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) September 30, 2014

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

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

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

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

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

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

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

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

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

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

Item 7.01 Regulation FD Disclosure.

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

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

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.

SIGNATURE

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

MATADOR RESOURCES COMPANY

Date: September 30, 2014

By:	/s/ Craig N. Adams
Name:	Craig N. Adams
Title:	Executive Vice President

Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.



Investor Presentation

September 2014 **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 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 make acquisitions on economically acceptable terms; availability of sufficient capital to execute Matador's business plan, including from its future cash flows, increases in Matador's borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.

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

Definitions – Proved oil and natural gas reserves are the estimated quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Matador's production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where Matador produces liquids-rich natural gas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. Estimated ultimate recovery (EUR) is a measure that by its nature is more speculative than estimates of proved reserves prepared in accordance with SEC definitions and guidelines and is accordingly less certain.



Company Summary

Matador History

Predecessor Entities

Foran Oil & Matador Petroleum

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

Matador Today

Matador Resources Company

- Founded by Joe Foran in 2003 with $6 million and a proven management and technical team and board of directors
- Grown entirely through the drill bit, with focus on unconventional reservoir plays, initially in Cotton Valley and Haynesville
- In 2008, sold Haynesville rights in approximately 9,000 net acres to Chesapeake for approximately $180 million; retained 25% participation interest, carried working interest and overriding royalty interest
- Redeployed capital into the Eagle Ford early in the play, acquiring over 30,000 net acres for approximately $100 million, mainly in 2010 and 2011
- 2012, 2013 and 2014E capital spending focused primarily on developing Eagle Ford and transitioning to oil
- IPO in February 2012 (NYSE: MTDR) at $12.00 (now $25.43)(2) had net cash proceeds of approximately $136 million
- Follow-on Offering in September 2013 at $15.25 (now $25.43)(2) had net cash proceeds of approximately $142 million
- Follow-on Offering in May 2014 at $24.25 (now $25.43)(2) had net cash proceeds of approximately $181 million

(1) Tom Brown acquired by Encana in 2004.
(2) As of September 26, 2014.

Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding[1]	73.3 million common shares
Share Price[2]	$25.43/share
Market Capitalization[1][2]	$1.9 billion

	2012 Actual	*2013 Actual*	*2014 Guidance[3]*
Capital Spending	$335 million	$374 million	$570 million
Total Oil Production	1.214 million Bbl	2.133 million Bbl	2.8 to 3.1 million Bbl[4]
Total Natural Gas Production	12.5 Bcf	12.9 Bcf	16.0 to 17.5 Bcf
Oil and Natural Gas Revenues	$156.0 million	$269.0 million	$380 to $400 million[5]
Adjusted EBITDA[6]	$115.9 million	$191.8 million	$270 to $290 million[5]

(1) Shares outstanding as reported in the Form 10-Q for the quarter ended June 30, 2014 filed on August 8, 2014.
(2) As of September 26, 2014.
(3) As reaffirmed on August 6, 2014.
(4) The Company guided investors to the top end of its oil production guidance range.
(5) Estimated 2014 oil and natural gas revenues and Adjusted EBITDA based on production guidance range. Estimated average realized prices for oil and natural gas used in these estimates were $95.00/Bbl and $5.00/Mcf, respectively, for the period July through December 2014.
(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.

Matador's Execution History – "Doing What We Say"

Matador continues to execute on its core strategy of acquiring great assets, retaining a best-in-class workforce, maintaining a strong balance sheet and generating significant shareholder returns

	At IPO(1)		2013 Follow-On(7)		Today(9)
Oil Production	▪ 414 Bbl/d of oil ▪ 6% oil	12x growth in oil production	▪ 4,916 Bbl/d of oil ▪ 46% oil	~80% growth in oil production	▪ 8,809 Bbl/d of oil ▪ 57% oil
Proved Reserves	▪ 27 MMBOE ▪ 1.1 MMBbl of oil ▪ 4% oil	11x growth in oil reserves	▪ 39 MMBOE ▪ 12.1 MMBbl of oil ▪ 31% oil	54% growth in oil reserves	▪ 57 MMBOE ▪ 18.6 MMBbl of oil ▪ 33% oil
PV-10(2)	▪ $155.2 million ▪ 24% of PV-10 in Eagle Ford	Over 3x growth in PV-10	▪ $522.3 million ▪ 90% of PV-10 in Eagle Ford	~60% growth in PV-10	▪ $826.0 million ▪ 72% of PV-10 in Eagle Ford
LTM Adjusted EBITDA(3)	▪ $50 million(4)	~200% growth	▪ $148 million	59% growth	▪ $236 million
Acreage	▪ ~7,500 net Permian acres	Over 4x growth in Permian acres	▪ ~32,900 net Permian acres	88% growth in Permian acres	▪ ~62,000 net Permian acres(10)
Enterprise Value ("EV")(5)	▪ $0.65 billion(6)	Doubled EV	▪ $1.2 billion(8)	~75% EV growth	▪ $2.1 billion(11)

(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 June 30, 2013.
(8) As of September 1, 2013.
(9) Unless otherwise noted, at or for the three months ended June 30, 2014.
(10) As of August 6, 2014.
(11) As of September 26, 2014.

Delivering Strong Results

Q2 2014 Achievements

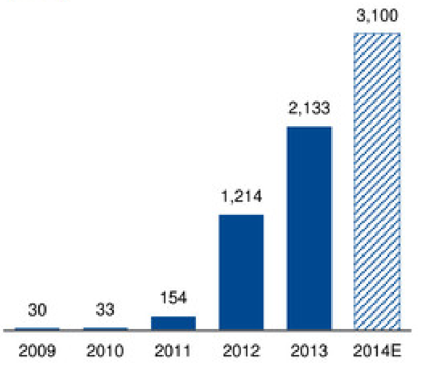
- **Oil Production – Company Record!**
  - 8,809 Bbl/d; 79% growth versus Q2 2013
- **Oil & Natural Gas Revenues**
  - $99.1 million; 70% growth versus Q2 2013
- **Adjusted EBITDA[(1)]**
  - $69.5 million; 70% growth versus Q2 2013

2014 Capital Budget and Guidance

- $570 million capital budget for 2014
- Adjusted EBITDA[(1)] of $270 to $290 million
- Oil and natural gas revenues of $380 to $400 million
- Guiding investors to top end of oil production guidance of 2.8 to 3.1 million Bbl
- Estimated natural gas production of 16.0 to 17.5 Bcf

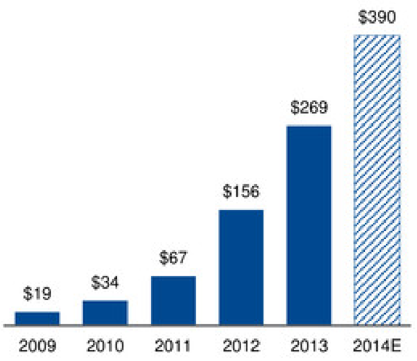
Oil Production[(2)]

(MBbl)



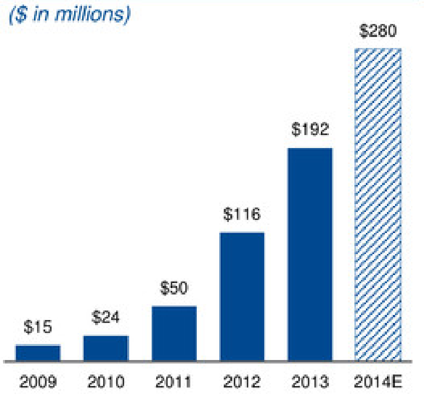
Oil & Natural Gas Revenues[(3)]

($ in millions)



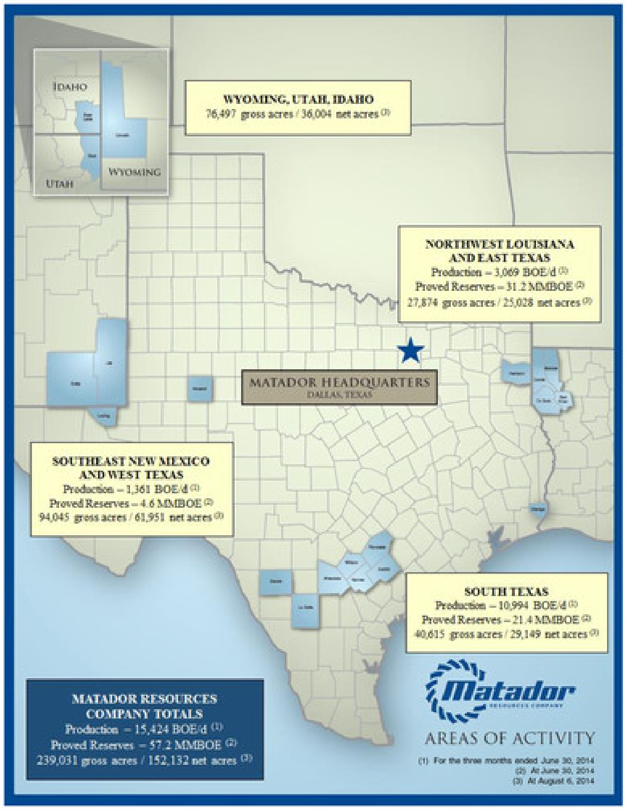
Adjusted EBITDA[(1)(3)]

($ in millions)



(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.
(2) 2014 estimate at top end of guidance range as reaffirmed on August 6, 2014.
(3) 2014 estimates at midpoint of guidance range as reaffirmed on August 6, 2014. Estimated average realized prices for oil and natural gas used in these estimates were $95.00/Bbl and $5.00/Mcf, respectively, for the period July through December 2014.

Matador Resources Company Overview



Market Capitalization[1]	**$1.9 billion**
Average Daily Production[2]	**15,424 BOE/d**
Oil (% total)	8,809 Bbl/d (57%)
Natural Gas (% total)	39.7 MMcf/d (43%)
Proved Reserves @ 6/30/14	**57.2 million BOE**
% Proved Developed	35%
% Oil	33%
2014E CapEx	**$570 million**
% South Texas	~56%
% Permian	~33%
% Oil and Liquids	~89%
Gross Acreage[3]	**239,031 acres**
Net Acreage[3]	**152,132 acres**
Engineered Drilling Locations[4][5]	**1,112 gross / 570.8 net**
Eagle Ford	273 gross / 229.3 net
Permian	241 gross / 177.7 net
Haynesville/Cotton Valley	598 gross / 163.8 net

(1) Market capitalization based on shares outstanding as reported in the Form 10-Q for the three months ended June 30, 2014 filed on August 8, 2014 and closing share price as of September 26, 2014.
(2) Average daily production for the three months ended June 30, 2014.
(3) At August 6, 2014.
(4) Presented as of December 31, 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.

Asset Highlights

Permian Basin
Exploratory and Delineation Program

- Currently running a two-rig drilling program (177.7 net drilling locations[(1)])
- ~62,000 net acres[(2)] in Lea and Eddy Counties, NM and Loving County, TX in the Permian Basin with multi-zone drilling potential
- Successful performance of 3 initial horizontal wells
  - **Ranger 33**: Almost 140,000 BOE (91% oil) in ten months; producing 350 to 400 Bbl/d of oil[(3)]; shallower than expected decline
  - **Dorothy White**: Almost 200,000 BOE in eight months (66% oil); producing 500 Bbl/d of oil and 1.4 MMcf/d of natural gas[(3)]; shallower than expected decline
  - **Rustler Breaks**: 86,000 BOE in four months; producing 200 Bbl/d of oil and 1.7 MMcf/d of natural gas[(3)]; shallower than expected decline
- Norton Schaub #1H and Pickard State 20-18-34 #1H had strong IP tests

Eagle Ford Shale
Development Program

- Currently running a two "walking" rig drilling program in South Texas (229.3 net drilling locations[(1)])
- Net oil production of ~7,800 Bbl/d in Q2 2014 (up 61% as compared to Q2 2013)[(4)]
- ~29,100 net acres[(5)] primarily located in the oil window
- Expect batch drilling operations to continue to improve drilling times and costs
- Fracture stimulation techniques continue to improve
- Gas lift operations adding value and reducing costs
- Continuing to acquire new leasehold interests at attractive prices to replace developed acreage and replenish inventory
- Encouraging 40 to 50-acre downspacing results

Haynesville Shale
Natural Gas Bank

- ~25,000 net acres in NW Louisiana and East Texas[(5)(6)]
  - ~6,900 net Tier 1 acres in the core of the play with 6 to 12 Bcf EURs
- Estimated ROR ranges from 60% to 100% at $4.00 to $4.50/Mcf and above in Elm Grove area
- Increased industry activity as a result of higher natural gas prices leading to additional non-operated participation opportunities
- Expect up to 56 gross (7.8 net) non-operated wells to be drilled on Matador's acreage in 2014
  - Anticipate Chesapeake to drill up to 30 gross (6.3 net) Haynesville wells in Elm Grove area in 2014
- Drilled and tested one of the first Haynesville wells

Applying our Expertise

(1) As of December 31, 2013.
(2) At August 6, 2014. Includes small amounts of acreage in Reeves, Ward, Howard and Dawson Counties, TX.
(3) As of September 8, 2014.
(4) Includes two wells producing small quantities of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(5) At August 6, 2014.
(6) Includes acreage prospective for Cotton Valley.

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, our capabilities and our process
  - 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
- **Execute**
  - Increase oil production from 2.1 million barrels of oil to 3.1 million barrels of oil
  - Maintain quality acreage position in the Eagle Ford, Permian and Haynesville
  - Maintain strong financial position, technical team and approach
  - Reduce drilling and completion times



Eagle Ford

South Texas

2014 South Texas Plan Details

- **2014 projected capital expenditures of ~$318 million or ~56% 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
  - 2014 Eagle Ford program is development drilling, with most locations planned at 40 to 50-acre spacing
  - No Upper Eagle Ford tests currently planned for 2014
- **Key objectives of 2014 South Texas plan**
  - Further improvement in operational efficiencies and well performance in the Eagle Ford
    - Batch drilling with two "walking" rigs to continue reducing drilling times and costs
    - Continue to improve and optimize stimulation operations – increased fluid and proppant volumes, reduced cluster spacing and increased number of stages, as needed
    - Continue to optimize artificial lift program – gas lift to rod pump and plunger lift implementations
    - Reduce LOE throughout all properties
      - *Four solid quarters of LOE improvement*
  - Successful implementation of 40 to 50-acre downspacing across acreage position
    - *Testing 40 to 50-acre spacing at Sickenius, Danysh, Pawelek in Eagle Ford Central and Martin Ranch and Northcut in Eagle Ford West with encouraging results*
  - Continue to add to acreage position as opportunities arise, particularly in and near existing properties
    - *Added 3,100 gross (2,900 net)[1] acres prospective for the Eagle Ford (up to 75 potential well locations) since January 1, 2014, more than replacing current year drilling inventory*

(1) At August 6, 2014.

Eagle Ford Overview

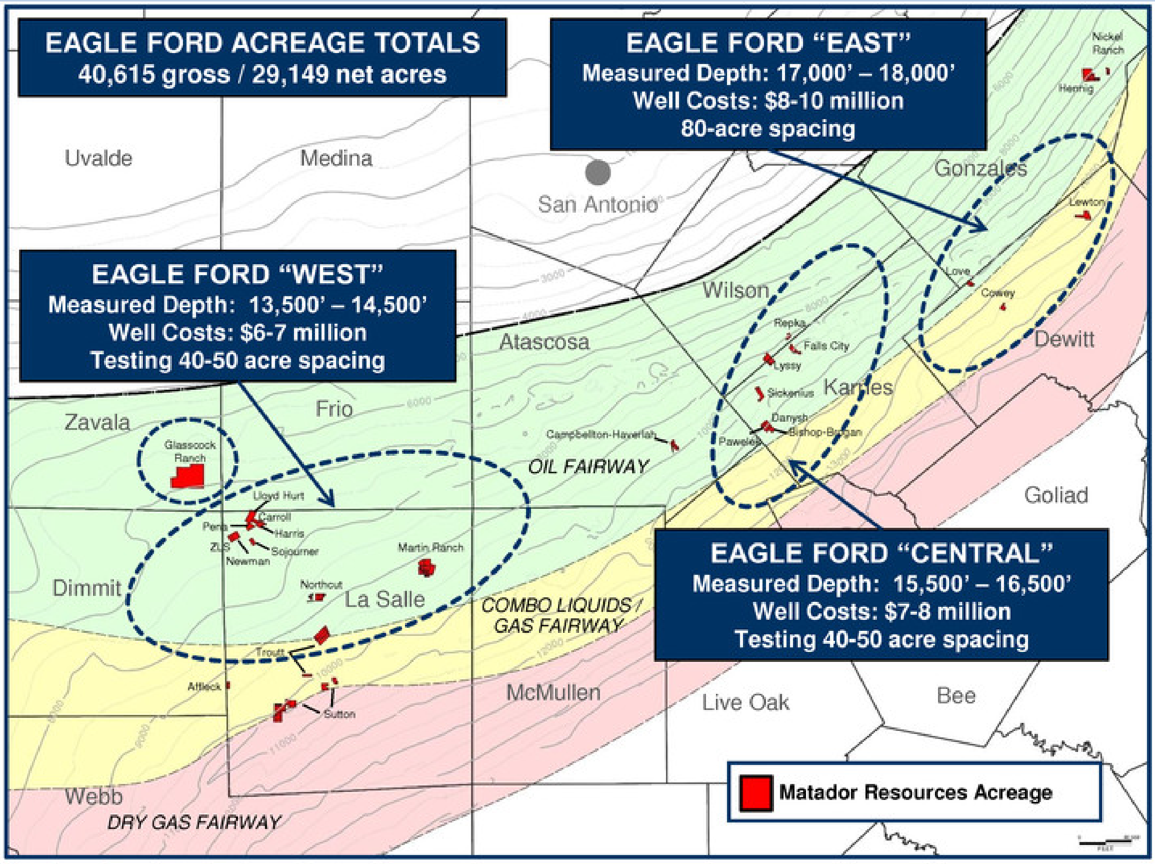
- **94 gross (80.6 net) wells[1] producing from the Eagle Ford**
  - An increase in oil production from ~330 Bbl/d[2] in 2011 to ~7,800 Bbl/d[3]
  - 273 gross (229.3 net) engineered drilling locations identified for potential future drilling[4][5]
- **2014 South Texas Drilling Plan**
  - Continuing a 2-rig program in the Eagle Ford
  - All H2 2014 drilling in Eagle Ford Central and West
  - $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 to 10% of yearly production capacity shut-in during 2014

Operations Summary

Proved Reserves @ 6/30/14	**21.4 million BOE**
% Proved Developed	59%
% Oil	73%
Daily Oil Equivalent Production[3]	**10,994 BOE/d (71% Oil)**
Gross Acres[6]	**40,615 acres**
Net Acres[6]	**29,149 acres**
% HBP[4]	82%
2014E CapEx Budget	**$318 million**
Engineered Drilling Locations[4][5]	**273 gross (229.3 net)**

(1) At July 30, 2014. Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) For the twelve months ended December 31, 2011.
(3) For the three months ended June 30, 2014.
(4) Presented as of December 31, 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) At August 6, 2014.

Eagle Ford Measured Depths and Well Costs



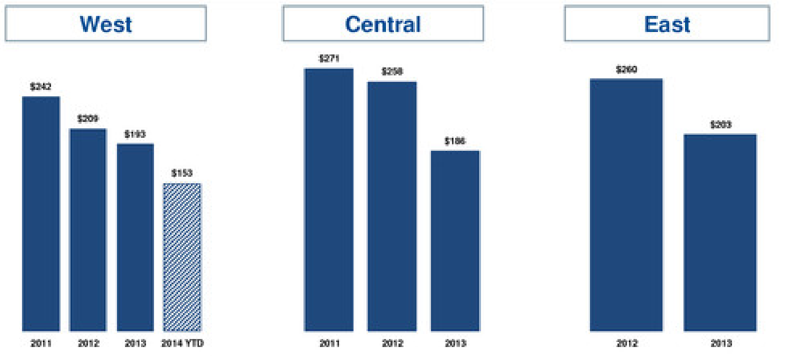
Note: All acreage at August 6, 2014. Some tracts not shown on map.

Operational Improvements (Normalized)

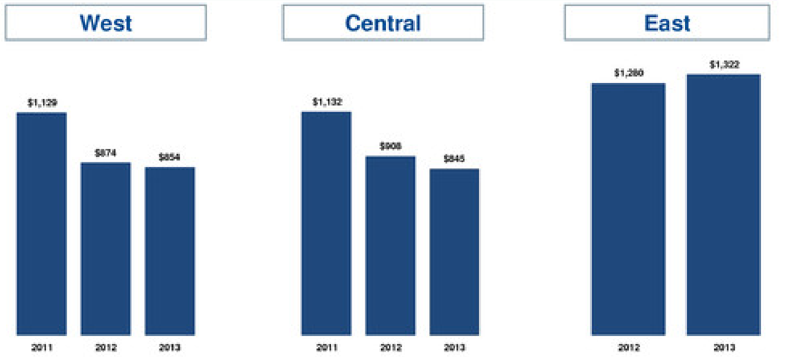
Overview

- Over the past two years, made significant progress and increased knowledge of how to drill, complete and produce Eagle Ford wells
- Experience and operational improvements have led to significant reductions in drilling and completion costs
- In 2013, began drilling from batch drilled pads using a drilling rig equipped with a "walking" package
  - Realized cost savings of approx. $325,000 per well on initial wells drilled using this rig
  - Expect the use of batch drilling and the "walking" rig will lead to total cost savings of approx. $400,000 per well or more going forward

Eagle Ford Drilling Costs / Drilled Foot(1)



Eagle Ford Completion Costs / Completed Foot(2)

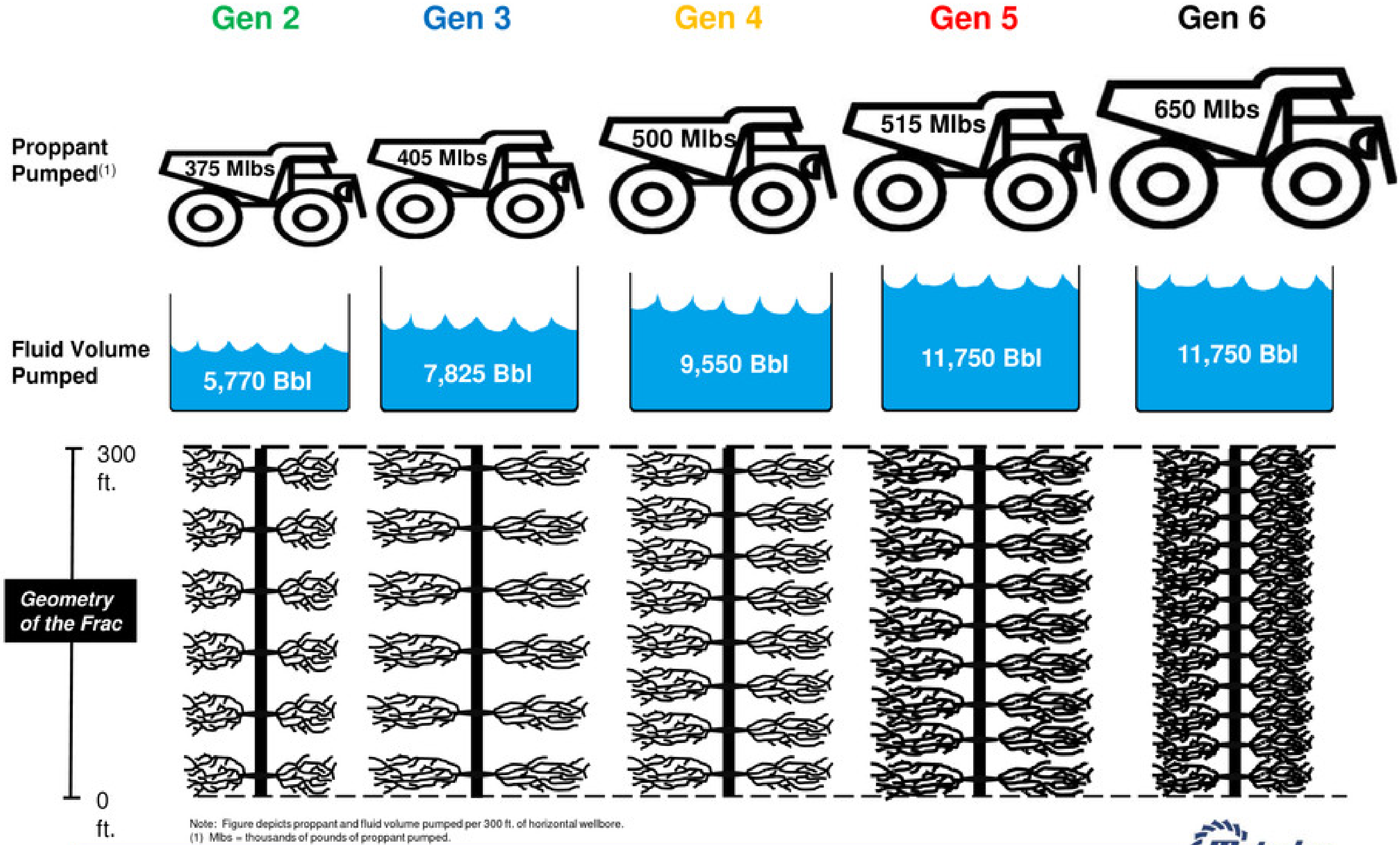


Note: "2014 YTD" – As of March 1, 2014. Year classification is based on spud date.
(1) Drilled foot is the measured depth from surface to total depth. Excludes any/all wells drilled with a pilot hole, any/all wells drilled outside the West, Central and East and any/all wells drilled with three strings of casing.
(2) Completed foot is the completed length of the lateral. Excludes any/all wells drilled with a pilot hole. Excludes any/all wells in the West and Central where premium proppant was used.

Technology Transfer and Application from Eagle Ford to Permian

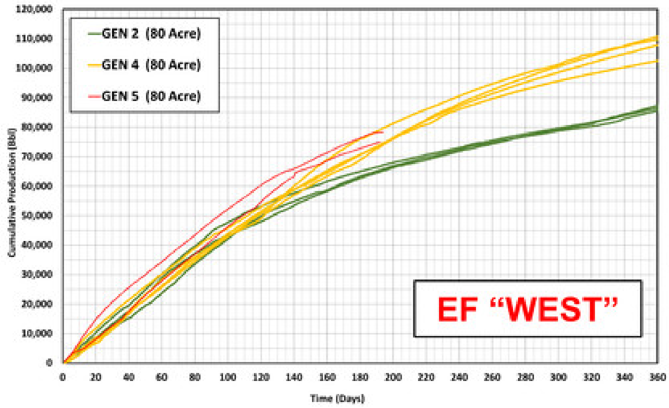
- **New rigs arriving in 2015 have even more advanced technology than current Eagle Ford rigs**
  - Walking packages, hydraulic catwalks, reconfiguration of rig layouts, high pressure circulating systems, etc.
  - New rig features designed to match drilling plans – i.e. reconfiguration of rig layout allows for simultaneous operations (hydraulic fracturing and drilling operations simultaneously, on same location)
- **Geosteering capabilities and techniques allowing us to stay within defined target zones**
  - Staying in target window maximizes well productivity and optimizes stimulation consistency
  - Target windows can be relatively thin within formations – i.e. the "X-Sand" target within the Wolfcamp "A" formation in Loving County, TX
- **Continuous improvement in frac design**
  - Bigger fracs making better, more economic wells, as compared to earlier offset completions
  - In particular, Wolfcamp has similar characteristics to Eagle Ford → using larger stimulation designs from the beginning
  - Frac designs will continue to evolve and improve
- **Production methods enhancing EURs, flattening declines and accelerating production**
  - Flowing wells on restricted chokes has led to better bottomhole pressure management, keeping wells flowing longer and (likely) increasing EUR's
  - Applying gas lift assist at optimal time is flattening decline rates and accelerating early production of hydrocarbons
    - *Dorothy White #1H, Ranger 33 State Com #1H and Rustler Breaks 12-24-27 #1H are some of the best wells in their respective areas*

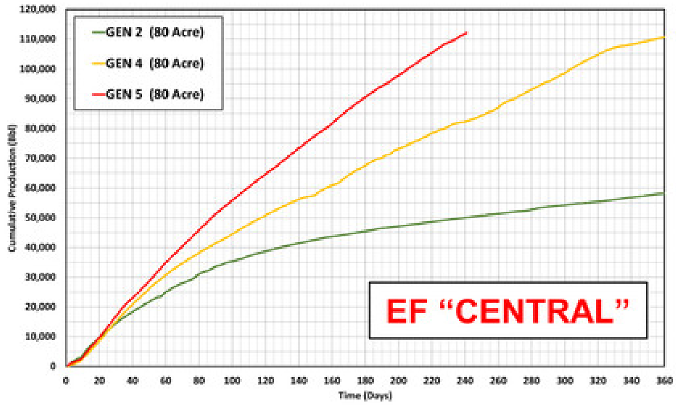
Evolution of Matador Eagle Ford Frac Design

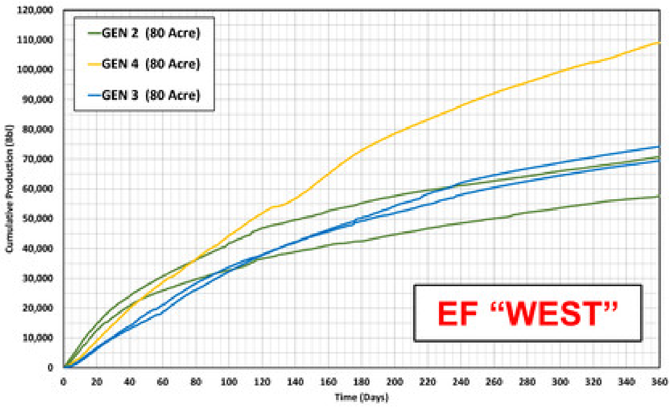


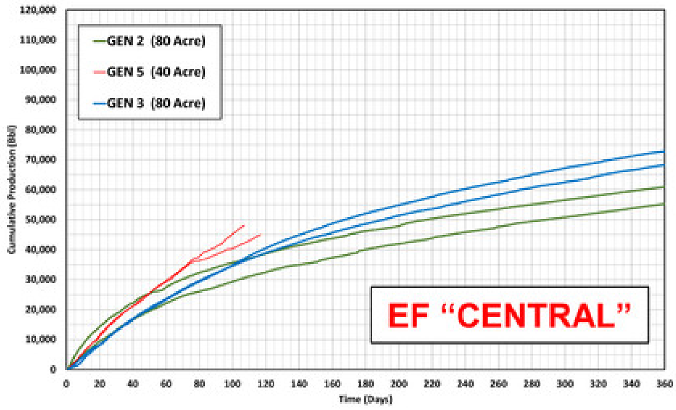
Note: Figure depicts proppant and fluid volume pumped per 300 ft. of horizontal wellbore.
(1) Mlbs = thousands of pounds of proppant pumped.

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

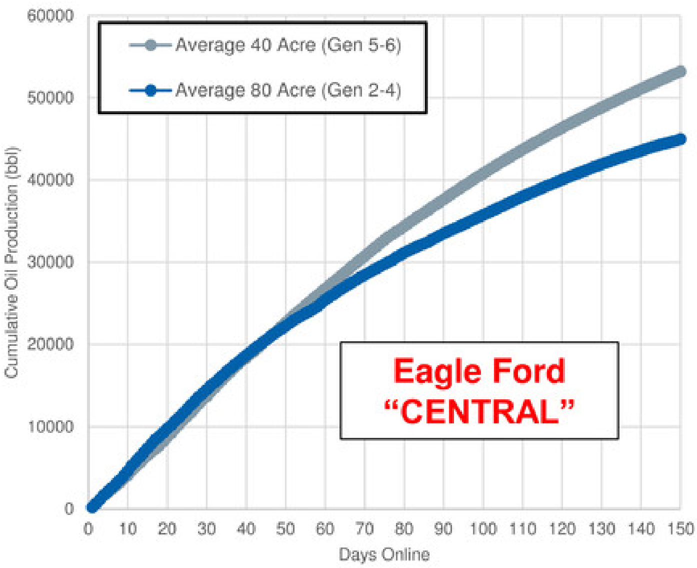


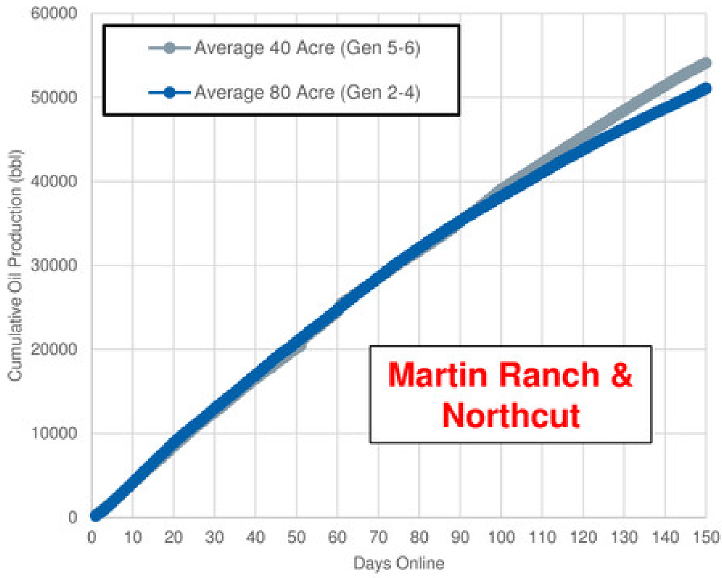






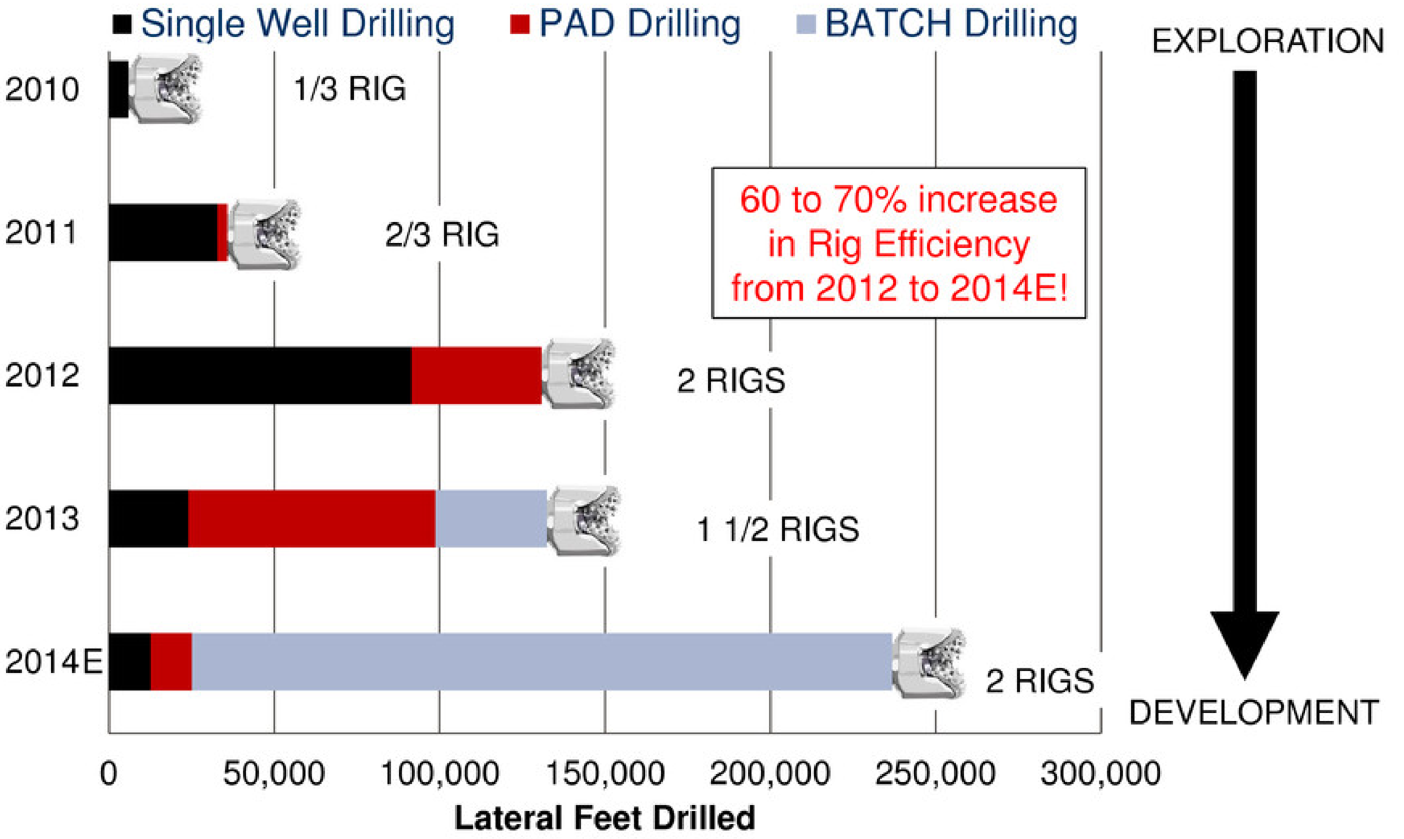
Downspacing Comparison (all wells normalized to 5,000' horizontal)





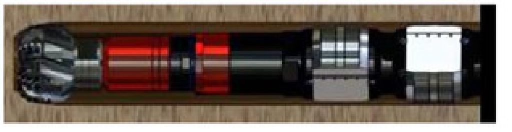
Note: Production is time and lateral length normalized to 5,000' perforated lateral length. The average 40-acre cumulative production is a combination of actual data and a smoothing trend representing possible future average results.

Improvement in Drilling Efficiency – Moving Towards Batch Drilling



Compressing Drill Times

- Improving rig fleet
  - High tech, fast moving, faster drilling, walking style rigs
- Improving Rate of Penetration (ROP)
  - Bit selection and development
  - Bottom Hole Assembly (BHA) selection
  - Rotary steerable systems
    - Vertical seeking
    - Directional drilling
- Minimize directional work related to surface locations
- Utilization of Managed Pressure Drilling
- Development Phase
  - Pre-setting surface casing
  - Simultaneous operations

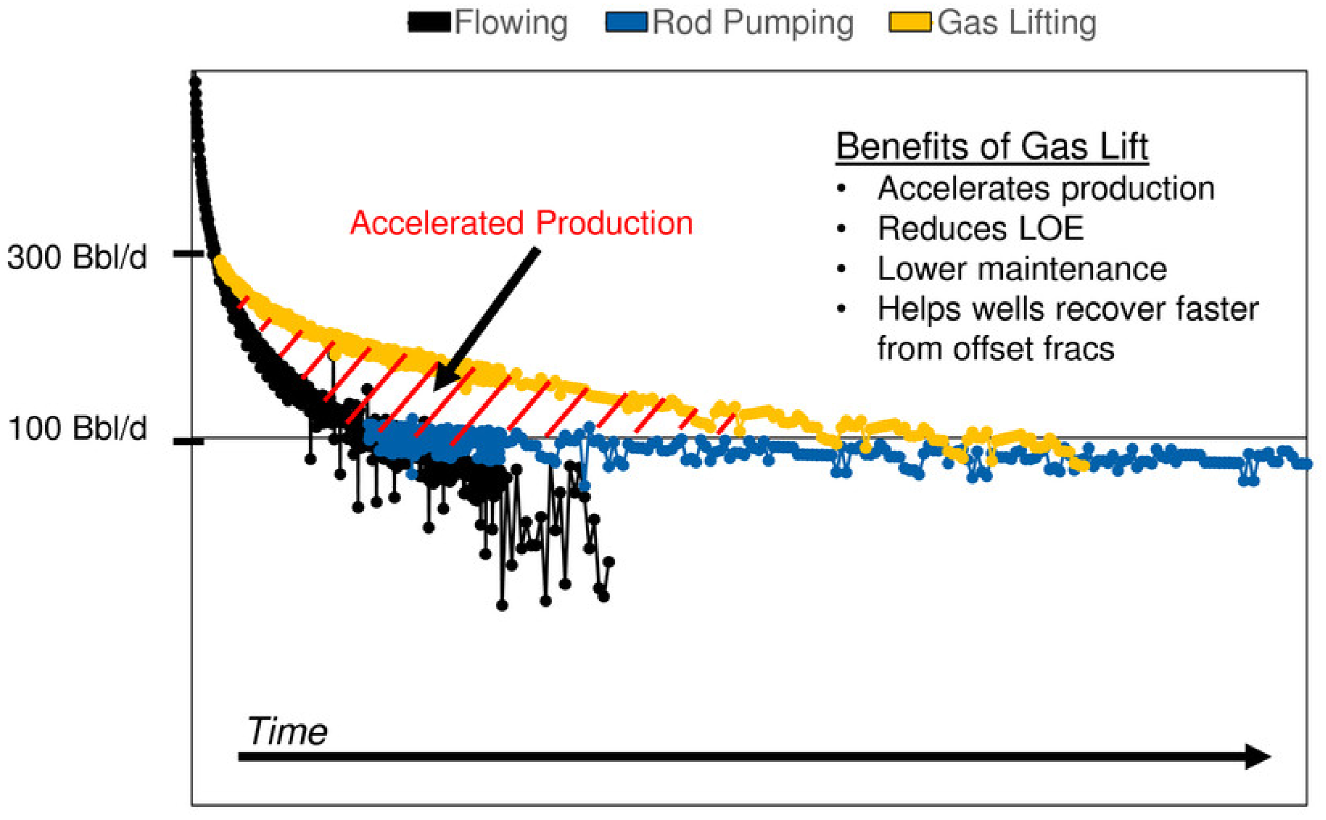


Progression of Drilling Rig Technology from 2010 to 2014

Advancing Rig Technology

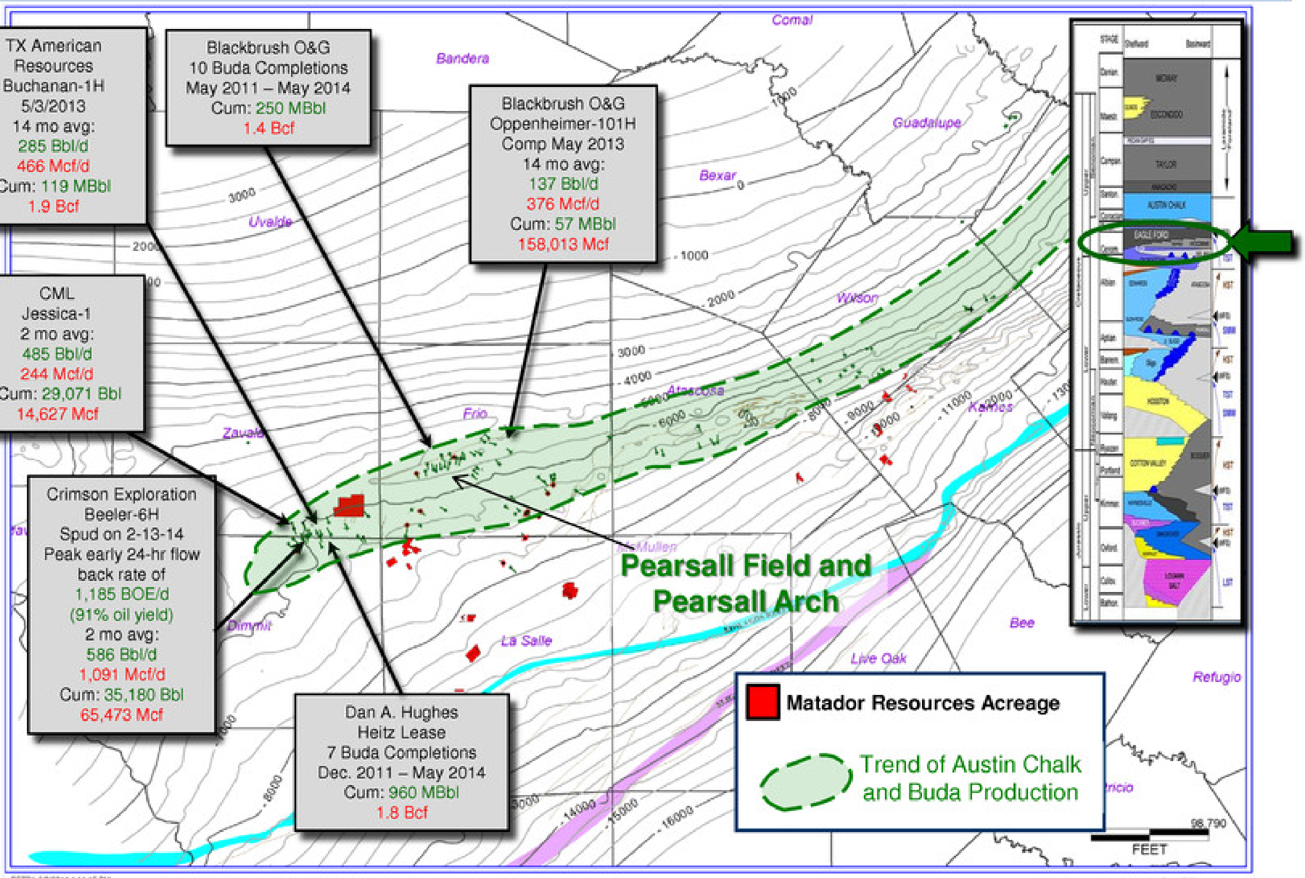
RIG #	ELECTRIC	1600 HP PUMPS	INTEGRATED TOP DRIVE	APEX RIG (FAST MOVE)	HYDRAULIC CATWALK BOP HANDLER THREE SHAKERS	AC DRIVE SYSTEM TECHNOLOGY	ROUND BOTTOM MUD PITS	WALKING PACKAGE
521								
135	✓	✓						
534	✓	✓						
203	✓	✓	✓	✓	✓			
250	✓	✓	✓	✓	✓	✓	✓	
239	✓	✓	✓	✓	✓	✓	✓	✓
279	✓	✓	✓	✓	✓	✓	✓	✓

Artificial Lift Reducing Natural Production Declines



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

Buda Wells Activity Since January 1, 2010 – Potential Test



Note: Well information from public sources available as of August 2014.



Permian Basin

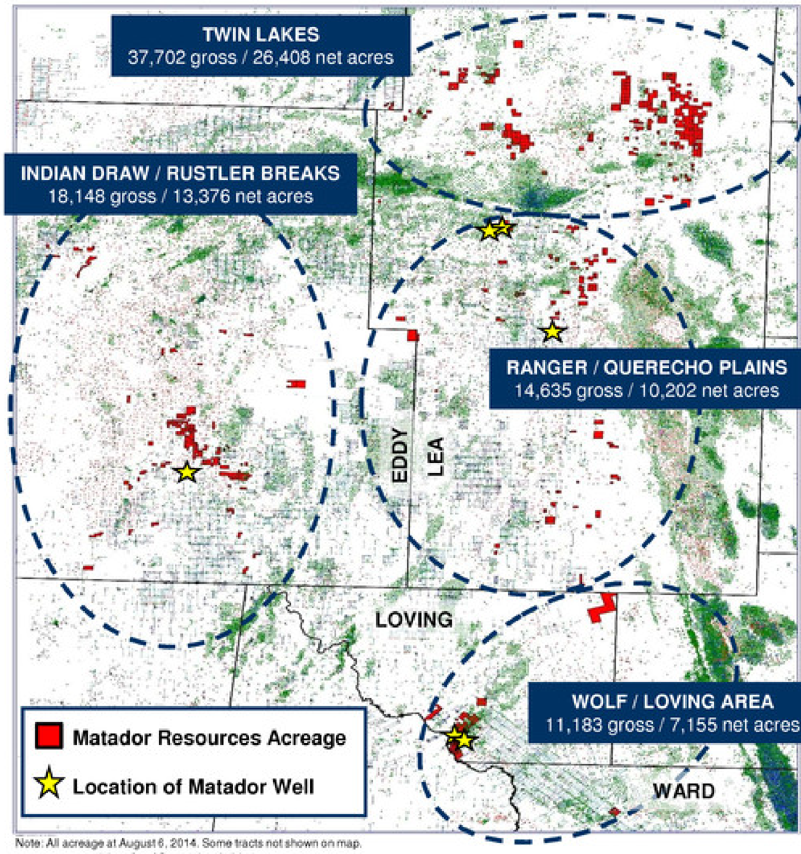
Southeast New Mexico and West Texas

2014 Permian Basin Plan Details

- **2014 projected capital expenditures of ~\$190 million or ~33% of total**
  - Continue 2-rig program working in Lea and Eddy Counties, NM and Loving County, TX
  - Drill and/or complete or participate in 14 gross (12.3 net) wells; several Wolf area wells drilled with second Permian rig on production in Q4 2014 or early 2015
  - Completion targets include various Bone Spring and Wolfcamp intervals across acreage position
    - *Initial and recently completed wells exceeding expectations*
  - \$80 million allocated to land, seismic and facilities
- **Key objectives of Permian Basin plan**
  - Further evaluate our acreage position and completion targets to define an expanded development program for 2015 and beyond
    - Planning to add at least one additional rig at the beginning of 2015
  - Validate and convert acreage position to held by production ("HBP")
  - 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
    - *Added 23,200 gross (17,200 net) acres[1] in Permian Basin since January 1, 2014*
    - *Doubled Loving County acreage position to 11,200 gross (7,200 net) acres[1]*

(1) At August 6, 2014.

Permian Basin



Permian Basin Total	
Gross Acres	94,045 acres
Net Acres	61,951 acres

Progress-to-date(1)

- Successful performance of first 3 initial horizontal wells
  - **Ranger 33**: Almost 140,000 BOE in 10 months; producing 350 to 400 Bbl/d of oil
  - **Dorothy White**: Almost 200,000 BOE in 8 months; producing about 500 Bbl/d of oil and 1.4 MMcf/d of natural gas
  - **Rustler Breaks**: 86,000 BOE in 4 months; producing 200 Bbl/d of oil and 1.7 MMcf/d of natural gas

Recent Activity

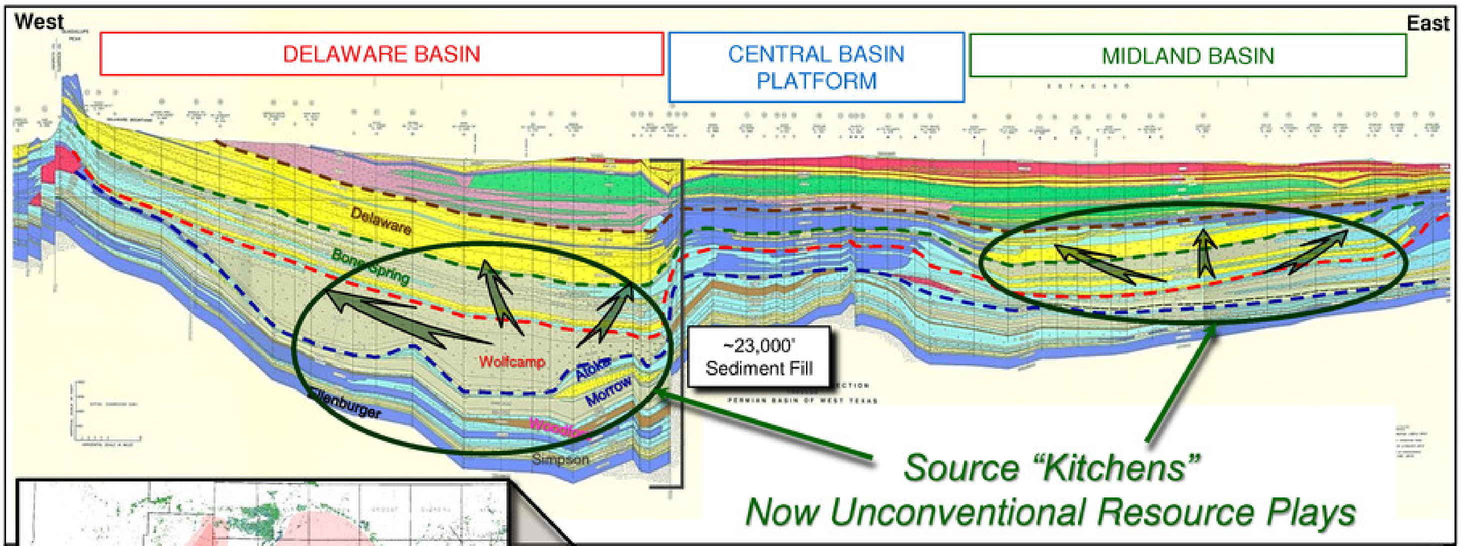
- **Norton Schaub #1H**(1) (Wolfcamp "A" test)
  - Mid-July 2014 test – Flowed 1,026 BOE/d, including 706 Bbl/d of oil and 1,922 Mcf/d of natural gas (69% oil)
- **Pickard 20-18-34 #1H**(1) (Second Bone Spring sand test)
  - Late July 2014 test – Flowed 592 BOE/d, including 535 Bbl/d of oil and 340 Mcf/d of natural gas (90% oil)
- **Arno #1H** (Wolfcamp "A" test), **Pickard 20-18-34 #2H** (Wolfcamp "D" test) and **Johnson 44-02S-B53 #204H** (Wolfcamp "A" test)
  - Wells in flowback period of their completion operations(2)

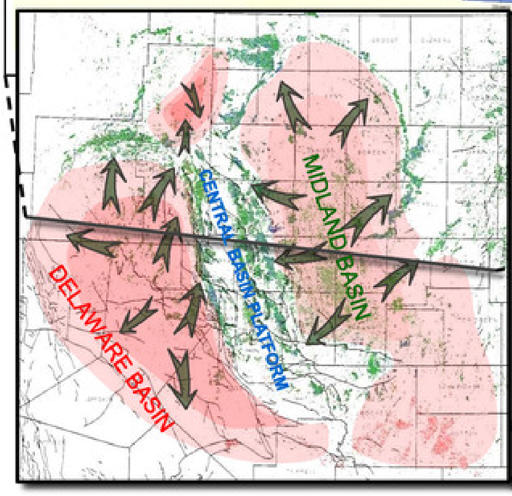
Current Activity

- Continue current 2-rig drilling program in Lea and Eddy Counties, NM and Loving County, TX
- Added ~17,200 net acres YTD 2014(3)

Note: All acreage at August 6, 2014. Some tracts not shown on map.
(1) As of September 8, 2014.
(2) As of September 26, 2014.
(3) At August 6, 2014

Permian Basin Petroleum Systems and the Wolfcamp "Kitchens"

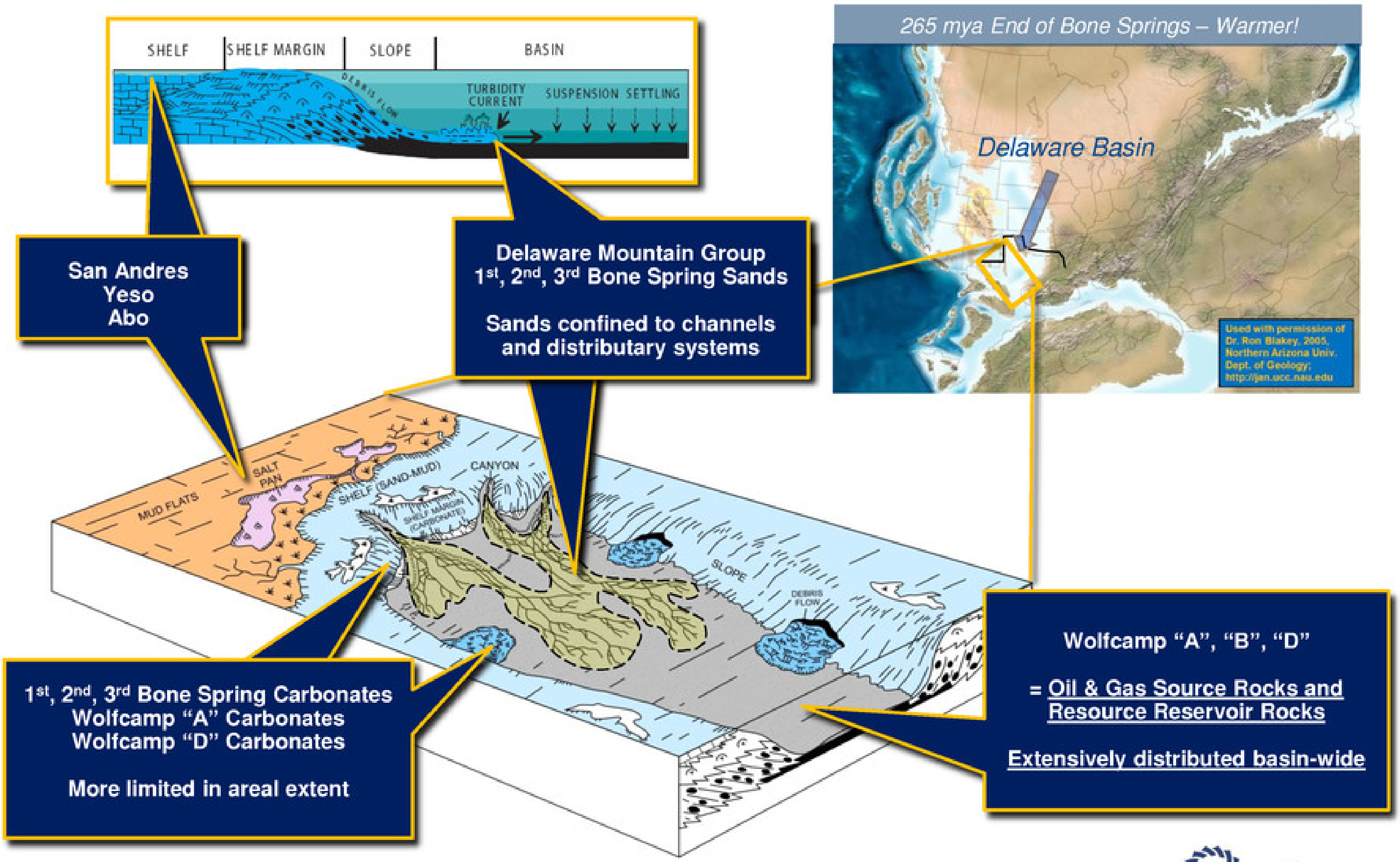




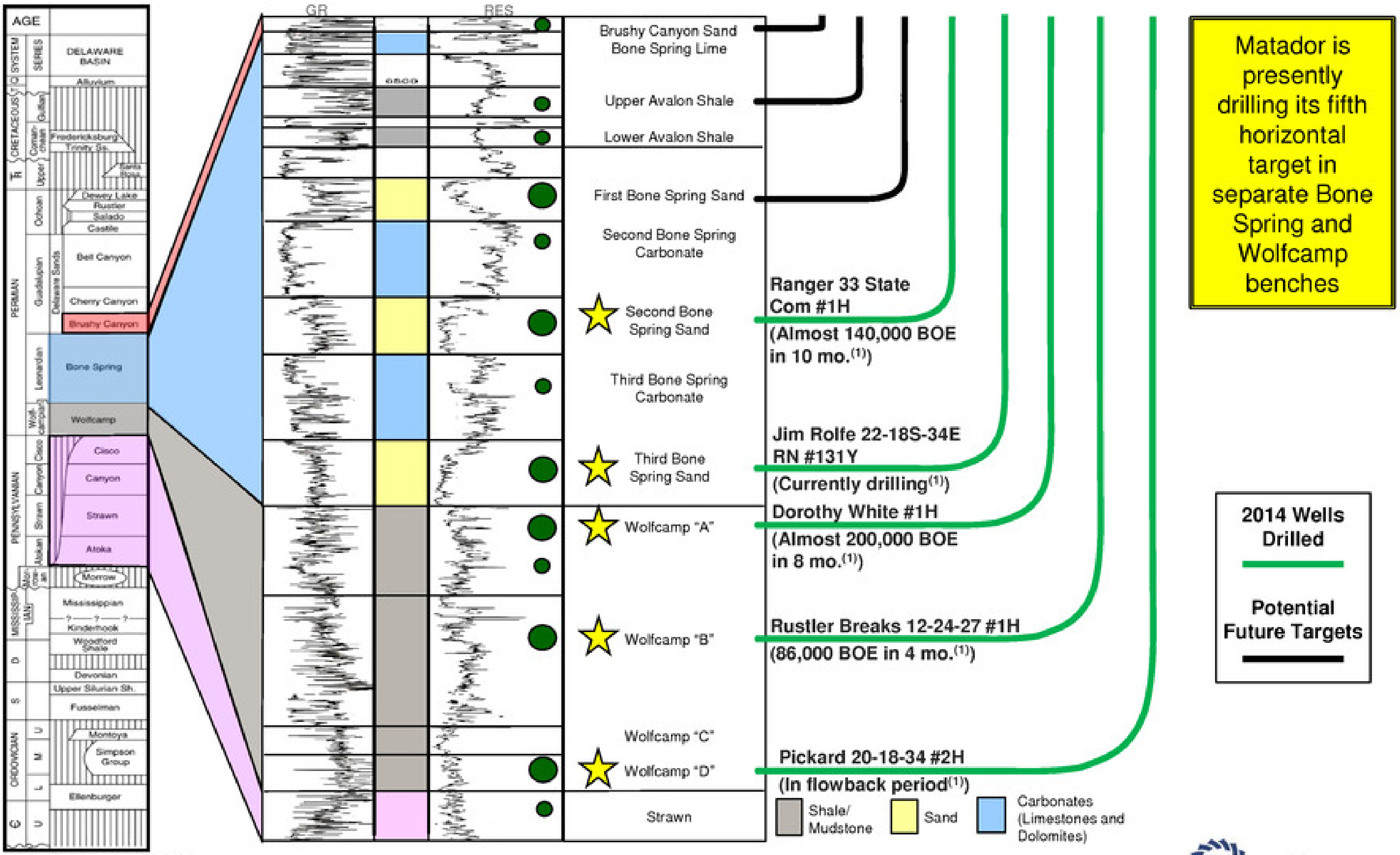
- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 conventional reservoirs with cumulative production >1.0 million Bbl each
- Cumulative production from 1,500 conventional reservoirs, as of year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

(1) Dutton et al, AAPG 2005

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

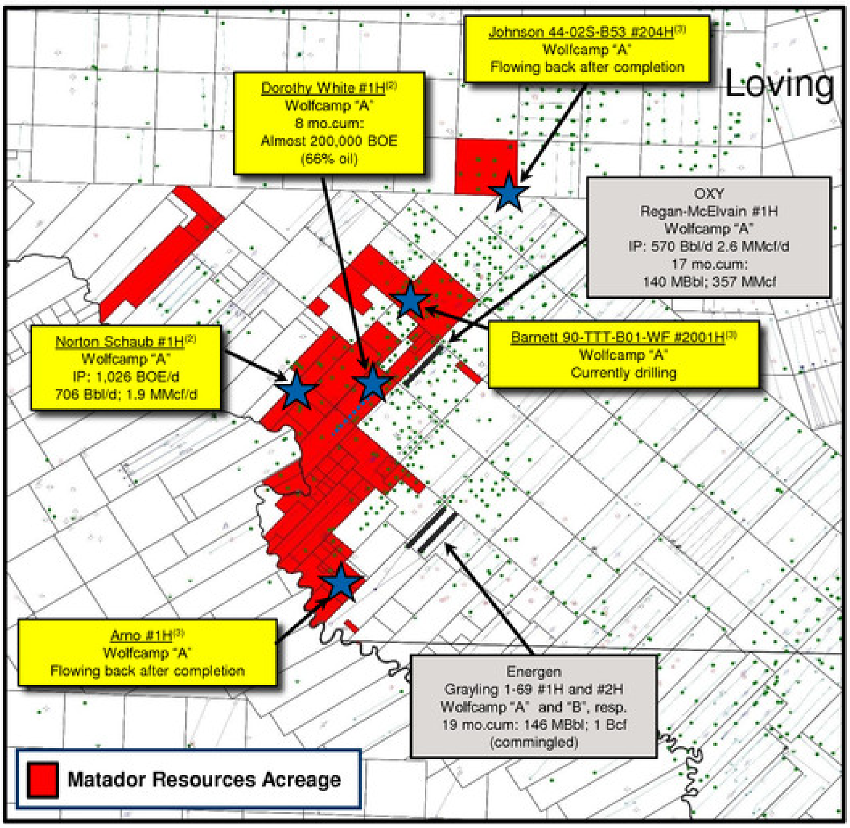


Targeting Multiple Benches in Permian Appraisal Program



(1) As of September 8, 2014.

Wolf / Loving Prospect Area

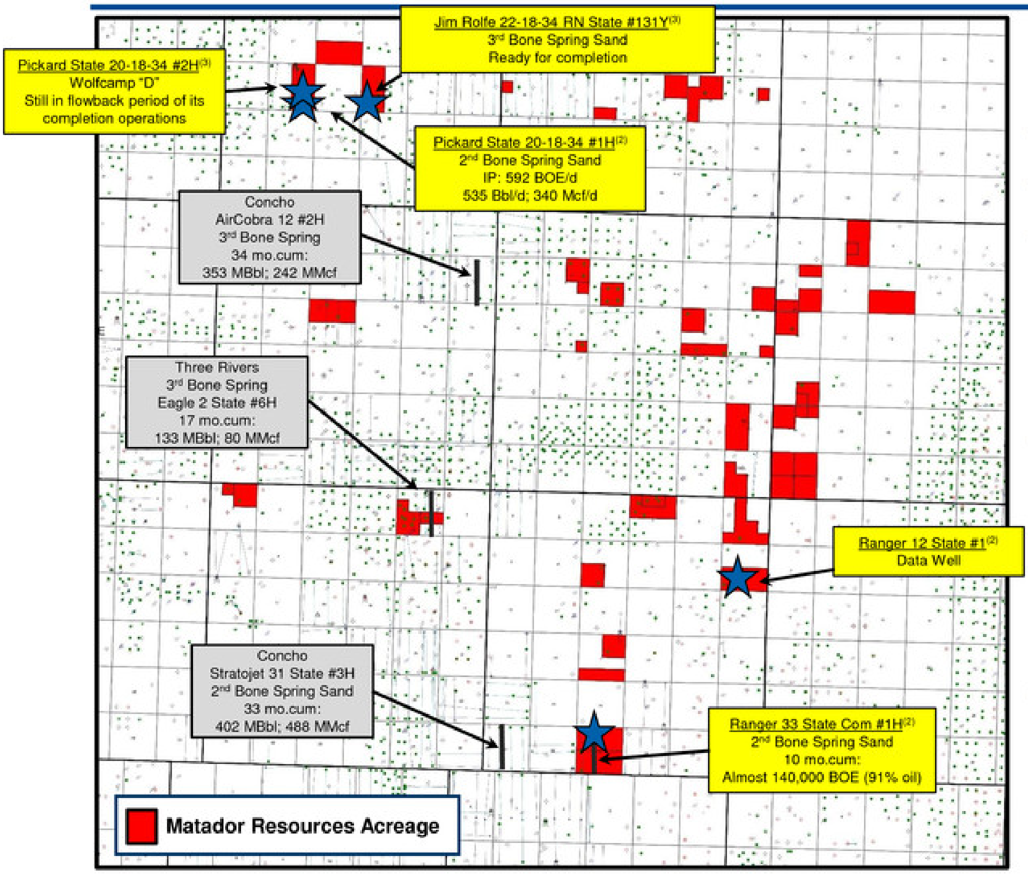


Location of Matador wells

- **11,183 gross (7,155 net) acres**
- **50 gross (35.4 net) locations(1)**
- **Primary Targets**
  - Wolfcamp "A"
  - 3rd Bone Spring
  - Avalon
- **Other Potential Targets**
  - 1st Bone Spring
  - 2nd Bone Spring
  - Wolfcamp "B"
- **6 wells planned for 2014**

Note: All Matador acreage information as of August 6, 2014. Some tracts not shown on map. Non-Matador well information from public sources available as of August 2014.
(1) Presented as of December 31, 2013.
(2) As of September 8, 2014.
(3) As of September 26, 2014.

Ranger / Querecho Plains Prospect Area

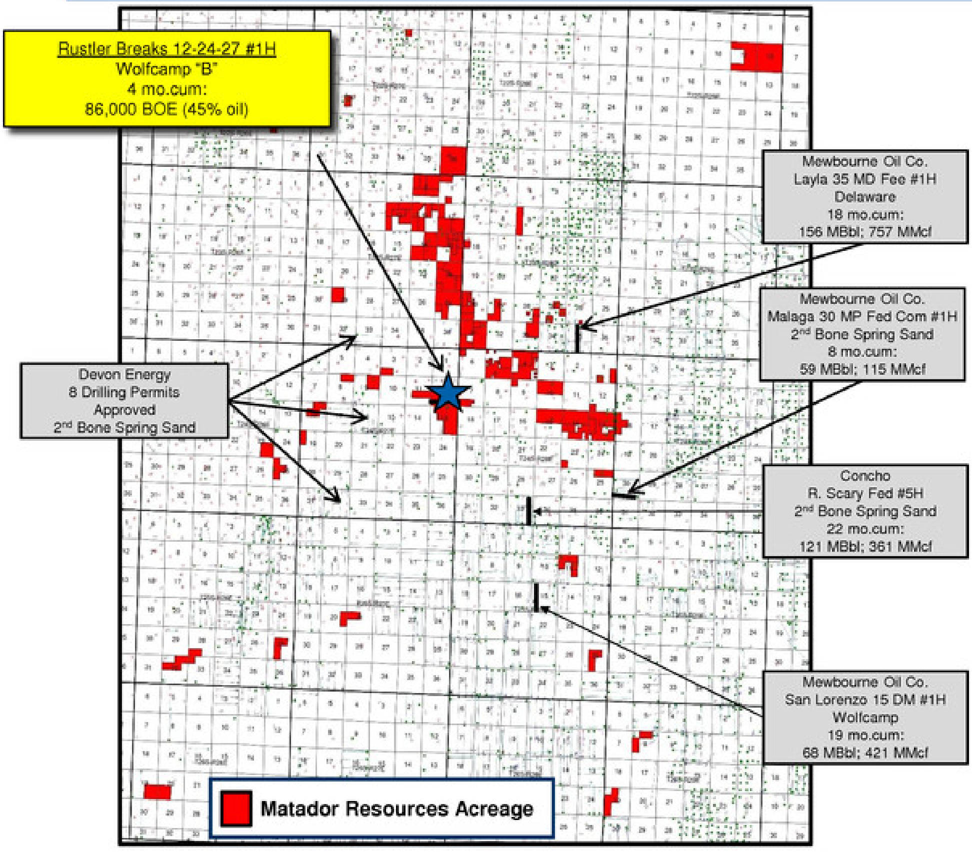


- **14,635 gross (10,202 net) acres**
- **83 gross (59.6 net) locations(1)**
- **Primary Targets**
  - 2nd Bone Spring
  - 3rd Bone Spring
  - Wolfcamp "A", "B" and "D"
- **Other Potential Targets**
  - Delaware
  - Avalon
  - 1st Bone Spring
  - Bone Spring Carbonates
- **3 wells planned for 2014**

Note: All Matador acreage information as of August 6, 2014. Non-Matador well information from public sources available as of August 2014.

(1) Presented as of December 31, 2013.
(2) As of September 8, 2014.
(3) As of September 26, 2014.

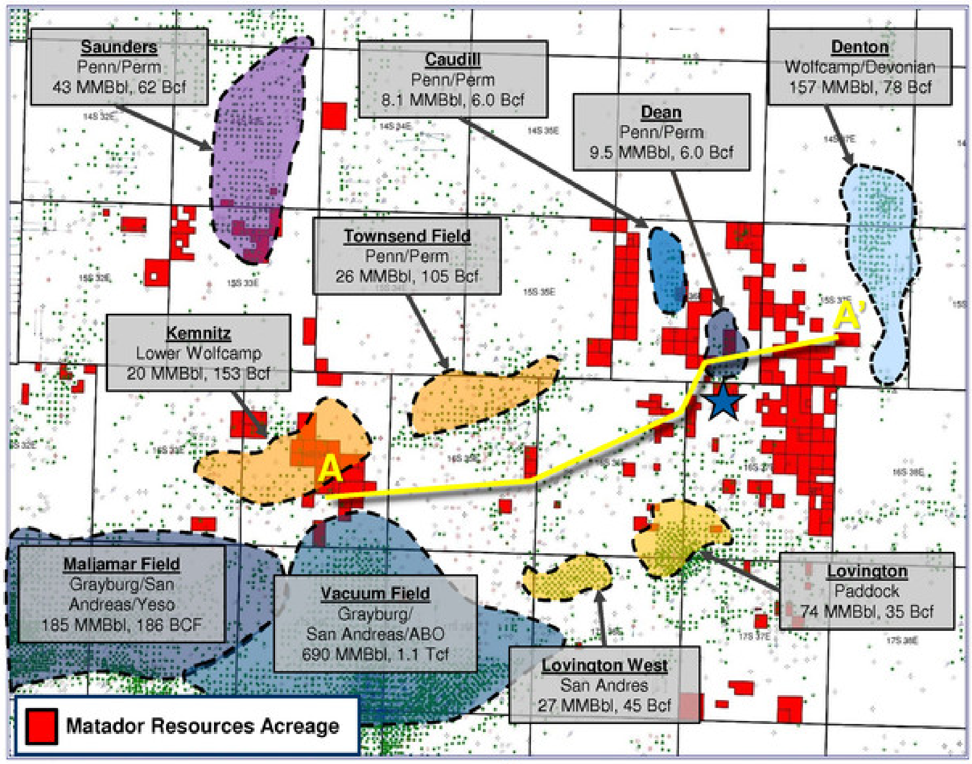
Indian Draw / Rustler Breaks Prospect Area



- **18,148 gross (13,376 net) acres**
- **108 gross (82.8 net) locations(1)**
- **Primary Targets**
  - Wolfcamp "B"
  - 2nd Bone Spring
  - Delaware
- **Other Potential Targets**
  - Avalon
  - 1st Bone Spring
  - 3rd Bone Spring
  - Wolfcamp "A"
- **4 wells planned for 2014**

Note: All Matador acreage information as of August 6, 2014. All Matador well information as of September 8, 2014. Other well information from public sources available as of August 2014.
(1) Presented as of December 31, 2013.

Twin Lakes Prospect Area



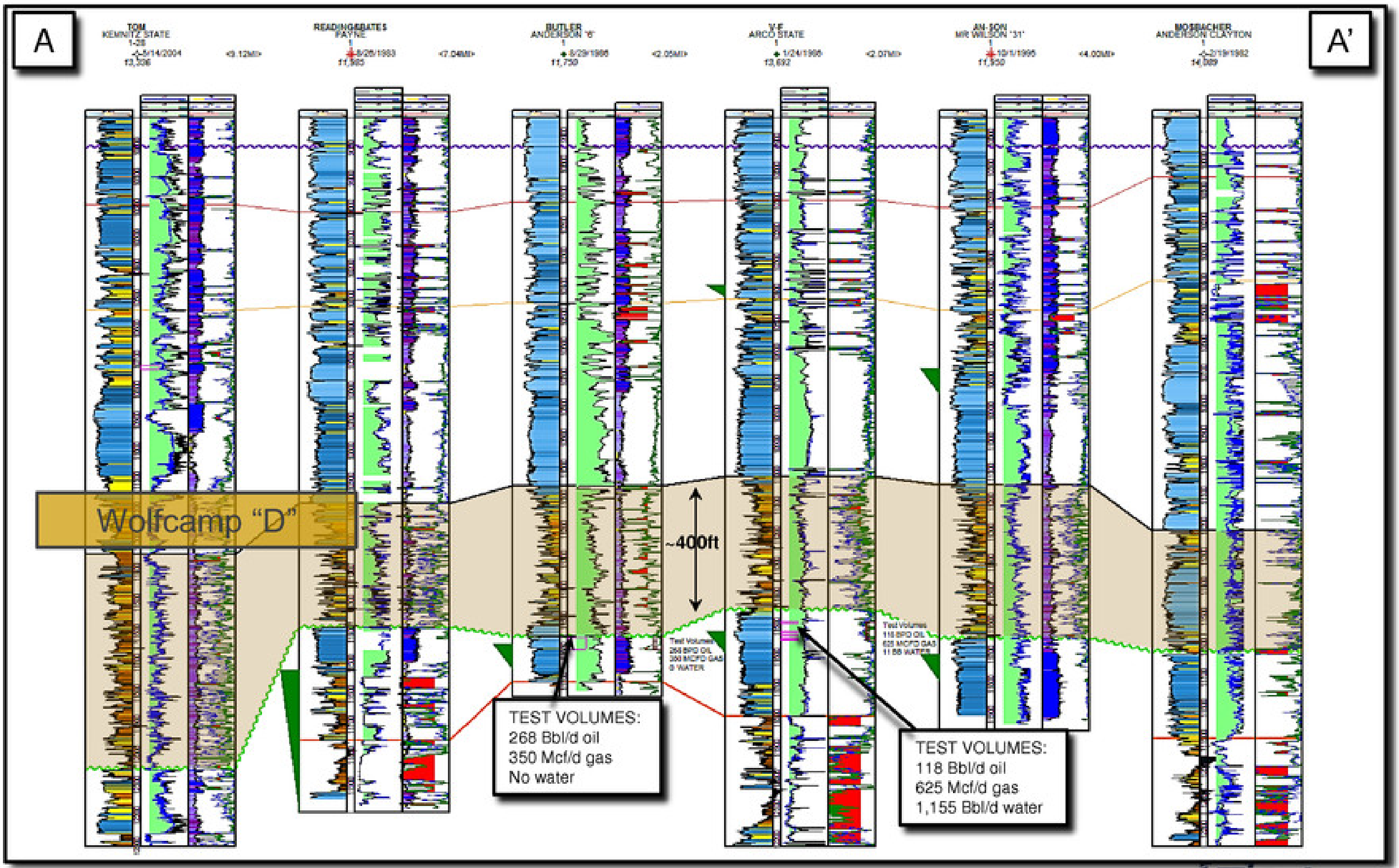
Location of Matador well

Historical Twin Lakes Area Production
1.3 Billion Barrels Cumulative Oil
2.2 Trillion Cubic Feet Cumulative Natural Gas

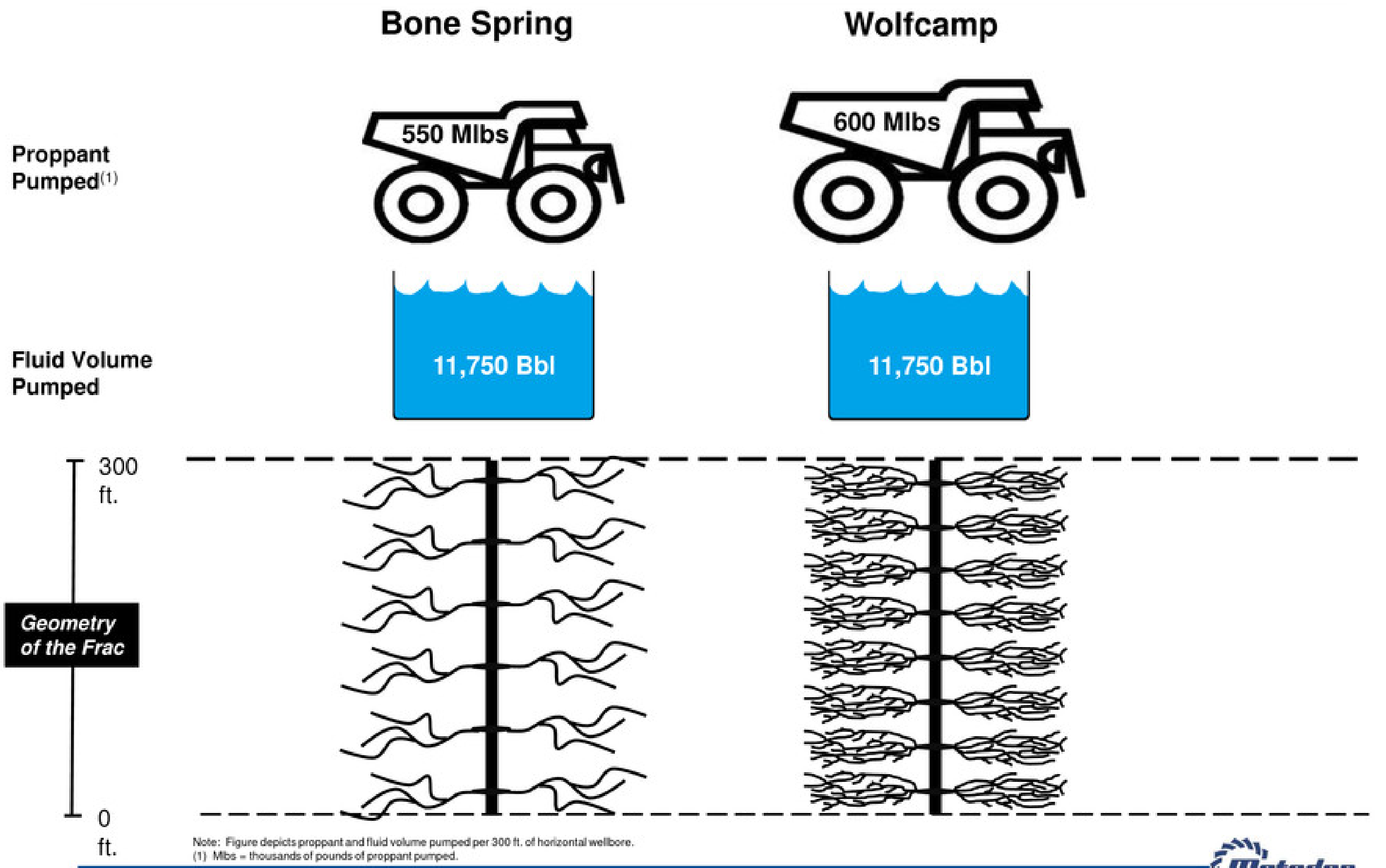
- **37,702 gross (26,408 net) acres**
- **Primary Targets**
  - Wolfcamp "D"
  - Strawn
  - Abo
- **Other Potential Targets**
  - Cisco/Canyon
  - Devonian
  - Glorieta/San Andres
- **1 vertical well planned for late 2014 or early 2015**
  - Vertical pilot hole to collect whole core and log data

Note: All acreage at August 6, 2014. Well information from public sources available as of August 2014.

Twin Lakes Area Cross Section



Matador Permian Basin – First Generation Frac Designs



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



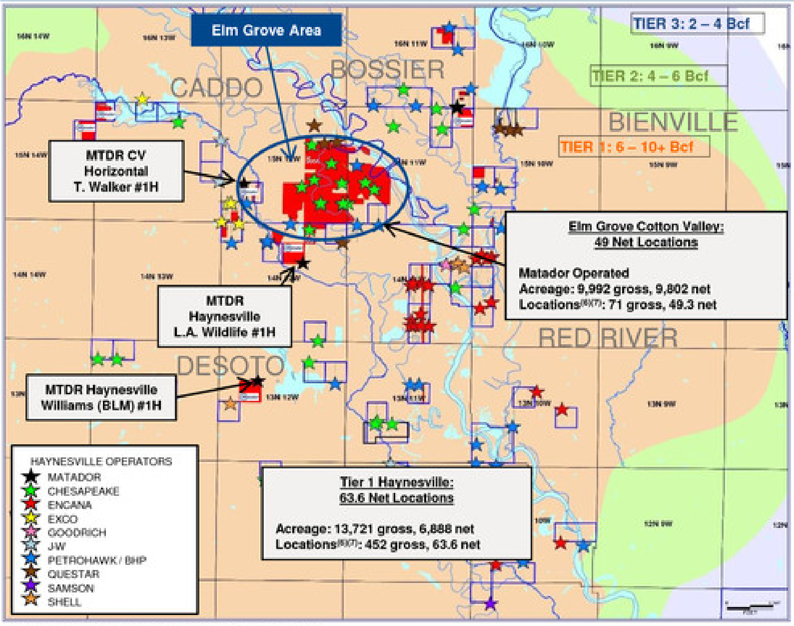
Haynesville Shale

2014 Tier 1 Haynesville Shale Plan

- **2014 projected capital expenditures of ~$62 million or about 11% of total**
  - Estimated participation in up to 56 gross (7.8 net) non-operated wells
  - Chesapeake may drill up to 30 gross (6.3 net to Matador) wells at Elm Grove in 2014; estimated CapEx of $50 million; 4 rigs currently running on Elm Grove properties(1)
  - 2014 capital plan includes no Matador operated Haynesville wells
- **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 improve sufficiently, but no plans to do so at present time**
- **Completion of natural gas gathering agreement in December 2013 for a portion of our Haynesville natural gas should reduce transportation costs by an average of approximately $0.70 or more per MMBtu in 2014 and increase net gas realizations by the same amount**
- **Haynesville/Cotton Valley continue to represent large "gas bank" providing significant and increasing value as natural gas prices improve above $4.00/Mcf**
  - Highly competitive well economics for Tier 1 Haynesville at $4.00 to $4.50/Mcf and above, with estimated RORs of 60% to 100% in Elm Grove area

(1) At August 6, 2014.

Significant Option Value on Natural Gas



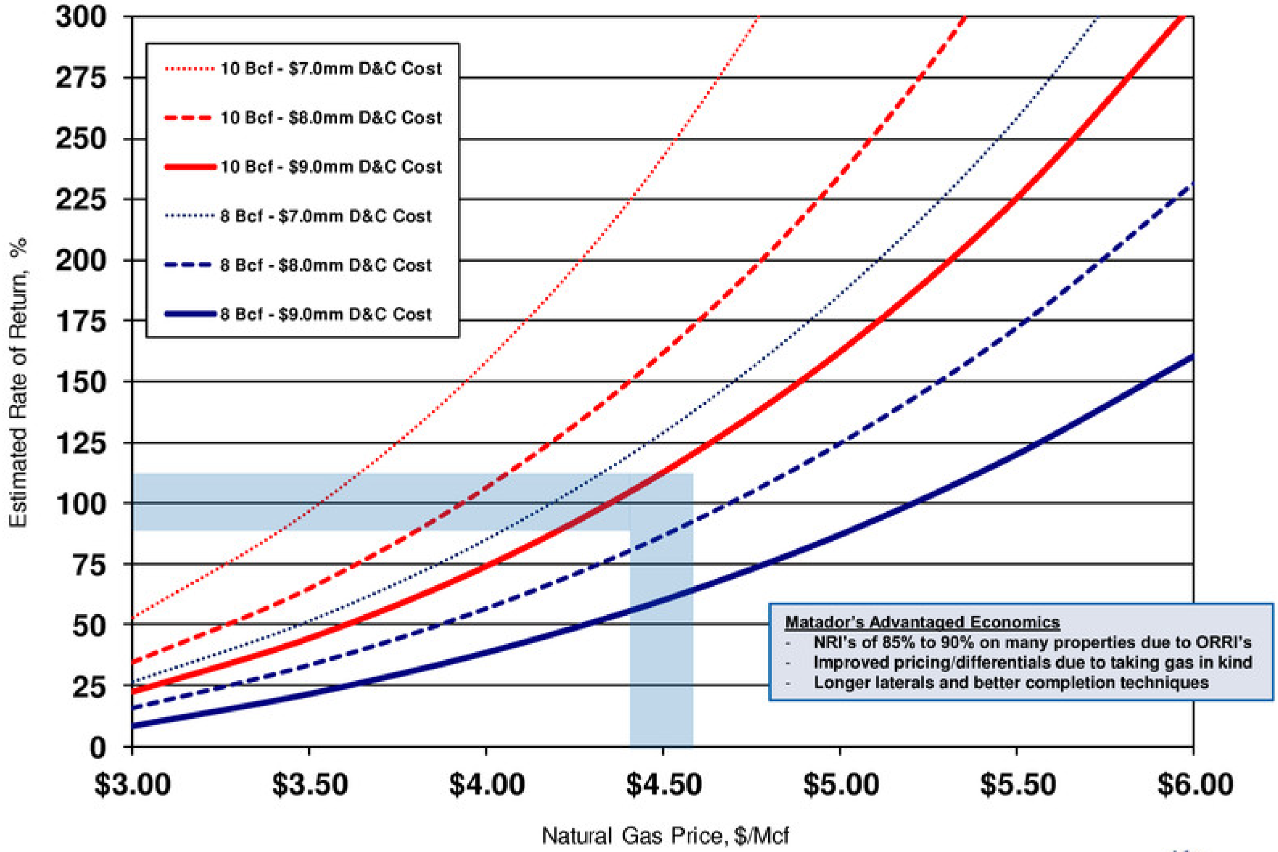
Note: All acreage at August 6, 2014. Matador acreage shown in red.

NW Louisiana / East Texas[1]	
Proved Reserves[2]	187.0 Bcfe
Daily Production[3]	3,069 BOE/d (>99% natural gas)
Net Acres[4]	25,028 acres
Net Producing Wells[5]	77.7
Drilling Locations[6][7]	163.8 net wells
% HBP[6][8]	97%

- **Significant acreage position in the Haynesville**
  - Added 3 sections in 2014 to provide more operated drilling opportunities
  - Also prospective for the Cotton Valley, Travis Peak / Hosston and other shallow formations
- **Highly competitive well economics on Tier 1 Haynesville wells at \$4.00 to \$4.50/Mcf and above**
  - Estimated ROR ranges from 60% to 100% in Elm Grove area
  - Elm Grove natural gas gathering contract should reduce costs an average of approximately \$0.70 or more per MMBtu – improved economics
- **Non-operated drilling activity increasing**
  - CHK may drill up to 30 wells at Elm Grove in 2014; 21 wells already proposed or in progress[4]
  - Other operators continuing activity
  - Expect up to 7.8 net wells in 2014; production impact in late 3rd and 4th quarters of 2014
- **Cotton Valley horizontal EURs ~6 Bcf**

(1) Includes both Haynesville and Cotton Valley acreage. Includes one well producing from the Frio formation in Orange County, Texas.
(2) At June 30, 2014.
(3) For the three months ended June 30, 2014.
(4) At August 6, 2014.
(5) Presented as of June 30, 2014.
(6) Presented as of December 31, 2013
(7) 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.
(8) Acreage held by production or fee mineral interests owned by Matador.

Elm Grove Tier 1 Haynesville – Chesapeake Operated



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. Natural gas price differential = ($0.55)/Mcf. D&C cost = drilling and completion cost.



2014 Capital Investment Plan

Summary and 2014 Guidance[1]

- **Continue 4-rig program full-time in H2 2014 – 2 rigs in the Eagle Ford and 2 rigs in the Permian**
- **Eagle Ford development expected 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**

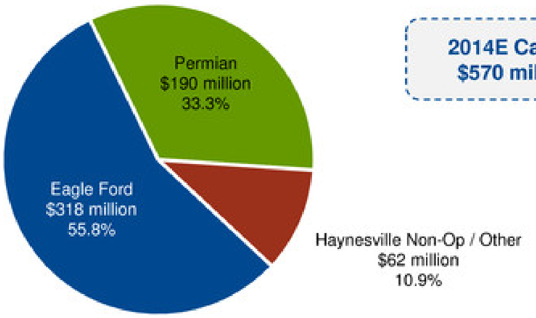
	2012 Actual	*2013 Actual*	*2014 Guidance*
Capital Spending	$335 million	$374 million	$570 million
Total Oil Production	1.214 million Bbl	2.133 million Bbl	2.8 to 3.1 million Bbl[2]
Total Natural Gas Production	12.5 Bcf	12.9 Bcf	16.0 to 17.5 Bcf
Oil and Natural Gas Revenues	$156.0 million	$269.0 million	$380 to $400 million[3]
Adjusted EBITDA[4]	$115.9 million	$191.8 million	$270 to $290 million[3]

(1) As reaffirmed on August 6, 2014.
(2) The Company guided investors to the top end of its oil production guidance range.
(3) Estimated 2014 oil and natural gas revenues and Adjusted EBITDA based on production guidance range. Estimated average realized prices for oil and natural gas used in these estimates were $95.00/Bbl and $5.00/Mcf, respectively, for the period July 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.

2014 Capital Investment Plan Summary

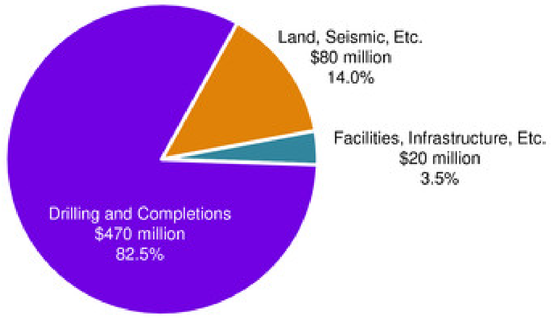
- Continue 4-rig program full time in H2 2014: 2 rigs in the Eagle Ford and 2 rigs in the Permian
- 2014E capital expenditures of $570 million
- Eagle Ford development expected to be the major driver of our growth in 2014 with growing Permian contribution
- Permian drilling program designed to further evaluate our acreage position and define an expanded development plan for 2015 and beyond
- Haynesville development assumes increased participation in non-operated wells

2014E CapEx by Region



2014E CapEx: $570 million

2014E CapEx by Expense Type



Funding for 2014 Capital Investment Plan

- **Anticipate funding 2014 capital expenditures through proceeds from May 2014 equity offering, operating cash flows and borrowings under revolving credit facility**
  - 0.9 million barrels of oil hedged for remainder of 2014, protecting cash flows below ~$88/Bbl oil price
  - 3.3 Bcf of natural gas hedged for remainder of 2014, protecting cash flows below ~$3.50/MMBtu gas price
- **Simple capital structure**
- **Strong liquidity position with Debt/LTM Adjusted EBITDA[(1)] ~0.9x**
- **Increased borrowing capacity to $450 million with recent borrowing base determination**
- **Flexibility to manage liquidity**
  - Most drilling is operated; low non-operated drilling obligations
  - $80 million estimated for discretionary land/seismic acquisitions
  - Limited long-term drilling rig or service contract commitments

(1) Assumes borrowings outstanding of approximately $210 million on September 8, 2014 and LTM Adjusted EBITDA of $236 million at June 30, 2014. 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.

Investment Highlights

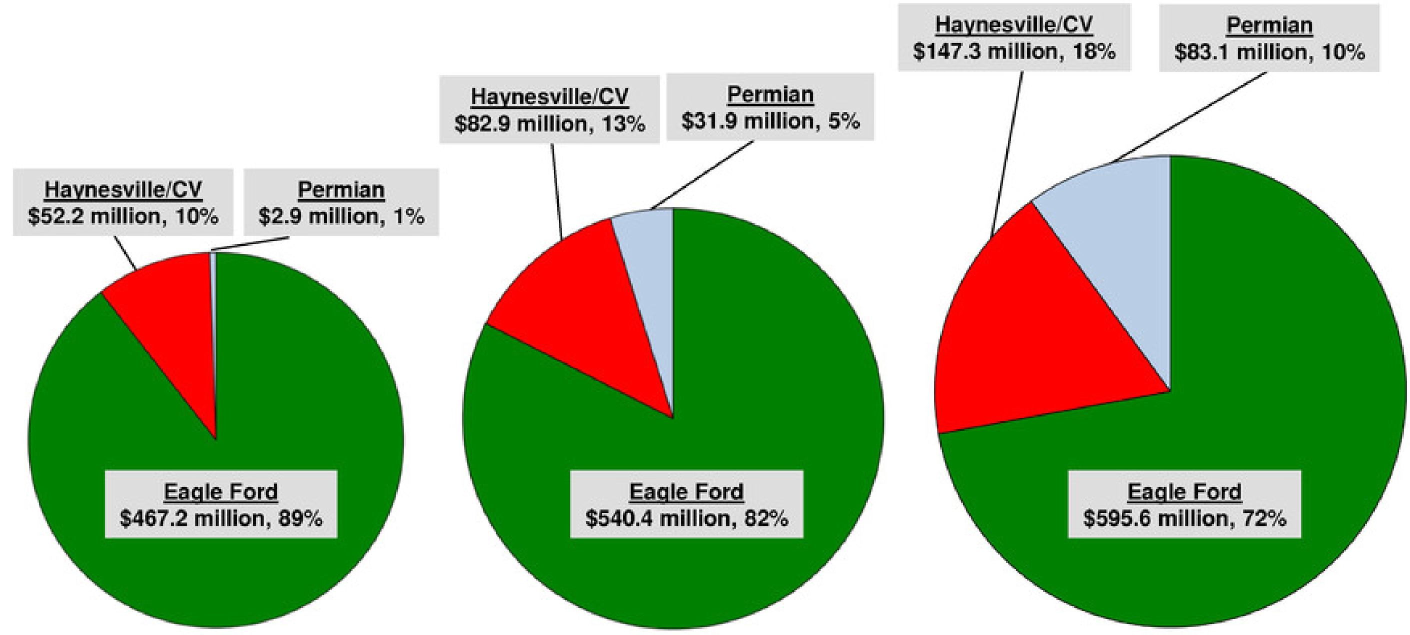
Strong Growth Profile with Increasing Focus on Oil / Liquids	– YE2011 to 2014E oil production CAGR of ~172%[1] with expected year-over-year growth of ~45%[1] in 2014 – ~89% of 2014E CapEx program focused on oil / liquids exploration and development
High Quality Asset Base in Attractive Areas[2]	– ~62,000 net acres in the Permian Basin prospective for the liquids-rich Wolfcamp, Bone Spring and other targets – ~29,100 net acres in the Eagle Ford in some of the most active counties in South Texas, including Atascosa, DeWitt, Gonzales, Karnes, La Salle, Wilson and Zavala Counties – Long-term option on natural gas with Haynesville, Cotton Valley and Bossier assets almost all HBP
Multi-year Drilling Inventory[3][4]	– 177.7 net drilling locations in the Permian Basin with escalating activity to de-risk the play; anticipate significant increase in locations with further delineation drilling – 229.3 net drilling locations in the Eagle Ford – 163.8 net drilling locations in the Haynesville and Cotton Valley
Low Cost Operations	– Substantially reduced Eagle Ford drilling days and well costs since IPO – Batch drilling program and other improvements have potential to further reduce well costs and improve spud to sales times
Strong Financial Position	– Low leverage[5] of ~0.9x allows for operational flexibility – Liquidity available to execute planned drilling program
Proven Management and Technical Team and Active Board of Directors	– Management and senior technical team average over 25 years of industry experience – Board with extensive industry knowledge, business experience and company ownership – Strong record of stewardship

(1) Represents the growth to top end of range of 2014 oil production guidance of 2.8 to 3.1 million barrels.
(2) At August 6, 2014.
(3) Presented as of December 31, 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) Assumes borrowings outstanding of approximately $210 million on September 8, 2014 and LTM Adjusted EBITDA of $236 million at June 30, 2014. 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.



Appendix

SEC Proved Reserves Value Growth By Area



June 30, 2013
PV-10[1]: $522.3 million
$88.13 oil[2], $3.44 natural gas[2]
(Standardized Measure = $477.6 million)

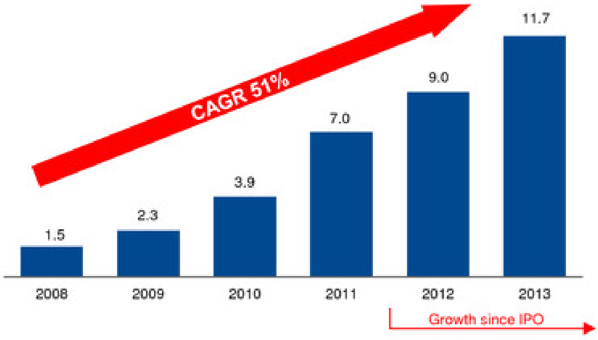
December 31, 2013
PV-10[1]: $655.2 million
$93.42 oil[2], $3.67 natural gas[2]
(Standardized Measure = $578.7 million)

June 30, 2014
PV-10[1]: $826.0 million
$96.75 oil[2], $4.10 natural gas[2]
(Standardized Measure = $723.0 million)

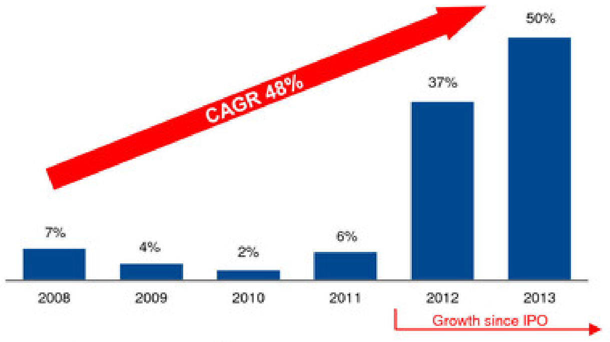
(1) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.
(2) Oil prices in $/Bbl; natural gas prices in $/MMBtu

Matador's Continued Growth

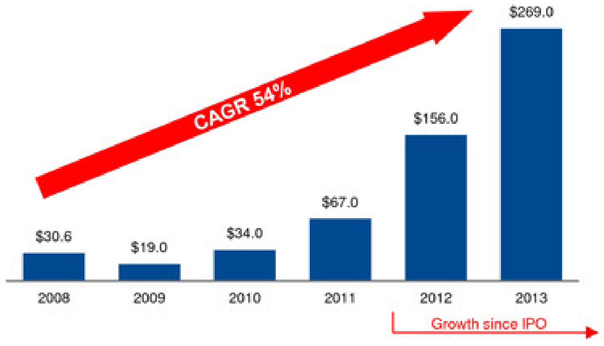
Average Daily Production
(MBOE/d)



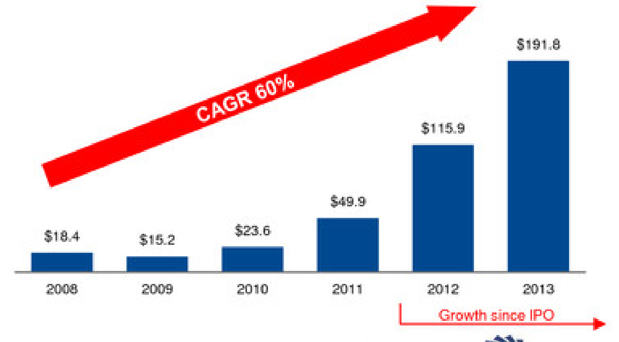
Oil Production Mix
(% of Average Daily Production)



Oil & Natural Gas Revenues
($ in millions)



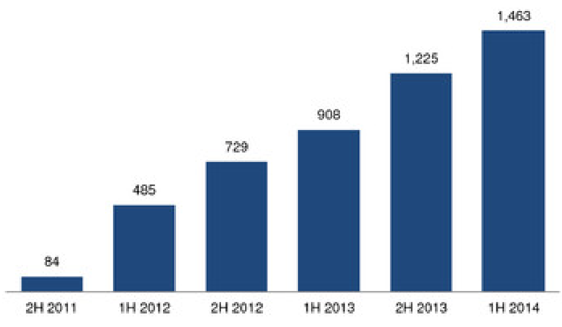
Adjusted EBITDA[(1)]
($ in millions)



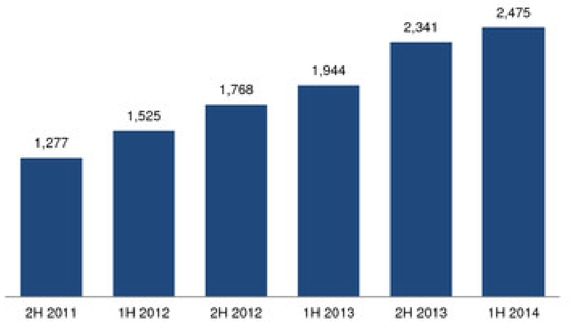
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.

Recent Semi-Annual Performance Metrics Through Mid-Year 2014

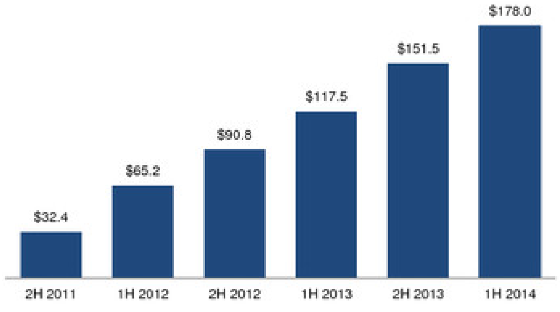
Oil Production
(Bbl in thousands)



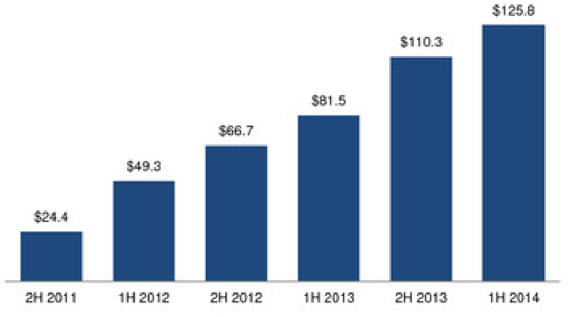
Oil Equivalent Production
(BOE in thousands)



Oil and Natural Gas Revenues
($ in millions)



Adjusted EBITDA(1)
($ in millions)



(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.

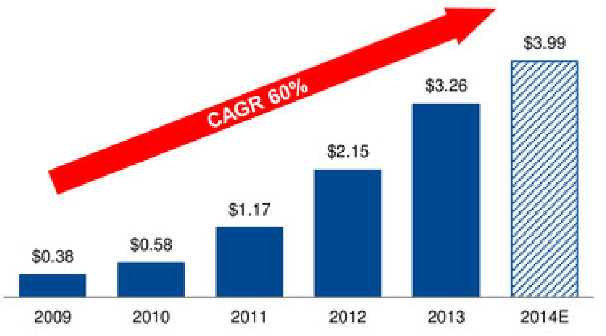
Matador Provides Growth on a Per Share[1] Basis

PV-10[2] per Share

($ per share)

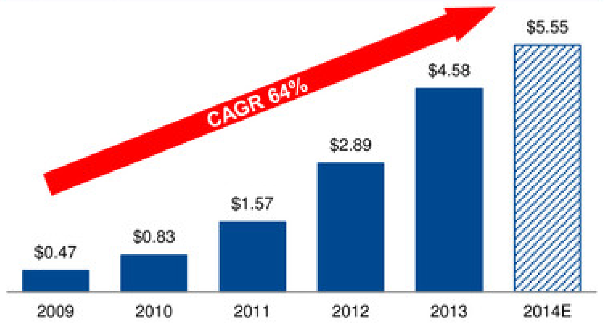
Adjusted EBITDA[3][4] per Share

($ per share)



Oil and Natural Gas Revenues[4] per Share

($ per share)



(in thousands)	Shares[1]	PV-10[2]	Adj. EBITDA[3][4]	Oil & Natural Gas Revenues[4]
2009	40,123	$70,359	$15,184	$19,039
2010	41,037	$119,869	$23,635	$34,042
2011	42,718	$248,700	$49,911	$67,000
2012	53,957	$423,200	$115,923	$155,998
2013	58,777	$655,200	$191,771	$269,030
2014E	70,218		$280,000	$390,000

(1) Weighted Average Basic Shares Outstanding. Value for 2014E assumes no shares issued for remainder of 2014.
(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) 2014 estimates at midpoint of guidance range affirmed on August 6, 2014. Estimated average realized prices for oil and natural gas used in these estimates were $95.00/Bbl and $5.00/Mcf, respectively, for the period July through December 2014.

Historical Financials and Margins

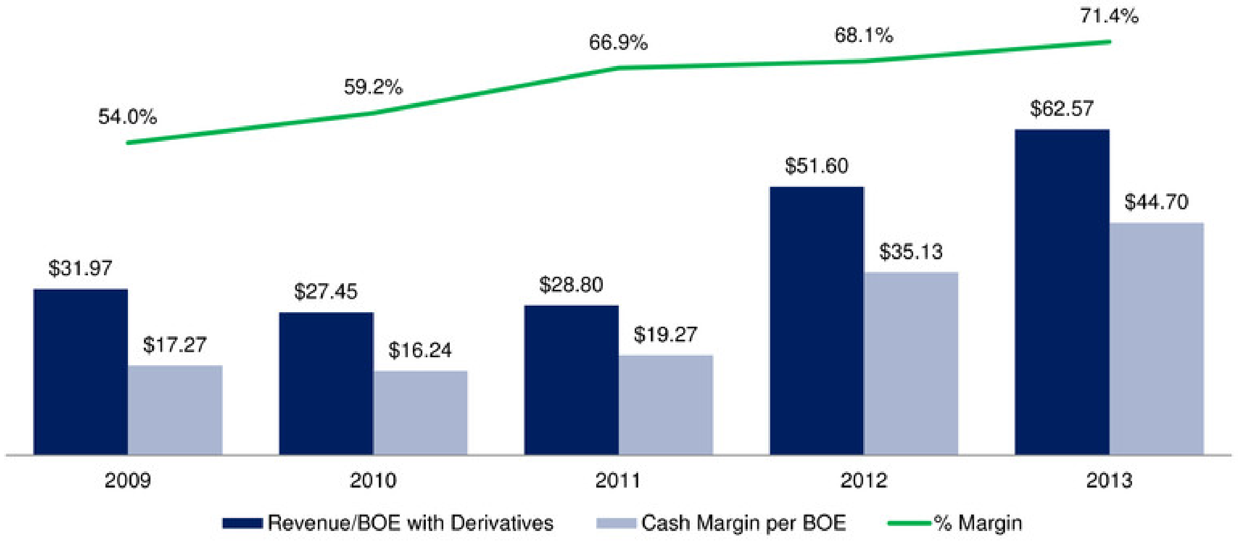
	Year Ended December 31,		
	2011	2012	2013
Production			
Oil Production (MBbl)	154	1,214	2,133
Natural Gas Production (Bcf)	14.5	12.5	12.9
% Oil	6%	37%	50%
Total Production (MBOE)	**2,573**	**3,294**	**4,285**
Average Daily Production (BOE/d)	**7,049**	**9,000**	**11,740**
Realized Oil Price ($/Bbl)(1)	$93.80	$103.55	$98.67
Realized Natural Gas Price ($/Mcf)(1)	$4.11	$3.55	$4.47
Total Oil & Natural Gas Revenues ($ thousands)(1)	**$74,106**	**$169,958**	**$268,121**
Total Revenues per BOE ($/BOE)(1)	**$28.80**	**$51.60**	**$62.57**
Operating Expenses			
Lease Operating ($/BOE)	$2.82	$8.56	$9.04
Production Taxes and Marketing ($/BOE)	$2.44	$3.54	$4.89
Cash G&A ($/BOE)(2)	$4.27	$4.37	$3.94
Total Cash Costs ($/BOE)	**$9.53**	**$16.47**	**$17.87**
Cash Margin ($/BOE)	**$19.27**	**$35.13**	**$44.70**
Adjusted EBITDA ($ thousands)(3)	**$49,911**	**$115,923**	**$191,771**

Significant increases in oil production . . .

. . . primarily responsible for increasing cash margin and per unit costs

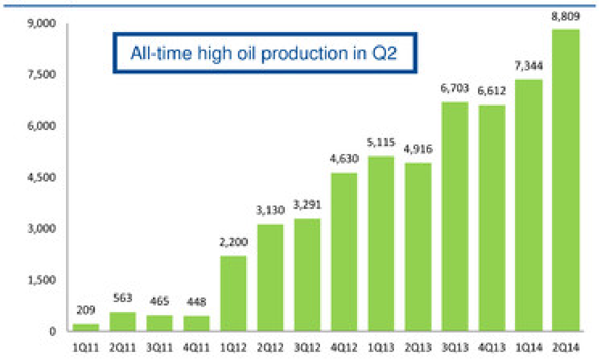
(1) Realized prices and total oil and natural gas revenues include the impact of realized gain or loss on derivatives.
(2) Excludes non-cash stock-based compensation expense.
(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.

Increasing Cash Operating Margin

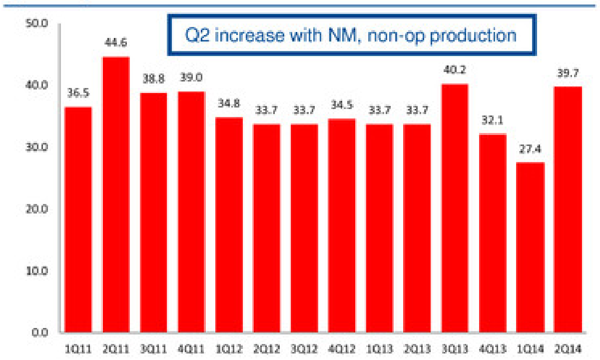


Oil Production and Revenues Through Q2 2014

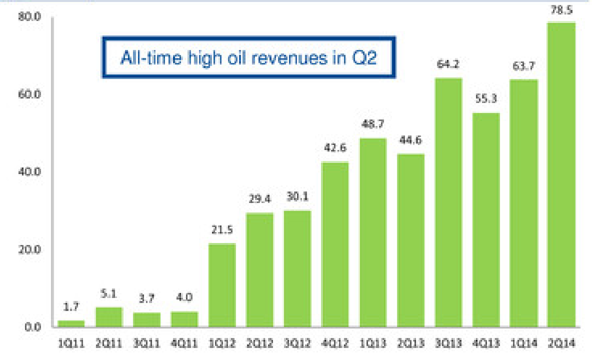
Average Daily Oil Production
(Bbl/d)



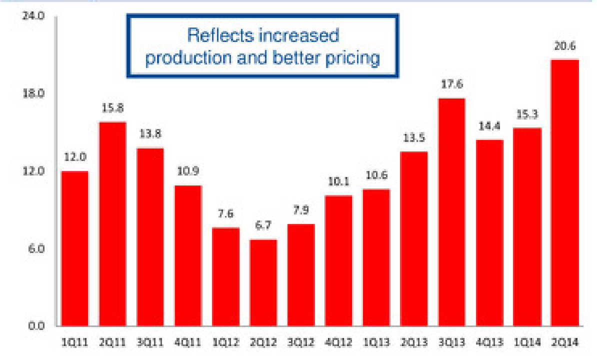
Average Daily Natural Gas Production
(MMcf/d)



Oil Revenues
($ in mm)

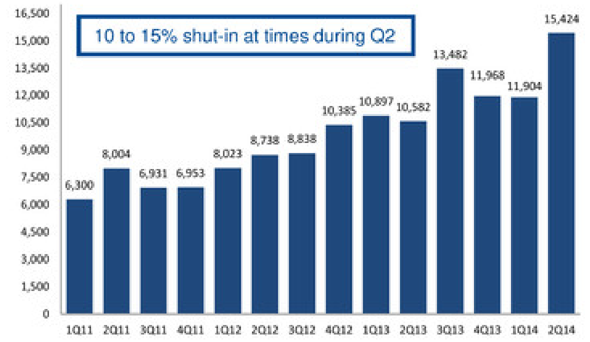


Natural Gas Revenues
($ in mm)

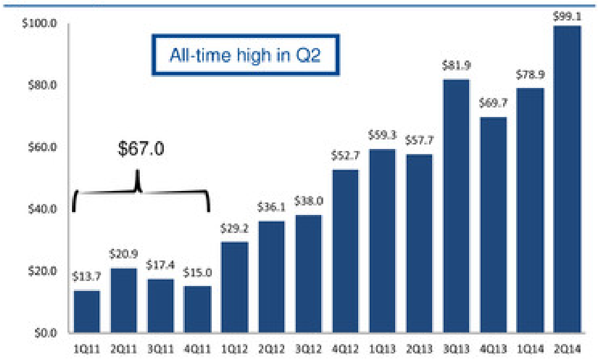


Quarterly Performance Metrics Through Q2 2014

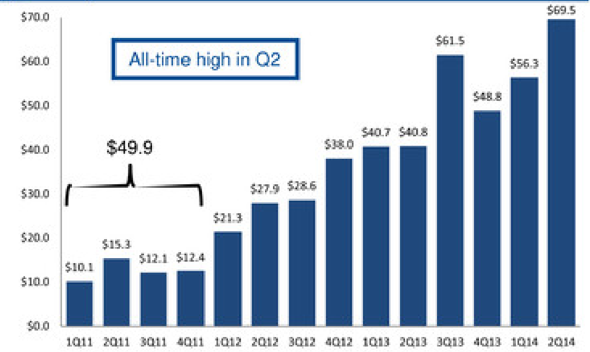
Average Daily Equivalent Production
(BOE/d)



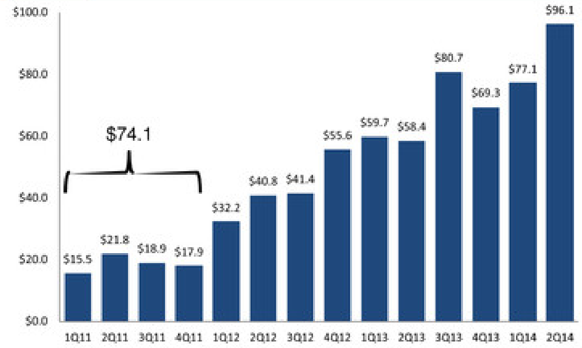
Oil and Natural Gas Revenues
($ in mm)



Adjusted EBITDA(1)
($ in mm)



Total Realized Revenues
($ in mm)

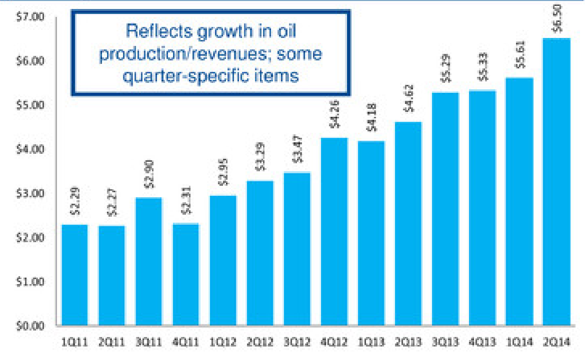


(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Quarterly Expense Metrics Through Q2 2014

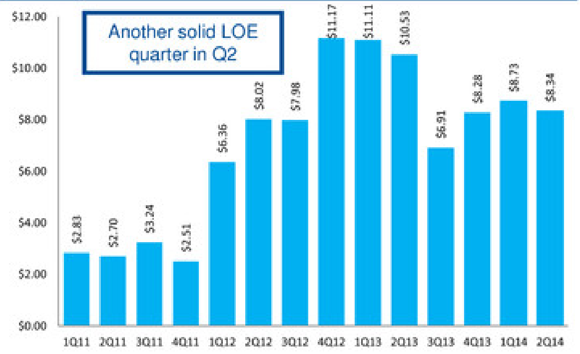
Production Taxes and Marketing

(per BOE)



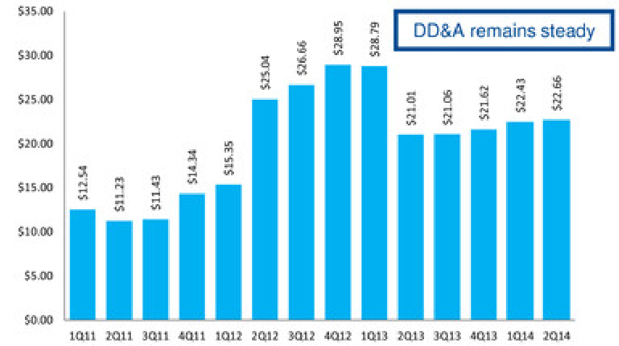
Lease Operating

(per BOE)



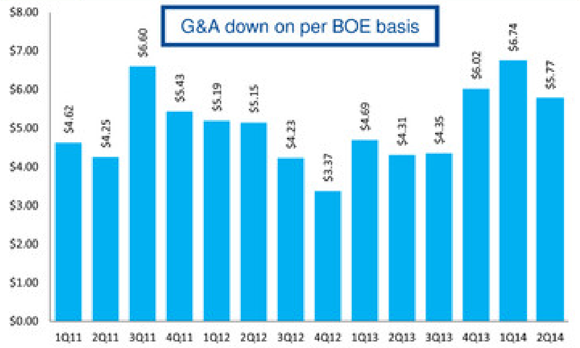
Depletion, Depreciation and Amortization

(per BOE)



General and Administrative

(per BOE)



Hedging Profile – Hedges in Place for Remainder of 2014 and 2015

At September 26, 2014, Matador had:

- 0.9 million barrels of oil hedged for remainder of 2014 at weighted average floor and ceiling of $88/Bbl and $99/Bbl, respectively
- 3.3 Bcf of natural gas hedged for remainder of 2014 at weighted average floor and ceiling of $3.50/MMBtu and $4.93/MMBtu, respectively
- 2.5 million gallons of natural gas liquids hedged for remainder of 2014 at weighted average price of $1.25/gal
- 1.7 million barrels of oil, 9.0 Bcf of natural gas and 3.8 million gallons of natural gas liquids hedged for 2015

Oil Hedges (Costless Collars)	2014	2015
Total Volume Hedged by Ceiling	884,800 Bbl	1,680,000 Bbl
Weighted Average Price	$98.95 /Bbl	$99.75 /Bbl
Total Volume Hedged by Floor	884,800 Bbl	1,680,000 Bbl
Weighted Average Price	$87.83 /Bbl	$83.00 /Bbl

Natural Gas Hedges (Costless Collars)	2014	2015
Total Volume Hedged by Ceiling	3.3 Bcf	9.0 Bcf
Weighted Average Price	$4.93 /MMBtu	$4.79 /MMBtu
Total Volume Hedged by Floor	4.4 Bcf	9.0 Bcf
Weighted Average Price	$3.50 /MMBtu	$3.77 /MMBtu

Natural Gas Liquids (NGLs) Hedges (Swaps)	2014	2015
Total Volume Hedged	2,548,000 gal	3,816,000 gal
Weighted Average Price	$1.25 /gal	$1.02 /gal

Note: Hedged volumes shown in table for 2014 are for remainder of 2014.

Credit Agreement Status

- **Strong, supportive bank group led by RBC**
- **Borrowing base at $450 million, based on July 31, 2014 reserves, increased from $385 million based on December 31, 2013 reserves, and increased from $125 million at time of IPO in February 2012**
- **Borrowings outstanding of $210 million at September 8, 2014**
- **Ability to request quarterly borrowing base increases with growth in oil and natural gas reserves throughout 2015, as needed**

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
Tier Six	100% < or = x < 110%	300 bps	200 bps	50 bps
Tier Seven	x = or > 110%	375 bps	275 bps	50 bps

- **Financial covenants**
  - Maximum Total Debt to Adjusted EBITDA[1] Ratio of not more than 4.25:1.00
  - No Current Ratio test

(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.

Board of Directors and Special Advisors – 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
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
Michael C. Ryan Director	- Partner, Berens Capital Management	International Business and Finance
Carlos M. Sepulveda, Jr. Director	- 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
Special Board Advisors	**Professional Experience**	**Business Expertise**
Marlan W. Downey Special Board Advisor	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil and Gas Exploration
Wade I. Massad Special Board Advisor	- Managing Member, Cleveland Capital Management, LLC - Former Executive Vice President – Capital Markets, Matador Resources Company - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Edward R. Scott, Jr. Special Board Advisor	- Former Chairman, Amarillo Economic Development Corporation - Law Firm of Gibson, Ochsner & Adkins	Law, Accounting and Real Estate Development
W.J. "Jack" Sleeper, Jr. Special Board Advisor	- 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 and James Cleo Thompson Jr.	33 years	Since Inception
Matthew V. Hairford President	- Samson, Sonat, Conoco	29 years	Since 2004
David E. Lancaster EVP, COO and CFO	- Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	34 years	Since 2003
David F. Nicklin Executive Director of Exploration	- ARCO, Senior Geological Assignments in UK, Norway, Indonesia, China and the Middle East	42 years	Since 2007
Craig N. Adams EVP – Land & Legal	- Baker Botts L.L.P., Thompson & Knight LLP	21 years	Since 2012
Ryan C. London VP and General Manager	- Matador Resources Company (Began as intern)	10 years	Since 2004
Bradley M. Robinson VP and CTO	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	36 years	Since Inception
Billy E. Goodwin VP of Drilling	- Samson, Conoco	29 years	Since 2010
William F. McMann VP of Production & Facilities	- Independent Consultant, Wagner Oil Company, Denbury Resources	28 years	Since 2011
Van H. Singleton, II VP of Land	- Southern Escrow & Title, VanBrannon & Associates	17 years	Since 2007
G. Gregg Krug VP of Marketing	- Williams Companies, Samson, Unit Corporation	30 years	Since 2005
Sandra K. Fendley VP and CAO	- J-W Midstream, Crosstex Energy	22 years	Since 2013
Kathryn L. Wayne Controller and Treasurer	- Matador Petroleum Corporation, Mobil	29 years	Since Inception

PV-10 Reconciliation

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

	At June 30, 2014	At December 31, 2013	At June 30, 2013	At December 31, 2012	At December 31, 2011	At September 30, 2011	At December 31, 2010	At December 31, 2009
PV-10 *(in millions)*	$826.0	$655.2	$522.3	$423.2	$248.7	$155.2	$119.9	$70.4
Discounted Future Income Taxes *(in millions)*	$(103.0)	$(76.5)	$(44.7)	$(28.6)	$(33.2)	$(11.8)	$(8.8)	$(5.3)
Standardized Measure *(in millions)*	$723.0	$578.7	$477.6	$394.6	$215.5	$143.4	$111.1	$65.1

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,						LTM at	LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	6/30/2013	6/30/2014
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):								
Net income (loss)	$103,878	($14,425)	$6,377	($10,309)	($33,261)	$45,094	($20,771)	$70,068
Interest expense	-	-	3	683	1,002	5,687	3,574	5,819
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	(703)	29,789
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	97,801	105,756
Accretion of asset retirement obligations	92	137	155	209	256	348	307	428
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	51,499	-
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	13,945	18,275
Stock-based compensation expense	665	656	898	2,406	140	3,897	1,836	6,002
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	617	-
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$148,105**	**$236,137**

	Year Ended December 31,						LTM at	LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	6/30/2013	6/30/2014
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	$156,614	$209,033
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	(12,161)	18,145
Interest expense	-	-	3	683	1,002	5,687	3,574	5,819
Current income tax (benefit) provision	10,448	(2,324)	(1,411)	(46)	-	404	78	3,140
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$148,105**	**$236,137**

Note: LTM is last 12 months

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	1Q 2014	2Q 2014
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	$ 16,363	$ 18,226
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616
Total income tax provision (benefit)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056	9,536	10,634
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	24,030	31,797
Accretion of asset retirement obligations	39	57	62	51	53	58	59	86	81	80	86	100	117	123
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	3,108	5,234
Stock-based compensation expense	53	128	1,234	991	(363)	191	(51)	363	492	1,032	1,239	1,134	1,795	1,834
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**	**$ 56,345**	**$ 69,464**

(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	1Q 2014	2Q 2014
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	$ 31,945	$ 81,530
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)	21,729	(15,221)
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616
Current income tax (benefit) provision	-	(45)	(1)	-	-	-	188	(188)	46	32	902	(576)	1,275	1,539
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**	**$ 56,345**	**$ 69,464**

Matador RESOURCES COMPANY

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)	Six Months Ended					
	12/31/2011	6/30/2012	12/31/2012	6/30/2013	12/31/2013	6/30/2014
Unaudited Adjusted EBITDA reconciliation to Net (Loss) Income:						
Net (loss) income	$ 10,135	$ (2,875)	$ (30,385)	$ 9,615	$ 35,479	$ 34,589
Interest expense	393	309	693	2,881	2,806	3,012
Total income tax (benefit) provision	1,430	(649)	(781)	78	9,619	20,170
Depletion, depreciation and amortization	16,463	31,119	49,335	48,466	49,929	55,827
Accretion of asset retirement obligations	113	111	145	162	186	241
Full-cost ceiling impairment	0	33,205	30,270	21,229	-	-
Unrealized loss (gain) on derivatives	(6,474)	(11,844)	16,646	(2,701)	9,933	8,342
Stock-based compensation expense	2,225	(172)	312	1,524	2,373	3,629
Net loss on asset sales and inventory impairment	154	60	425	192	-	-
Adjusted EBITDA	**$ 24,439**	**$ 49,264**	**$ 66,660**	**$ 81,446**	**$ 110,325**	**$ 125,810**

(In thousands)	Six Months Ended					
	12/31/2011	6/30/2012	12/31/2012	6/30/2013	12/31/2013	6/30/2014
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:						
Net cash provided by operating activities	$ 42,337	$ 51,526	$ 72,702	$ 83,912	$ 95,558	$ 113,475
Net change in operating assets and liabilities	(18,290)	(2,571)	(6,735)	(5,425)	11,635	6,509
Interest expense	393	309	693	2,881	2,806	3,012
Current income tax provision (benefit)	(1)	-	-	78	326	2,814
Adjusted EBITDA	**$ 24,439**	**$ 49,264**	**$ 66,660**	**$ 81,446**	**$ 110,325**	**$ 125,810**