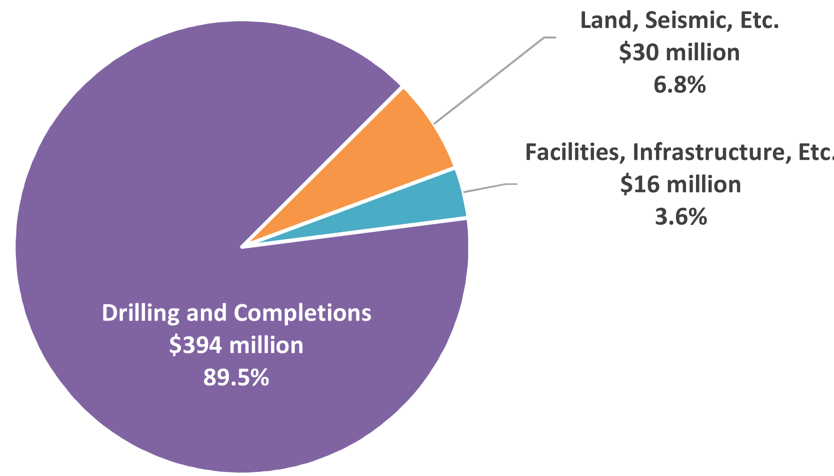
2014 Capital Investment Plan Summary

- **Continue 3-rig program in 2014 – 2 rigs in Eagle Ford and 1 rig in Permian**
- **2014 estimated capital expenditures of ~$440 million**
  - Increase of ~19% from 2013 estimated capital expenditures of ~$370 million
- **Eagle Ford development will continue to be the major driver of our growth in 2014**
- **Permian drilling program designed to further evaluate our acreage position and define an expanded development plan for 2015 and beyond**
- **Haynesville development assumes only participation in non-operated wells**

2014 Estimated CapEx = $440 million



2014 Estimated CapEx = $440 million



Oil/Liquids Focus Continues to Drive 2014 Growth

	2014 Anticipated Drilling			2014 Anticipated First Sales[1]			2014E CapEx *(in millions)*	
	Gross Wells[2]	Net Wells[2]		Gross Wells[2]	Net Wells[2]			
	Total	Total	%	Total	Total	%	Total	%
South Texas								
Eagle Ford	49	46.0	78.4%	42	39.0	78.3%	$300.1	68.2%
Buda	1	1.0	1.7%	1	1.0	2.0%	$4.8	1.1%
Facilities/Pipelines/Etc.	-	-	-	-	-	-	$6.0	1.4%
Land/Seismic/Etc.	-	-	-	-	-	-	$7.5	1.7%
Area Total	50	47.0	80.1%	43	40.0	80.3%	$318.4	72.4%
West Texas/Southeast New Mexico								
Bone Spring/Wolfcamp	12	9.8	16.7%	10	8.3	16.7%	$78.6	17.9%
Facilities/Pipelines/Etc.	-	-	-	-	-	-	$10.0	2.3%
Land/Seismic/Etc.	-	-	-	-	-	-	$20.0	4.5%
Area Total	12	9.8	16.7%	10	8.3	16.7%	$108.6	24.7%
Northwest Louisiana								
Haynesville Shale	26	1.5	2.6%	26	1.5	3.0%	$9.5[3]	2.2%
Land/Seismic/Etc.	-	-	-	-	-	-	$2.5	0.5%
Area Total	26	1.5	2.6%	26	1.5	3.0%	$12.0	2.7%
Southwest Wyoming								
Meade Peak Shale	1	0.4	0.7%	-	-	-	$1.0	0.2%
Total	**89**	**58.7**	**100.0%**	**79**	**49.8**	**100.0%**	**$440.0**	**100.0%**

- ***97% of our 2014 capital investments directed toward oil and liquids-rich targets***

(1) Some wells drilled in late 2014 will not be completed and turned to sales until early 2015. As a result, they do not contribute to our estimated oil and natural gas production volumes for 2014.
(2) Includes Matador operated and non-operated wells.
(3) A portion of the CapEx associated with these wells is expected to be incurred in 2013, as some wells are already being drilled at December 12, 2013.

2014 Oil and Natural Gas Production Estimates

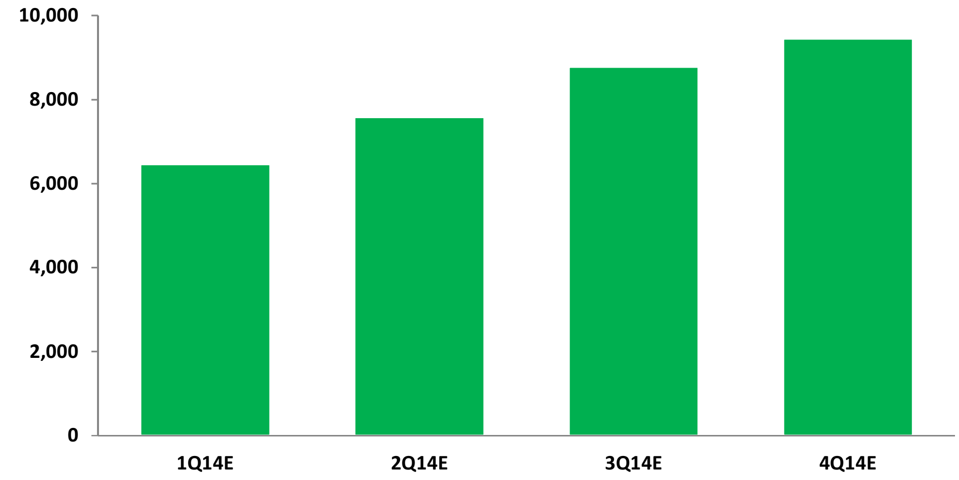
2014E Oil Production

- Estimated oil production of 2.8 to 3.1 million barrels
- Increase of 40 to 50% from 2013, despite an average of 5 to 10% of oil production shut-in throughout 2014
- Oil production growth to over 9,000 Bbl/d by YE 2014
- Estimated 87% of oil production from Eagle Ford and 13% from Permian in 2014
- Quarterly production growth will continue to be somewhat variable, but less so than in 2013
  - Timing effects due to batch drilling, shut-ins due to offset fracturing operations, etc.

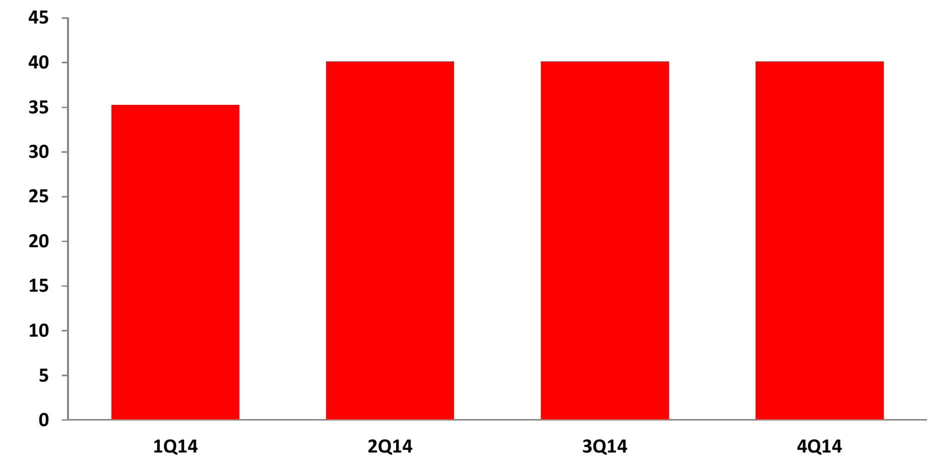
2014E Natural Gas Production

- Estimated natural gas production of 13.5 to 15.0 Bcf
- Increase of ~14% from 2013, due primarily to participation in additional Haynesville non-op wells
- Estimated 50% of natural gas production from Haynesville and Cotton Valley, 43% from Eagle Ford and 7% from Permian in 2014
- Uplift of $2.00 to $2.50/Mcf due to NGL's

Oil Production @ Midpoint(1) (Bbl/d)



Natural Gas Production @ Midpoint(1) (MMcf/d)



(1) Estimated quarterly average oil and natural gas production at midpoint of 2014 guidance range.

2014 Financial Estimates

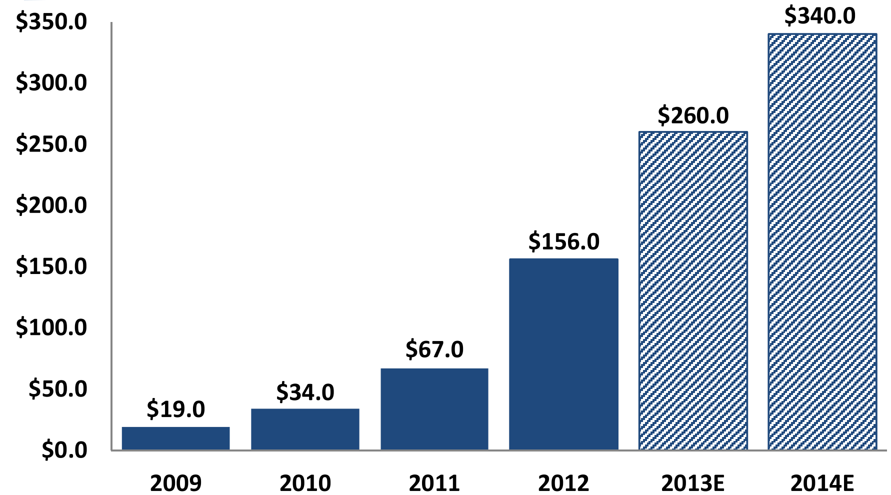
2014E Revenues and Adjusted EBITDA(1)(2)

- Revenues and Adjusted EBITDA(1)(2) growth impacted by lower 2014 realized oil price estimate
  - 2014 realized oil price of $95/Bbl vs ~$100/Bbl realized in 2013
  - 2014 realized natural gas price of $4.25/Mcf similar to 2013
- Estimated oil and natural gas revenues of $325 to $355 million
  - Increase of ~31% from estimated $250 to $270 million in 2013
- Estimated Adjusted EBITDA(1)(2) of $235 to $265 million
  - Increase of ~35% from estimated $180 to $190 million in 2013
- 2014 production and revenue composition
  - Estimated 55% oil by volume, approaching 60% by YE 2014
  - Estimated 82% oil by revenue, approaching 85% by YE 2014

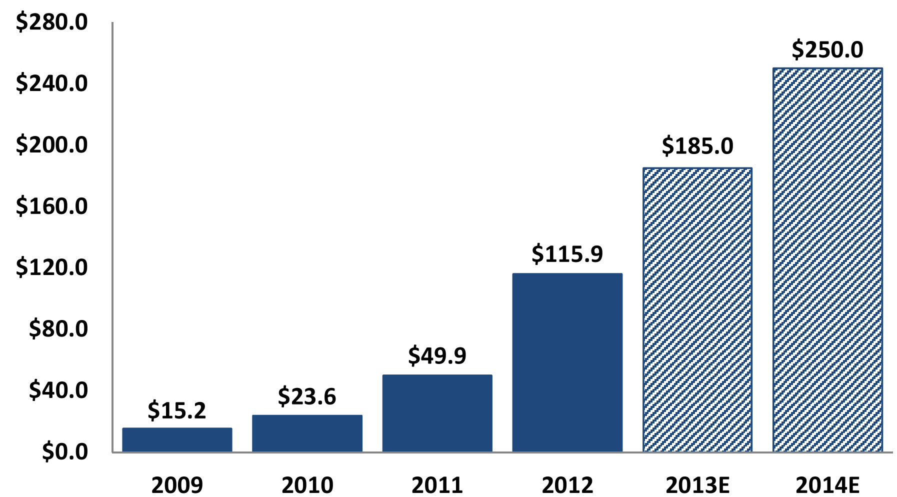
2014E Operating Costs

- Estimated average unit costs per BOE
  - Production taxes/marketing = $5.00
  - Lease operating = $8.00
  - G&A = $4.75
  - Operating cash costs, excluding interest = $17.75; compares to ~$19.00 in 2013
  - Costs vary +/- 5% over course of year
  - DD&A = $25.00

Oil and Natural Gas Revenues(2) (millions)



Adjusted EBITDA(1)(2) (millions)



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Funding for 2014 Capital Investment Plan

- **Anticipate funding 2014 capital expenditures through operating cash flows and borrowings under revolving credit facility**
  - 2.4 million barrels of oil (80 to 85% of estimated oil production) hedged for 2014, protecting cash flows below ~$88/Bbl oil price
- **Simple capital structure; no high-yield debt or convertibles on balance sheet**
- **Strong liquidity position with current Debt/Adjusted EBITDA[(1)] < 1.0**
- **Flexibility to manage liquidity**
  - Most drilling is operated and no significant non-operated drilling obligations
  - $30 million estimated for discretionary land/seismic acquisitions
  - No long-term drilling rig or service contract commitments

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2014 Hedging Profile

- 2.4 million barrels of oil hedged for 2014 at weighted average floor and ceiling of $88/Bbl[1] and $99/Bbl[1], respectively
- 10.8 Bcf of natural gas hedged at weighted average floor and ceiling of $3.42/MMBtu[2] and $4.98/MMBtu[2], respectively
- 7.6 million gallons of natural gas liquids hedged at weighted average price of $1.25/gal[3]

Oil Hedges (Costless Collars)	2014
Total Volume Hedged by Ceiling	2,414,000 Bbl
Weighted Average Price	$99.00 /Bbl
Total Volume Hedged by Floor	2,414,000 Bbl
Weighted Average Price	$87.61 /Bbl

Natural Gas Hedges (Costless Collars)	2014
Total Volume Hedged by Ceiling	10.8 Bcf
Weighted Average Price	$4.98 /MMBtu
Total Volume Hedged by Floor	10.8 Bcf
Weighted Average Price	$3.42 /MMBtu

Natural Gas Liquids (NGLs) Hedges (Swaps)	2014
Total Volume Hedged	7,644,000 gal
Weighted Average Price	$1.25 /gal

(1) NYMEX West Texas Intermediate oil futures.
(2) NYMEX Henry Hub natural gas futures.
(3) Mont Belvieu Spot Gas Liquids prices: NON-TET prop.

Credit Agreement Status

- **Strong, supportive bank group led by RBC**
- **Borrowing base at $350 million, based on June 30, 2013 reserves**
- **Current borrowings at $175 million; estimated borrowings outstanding of ~$200 million at YE 2013**
- **Ability to request quarterly borrowing base increases with growth in oil and natural gas reserves throughout 2014, as needed**

TIER	Borrowing Base Utilization	LIBOR Margin	BASE Margin	Commitment Fee
Tier One	x < 25%	175 bps	75 bps	37.5 bps
Tier Two	25% < or = x < 50%	200 bps	100 bps	37.5 bps
Tier Three	50% < or = x < 75%	225 bps	125 bps	50 bps
Tier Four	75% < or = x < 90%	250 bps	150 bps	50 bps
Tier Five	90% < or = x < 100%	275 bps	175 bps	50 bps
Tier Six	100% < or = x < 110%	325 bps	225 bps	50 bps
Tier Seven	x = or > 110%	400 bps	300 bps	50 bps

- **Financial covenants**
  - Minimum current ratio of not less than 1.0:1.0, with current ratio first tested at June 30, 2014
  - Maximum Total Debt to Adjusted EBITDA[(1)] Ratio of not more than 4.0:1.0

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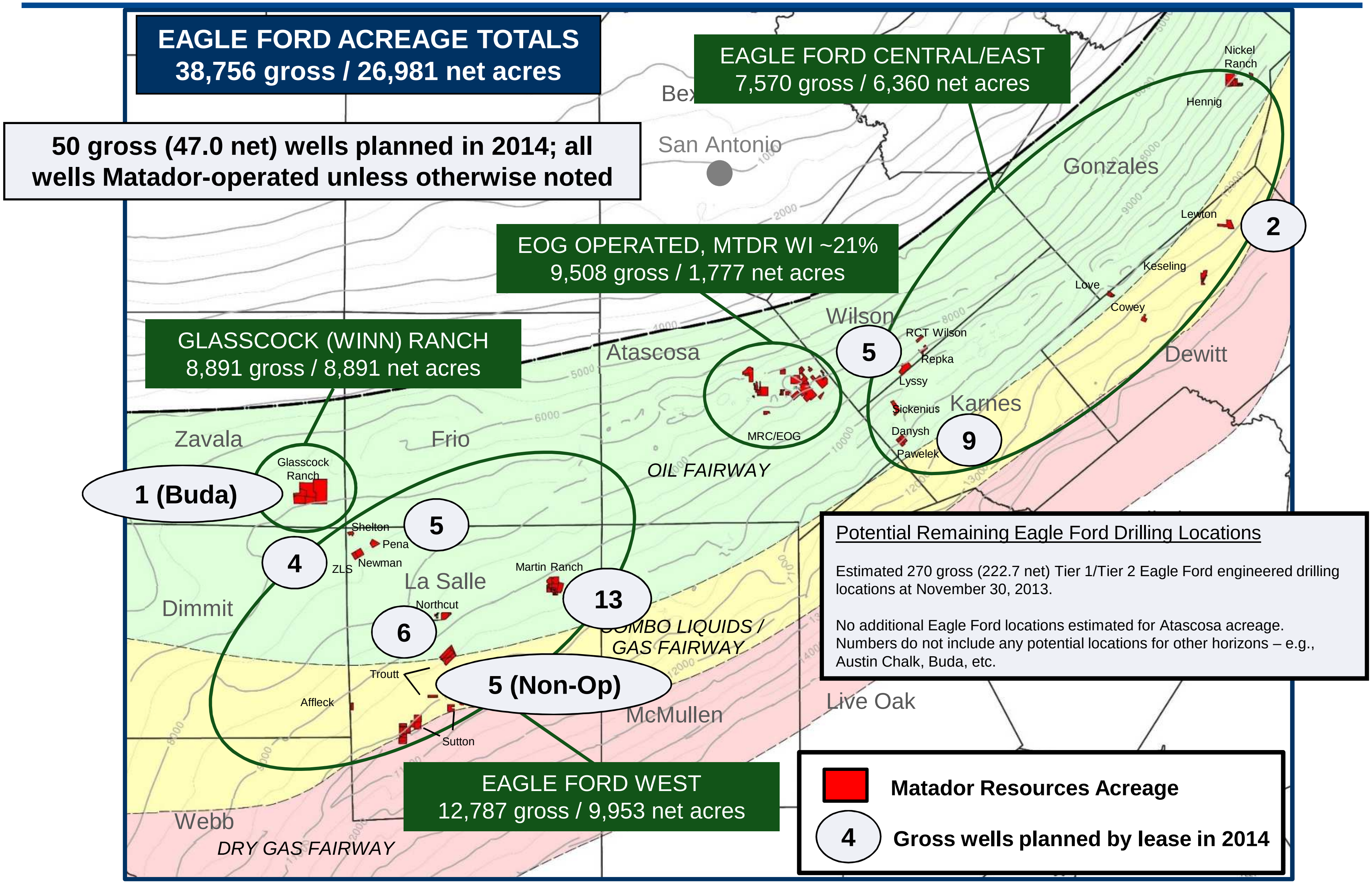
2014 South Texas Plan Details

- **2014 projected capital expenditures of ~$318 million or ~72% of total**
  - 2-rig program with almost all of the 2014 South Texas capital budget directed to the Eagle Ford shale
  - Drill and/or complete or participate in 50 gross (47.0 net) wells; 43 gross (40.0 net) wells turned to sales
  - Includes $13.5 million for additional land/seismic and facilities
  - 2014 Eagle Ford program is development drilling, with most locations planned at 40-acre spacing
  - No Upper Eagle Ford tests currently planned for 2014
- **One exploratory Buda test planned at Glasscock Ranch**
  - Location to be selected from seismic data shot over Glasscock Ranch during 2013
  - Looking to extend trend of encouraging Buda drilling nearby, particularly southwest of Glasscock Ranch
- **Key objectives of 2014 South Texas plan**
  - Further improvement in operational efficiencies and well performance in the Eagle Ford
    - Batch drilling to continue reducing drilling times and costs; plan to pick up second "walking" rig
    - Continue to improve and optimize stimulation operations – increased fluid and proppant volumes, reduced cluster spacing and additional stages, as needed
    - Continue to optimize artificial lift program – gas lift to rod pump implementations
    - Reduce LOE throughout all properties
  - Successful implementation of 40-acre downspacing across acreage position
  - Continue to add to acreage position as opportunities arise, particularly in and near existing properties

2014 South Texas Drilling Plan – 2-Rig Program

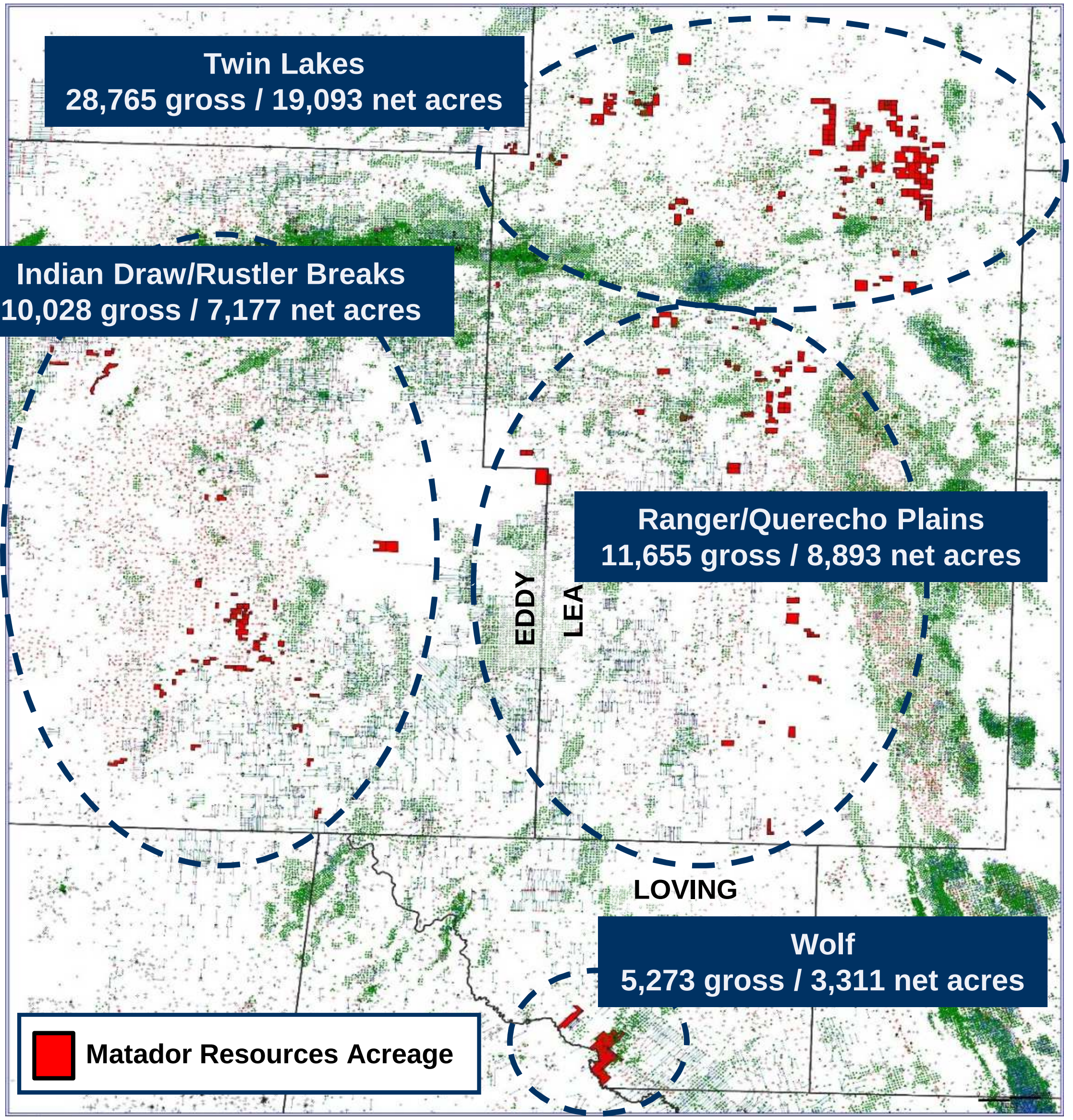


Note: All acreage at November 30, 2013.

2014 Permian Basin Plan Details

- **2014 projected capital expenditures of ~$109 million or ~25% of total**
  - 1-rig program working in Lea and Eddy Counties, NM and Loving County, TX
  - Drill and/or complete or participate in 12 gross (9.8 net) wells; 10 gross (8.3 net) wells turned to sales
  - Includes $30 million for additional land/seismic and facilities
  - Completion targets include various Bone Spring and Wolfcamp intervals across acreage position
- **Key objectives of Permian Basin plan**
  - Further evaluate our acreage position and completion targets to define an expanded development program for 2015 and beyond
    - With success, prepare for potential multi-rig development program beginning in late 2014 or early 2015
  - Leverage and transfer knowledge from Eagle Ford and Haynesville experience to improve operating efficiencies in the Permian Basin
  - Continue to add to acreage position as opportunities arise, particularly in and near existing properties

Permian Basin Acreage Position

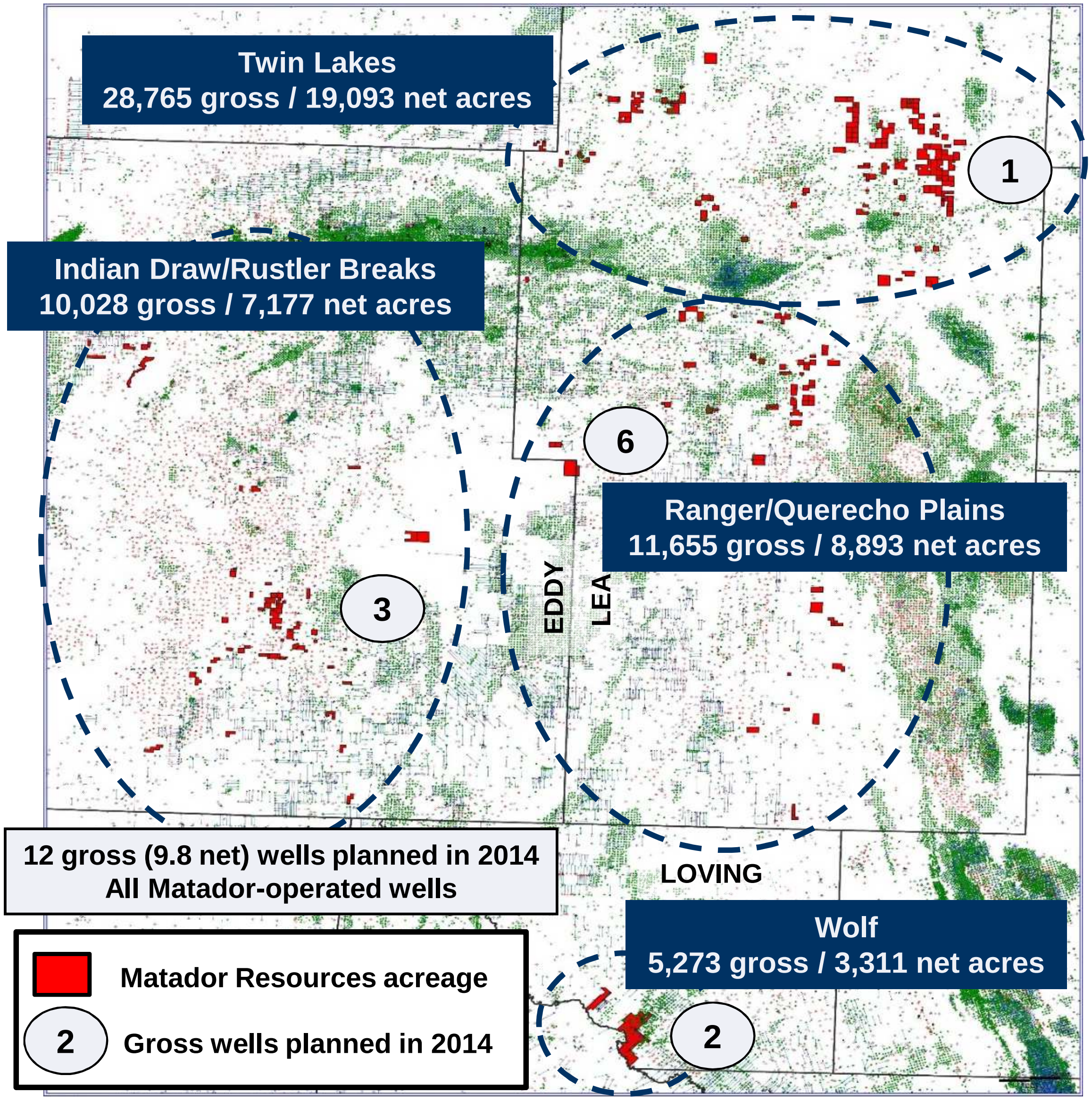


Permian Basin Total	
Gross Acres(1)	65,185 acres
Net Acres(1)	40,824 acres

- Acreage position in good neighborhoods, surrounded by other operators' ongoing drilling
- Drilled 3 wells in 2013 – two in Ranger and one in Wolf prospect areas
- Estimated 235 gross (171.8 net) engineered drilling locations(2); anticipated to grow over time with drilling success
- Plan to run one rig full-time in West Texas and Southeast New Mexico throughout 2014
- Year to date(3) acquired ~49,700 gross (~33,200 net) acres primarily in Lea and Eddy Counties, NM
  - Have also acquired 1,580 gross (1,300 net) acres in eastern Permian Basin in Howard County, TX

(1) Total acreage in Southeast New Mexico and West Texas as of November 30, 2013, including some tracts not shown on map.
(2) At November 30, 2013.
(3) From January 1, 2013 through November 30, 2013.

2014 Permian Basin Drilling Plan



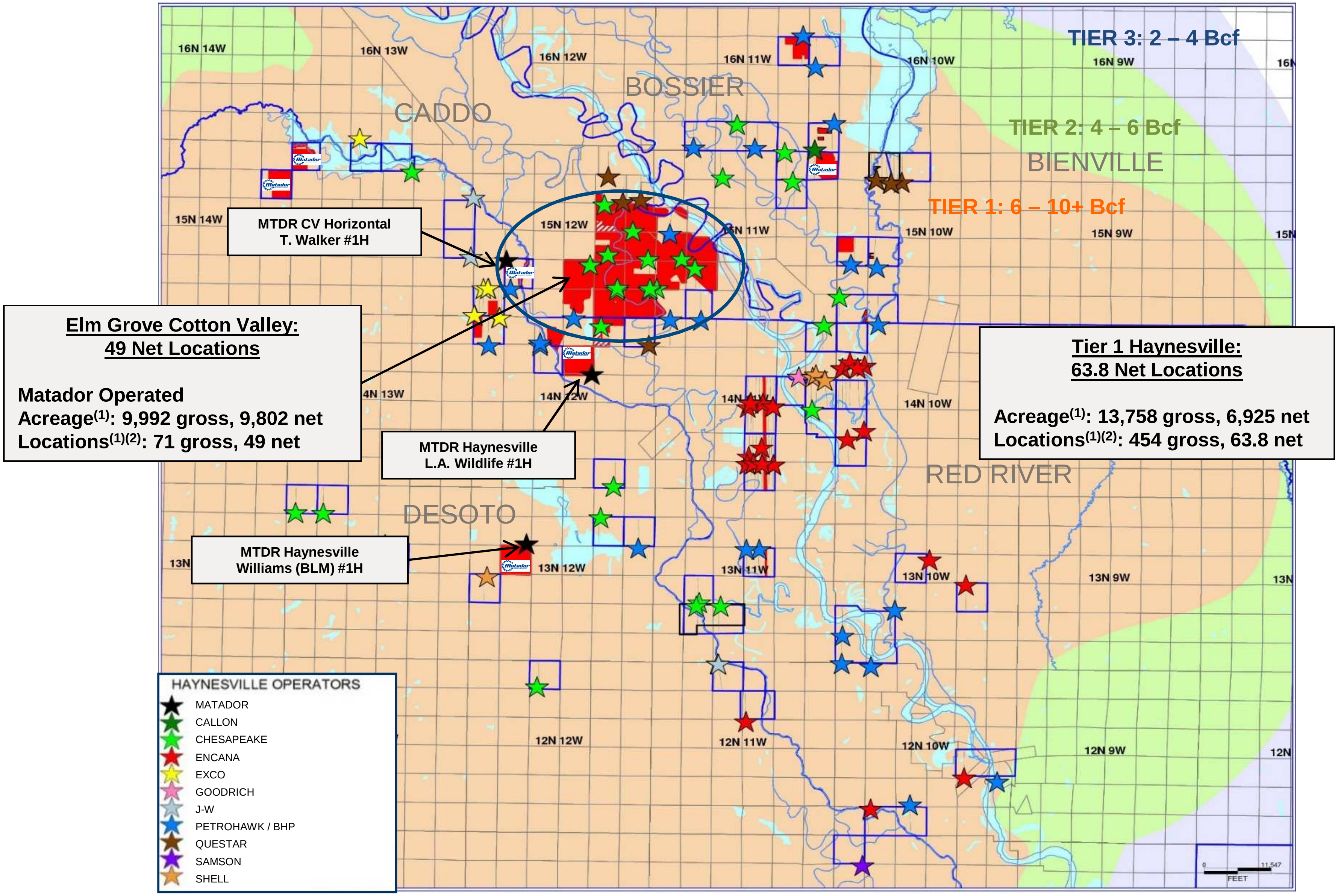
2014 Drilling Plan Highlights

- Estimated capital expenditures of ~$109 million, including ~$30 million for land/seismic and facilities
- 12 gross (9.8 net) wells planned for 2014, with 10 gross (8.3 net) wells turned to sales
- Ranger/Querecho Plains
  - 6 gross (4.5 net) wells testing 1st, 2nd and 3rd Bone Spring and Wolfcamp D targets
- Indian Draw/Rustler Breaks
  - 3 gross (2.5 net) wells testing 2nd Bone Spring and Wolfcamp B targets
- Wolf
  - 2 gross (1.8 net) wells testing Wolfcamp A
- Twin Lakes
  - 1 gross (1.0 net) well targeting Wolfcamp D
  - Pilot hole budgeted to gather detailed logs, whole core, etc.

2014 Tier 1 Haynesville Shale Plan

- **2014 projected capital expenditures of ~$12 million or about 3% of total**
  - Estimated participation in 26 gross (1.5 net) non-operated wells, some already drilling in late 2013
  - 2014 capital plan includes no Matador operated Haynesville wells
  - Includes $2.5 million for additional acreage acquisition as opportunities arise
- **Haynesville/Cotton Valley acreage in Northwest Louisiana and East Texas is essentially all held by existing production**
- **Operational flexibility to drill operated Haynesville shale well(s) in 2014 should natural gas prices continue to improve, but no plans to do so at present time**
- **Pending completion of new gas gathering agreement in December 2013 for a portion of our Haynesville natural gas should reduce costs and improve pricing in 2014**
- **Haynesville/Cotton Valley continue to represent large "gas bank" providing significant and increasing value as natural gas prices improve above $4.00/Mcf**
  - Competitive well economics for Tier 1 Haynesville at $4.50/Mcf and above, with estimated ROR's of 40 to 100+%

Tier 1 Haynesville and Elm Grove Cotton Valley Acreage Positions



Note: All acreage at November 30, 2013. Matador acreage shown in red.
(1) At November 30, 2013.
(2) Identified and engineered Tier 1 and Tier 2 locations identified for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation.

Summary and 2014 Guidance

- Continue 3-rig program in 2014 – 2 rigs in Eagle Ford and 1 rig in Permian
- Eagle Ford development will continue to be the major driver of our growth in 2014
- Permian drilling program designed to further evaluate our acreage position and define an expanded development plan for 2015 and beyond

	2013 Guidance(1)	2014 Guidance	% Increase
Capital Spending	\$370 million	\$440 million	~19%
Total Oil Production	2.0 to 2.1 million Bbl	2.8 to 3.1 million Bbl	~44%
Total Natural Gas Production	12.0 to 13.0 Bcf	13.5 to 15.0 Bcf	~14%
Oil and Natural Gas Revenues	\$250 to \$270 million(2)	\$325 to \$355 million(3)	~31%
Adjusted EBITDA(4)	\$180 to \$190 million(2)	\$235 to \$265 million(3)	~35%

(1) As updated on November 6, 2013.
(2) Estimated 2013 oil and natural gas revenues and Adjusted EBITDA based upon production guidance range as updated on November 6, 2013. Guidance includes actual results for the nine months ended September 30, 2013 and estimated results for the remainder of 2013. Estimated average realized prices for oil and natural gas used in these estimates were \$96.00/Bbl and \$4.30/Mcf, respectively, for the period October through December 2013.
(3) Estimated 2014 oil and natural gas revenues and Adjusted EBITDA at midpoint of production guidance range. Estimated average realized prices for oil and natural gas used in these estimates were \$95.00/Bbl and \$4.25/Mcf, respectively, for the period January through December 2014.
(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.

MATADOR RESOURCES COMPANY

Eagle Ford Development and Operations

Eagle Ford Overview

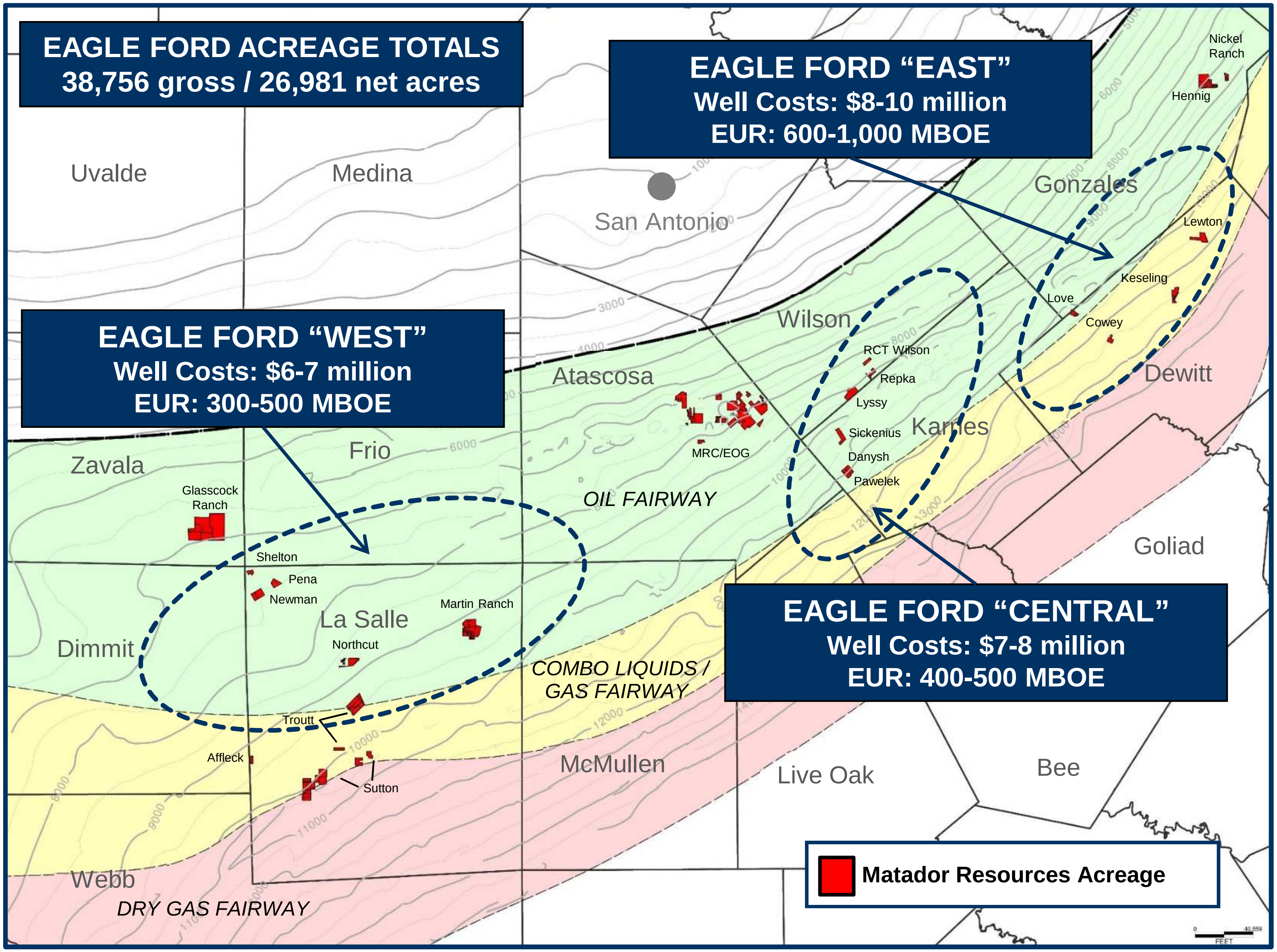
- **57 gross (50 net) wells[(1)] currently producing from the Eagle Ford**
  - An increase in oil production from ~330 Bbl/d[(2)] to ~6,700 Bbl/d[(3)]
  - 270 gross (222.7 net) engineered drilling locations identified for potential future drilling[(1)(4)]
- **2014 South Texas Drilling Plan**
  - Continuing a two-rig program in the Eagle Ford
  - $318 million CapEx (including facilities, land and seismic)
  - Drill 50 gross wells (45 Operated)
  - Complete 45 gross wells (43 operated)
  - Turn 43 gross wells to sales (38 operated)
  - Approximately 5-10% of yearly production capacity shut-in during 2014

Operations Summary

Proved Reserves @ 9/30/2013	**17.9 million BOE**
% Proved Developed	55%
% Oil	75%
Daily Oil Equivalent Production[(3)]	**7,865 BOE/d (70% Oil)**
Gross Acres[(5)]	**38,756 acres**
Net Acres[(5)]	**26,981 acres**
2014E CapEx Budget	**$318 million**
Engineered Drilling Locations[(1)(4)]	**270 gross (222.7 net)**

(1) At December 11, 2013.
(2) For the year ended December 31, 2011.
(3) For the nine months ended September 30, 2013.
(4) Identified and engineered Tier 1 and Tier 2 locations identified for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation.
(5) At November 30, 2013.

Eagle Ford Well Costs and Estimated Ultimate Recovery ("EUR")



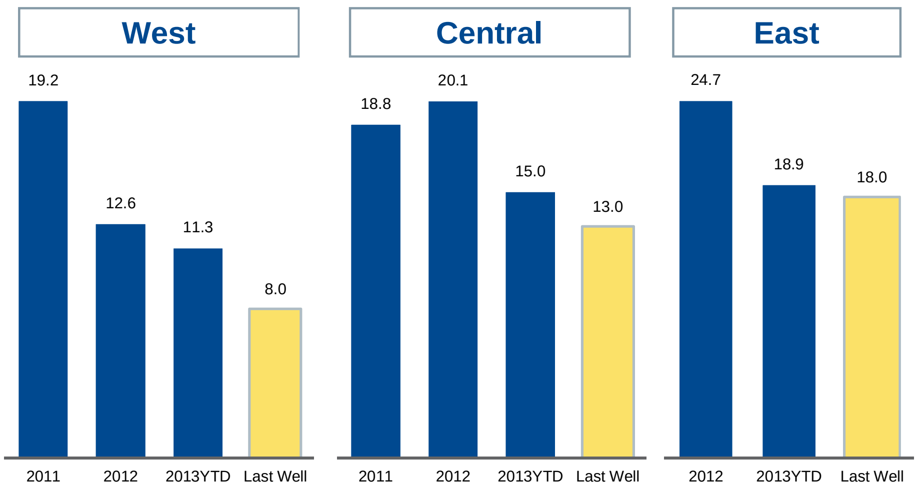
Note: All acreage at November 30, 2013. EURs represent typical range of results over last 12 months by area. Well costs reflect actual costs of all 2013 wells by area.

Operational Improvements

Overview

- Experience in the Eagle Ford has led to significant reductions in drilling days and well costs
- Drilling from four-well batch drilled pads yields additional savings

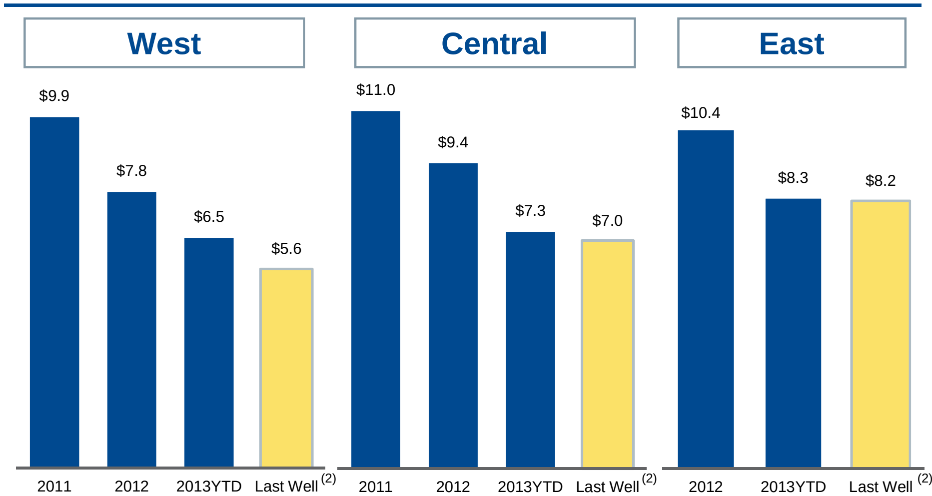
Eagle Ford Drilling Days(1)



Four-Well Batch Drilled Pad vs. Single-Well Pad

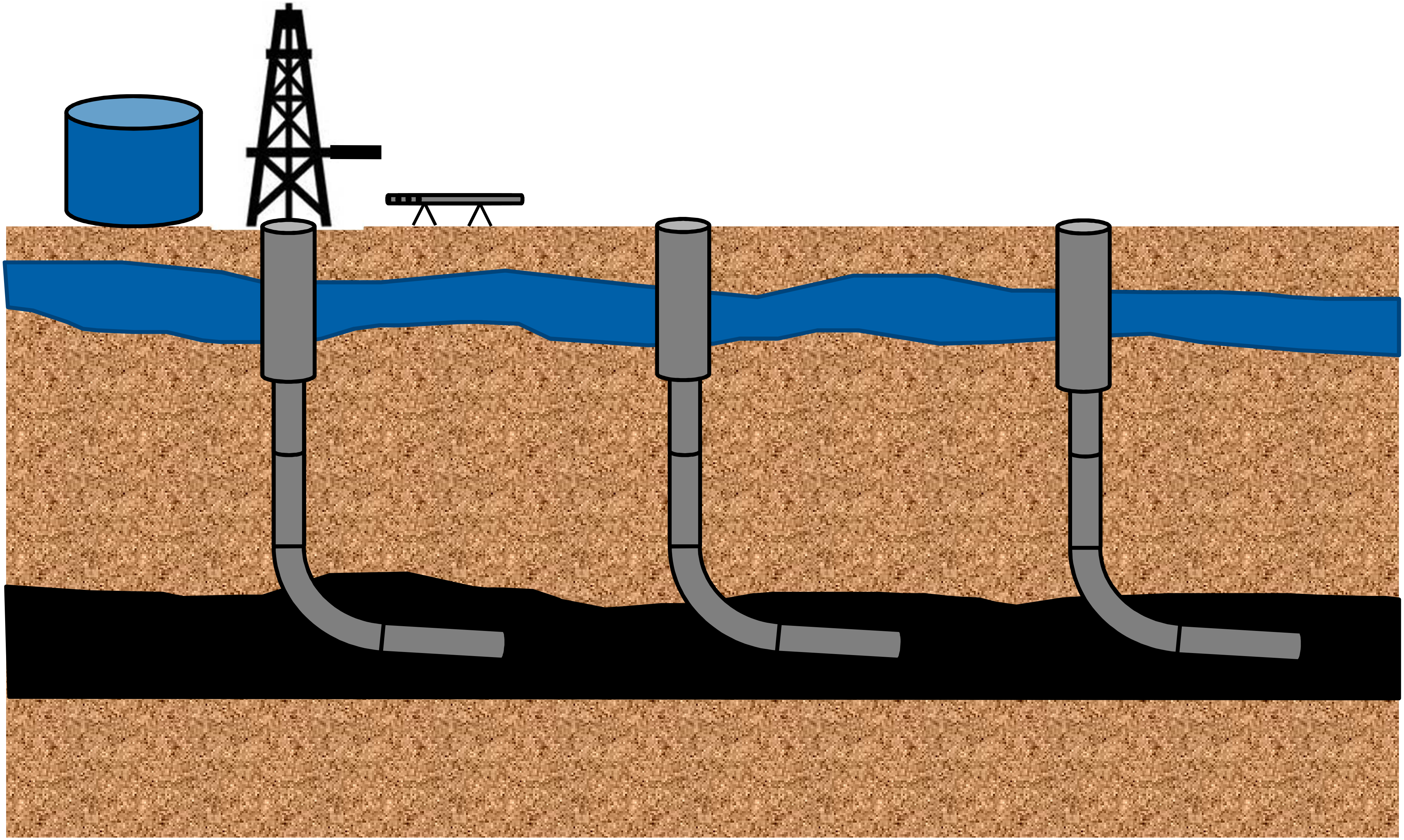
<u>Cost Savings</u>	
Rig Moves	**~$115,000**
Location	**~$60,000**
Drilling Efficiencies	**~$125,000**
Total Per Well Cost Savings	**~$300,000**

Eagle Ford Total Well Cost(1)

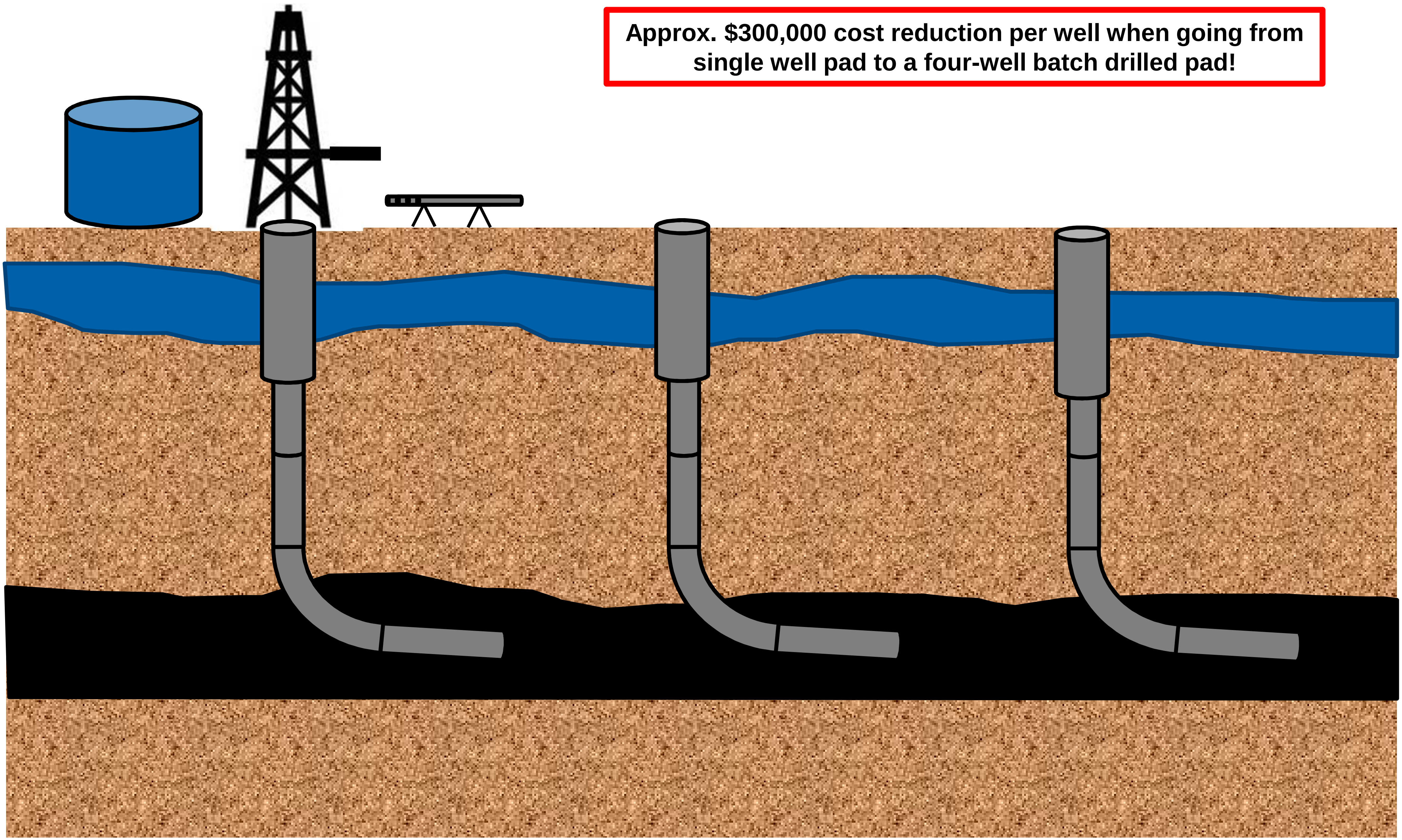


Note: "2013 YTD" and "Last Well" – As of November 6, 2013. Year classification is based on spud date.
(1) Excludes any/all wells drilled with a pilot hole. Drilling days are from spud to total depth.
(2) Reflects the most recent drilled and completed development well – excludes a well that is burdened with extra costs associated with drilling the first well on any given lease, for example: constructing a frac pit, building the lease road, etc.

Pad Drilling



Batch Drilling



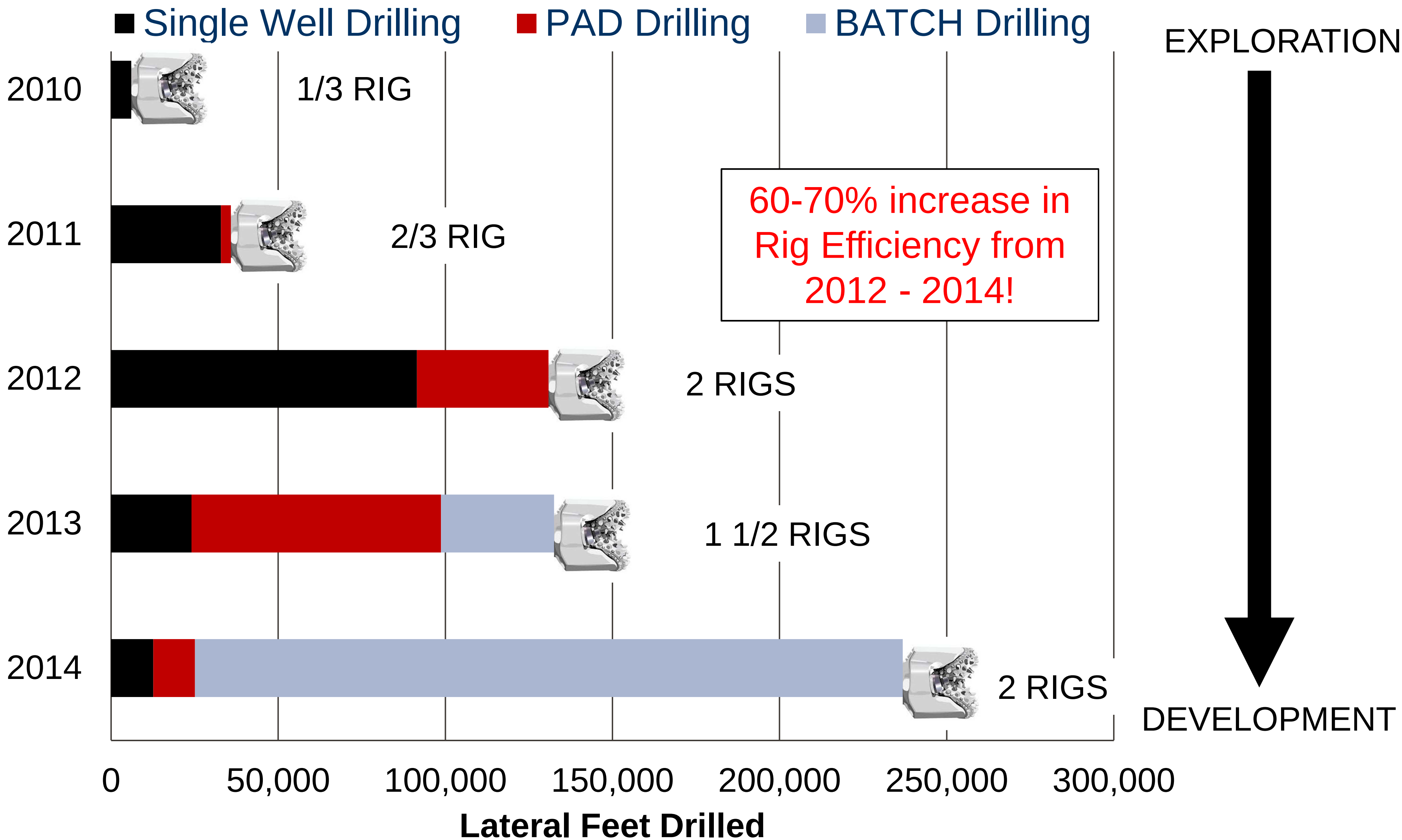
Approx. $300,000 cost reduction per well when going from single well pad to a four-well batch drilled pad!

Progression of Drilling Rig Technology from 2010 to 2014

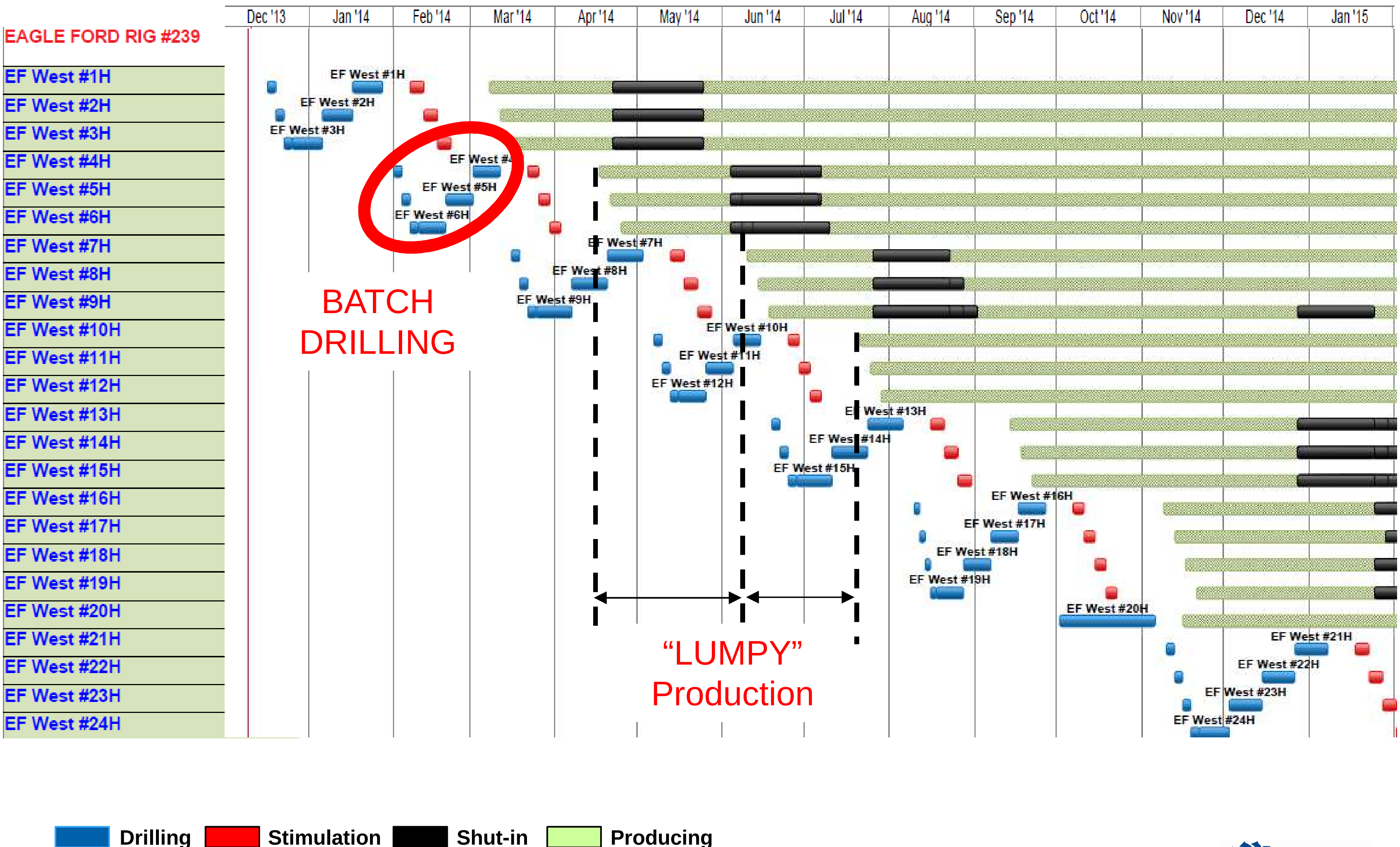
Advancing Rig Technology →

RIG #	ELECTRIC	1600 HP PUMPS	INTEGRATED TOP DRIVE	APEX RIG (FAST MOVE)	HYDRAULIC CATWALK BOP HANDLER THREE SHAKERS	AC DRIVE SYSTEM TECHNOLOGY	ROUND BOTTOM MUD PITS	WALKING PACKAGE
521								
135	✓	✓						
534	✓	✓						
203	✓	✓	✓	✓	✓			
250	✓	✓	✓	✓	✓	✓	✓	
239	✓	✓	✓	✓	✓	✓	✓	✓
279 March 2014	✓	✓	✓	✓	✓	✓	✓	✓

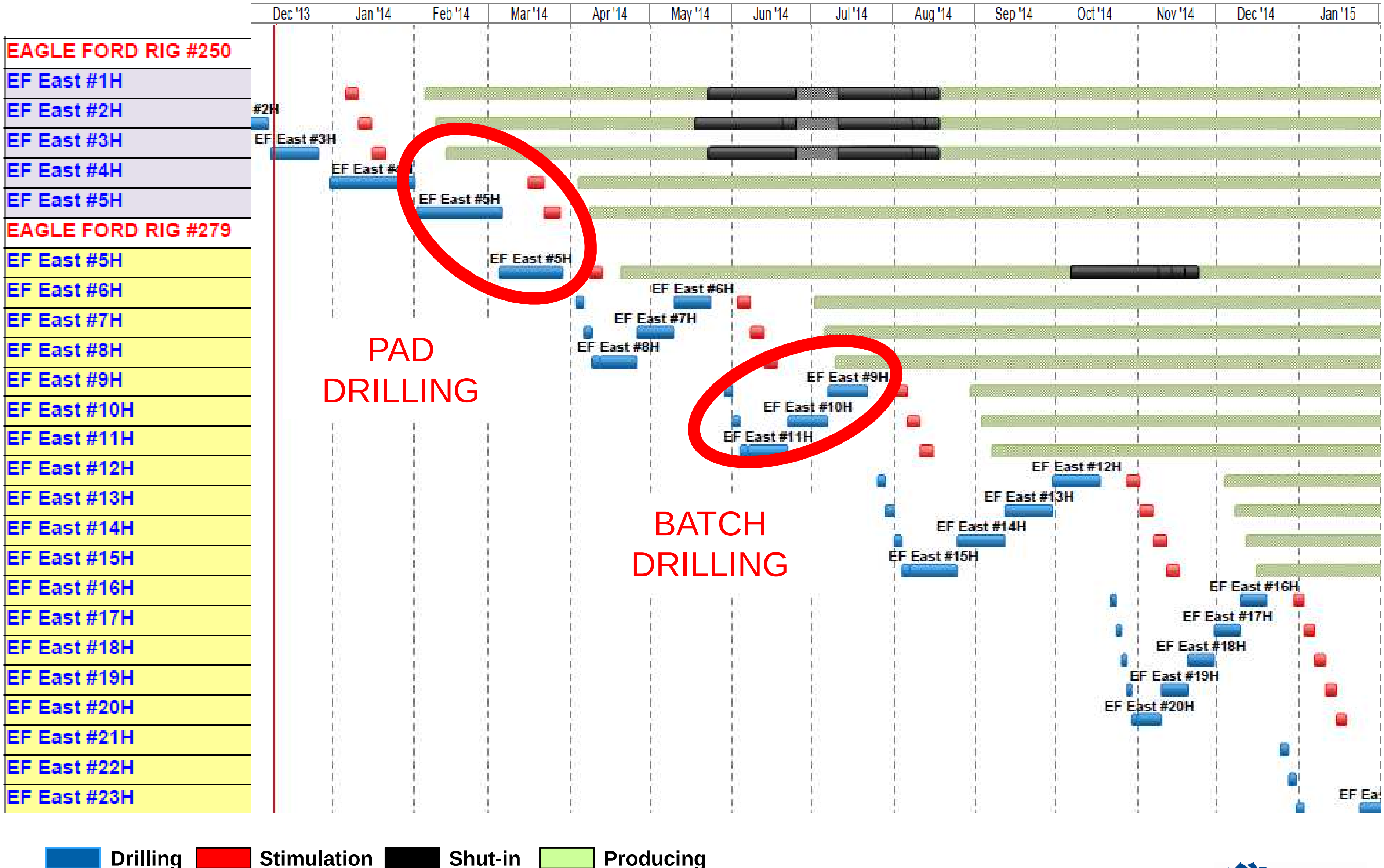
Improvement in Drilling Efficiency – Moving Towards Batch Drilling



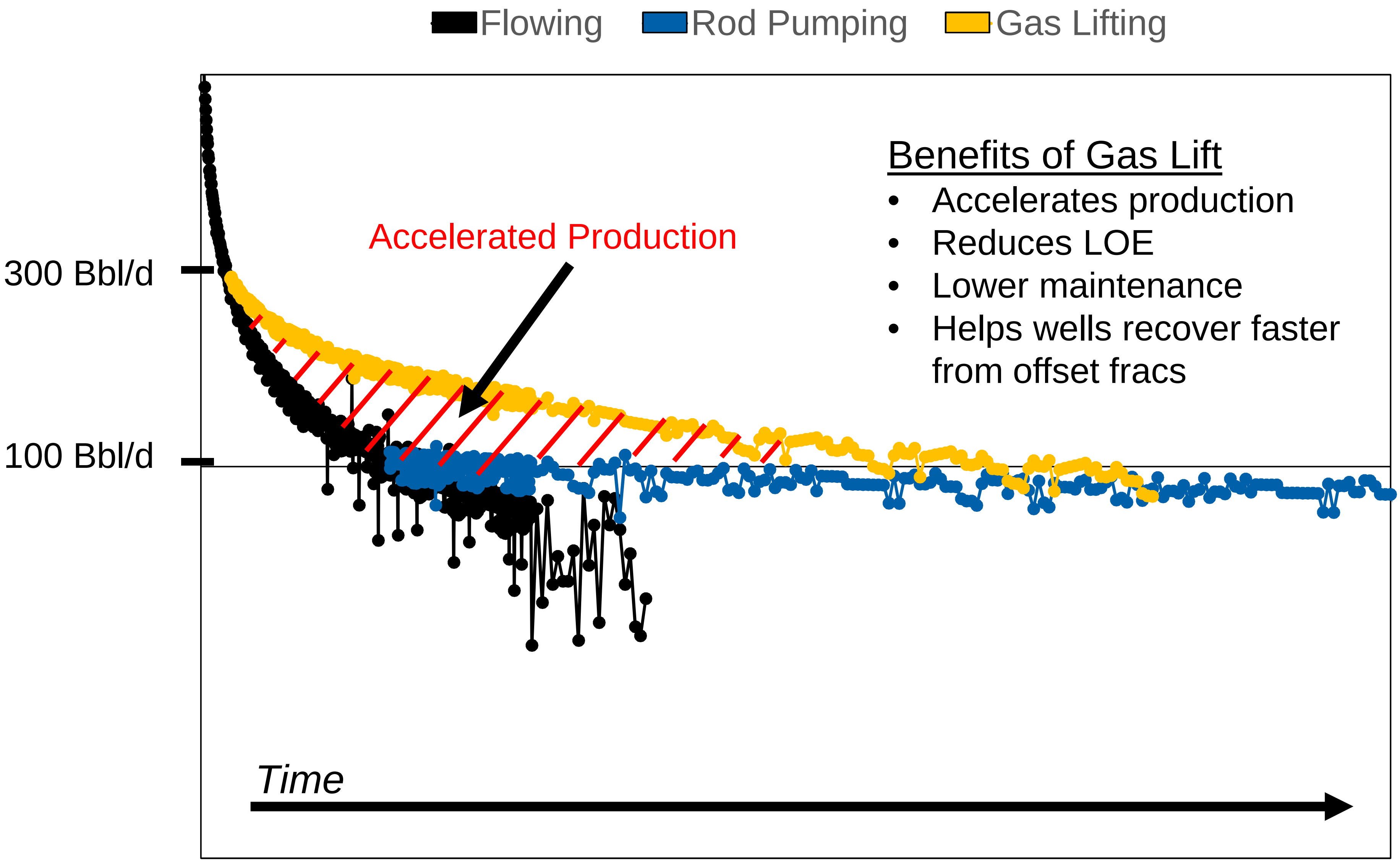
2014 Planned Operated Drilling Schedule



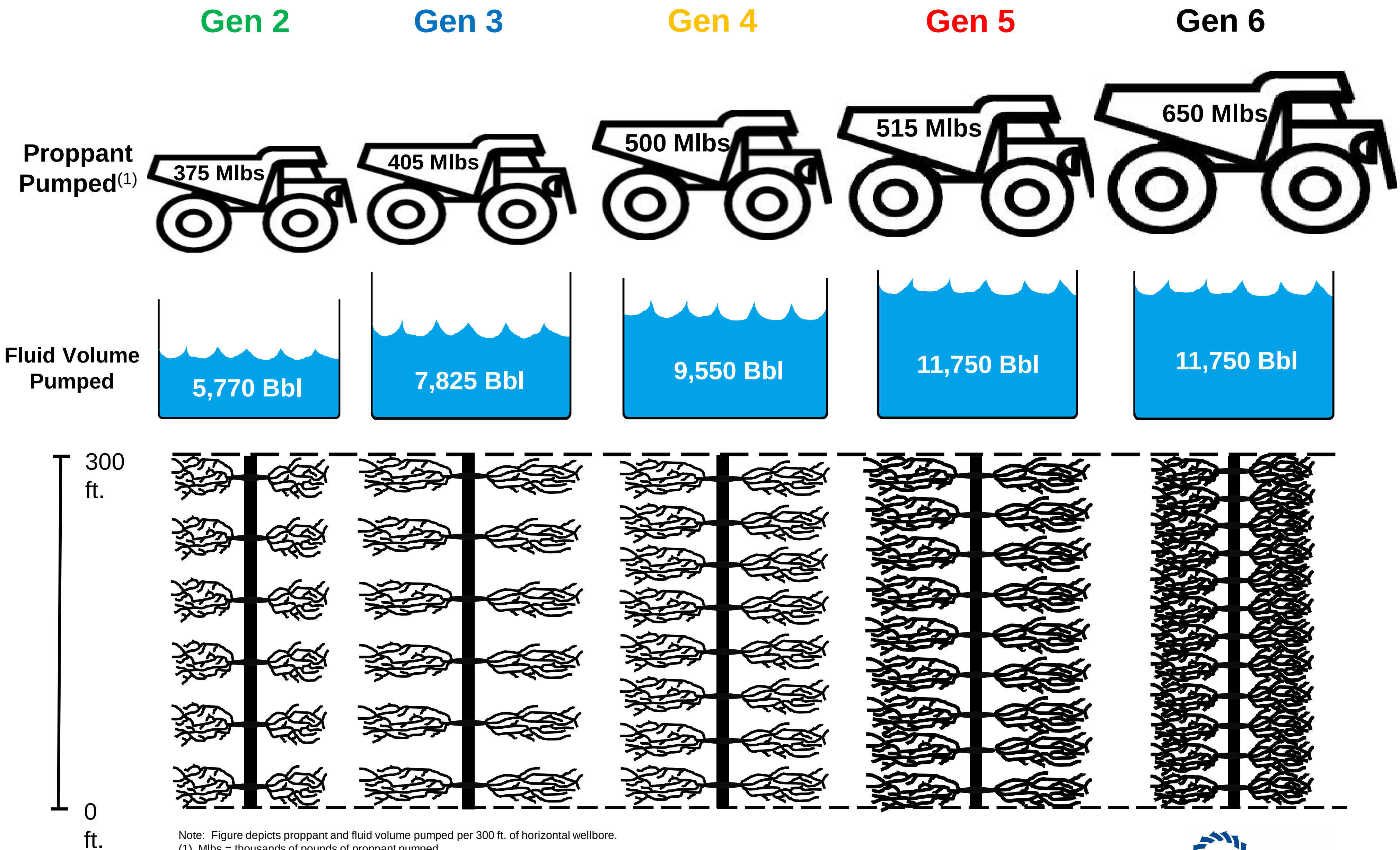
2014 Planned Operated Drilling Schedule



Artificial Lift

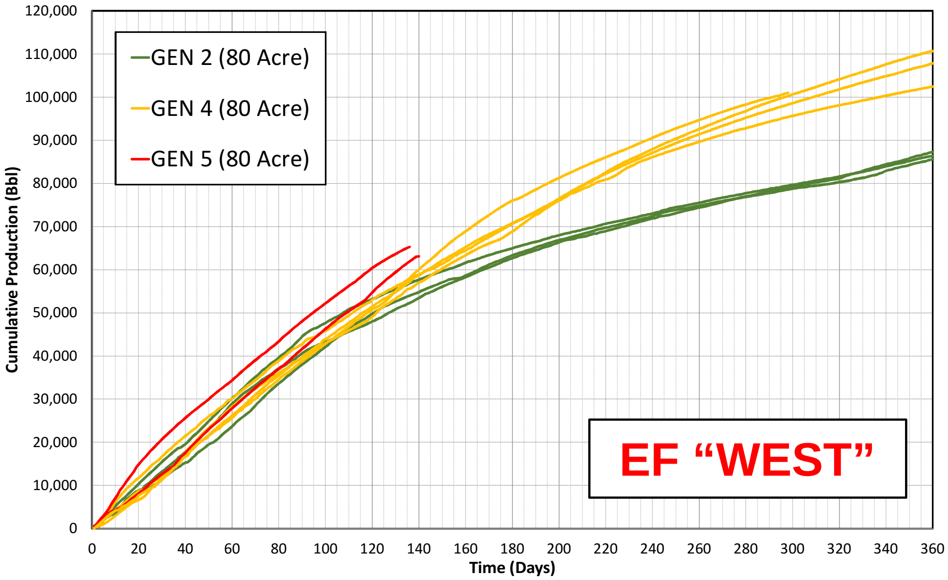


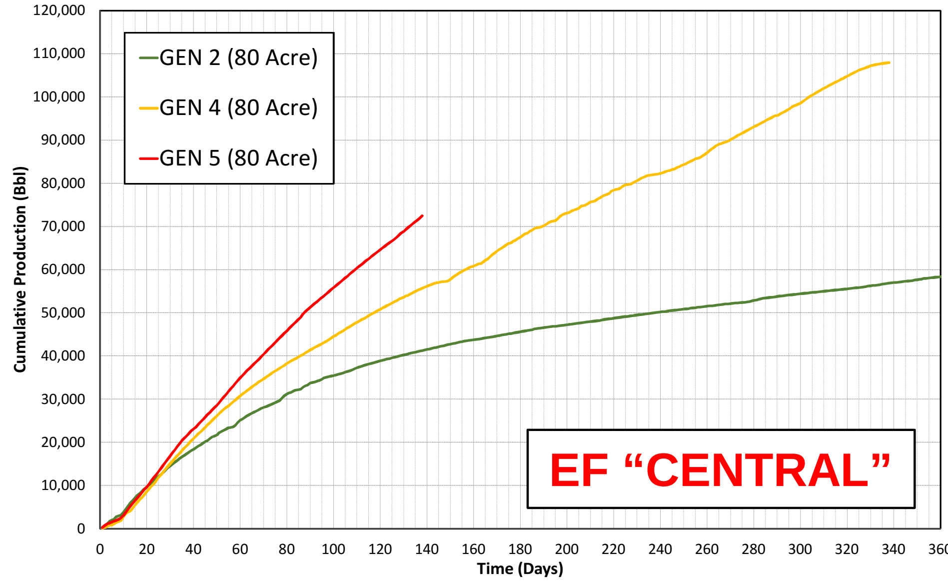
Evolution of Matador Frac Design

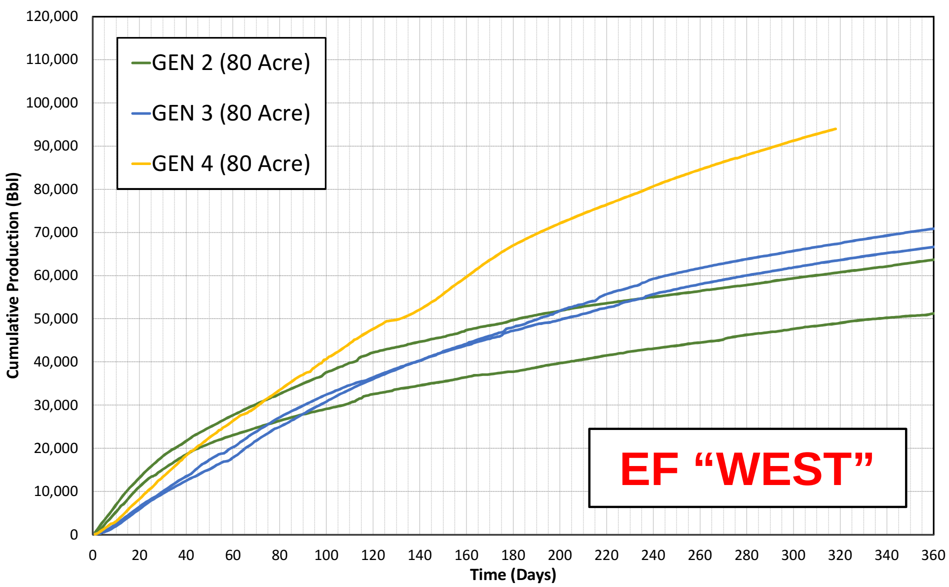


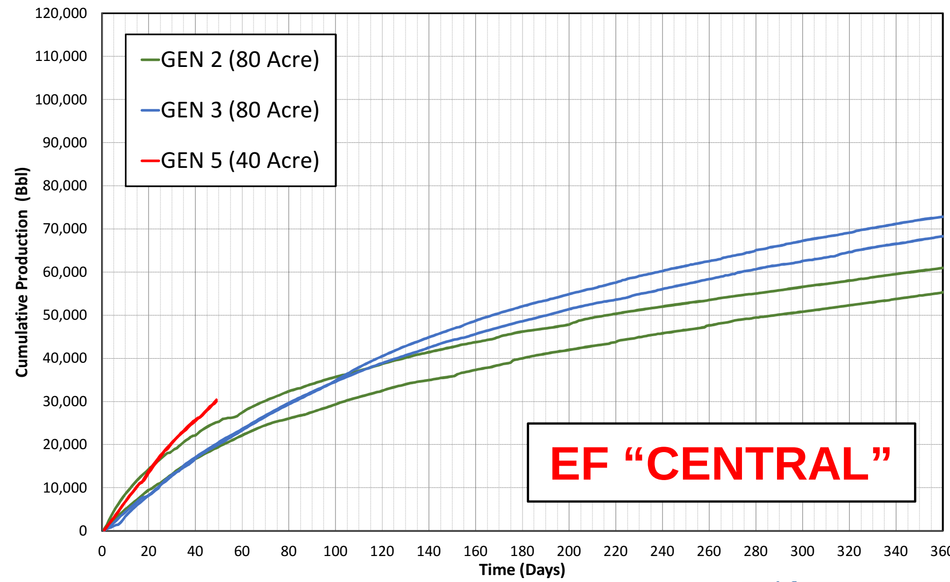
Note: Figure depicts proppant and fluid volume pumped per 300 ft. of horizontal wellbore.
(1) Mlbs = thousands of pounds of proppant pumped.

Frac Generation Comparison (all wells normalized to 5,000' horizontal)

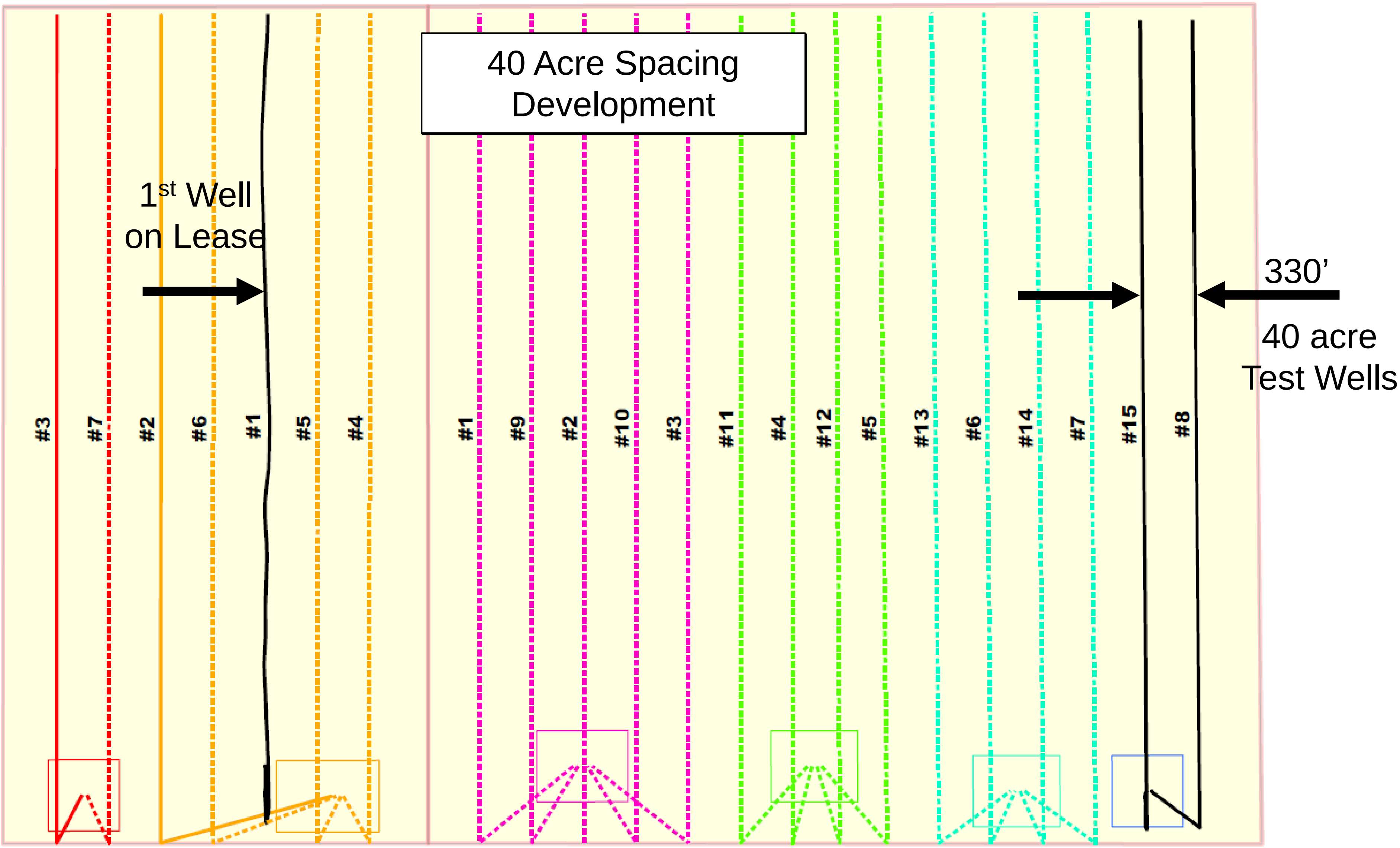




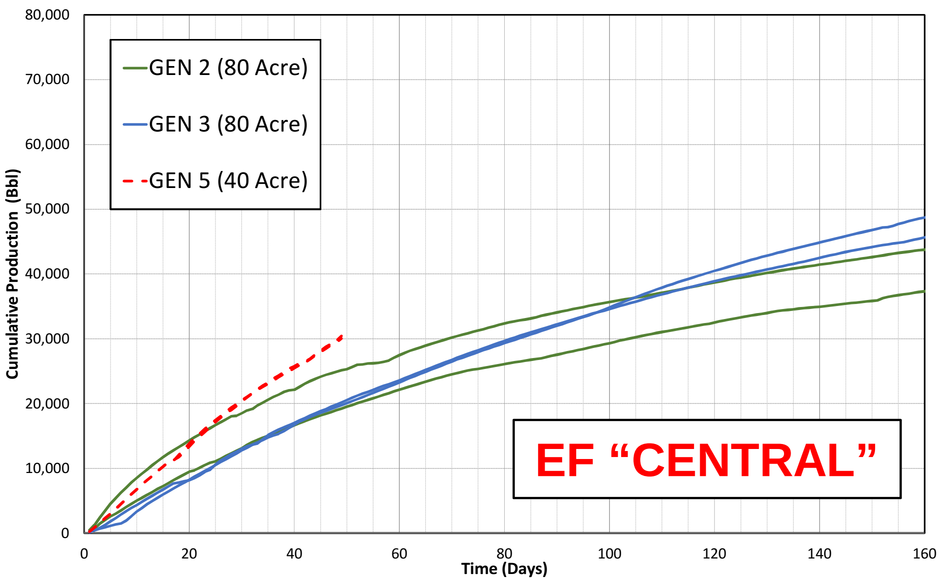


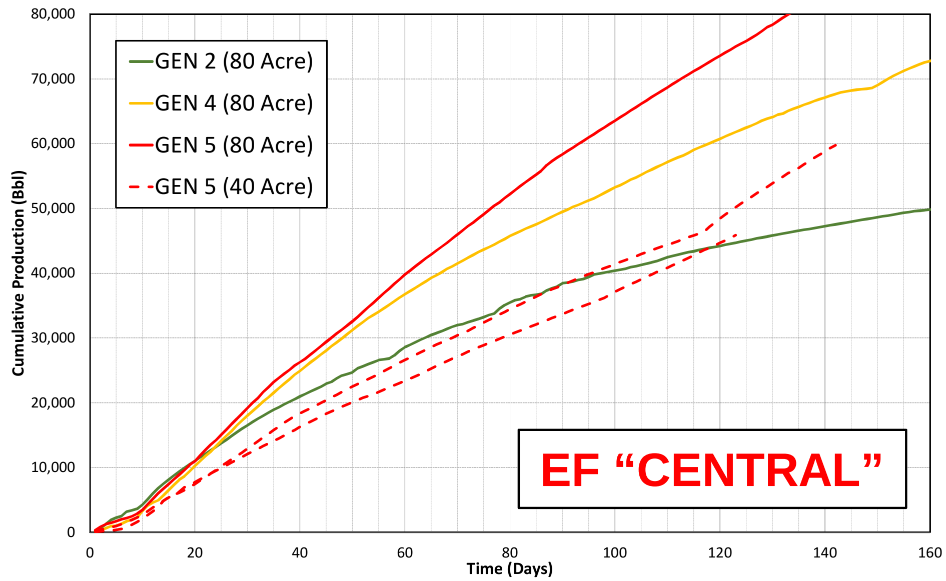


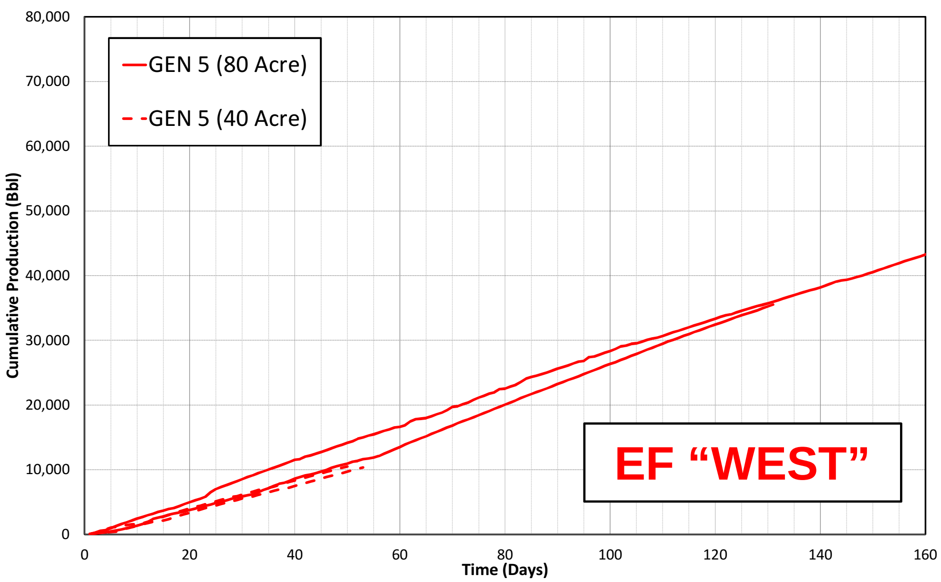
Downspacing Program

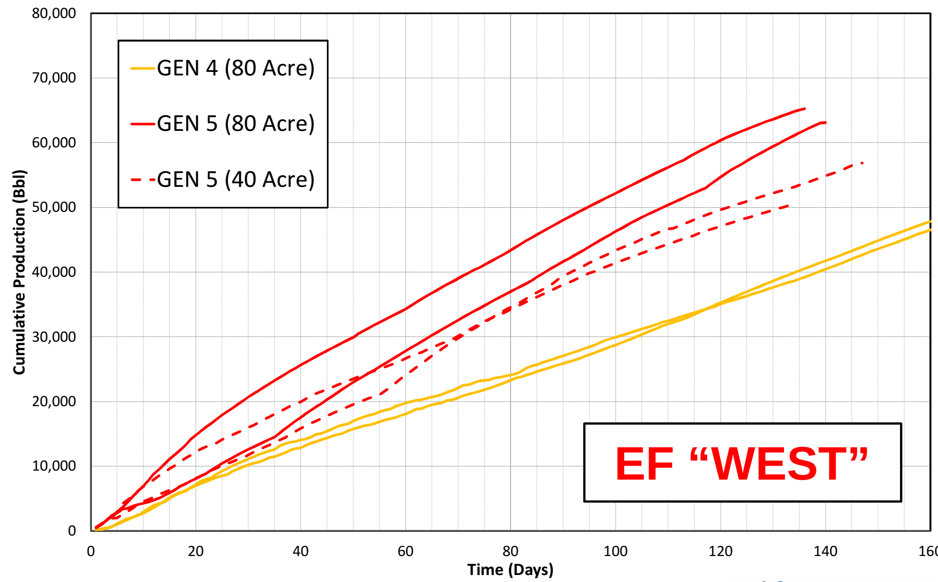


Downspacing Program – Cumulative Production vs. Time

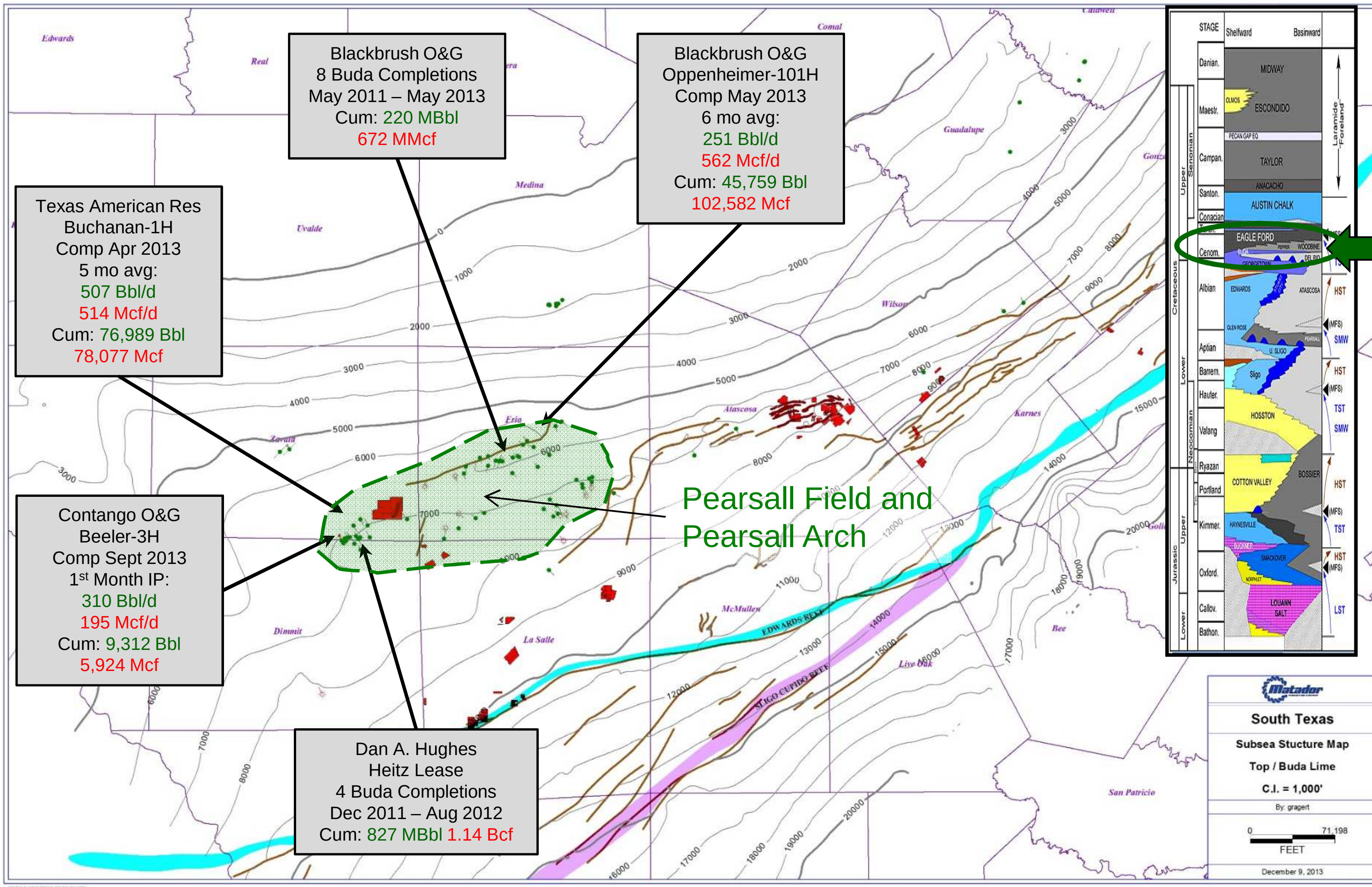








Buda Wells Activity Since January 1, 2010

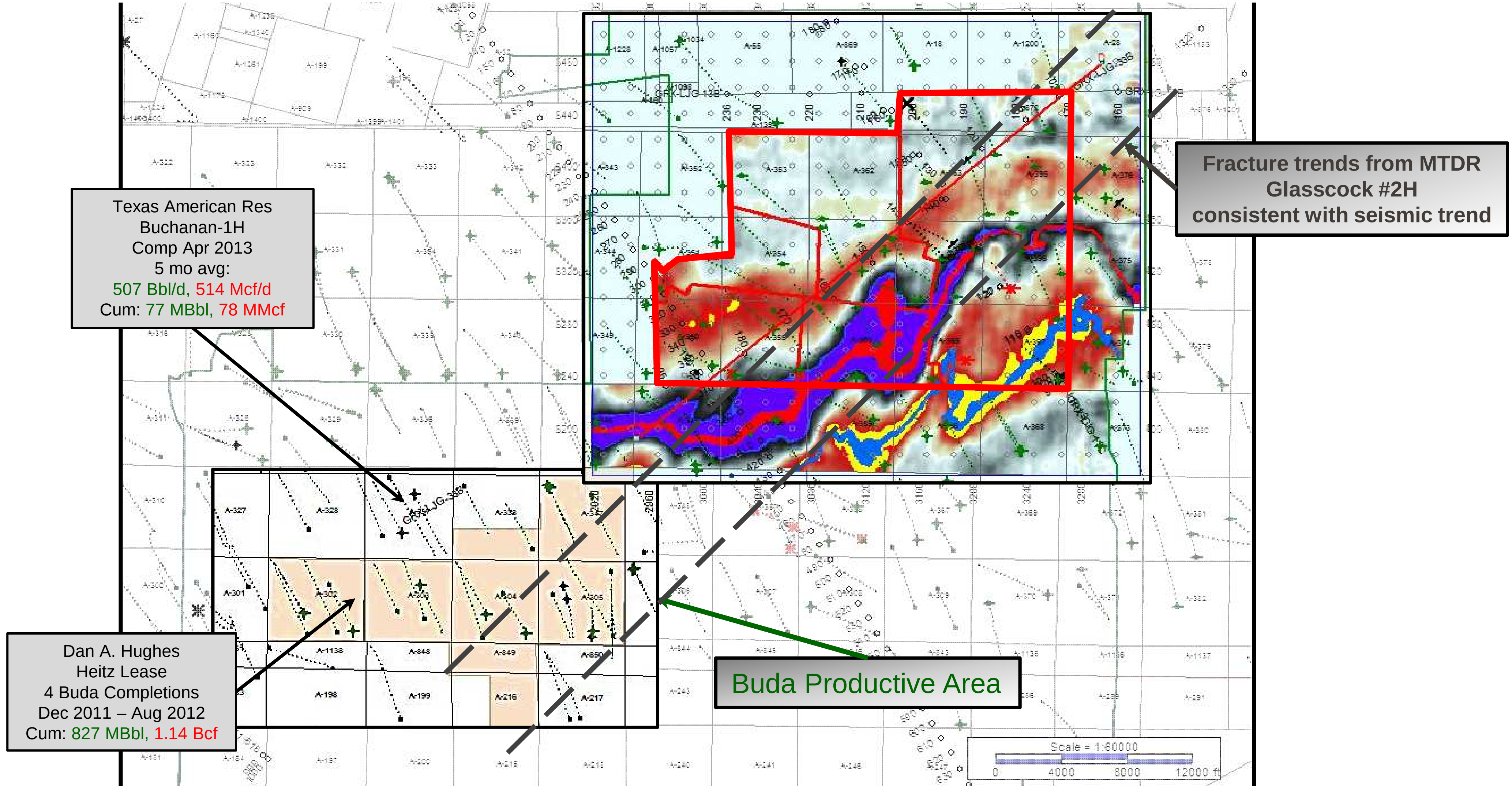


Note: Well information from public sources as of November 2013.

Glasscock Ranch Seismic Mapping of Natural Fracture Trends

Glasscock Ranch - Frio South Survey

Amplitude at Time Slice Near Top Buda



Note: Well information from public sources as of November 2013.

Permian Exploration and Operations

Permian Basin – Matador's Next Major Growth Area

Why the Permian?

- **The Permian Basin is a world class, stacked petroleum system that has been explored and developed for over 100 years with a solid base of infrastructure**
- **Over 30 billion barrels of oil have been recovered from conventional reservoirs within the basin and the basin flanks**
- **Potential future recovery of over 100 billion barrels from basin center unconventional plays and from additional conventional plays in the basin and its flanks**
- **Other operators achieving success in developing unconventional plays in the basin with more wells greater than 500 barrels per day (30-day average IPs) concentrated in Southeastern New Mexico than anywhere else in the basin**
- **The Delaware Basin is less developed than the Midland Basin (fewer wells) but is the deepest and thickest part of the Permian Basin**
- **Matador technical teams have significant experience working in the Permian Basin**
- **Matador I was one of the top 15 producers in Southeastern New Mexico prior to sale in 2003**

Matador's Criteria for Screening and High-Grading Opportunities

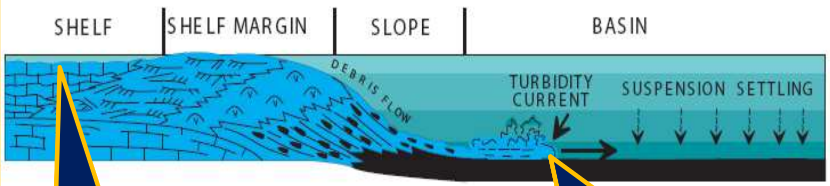
Basin Scale:

- Large basins, "supercharged", stacked, petroleum systems
- Stratigraphically and structurally predictable
- Significant drilling and conventional production history

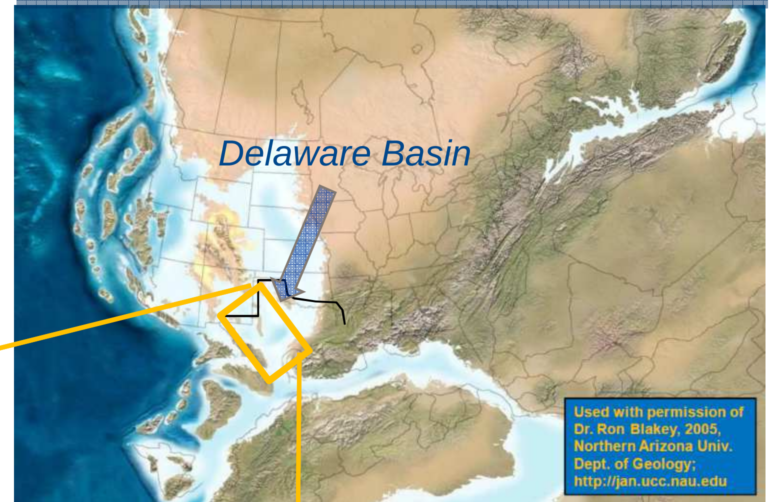
Target (Pay-Zone) Scale:

▪ Density porosity (permeability)	: > 7%
▪ Organic richness, maturity and continuity	: > 3% TOC at Ro 0.8-1.0
▪ Thickness and extent	: > 100 feet
▪ Fluid saturations	: Sw < 50%; > 10 ohms resistivity
▪ Formation pressure	: > 0.5 psi/ft
▪ Frac-ability (geo-mechanics)	: Vclay < 30%
▪ Estimated project economics	: IRR > 20%

“Wolf-Bone” Geological Setting, Predicting Where the Better Rocks Are



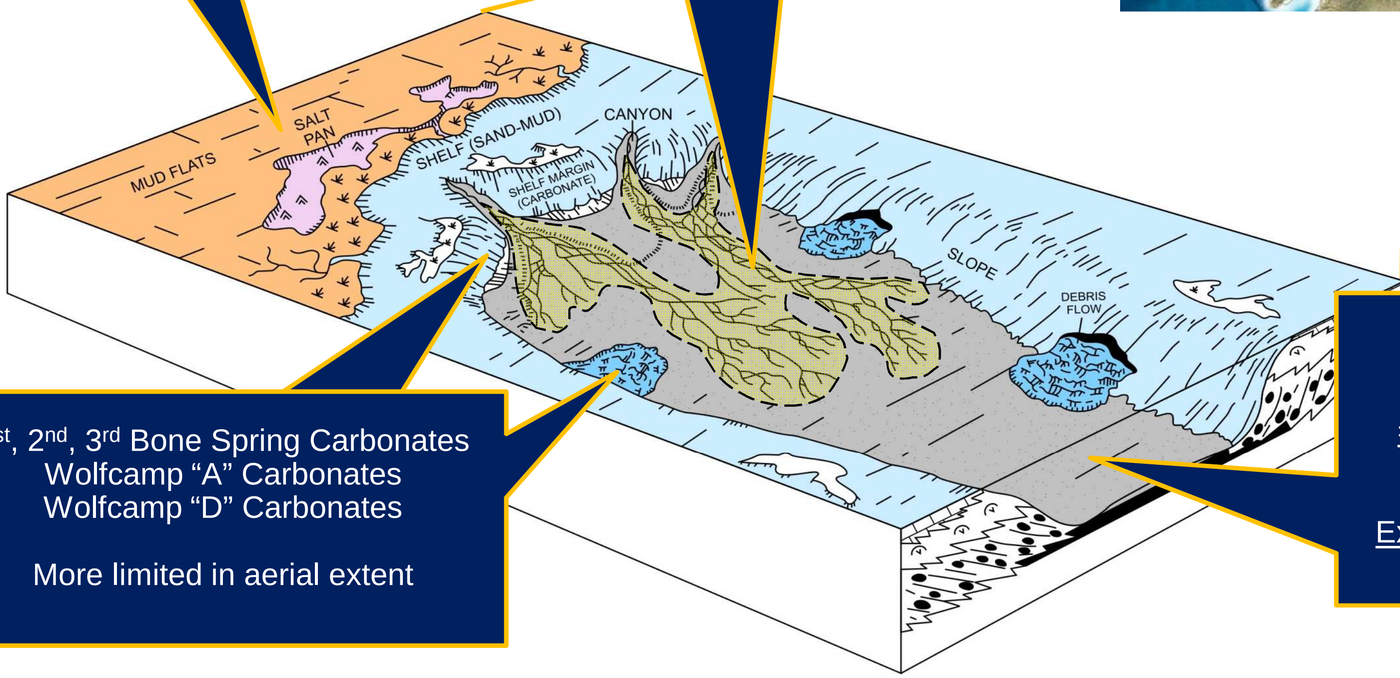
265 mya End of Bone Springs – Warmer!



San Andres
Yeso
Abo

Delaware Mountain Group
1st, 2nd, 3rd Bone Spring Sands

Sands confined to channels and distributary systems



1st, 2nd, 3rd Bone Spring Carbonates
Wolfcamp “A” Carbonates
Wolfcamp “D” Carbonates

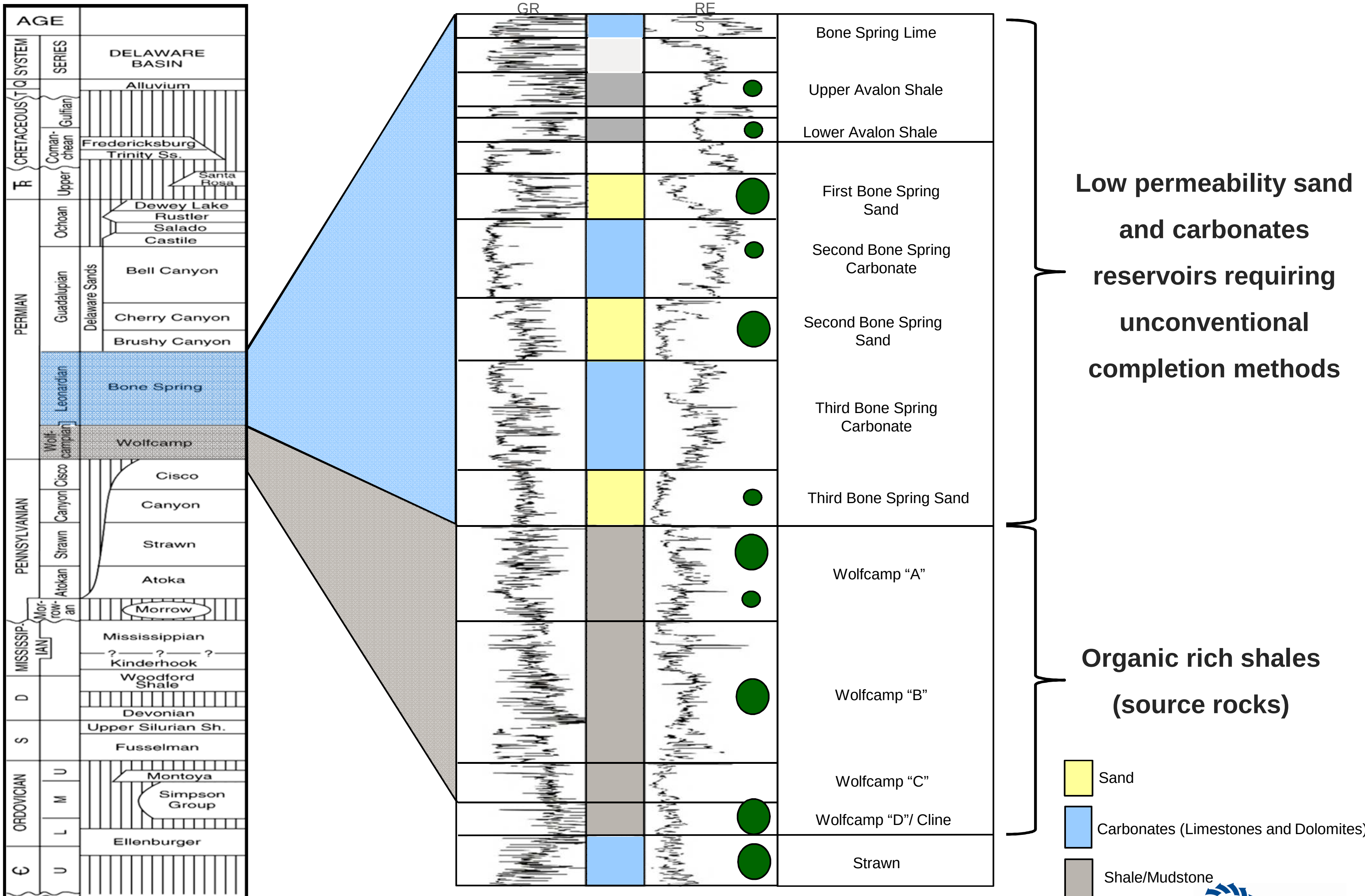
More limited in aerial extent

Wolfcamp “A”, “B”, “D”

= Oil & Gas Source Rocks and Resource Reservoir Rocks

Extensively distributed basin-wide

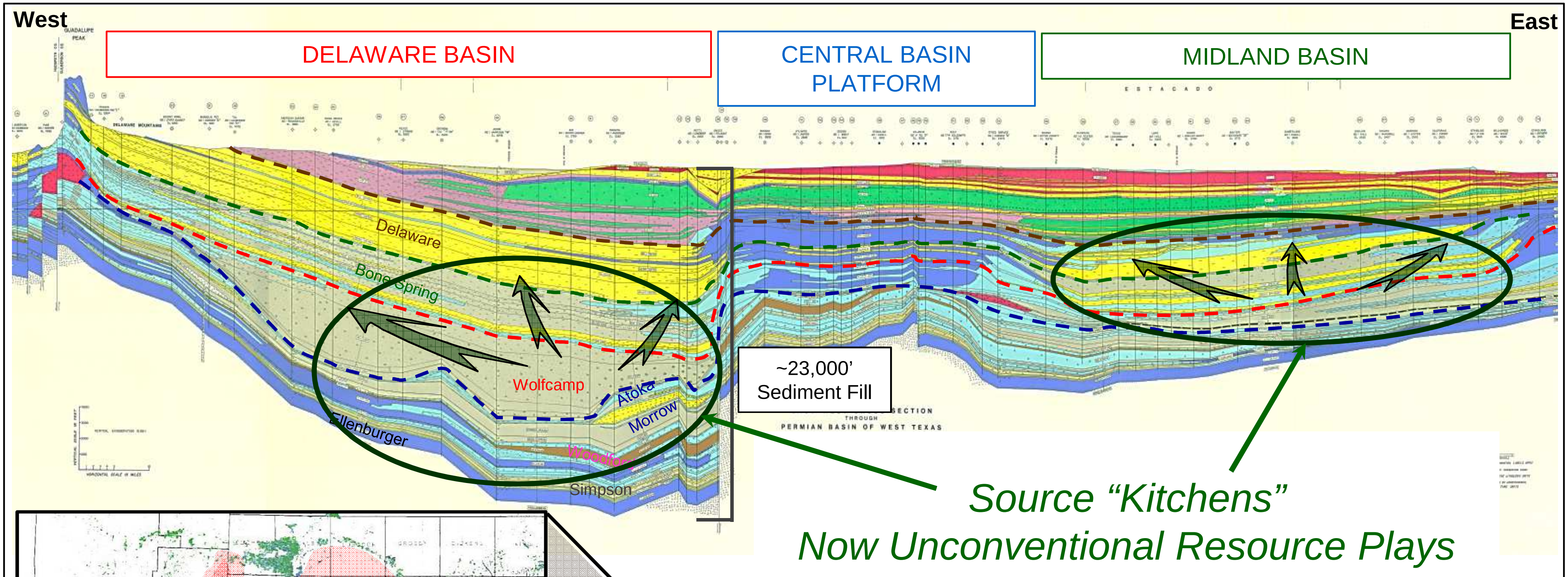
Permian Basin Stratigraphy and Lower Permian Petroleum Systems

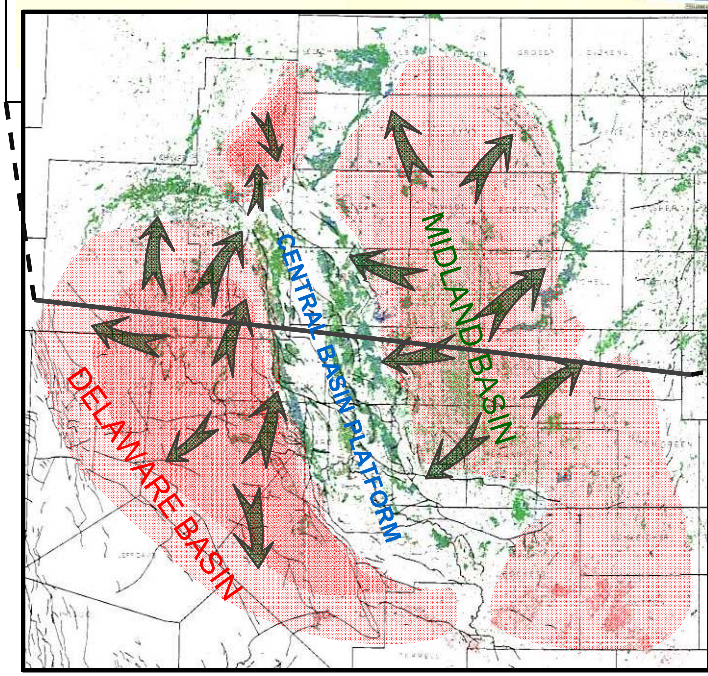


Low permeability sand and carbonates reservoirs requiring unconventional completion methods

Organic rich shales (source rocks)

Permian Basin Petroleum Systems and The Wolfcamp "Kitchens"

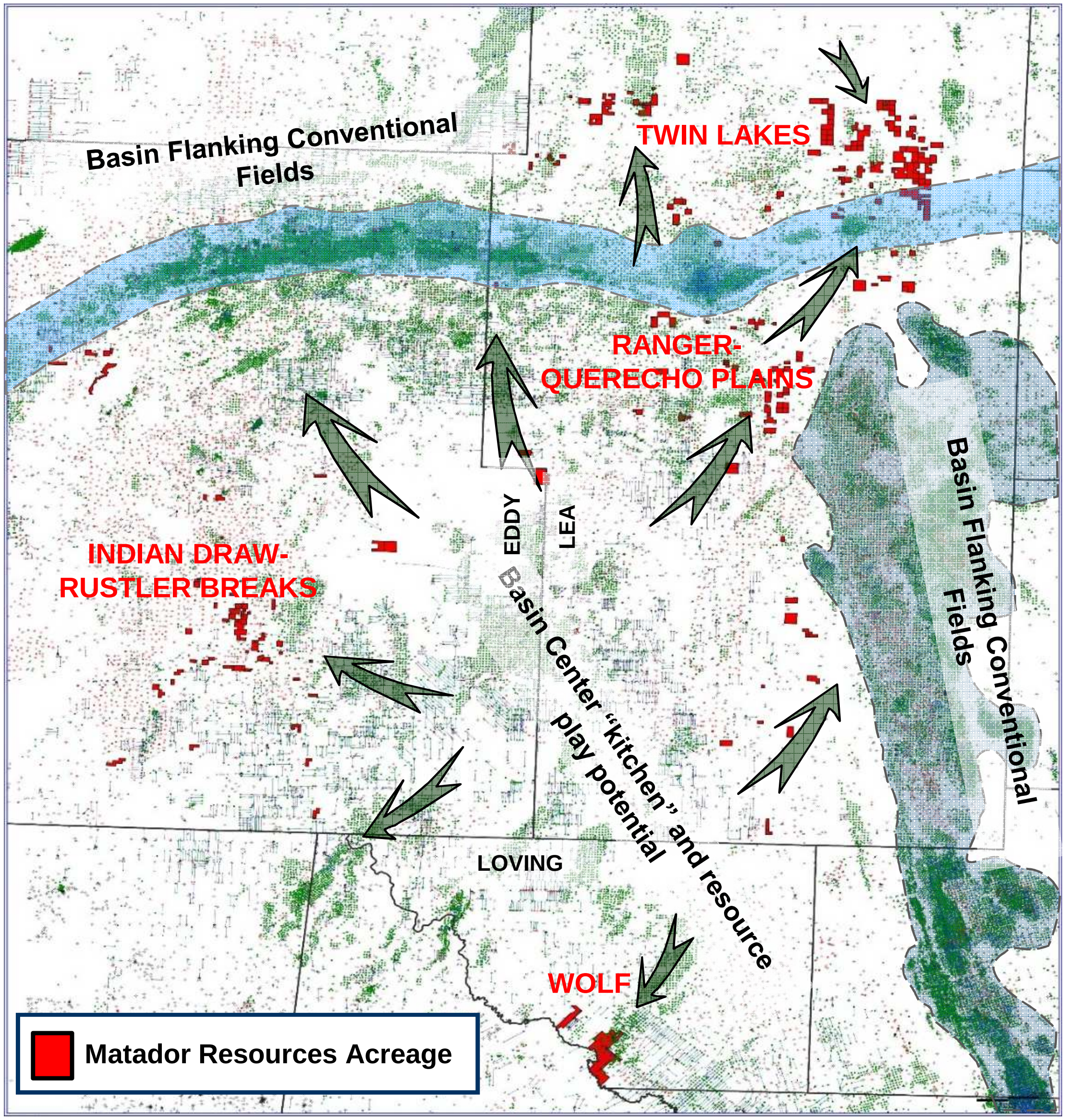




- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 conventional reservoirs with cum production > 1.0 million Bbl
- Cumulative production from 1,500 conventional reservoirs, as of year 2,000 (pre-horizontal drilling) > 30.0 billion Bbl[1]

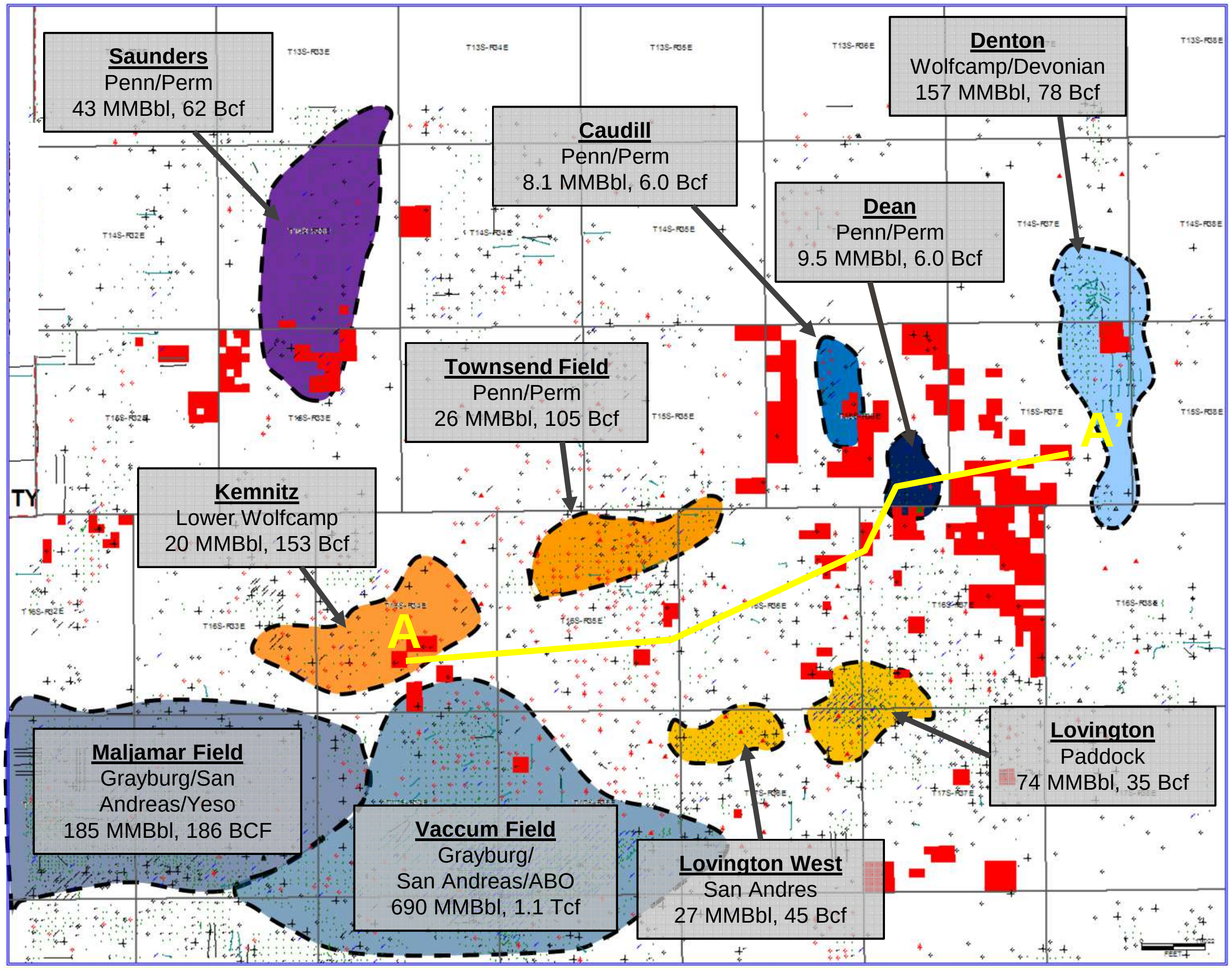
(1) Dutton et al, AAPG 2005

Permian Basin Acreage Position



- Offsetting multi-billion barrels in basin flanking conventional fields
- Hydrocarbon migration route-ways
- Stacked conventional and unconventional reservoir potential
- Primary Targets
  - Bone Spring (Avalon, 1st, 2nd and 3rd Bone Spring Sands)
  - Wolfcamp "A", "B" and "D"
- Secondary Targets
  - Delaware (Brushy, Cherry Canyon)
- Future Targets
  - Pennsylvanian, Morrow and Devonian

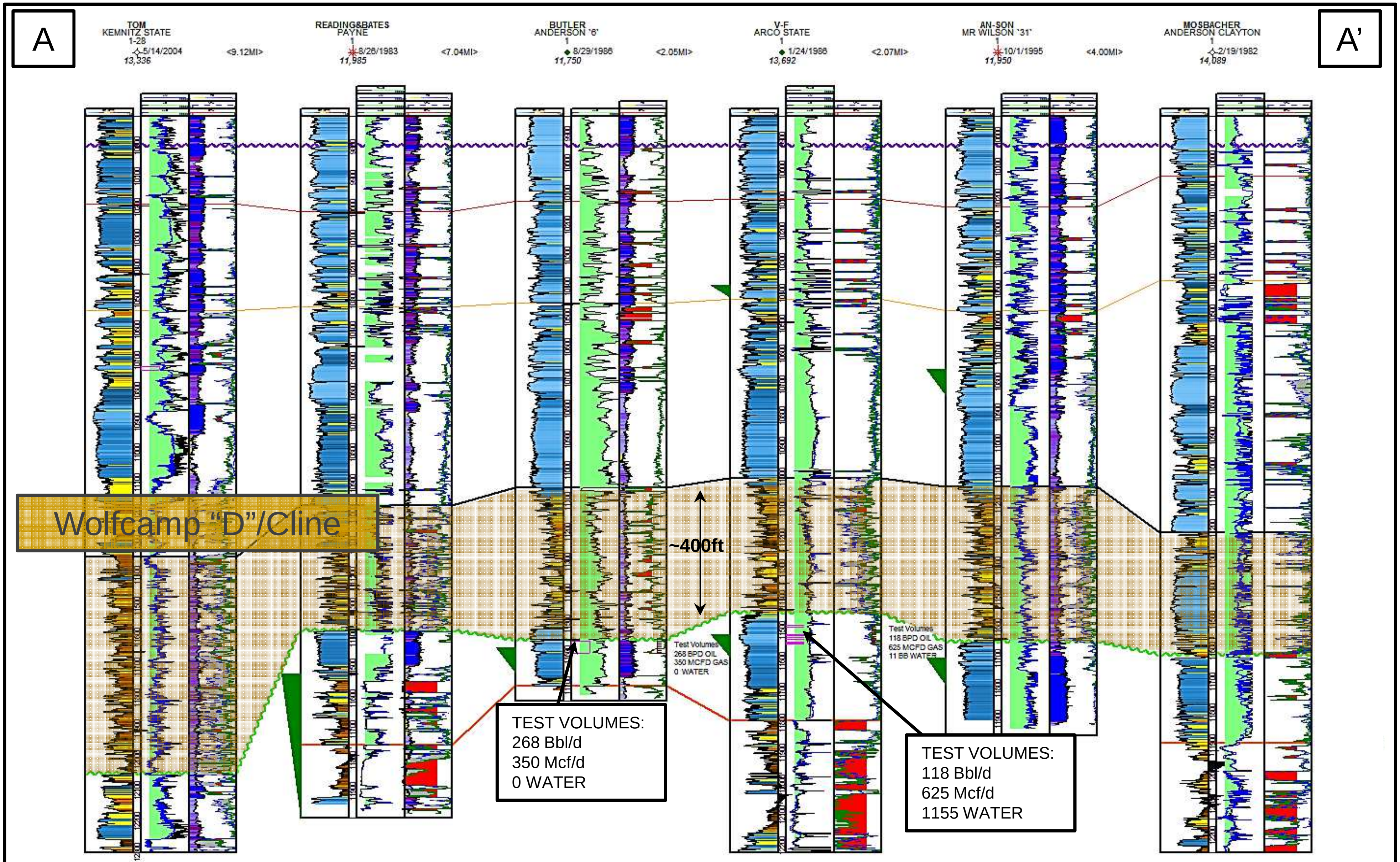
Twin Lakes Prospect Area



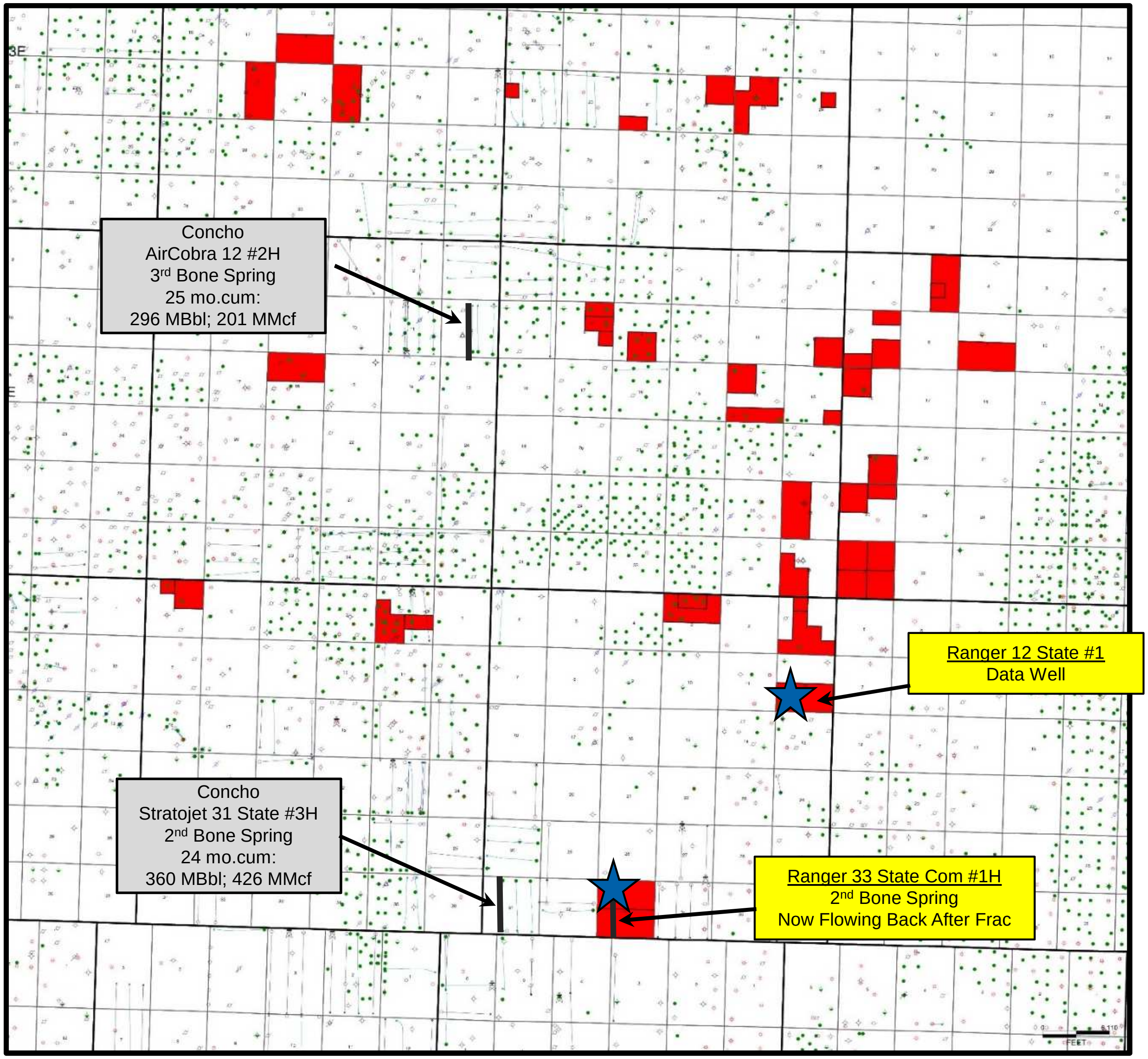
- **27,485 gross (17,813 net) acres**
- **Primary Targets**
  - Wolfcamp “D” (Cline)
  - Strawn
  - Abo
- **Other Potential Targets**
  - Cisco/Canyon
  - Devonian
  - Glorieta/San Andres
- **1 well planned for 2014**

Note: All acreage at November 30, 2013. Well information from public sources as of November 2013. Matador acreage shown in red.

Twin Lakes Area Cross Section



Ranger-Querecho Plains Prospect Area



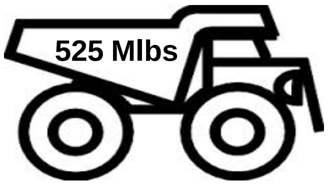
Location of Matador 2013 test wells

- **11,655 gross (8,893 net) acres**
- **82 gross (58.6 net) locations**
- **Primary Targets**
  - 2nd Bone Spring
  - 3rd Bone Spring
  - Wolfcamp "A", "B" and "D"
- **Other Potential Targets**
  - Delaware
  - Avalon
  - 1st Bone Spring
  - Bone Spring Carbonates
- **6 wells planned for 2014**

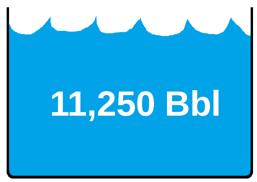
Note: All acreage at November 30, 2013. Well information from public sources as of November 2013. Matador acreage shown in red.

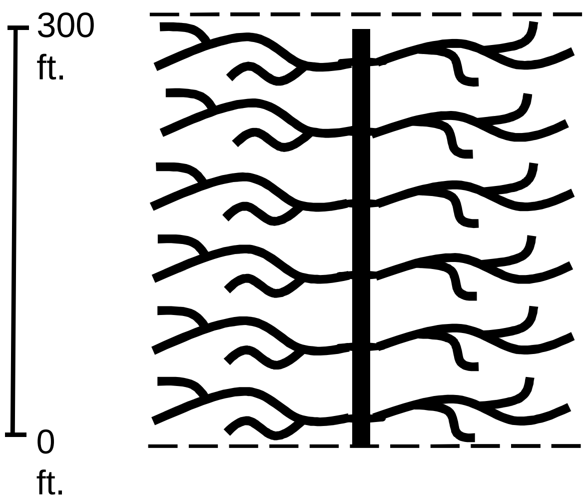
Ranger 33 State Com #1H Frac Overview

Proppant Pumped[1]



Fluid Volume Pumped

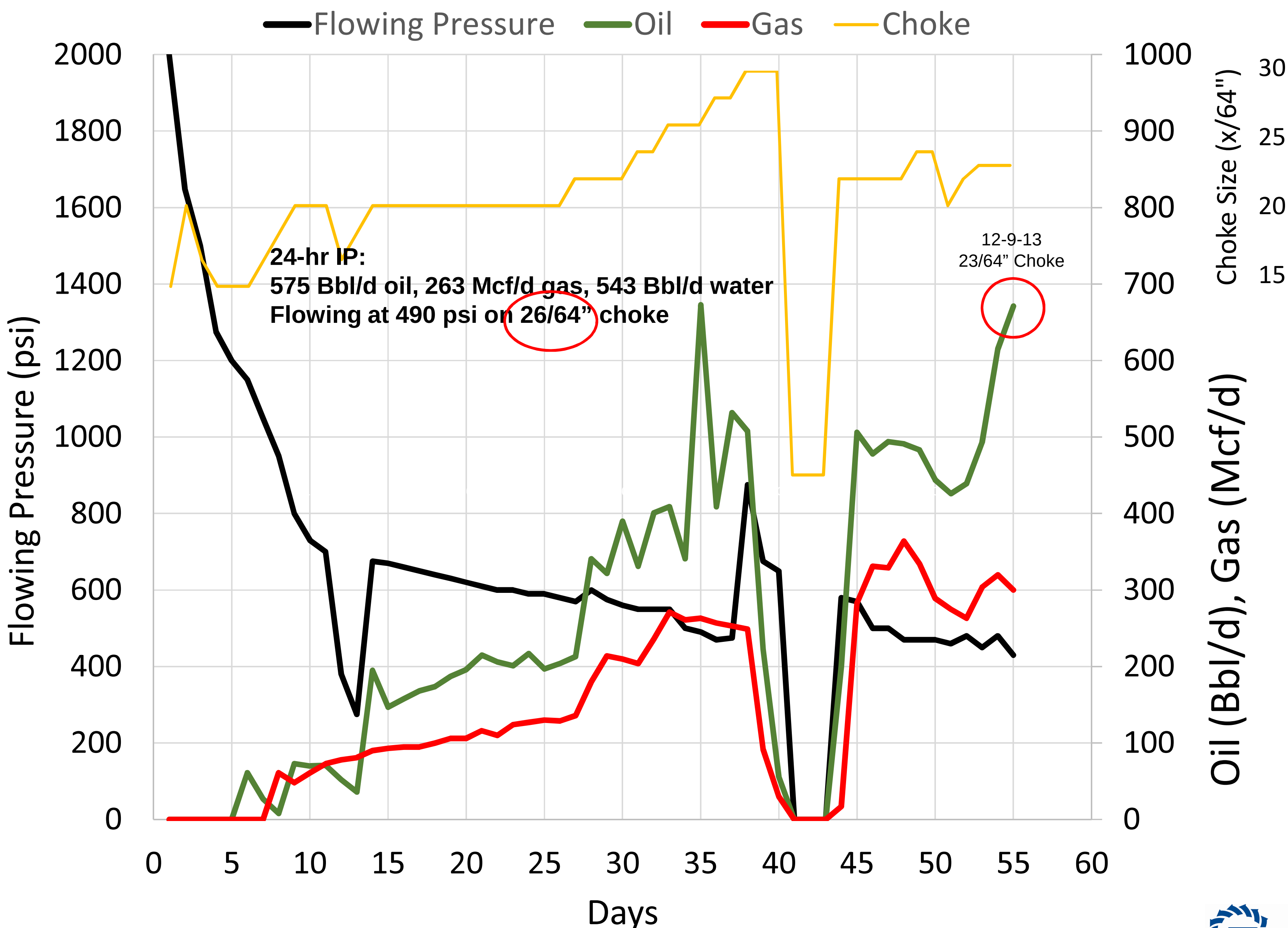




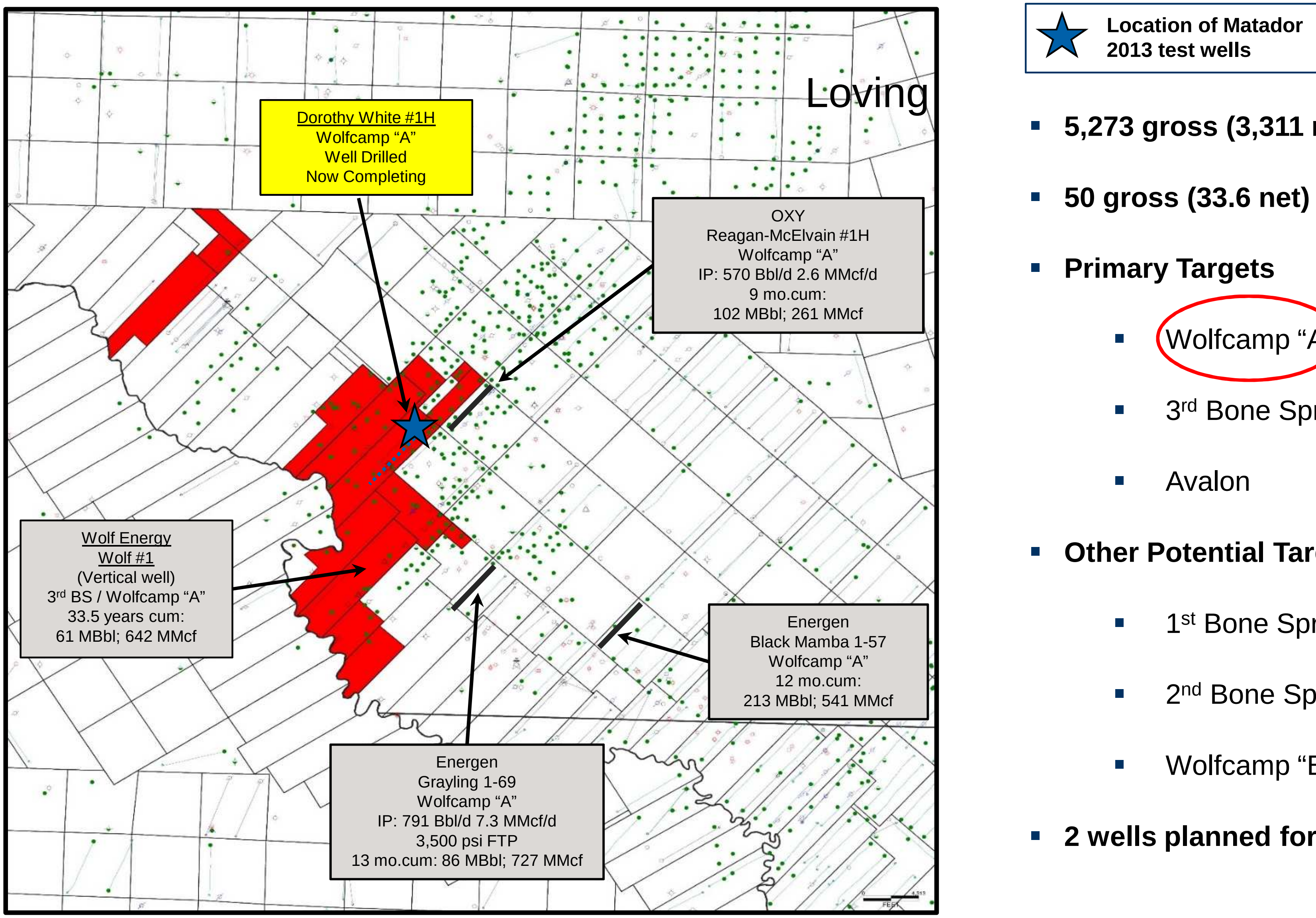
- **18 total stages**
- **450,000 lbs per stage**
  - 400,000 lbs 30/50 white sand per stage
  - 50,000 lbs resin-coated sand tail-in per stage
- **50-ft spacing between clusters**
- **5 clusters per stage**

Note: Figure depicts proppant and fluid volume pumped per 300 ft. of horizontal wellbore.
(1) Mlbs = thousands of pounds of proppant pumped.

Ranger 33 State Com #1H Production History



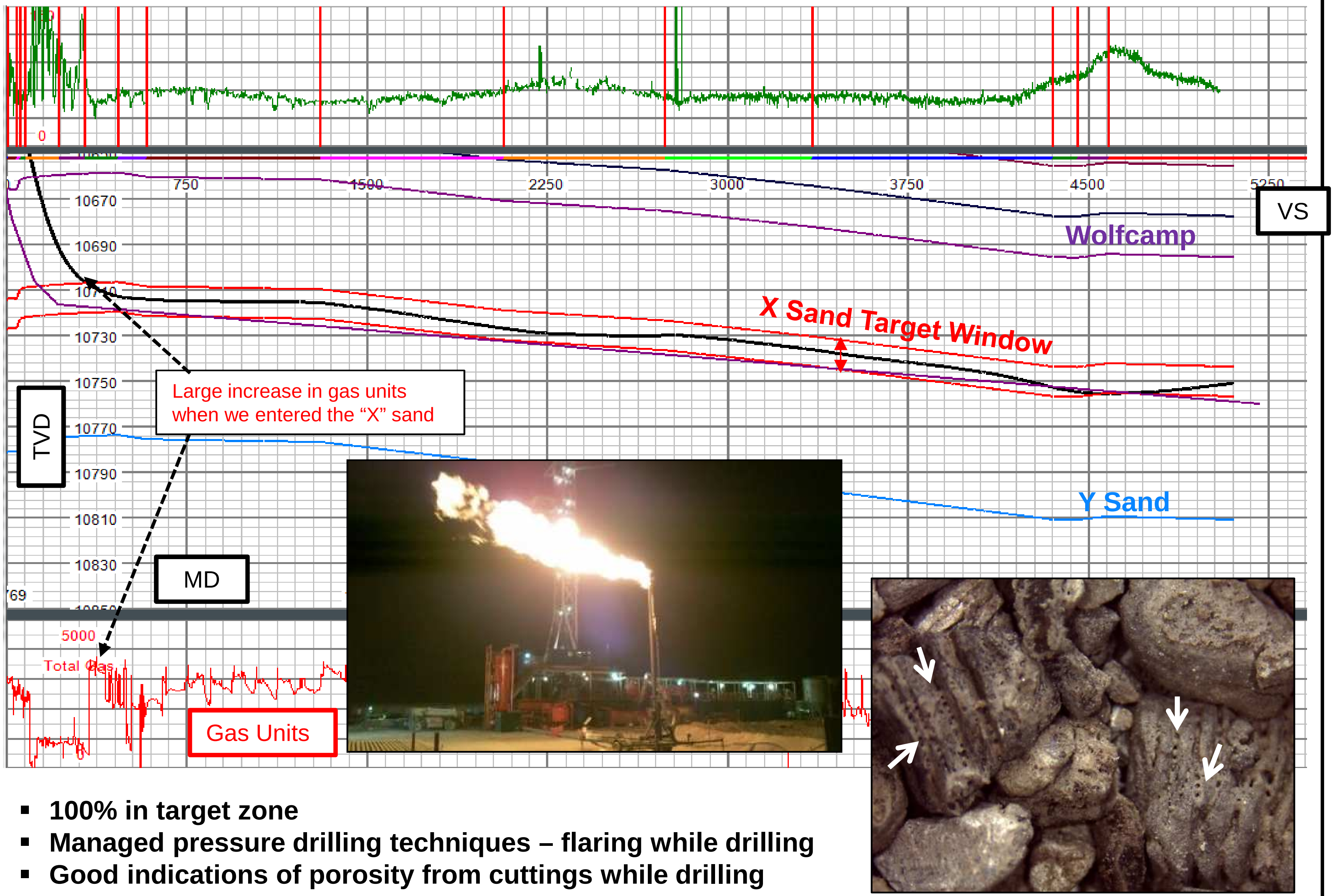
Wolf Prospect Area



- **5,273 gross (3,311 net) acres**
- **50 gross (33.6 net) locations**
- **Primary Targets**
  - Wolfcamp "A"
  - 3rd Bone Spring
  - Avalon
- **Other Potential Targets**
  - 1st Bone Spring
  - 2nd Bone Spring
  - Wolfcamp "B"
- **2 wells planned for 2014**

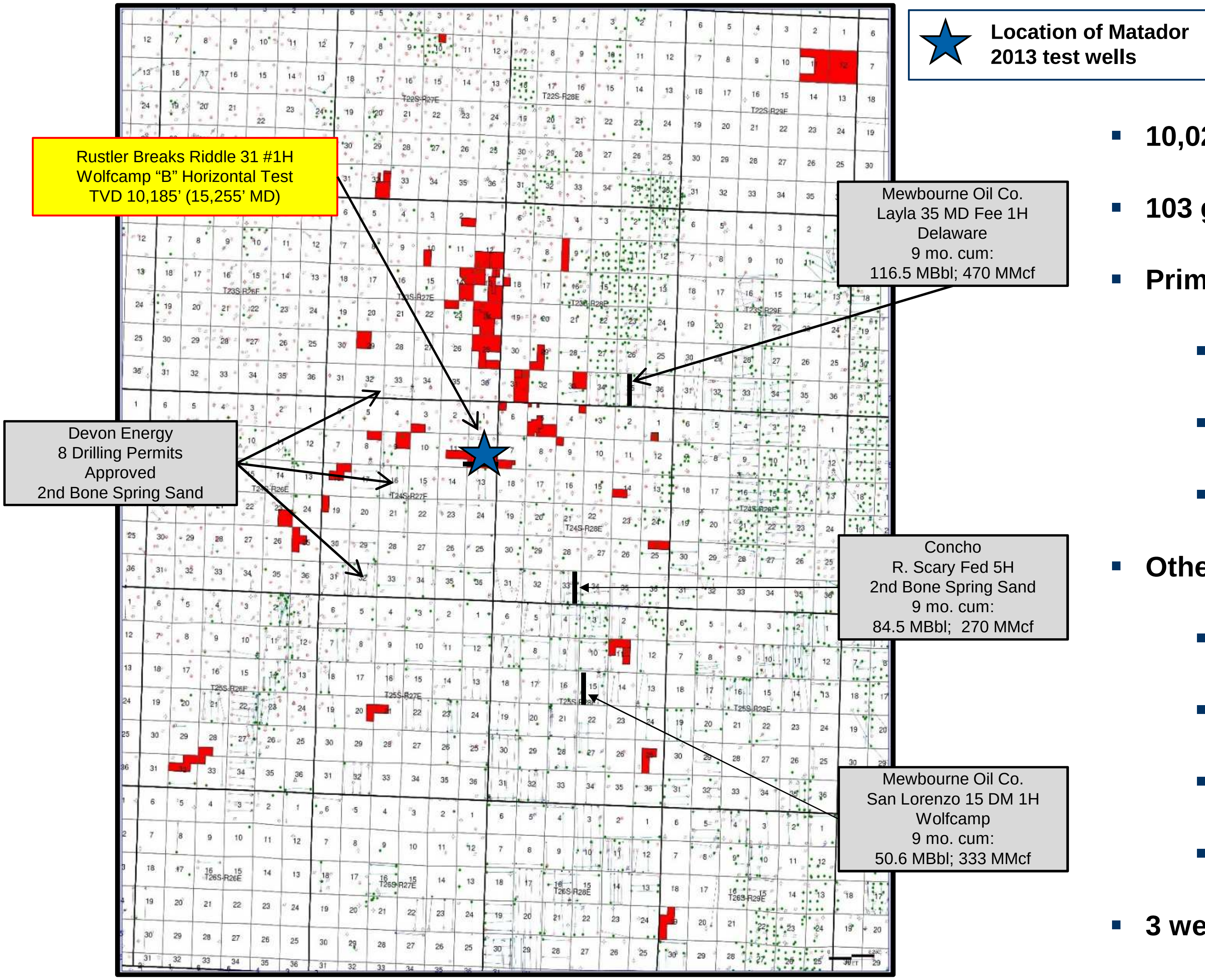
Note: All acreage at November 30, 2013. Well information from public sources as of November 2013. Matador acreage shown in red.

Dorothy White #1H Horizontal Well Profile



- **100% in target zone**
- **Managed pressure drilling techniques – flaring while drilling**
- **Good indications of porosity from cuttings while drilling**

Indian Draw-Rustler Breaks Prospect Area



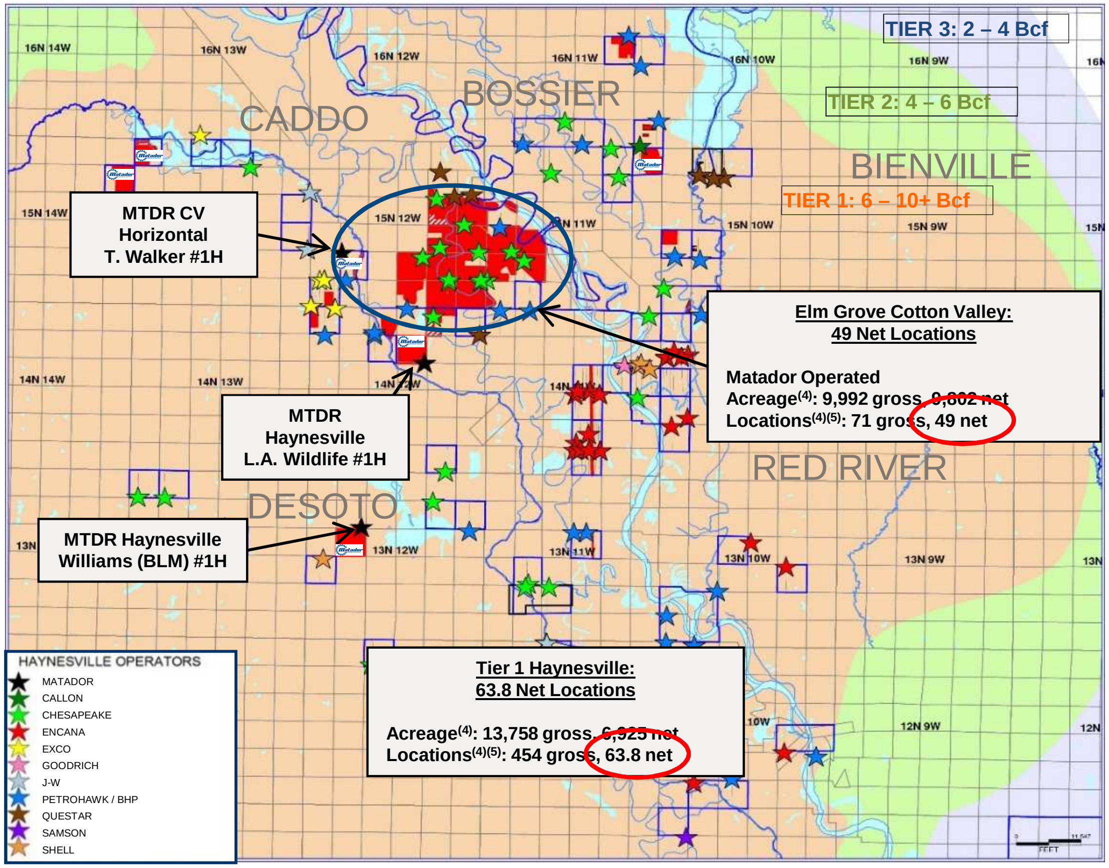
- **10,028 gross (7,177 net) acres**
- **103 gross (79.6 net) locations**
- **Primary Targets**
  - Wolfcamp "B"
  - 2nd Bone Spring
  - Delaware
- **Other Potential Targets**
  - Avalon
  - 1st Bone Spring
  - 3rd Bone Spring
  - Wolfcamp "A"
- **3 wells planned for 2014**

Note: All acreage at November 30, 2013. Well information from public sources as of November 2013. Matador acreage shown in red.



Haynesville and Other Natural Gas Operations

Significant Option Value on Natural Gas



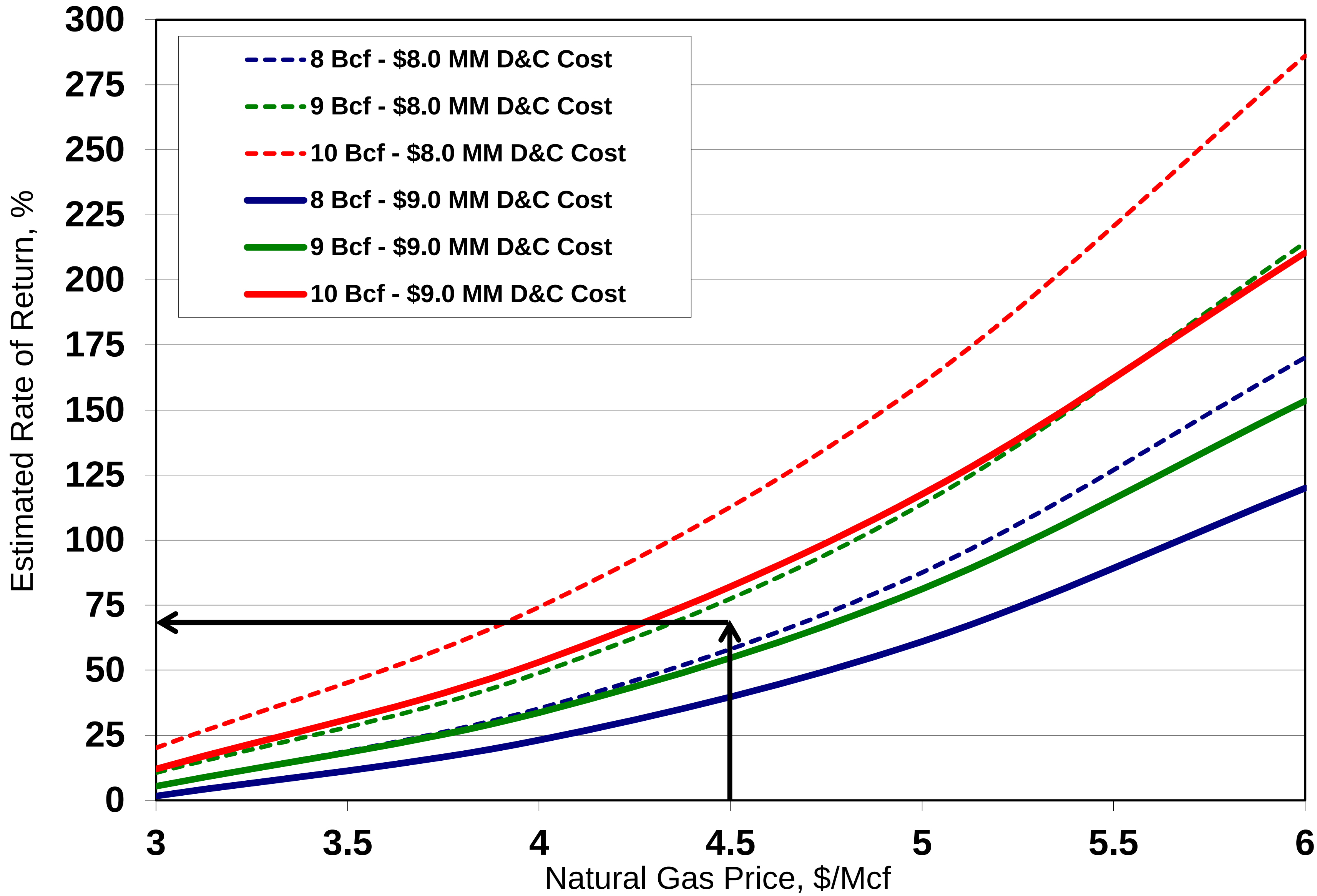
Note: All acreage at November 30, 2013. Matador acreage shown in red.

NW Louisiana / East Texas(1)	
Proved Reserves(2)	154.1 Bcfe
Daily Production(3)	3,772 BOE/d (99% natural gas)
Net Acres(4)	26,153 acres
Net Producing Wells(4)	83.3
Drilling Locations(4)(5)	164.1 net wells
% HBP(4)(6)	97%

- **Significant acreage position in the Haynesville**
  - Recently added 3 sections to provide more operated drilling opportunities
  - Also prospective for the Cotton Valley, Travis Peak/Hosston and other shallow formations
- **Competitive well economics on Tier 1 Haynesville wells at $4.50 /Mcf**
  - Estimated ROR ranges from 40% - 100+%
  - Pending Elm Grove gas gathering contract should reduce cost $0.65 - $0.92 /MMBtu – improved economics
- **Anticipate increase in future drilling activity**
  - CHK evaluating drilling program at Elm Grove
  - Other operators continuing activity
  - Expect ~1.5 net wells in 2014 and 2015
- **Cotton Valley horizontal EURs ~6 Bcf**

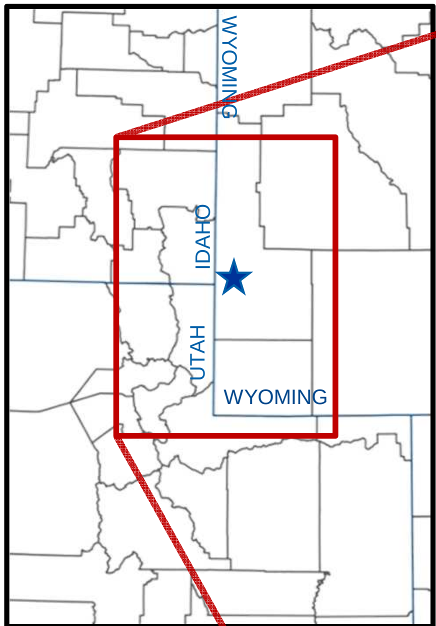
(1) Includes both Haynesville and Cotton Valley acreage.
(2) At September 30, 2013.
(3) For the nine months ended September 30, 2013.
(4) At November 30, 2013.
(5) Identified and engineered Tier 1 and Tier 2 locations identified for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation.
(6) Acreage held by production or fee mineral interests owned by Matador.

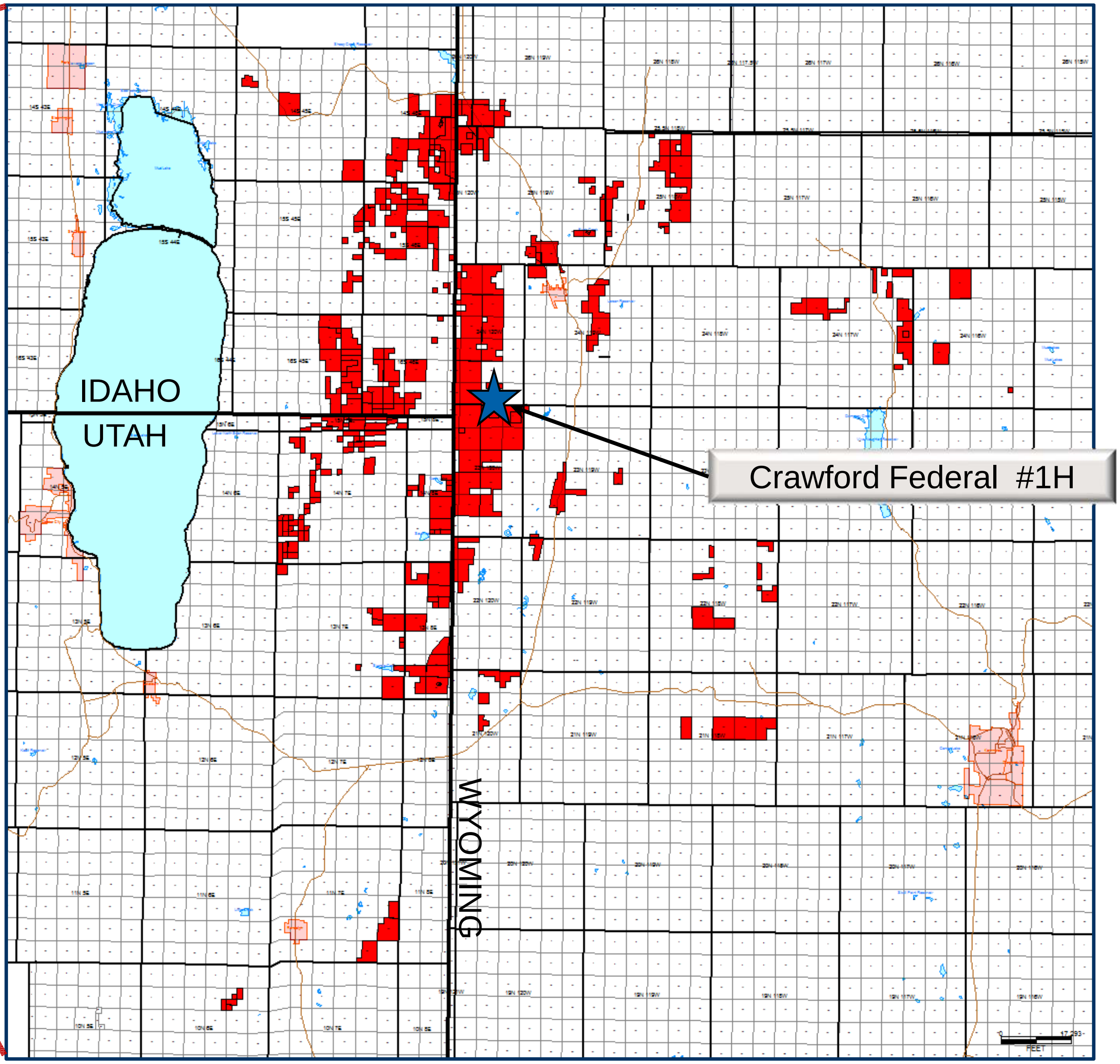
Haynesville Well Economics – Tier 1 Area



Note: Individual well economics only. D&C cost = drilling and completion cost. Natural gas price differential = ($0.85)/Mcf.

Matador Gracie Prospect – Meade Peak Gas Shale





Summary

- 76,500 gross (36,000 net) acres
- Drilled Crawford Fed #1H in late 2012
- Recently completed 5-stage fracture treatment
- Initiated flow back to recover frac fluid and flow test

Note: All acreage at November 30, 2013. Matador acreage shown in red.

Summary and Closing Remarks/Q&A

Summary and 2014 Guidance

- **Continue 3-rig program in 2014 – 2 rigs in Eagle Ford and 1 rig in Permian**
- **Eagle Ford development will continue to be the major driver of our growth in 2014**
- **Permian drilling program designed to further evaluate our acreage position and define an expanded development plan for 2015 and beyond**

	2013 Guidance(1)	*2014 Guidance*	*% Increase*
Capital Spending	$370 million	$440 million	~19%
Total Oil Production	2.0 to 2.1 million Bbl	2.8 to 3.1 million Bbl	~44%
Total Natural Gas Production	12.0 to 13.0 Bcf	13.5 to 15.0 Bcf	~14%
Oil and Natural Gas Revenues	$250 to $270 million(2)	$325 to $355 million(3)	~31%
Adjusted EBITDA(4)	$180 to $190 million(2)	$235 to $265 million(3)	~35%

(1) As updated on November 6, 2013.
(2) Estimated 2013 oil and natural gas revenues and Adjusted EBITDA based upon production guidance range as updated on November 6, 2013. Guidance includes actual results for the nine months ended September 30, 2013 and estimated results for the remainder of 2013. Estimated average realized prices for oil and natural gas used in these estimates were $96.00/Bbl and $4.30/Mcf, respectively, for the period October through December 2013.
(3) Estimated 2014 oil and natural gas revenues and Adjusted EBITDA at midpoint of production guidance range. Estimated average realized prices for oil and natural gas used in these estimates were $95.00/Bbl and $4.25/Mcf, respectively, for the period January through December 2014.
(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.

RESOURCES COMPANY

2013 Analyst Day Presentation

December 12, 2013

NYSE: MTDR



Appendix

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 forward-looking or prospective in nature, and not based on historical fact, the table does not provide a reconciliation. The Company could not provide such reconciliation without undue hardship because the forward-looking Adjusted EBITDA numbers included in this investor presentation 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.

	Year Ended December 31,						Nine Months Ended	LTM at
(In thousands)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**9/30/2013**	**9/30/2013**
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):								
Net (loss) income	($300)	$103,878	($14,425)	$6,377	($10,309)	($33,261)	$29,720	$8,532
Interest expense	-	-	-	3	683	1,002	4,919	5,468
Total income tax provision (benefit)	-	20,023	(9,925)	3,521	(5,521)	(1,430)	2,641	2,453
Depletion, depreciation and amortization	7,889	12,127	10,743	15,596	31,754	80,454	74,593	102,248
Accretion of asset retirement obligations	70	92	137	155	209	256	248	334
Full-cost ceiling impairment	-	22,195	25,244	-	35,673	63,475	21,229	47,903
Unrealized loss (gain) on derivatives	211	(3,592)	2,375	(3,139)	(5,138)	4,802	6,626	10,279
Stock-based compensation expense	220	665	656	898	2,406	140	2,763	3,126
Net (gain) loss on asset sales and inventory impairment	-	(136,977)	379	224	154	485	192	617
Adjusted EBITDA	**$8,090**	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$142,931**	**$180,960**

	Year Ended December 31,						Nine Months Ended	LTM at
(In thousands)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**9/30/2013**	**9/30/2013**
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:								
Net cash provided by operating activities	$7,881	$25,851	$1,791	$27,273	$61,868	$124,228	$127,192	$171,095
Net change in operating assets and liabilities	209	(17,888)	15,717	(2,230)	(12,594)	(9,307)	9,840	3,605
Interest expense	-	-	-	3	683	1,002	4,919	5,468
Current income tax provision (benefit)	-	10,448	(2,324)	(1,411)	(46)	-	980	792
Adjusted EBITDA	**$8,090**	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$142,931**	**$180,960**

Note: LTM is last 12 months through September 30, 2013.

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. The PV-10 at September 30, 2013 and September 30, 2011 were, in millions, $538.6 and $155.2 respectively, and 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. The discounted future income taxes at September 30, 2013 and September 30, 2011 were, in millions, $52.5 and $11.8 respectively.