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

FORM 8-K

CURRENT REPORT

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

Date of report (Date of earliest event reported): February 11, 2014

DIAMONDBACK ENERGY, INC.
(Exact Name of Registrant as Specified in Charter)

Delaware	001-35700	45-4502447
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification Number)

500 West Texas Suite 1225 Midland, Texas	79701
(Address of principal executive offices)	(Zip code)

(432) 221-7400
(Registrant's telephone number, including area code)

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

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

☐ Written communications pursuant to Rule 425 under the Securities Act

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act

Item 7.01. Regulation FD Disclosure

Attached as Exhibit 99.1 is a presentation to be given by senior officers of Diamondback Energy, Inc. on February 11, 2014 at the Credit Suisse Energy Summit.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

Number	Exhibit
99.1	Investor Presentation Materials.

Note: The information contained in this report (including Exhibit 99.1) shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

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 thereunto duly authorized.

DIAMONDBACK ENERGY, INC.

Date: February 10, 2014

By: /s/ Teresa L. Dick
Teresa L. Dick
Senior Vice President and Chief Financial Officer

Exhibit Index

Number	Exhibit
99.1	Investor Presentation Materials.

Exhibit 99.1

DIAMONDBACK Energy

Investor Presentation

February 2014

Forward Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Diamondback Energy, Inc. (the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced in the Company's filings with the Securities and Exchange Commission ("SEC"), including its Forms 10-K, 10-Q and 8-K, risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this communication, the Company may use the term "unproved reserves" which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. Unproved reserves may not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities that may be ultimately recovered from the Company's interests may differ substantially. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company's assets provide additional data. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation contains guidance regarding our estimated future production, capital expenditures, expenses and other matters. This guidance is based on certain assumptions and analyses made by the Company and is affected by such factors as market demand for oil and natural gas, commodity price volatility and the Company's actual drilling program, which will be directly affected by the availability of capital, drilling and production costs, developmental drilling tests and results, commodity prices, availability of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals, field spacing rules and actual drilling results. This guidance is speculative by its nature and, accordingly, is subject to great risk of not being actually realized by the Company. For additional information, we refer you to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, its Quarterly Reports on Form 10-Q for the three months ended March 31, 2013, June 30, 2013 and September 30, 2013 and its Current Reports on Form 8-K.

Diamondback Energy – Key Executives

Travis Stice
Chief Executive Officer

- Chief Executive Officer since January 2012, President and Chief Operating Officer from April 2011 to January 2012
- Apache Corporation – Permian Basin Production Manager
- Laredo Petroleum – Vice President, Permian Basin
- ConocoPhillips – Development Manager, Mid-Continent Business Unit
- Burlington Resources – General Manager of Engineering, Operations and Business Reporting, Mid-Continent Division
- Over 28 years of experience with 15 years focused in the Permian

Tracy Dick
Chief Financial Officer

- Chief Financial Officer and Senior Vice President since November 2009, Corporate Controller from November 2007 to November 2009
- Hiland Partners (publicly-traded MLP) – Controller / Tax Director
- Over 20 years of accounting experience, including over 9 years of public company experience in both audit and tax areas

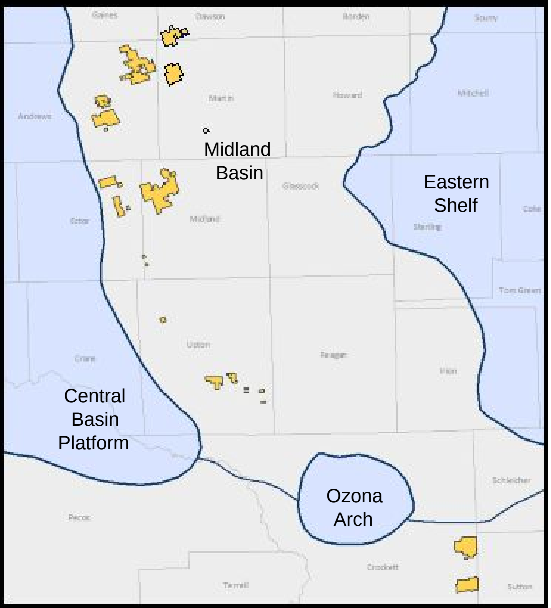
Russell Pantermuehl
VP Reservoir Engineering

- Vice President – Reservoir Engineering since August 2011
- Concho Resources – Wolfberry Reservoir Engineering Supervisor
- ConocoPhillips – Reservoir Engineering Advisor
- Burlington Resources – Reservoir Engineering Advisor
- Over 32 years of experience with 16 years focused in the Permian

Diamondback Energy Overview

- **Aggressive Developer of Horizontal Inventory**
  - Currently running 4 horizontal and 1 vertical rig
  - 5th horizontal rig expected in 2Q'14
  - Execution focus drives peer leading performance
- **Volume and Reserve Growth To Continue**
  - 2013 volumes increased 149% y/y
  - 2014E forecasted to increase 112% y/y
  - Total reserves increased 58% y/y to 63.6 MMboe
  - Proved developed increased 143% y/y to 30.0 MMboe
- **Peer Leading Cash Margin of Nearly $70/boe in 3Q'13**
  - Four consecutive quarters of double digit decline in LOE/BOE
  - 75% oil – highest among peers
  - Cash margins exceeded peers by nearly 50% in 3Q'13
- **Minerals Drive $70-$80 MM of Free Cash Flow**
  - Forecasted free cash flow expected to grow
  - No additional capital required to generate free cash flow

Diamondback Energy Acreage



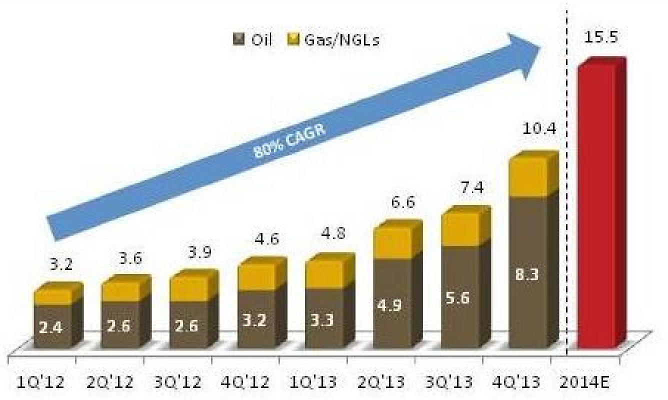
Key Highlights

- Market capitalization of $2.7 billion (1)
- Over 67,000 net acres; ~99% operated
- Proved reserves: 63.6 MMBOE (12/31/13) (2)
  - 67% Oil, 17% NGL, 16% Gas
  - 47% Proved Developed

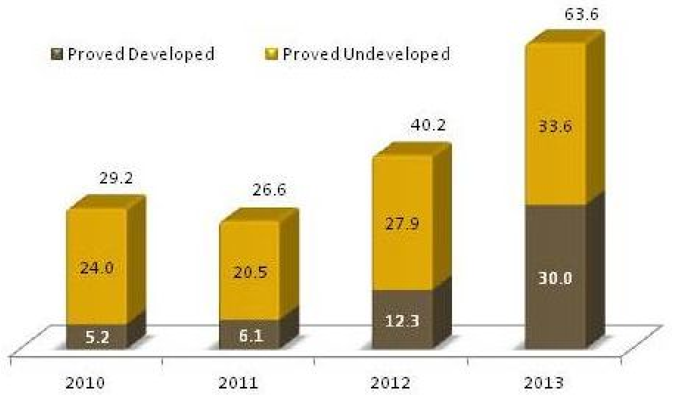
Source: Bloomberg, Ryder Scott, Company filings, management data and estimates. (1) Market data based on 47.1MM shares outstanding and $56.72 share price on February 7, 2014. (2) Based upon Diamondback Energy Inc. Estimated Future Reserves and Income Attributable to Certain Leasehold Interests, dated December 31, 2013, prepared by Ryder Scott Company.

A Growth Story

Average Daily Net Production[1,2] (BOEPD)



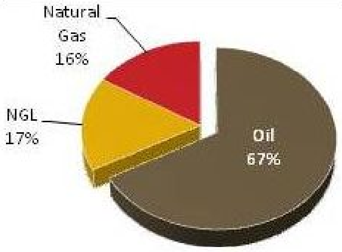
Total Reserves Growth[1,2,3] (MMBOE)



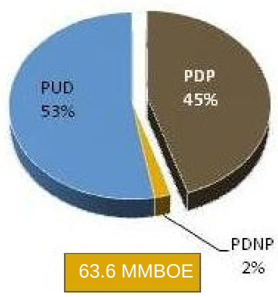
Key Highlights

- Shift to horizontal development driving accelerated growth.
- Less than 5% of horizontal resource potential booked as PUDs.
- Continuing to prove up additional horizontal benches.

1P – By Commodity[3]



1P – By Category[3]

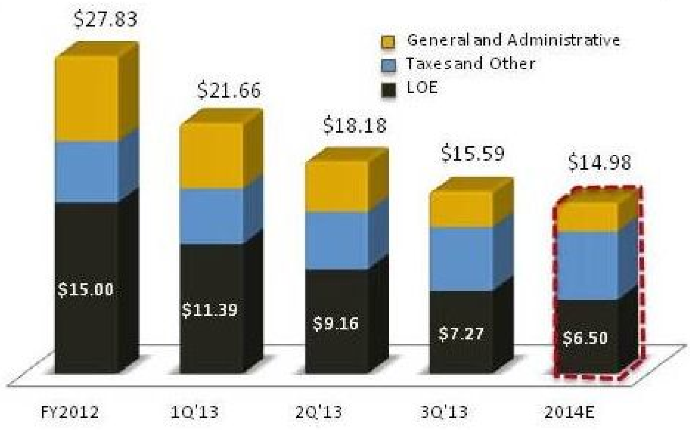


Source: Company filings, Ryder Scott, management data and estimates. (1) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the Permian Basin interests of Gulfport as if those interests had been contributed to Diamondback on January 1, 2012. (2) Based on 2014 guidance published on October 23, 2013, which is subject to numerous assumptions and risks. Midpoint of forecast shown for 2014E. See disclaimer at beginning of this presentation. (3) Based upon Diamondback Energy Inc. Estimated Future Reserves and Income Attributable to Certain Leasehold Interests, dated December 31, 2013, prepared by Ryder Scott Company.

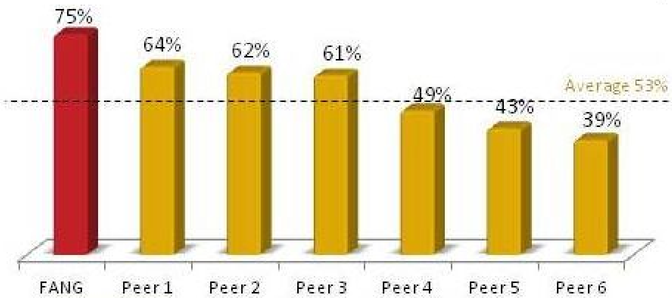
Peer Leading in Cash Margins

Cash Margins Exceed Peers by Nearly 50%[2,3]

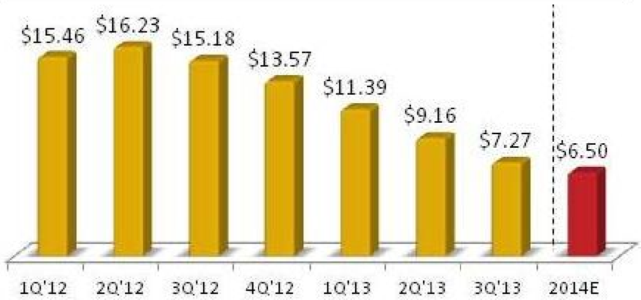
FANG Operating Expenses Over Time[4] ($/BOE)



FANG Percent Oil vs. Public Permian Peers[1,2]



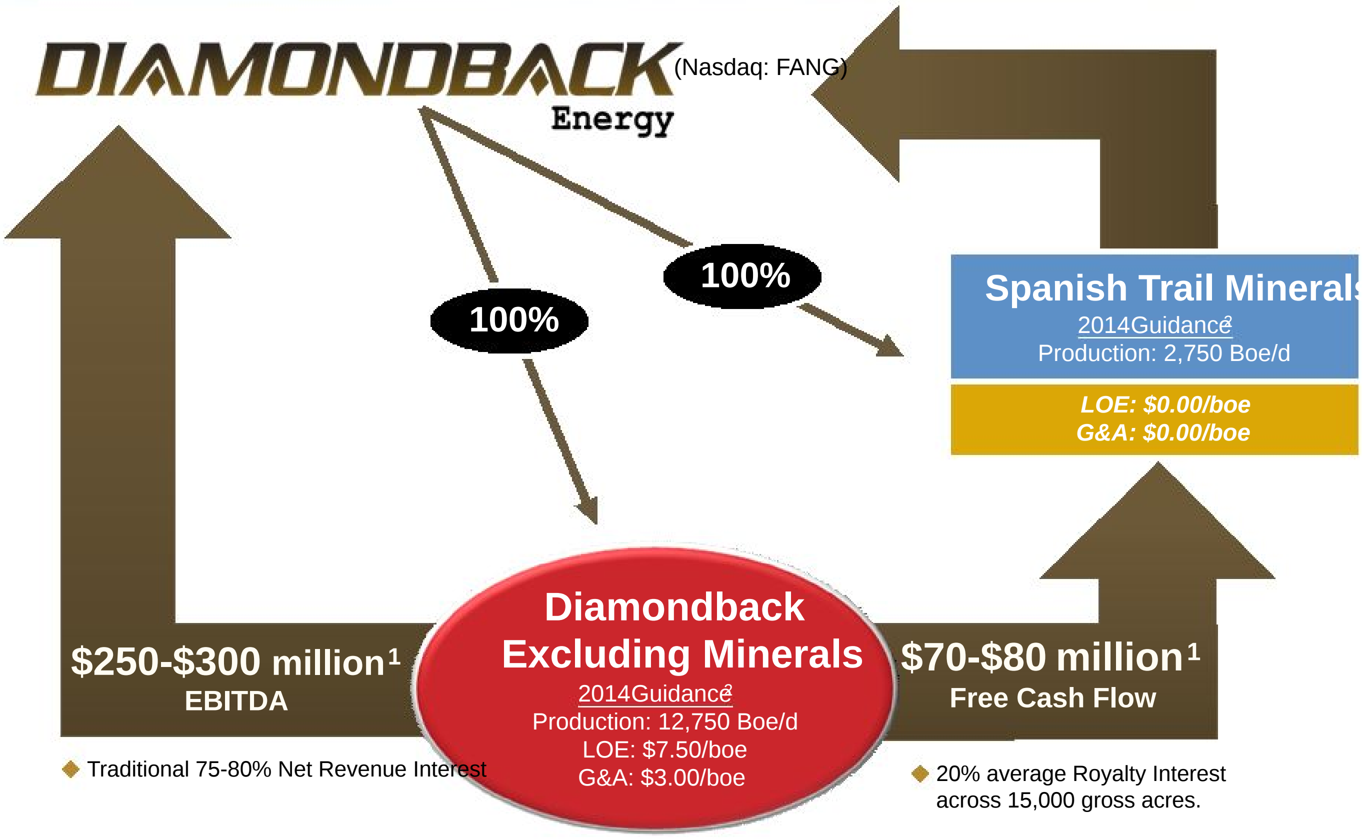
Quarterly LOE ($/BOE)[3,4]



Source: Company filings, management data and estimates. (1) Represents latest reported production percentage of oil. (2) Peers include ATHL, AREX, CXO, LPI, PXD and CPE. (3) Cash margin represents publicly reported EBITDA divided by BOE production for the period. (4) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the Permian Basin interests of Gulfport if such interests has been contributed to Diamondback on January 11, 2012. Based on 2014 guidance published on October 23, 2013, which is subject to numerous assumptions and risks. LOE reflects reclassification of as valorem taxes per published guidance. Midpoint of forecast shown for 2014E. See the disclaimer at the beginning of this presentation.

DIAMONDBACK Energy

Advantaged Structure Increases Cash Flow through Minerals Ownership

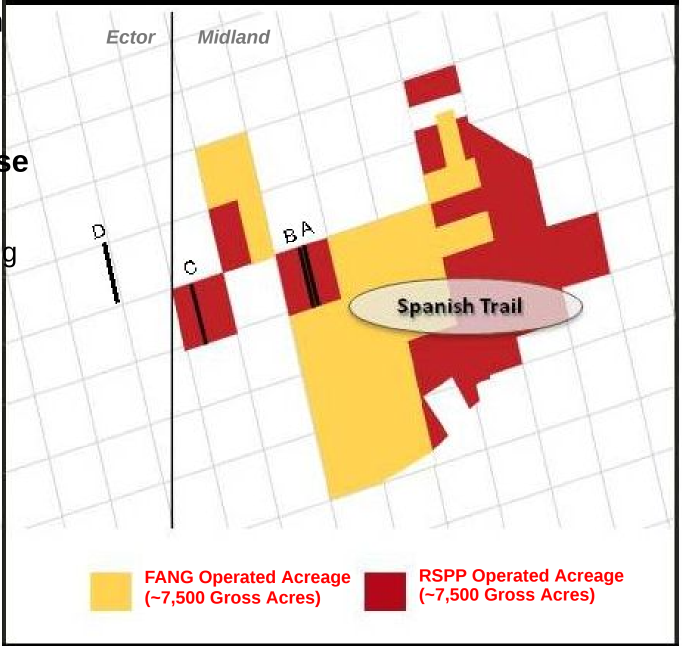


(1) Projections based upon oil price range of $85-$100 per barrel (2) Guidance projected at midpoint of range – October 23, 2013.

Diamondback Energy – Minerals Ownership Impact

- **Completed the acquisition of mineral inter[…] under ~15,000 gross (~12,500 net) acres in Midland County in September 2013**
- **Diamondback receives an average ~20% royalty interest on all production from these ~15,000 gross acres[1] in Spanish Trail**
  - Estimated net production of 2,100 BOEPD during January 2014
- **Free cash flow is expected to grow for the next several years**
- **No additional future capital or operating expenses required to receive run-rate cash flows**
- **Diamondback operates ~50% of the net acreage**
- **Anticipate will generate $70 – $80 MM of cash flow in 2014[2]**

Two Dedicated Hz Drillers

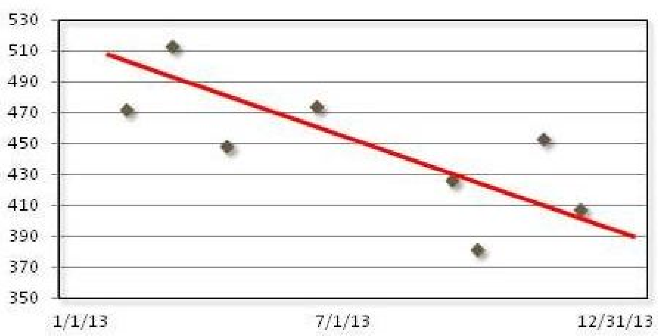


A. Kemmer 4210H Lower Spraberry
B. Kemmer 4210WB Wolfcamp 'B'
C. Sarah Ann 3814 Middle Spraberry
D. Parks Bell 330LH Lower Spraberry

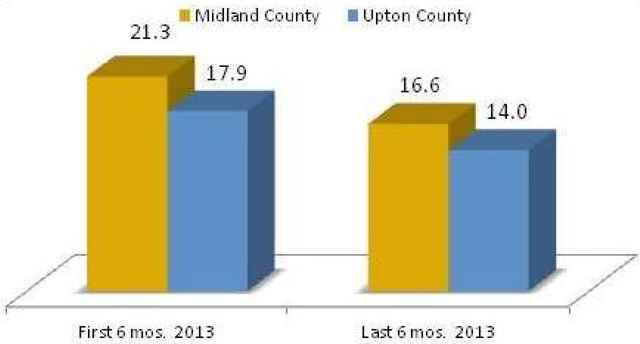
Source: Company filings, management data and estimates. (1) Standard Permian Basin royalty interest is 25% of revenue interest. Diamondback has acquired an average ~20% royalty interest (out of 25%) across the ~15,000 gross acres. Net revenue interest equals working interest multiplied by royalty interest. (2) Subject to numerous assumptions and risks. See the disclaimer at the beginning of this presentation.

Execution and Cost Structure Peer Leading Performance

Drilling $/Lateral Foot[1] (Midland County)

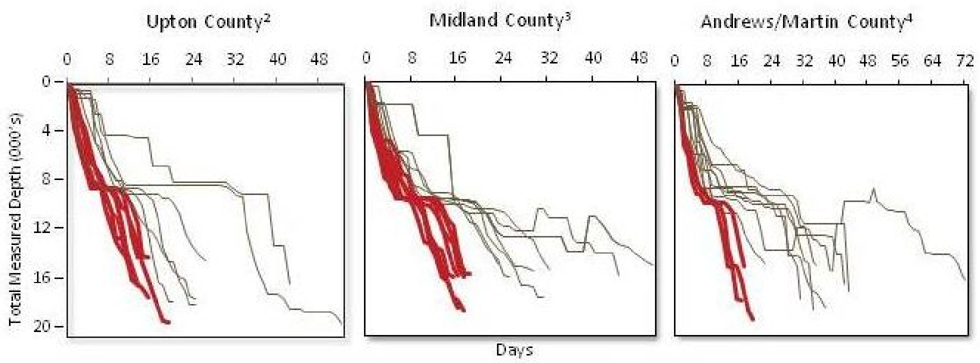


Spud to TD[1] (Days)



Days vs Depth Hz

Diamondback — Peers



Internal Records

Lateral Length	Days	Cost $MM
5,000'	11	$4.8
7,500'	12	$5.9
10,000'	17	$9.1

Source: Company filings, management data and estimates (1) ~7,500' laterals (2) Offset wells are from the following companies: CXO, PXD, CPE (3) Offset wells are from the following companies: RSPP, CPE, Henry Resources (4) Offset wells are from the following companies: PXD, SM, and WTI

DIAMONDBACK Energy

Diamondback Energy Acreage – Encouraging Results

FANG – UL III 4-1H Wolfcamp B
24-hr IP: 613 BOEPD
Peak 30-day avg. rate: 440 BOEPD; ~83% oil
4,051' lateral length

FANG – UL Mason #1H Wolfcamp B
7,500' lateral length
Drilling operations underway

PXD – University 7-43 10H Wolfcamp D
24-hr IP: 3,605 BOEPD ; ~74% oil
7,382' lateral length

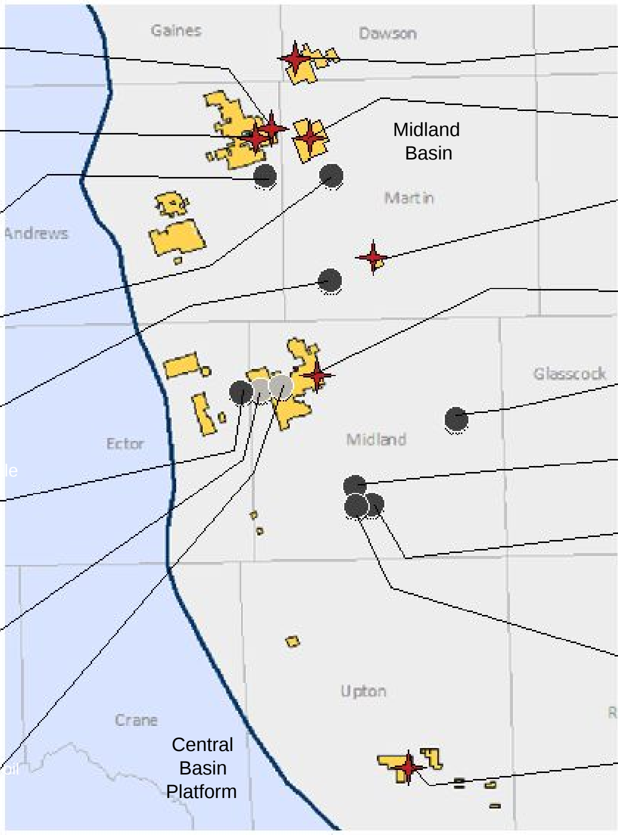
PXD – Scharbauer Ranch #201H Wolfcamp D
24-hr IP: 1,509 BOEPD
Peak 30-day avg. rate: 662 BOEPD; ~60% oil
7,862' lateral length

PXD – Mabee K #1H Wolfcamp B
24-hr IP: 1,572 BOEPD
Peak 30-day avg. rate: 1,040 BOEPD; ~76% o
6,671' lateral length

RSPP – Parks Bell 3304 LS Lower Spraberry Shale
Avg. 24-hr IP: 603 BOEPD
Peak 30-day avg. rate: 547 BOEPD
~4,800' lateral length

RSPP/FANG Staggered Lateral
Kemmer 4210H Lower Spraberry
Peak 24-hr IP: 1,076 BOEPD ~ 91% oil
Peak 30-day avg. rate: 955 BOEPD ~90% oil
Kemmer 4210WB Wolfcamp B
Peak 24-hr IP: 966 BOEPD ~89%oil
Peak 30-day avg. rate: 657 BOEPD ~88% oil
5,043' lateral length (both wells)

RSPP/FANG Middle Spraberry Shale
Sarah Ann 3814H Peak 24-hr IP: 733 BOEPD; 90% oil
5,041' lateral length
Peak 30-day avg. rate: 472 BOEPD ~78% oil



FANG – Kent CSL A 17-1H Wolfcamp B
Well drilled to 7,975' lateral length
Frac scheduled

FANG – Mabee Breedlove 22-1H Wolfcamp B
Flowback operations underway
8296' Lateral Length

FANG – Nail Ranch 2601H Wolfcamp B
Well drilled to ~5,000' lateral length
Frac scheduled

FANG Average Midland County Well Wolfcamp B
Peak 24-hr IP: 899 BOEPD
Peak 30-day rate on artificial lift: 650 BOEPD
~88% oil ~5,591' average lateral length

PXD – E.T O'Daniel #2H Wolfcamp D
Avg. 24-hr IP: 3,156 BOEPD ~69% oil
9,112' lateral length

PXD – DL Hutt C #2H Wolfcamp A
24-hr IP: 1,712 BOEPD
Peak 30-day avg. rate: 1,107 BOEPD
~74% oil; 7,380' lateral length

PXD – DL Hutt C #1H Wolfcamp B
Avg. 24-hr IP: 1,693 BOEPD
Peak 30-day natural flow rate:
1,402 BOEPD; ~75% oil
7,380' lateral length

PXD – DL Hutt C #4H Wolfcamp D
24-hr IP: 2,128 BOEPD
Peak 30-day avg. rate: 856 BOEPD
~69% oil; 6,962' lateral length

FANG – Average Upton County Well Wolfcamp
Peak 24-hr IP: 880 BOEPD
Peak 30-day rate on
artificial lift: 566 BOEPD; ~83% oil
~6,453' avg. lateral length

Source: Company and peer filings, management data and estimates
Map locations are approximate.

Represents Diamondback well

Represents Pioneer and other operator wells (Diamondback does not have any working interest in these wells)

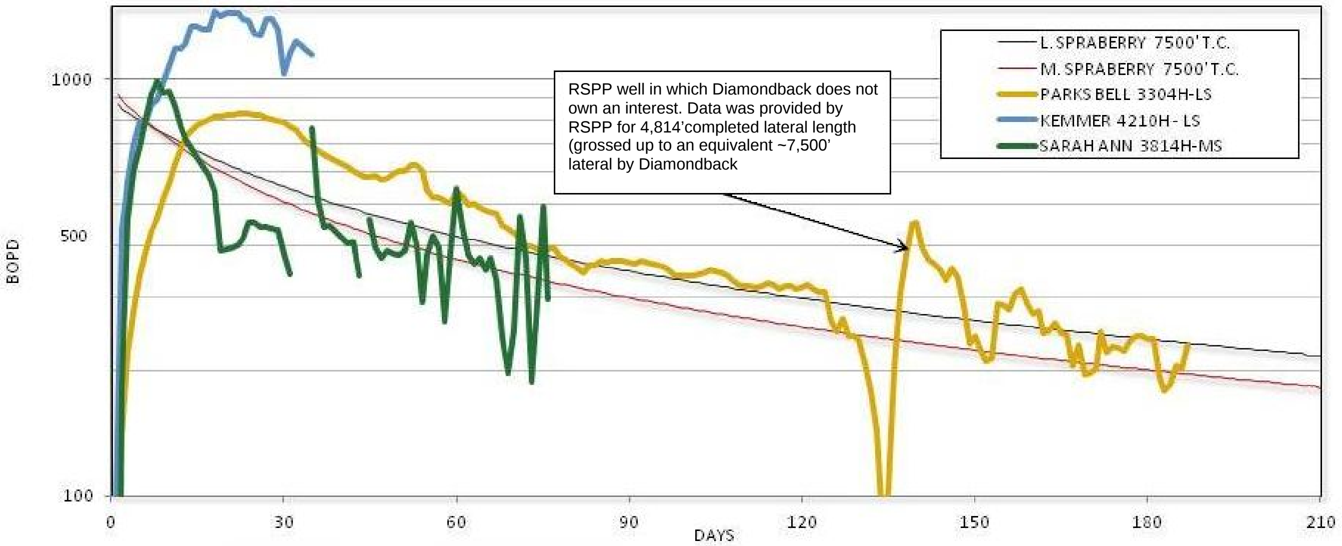
Diamondback non-op partner

DIAMONDBACK Energy

Spraberry Type Curve – Results Exceeding Expectations

- **Lower Spraberry Type Curve is 650 MBOE (2 stream) with 81% oil (87% oil 1st year). 3 stream equivalent is 692 MBOE**
  - Represents a 30% increase over previous EUR estimates and a 60% increase in PV10
  - Type Curve is based on initial well. 2nd well (Kemmer 4210H) is significantly outperforming initial well
- **Middle Spraberry Type Curve is 565 MBOE (2 stream) with 73% oil (82% oil 1st year). 3 stream equivalent is 617 MBOE**
  - Represents a 13% increase over previous EUR estimates and a 27% increase in PV10

Midland County Lower and Middle Spraberry Results – Normalized to 7500 Lateral



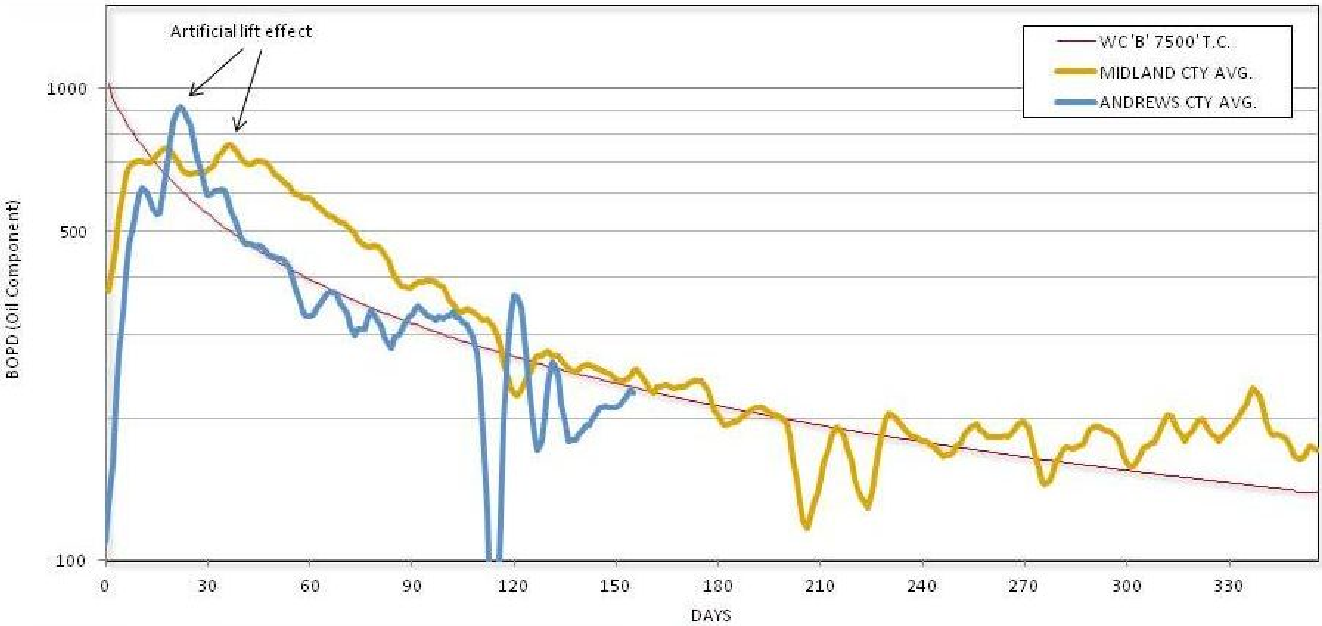
Source: Company filings, management data and estimates.
(1) As of February 1, 2014. Reflects averages only for actual periods of production.

DIAMONDBACK Energy

Wolfcamp B Type Curve – Positive Revisions to North Area

- **Type Curve is 638 MBOE (2 stream) with 74% oil (85% oil 1st year). 3 stream equivalent is 695 MBOE**
  - Represents a 6% increase over previous EUR estimates and a 23% increase in PV10
  - Oil portion of new type curve is a 10% increase over prior estimates

Midland/Andrews County Type Curve(1) – Normalized to 7,500' Lateral

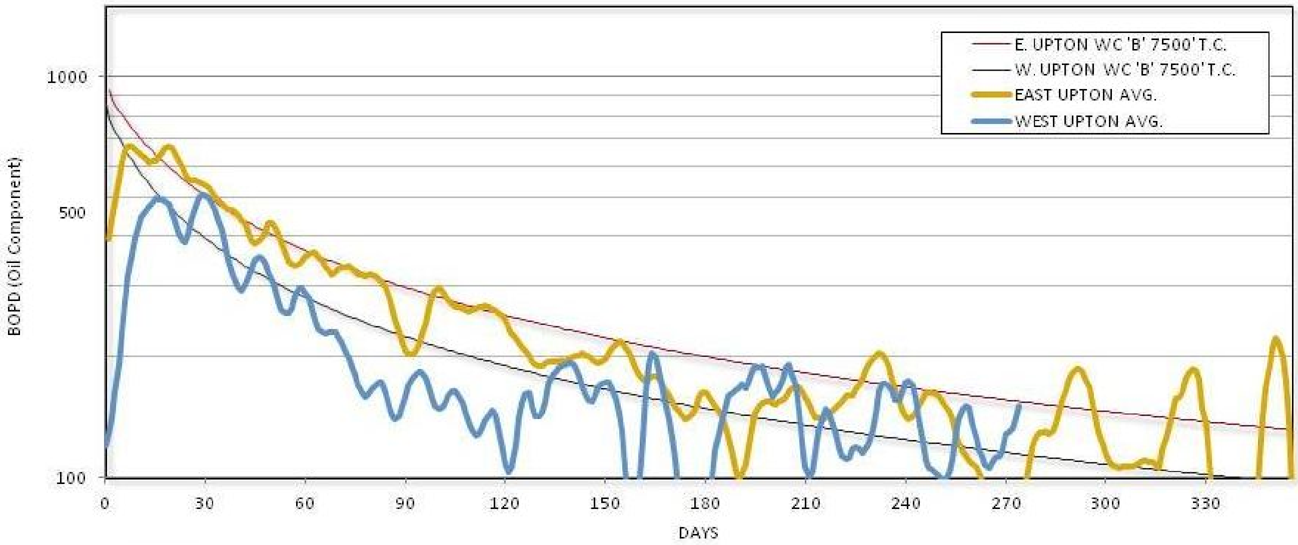


Source: Company filings, management data and estimates.
(1) As of February 1, 2014. Reflects averages only for actual periods of production.

Wolfcamp B Type Curve – South Area Results

- **East Upton Type Curve is 604 MBOE (2 stream), with 72% oil (80% oil 1st year). 3 stream equivalent is 671 MBOE**
  - Represents no change to prior estimates
- **West Upton Type Curve is 463 MBOE (2 stream), with 70% oil (78% oil 1st year). 3 stream equivalent is 519 MBOE**
  - Represents a 22% decrease to previous EUR estimates.
  - Projects are still economic and deliver a >30% ROR

Upton County Type Curve[(1)] - Normalized to 7,500' Lateral

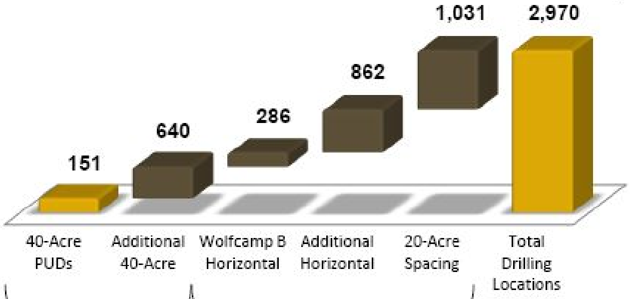


Source: Company filings, management data and estimates.
(1) As of February 1, 2014. Reflects averages only for actual periods of production.

DIAMONDBACK Energy

Multi-year Inventory Continues to Grow

Identified Net Potential Drilling Locations



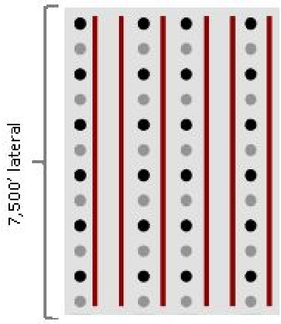
~19% of 40-acre vertical locations booked as PUDs[1]

Additional upside from horizontal locations[2] and vertical 20-acre locations

Horizontal Resource Potential (excluding minerals)

Horizontal Target	Wolfcamp B	Wolfcamp A	Lower Spraberry	Middle Spraberry	Cline	Clearfork	Wolfcamp C	Total
Locations (gross / net)[3]	354/286	203/161	250/202	191/153	176/137	185/149	71/60	**1430/1148**
EUR / Well (MBOE)[4]	600 -700	450 -550	550-650	500 -600	400 -500	350 -450	350 -450	**500 – 600**
Average Lateral Length	6,460'	6,190	6,210'	6,220'	6,130'	6,300'	6,100'	**6,270'**
Resource Potential (MMboe)	122	50	76	53	38	38	15	***393*[5]**

160 Acre Hz Spacing



40-acre spacing

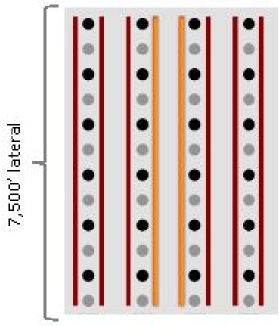
20-acre infill spacing

Horizontal (Wolfcamp B)

Prospective Horizons:

- Clearfork
- Lower Spraberry
- Middle Spraberry
- Wolfcamp A, B and C
- Cline (Wolfcamp D)
- Atoka

120 Acre Hz Spacing



- Pilot test wells show no degradation in well performance
- 660' test in Midland County ST NW 3602H and ST NW 3603H

Source: Company filings, management data and estimates Management estimates as of December 31, 2013. (1) PUDs based on Ryder Scott prepared estimates as of 12/31/2013. (2) Twenty seven of the horizontal locations are booked as PUDs (3) Lateral lengths vary from ~5,000' to 10,00' depending on lease geometry and other considerations (4) Aside from Wolfcamp B, EURs are based on management estimates based on wells drilled by other operators. The Company's results may vary materially. All EUR estimates are based on 7,500' laterals. (5) Net potential assuming average 24% royalty burden.

DIAMONDBACK Energy

Diamondback Energy - Financial Summary

Revenue Growth(1) ($ in MMs)

Hedging

Oil Swaps 2014	Average Bbls Per Day	Average Price Per Bbl
First Quarter-LLS	2,311	$99.45
First Quarter-Brent	1,000	$109.70
Second Quarter-LLS	3,670	$98.86
Second Quarter-Brent	330	$109.70
Third Quarter-LLS	4,000	$97.64
Fourth Quarter-LLS	4,000	$97.64
2014 Average	**3,830**	**$99.23**

EBITDA Growth(1) ($ in MMs)

Cash Margins(1) ($/BOE)(2)

Source: Company filings, management data and estimates. (1) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the Permian Basin interests of Gulfport as if those interests had been acquired by Diamondback on January 1, 2012. (2) Cash margin represents EBITDA/BOE production.

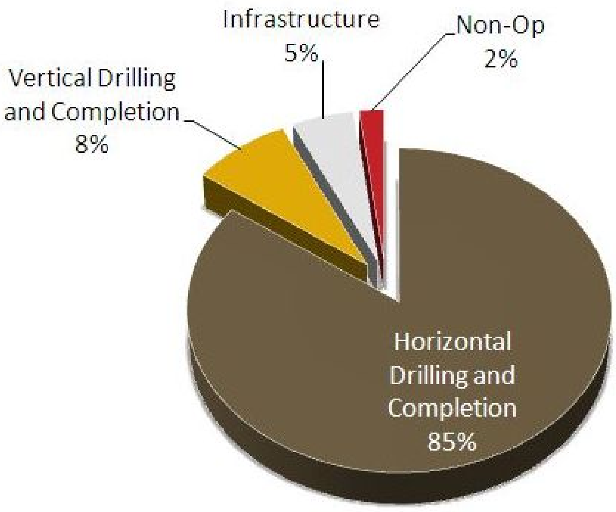
DIAMONDBACK Energy

Diamondback Energy - 2014 Capital Program

Drilling Program[1]

- **65-75 gross horizontal and 20-25 gross vertical wells planned for 2014**
- **Average Hz lateral length (all wells) 6,660'**
- **Expected cost range**
  - $6.9 -$7.4MM for 7,500' lateral horizontal well
  - $2.0 -$2.2MM for vertical wells

2014E Capital Expenditures



$425-$475MM

Key Highlights

- 2014 capital budget fully financed based on current liquidity and cash flow
- Will generate additional liquidity throughout the year with expected growth in borrowing base over time
- 2014 budget 48% higher than 2013
- Priorities are derisking & delineation

(1) As of October 23, 2013 Guidance

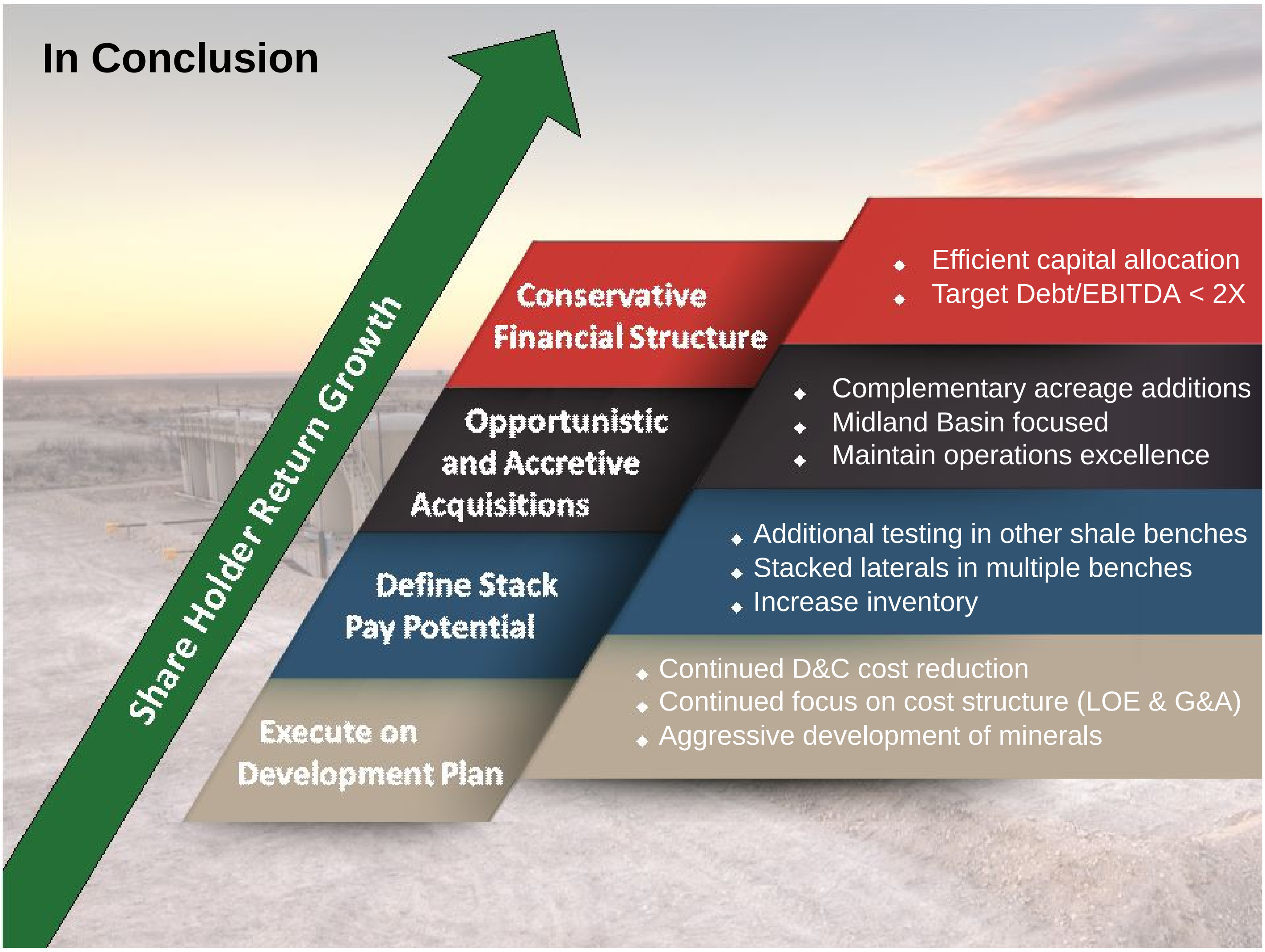
DIAMONDBACK Energy

Diamondback Energy - 2014 Guidance

	Diamondback Excluding Minerals	Minerals	Diamondback Energy
Total Net Production - MBoe/d	12.5 – 13.0	2.5 – 3.0	15.0 – 16.0
Unit costs ($/boe)			
Lease operating expenses[1]	$7.00 - $8.00	$0.00	$6.00 - $7.00
G&A	$2.50 - $3.50	$0.00	$2.00 - $3.00
DD&A	$22.00-$24.00	$26.00-$28.00	$23.00 - $25.00
Production and Ad Val Taxes (% of Revenue)[2]	7.0%	7.5%	7.1%
$ - million			
Gross Horizontal Well Costs[3]	$6.9 - $7.4	n/a	$6.9 - $7.4
Horizontal Wells Drilled (net)	65-75 (52 – 60)	n/a	65-75 (52 – 60)
Gross Vertical Well Costs	$2.0 - $2.2	n/a	$2.0 - $2.2
Gross Vertical Wells Drilled (net)	20-25 (16 – 20)	n/a	20-25 (16 – 20)
Capital Expenditures	$425 - $475	n/a	$425 - $475
Net Interest expense	n/a	n/a	$36.00 - $38.00

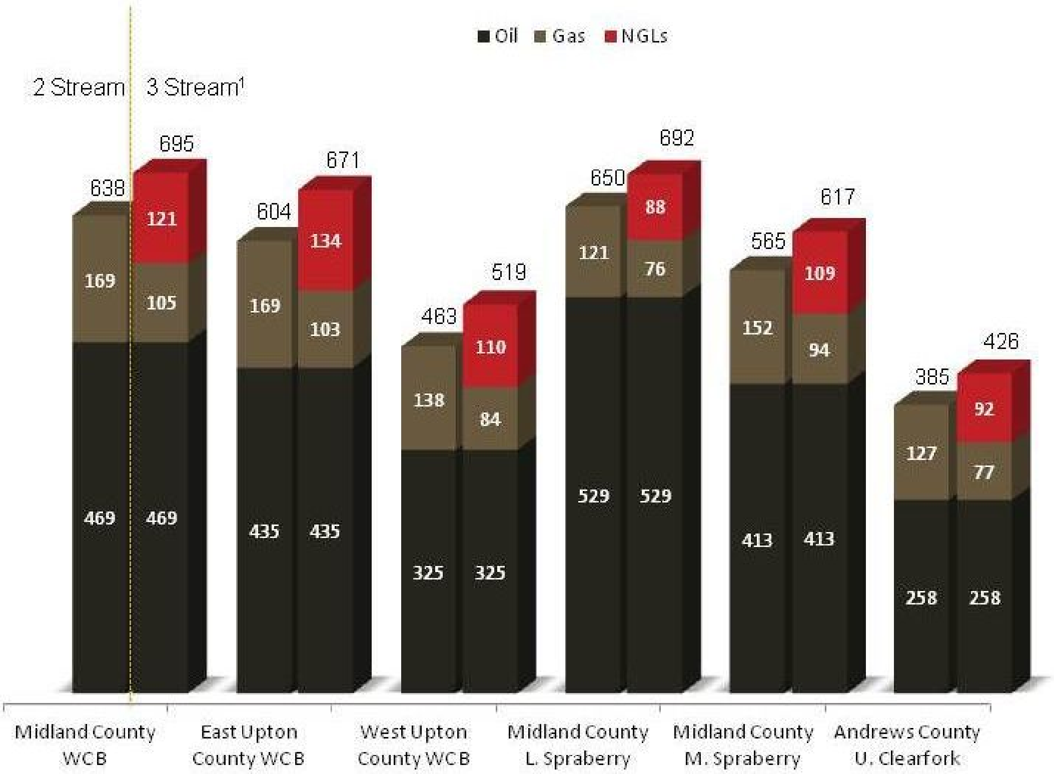
1 - 2013 guidance included ad-valorem taxes in lease operating expense. The Company has reclassified these taxes and these taxes will now be reported in production and ad valorem taxes. Corporate overhead, previously reported as indirect LOE, is now included as part of lease operating expenses. 2013 guidance has been adjusted to reflect this reclassification. 2 - Includes production taxes of 4.6% for crude oil and 7.5% for natural gas and NGLs and ad valorem taxes. 2013 guidance excluded estimated ad valorem taxes of $1.50/boe of lease operating expense. 3 - Assumes a 7,500' average lateral length.

DIAMONDBACK Energy


In Conclusion
Share Holder Return Growth
Conservative Financial Structure
Efficient capital allocation
Target Debt/EBITDA < 2X
Opportunistic and Accretive Acquisitions
Complementary acreage additions
Midland Basin focused
Maintain operations excellence
Define Stack Pay Potential
Additional testing in other shale benches
Stacked laterals in multiple benches
Increase inventory
Execute on Development Plan
Continued D&C cost reduction
Continued focus on cost structure (LOE & G&A)
Aggressive development of minerals

APPENDIX

3 Stream Effect on EUR - MBOE



(1) 3 stream volumes based on sales volumes after fuel, line loss and plant take. Midland County gas shrink = 38% and ngl yield = 120 bbl/MMcf. Andrews County shrink = 40% and yield = 120 bbl/MMcf. Upton County shrink = 39% and yield = 132 bbl/MMcf