Quarterly Update

MAY 3, 2017

1Q17

CONCHO

Forward-Looking Statements and Other Disclaimers

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 Concho Resources Inc. (the “Company”) expects, believes or anticipates will or may occur in the future are forward-looking statements. Forward-looking statements contained in this presentation specifically include statements, estimates and projections regarding the Company’s future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditure budget, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. The words “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “goal” or other similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements, which generally are not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. These statements are based on certain assumptions and analyses made by the Company based on management’s experience, expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Forward-looking statements are not guarantees of performance. Although the Company believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, 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 risk factors discussed or referenced in the Company’s most recent Annual Report on Form 10-K and in the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2017; risks relating to declines in, or the sustained depression of, the prices the Company receives for its oil and natural gas; uncertainties about the estimated quantities of oil and natural gas reserves; drilling, completion and operating risks; the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas; environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination; difficult and adverse conditions in the domestic and global capital and credit markets; risks related to the concentration of the Company’s operations in the Permian Basin of Southeast New Mexico and West Texas; disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver the Company’s oil, natural gas liquids and natural gas and other processing and transportation considerations; the costs and availability of equipment, resources, services and qualified personnel required to perform the Company’s drilling and operating activities; potential financial losses or earnings reductions from the Company’s commodity price risk-management program; risks and liabilities associated with acquired properties or businesses; uncertainties about the Company’s ability to successfully execute its business and financial plans and strategies; the adequacy of the Company’s capital resources and liquidity including, but not limited to, access to additional borrowing capacity under the Company’s credit facility; the impact of potential changes in the Company’s credit ratings; cybersecurity risks, such as those involving unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues; uncertainties about the Company’s ability to replace reserves and economically develop its current reserves; general economic and business conditions, either internationally or domestically; competition in the oil and natural gas industry; uncertainty concerning the Company’s assumed or possible future results of operations; and other important factors that could cause actual results to differ materially from those projected.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), including adjusted net income, adjusted EPS and EBITDAX. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of adjusted net income, adjusted EPS and EBITDAX to the nearest comparable measures in accordance with GAAP, please see the appendix.

The Securities and Exchange Commission (“SEC”) requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using the trailing 12-month average first-day-of-the-month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, the Company currently does not disclose probable or possible reserves in its SEC filings.

In this presentation, proved reserves attributable to the Company at December 31, 2016 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $39.25 per Bbl of oil and $2.48 per MMBtu of natural gas. The Company’s estimate of its total proved reserves at December 31, 2016 is based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. The Company may use the terms “unproved reserves,” “resource potential,” “EUR” per well, “upside potential” and “prospective acreage” to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are based on analogy to the Company’s existing models applied to additional acres, additional zones and tighter spacing and are the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute “reserves” within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules. EUR estimates, resource potential and identified drilling locations have not been fully risked by Company management and are inherently more speculative than proved reserves estimates. Actual locations drilled and quantities that may be ultimately recovered from the Company’s interests could differ substantially. There is no commitment by the Company to drill all of the drilling locations, which have been attributed to these quantities. 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, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Estimates of unproved reserves, resource potential, per well EUR and upside potential may change significantly as development of the Company’s oil and natural gas assets provide additional data. 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.

Key Messages

Committed to Our Strategy

- Hire the best
- Develop the best asset base
- ROR-driven
- Prioritize financial strength

Disciplined Capital Allocation

- Capital spending on high-ROR projects
- Differentiated growth within cash flow
- Robust long-term outlook

Our Scale & Execution Strength Wins

- Drive productivity gains
- Control costs
- Leverage new technology
- Mitigate risks to efficiency

Capital-Efficient Platform to Deliver Long-Term Growth & Value Creation

Driving Superior Capital Efficiency through Scale

Defining the Scale Advantage

Premier Permian Position

Size & Quality

- High-quality assets, better well productivity, exceptional source of upside
- Long lateral, manufacturing-style development

Drilling Machine

Large-Scale Program

- More is better – drill more wells, generate more data, drive better outcomes
- Economies of scale; utilization = cost advantage
- Smart infrastructure investments protect the program and margins
- Marketing strategy to capture the most value and takeaway assurance

Strong Financial Position

Conservative Leverage Profile

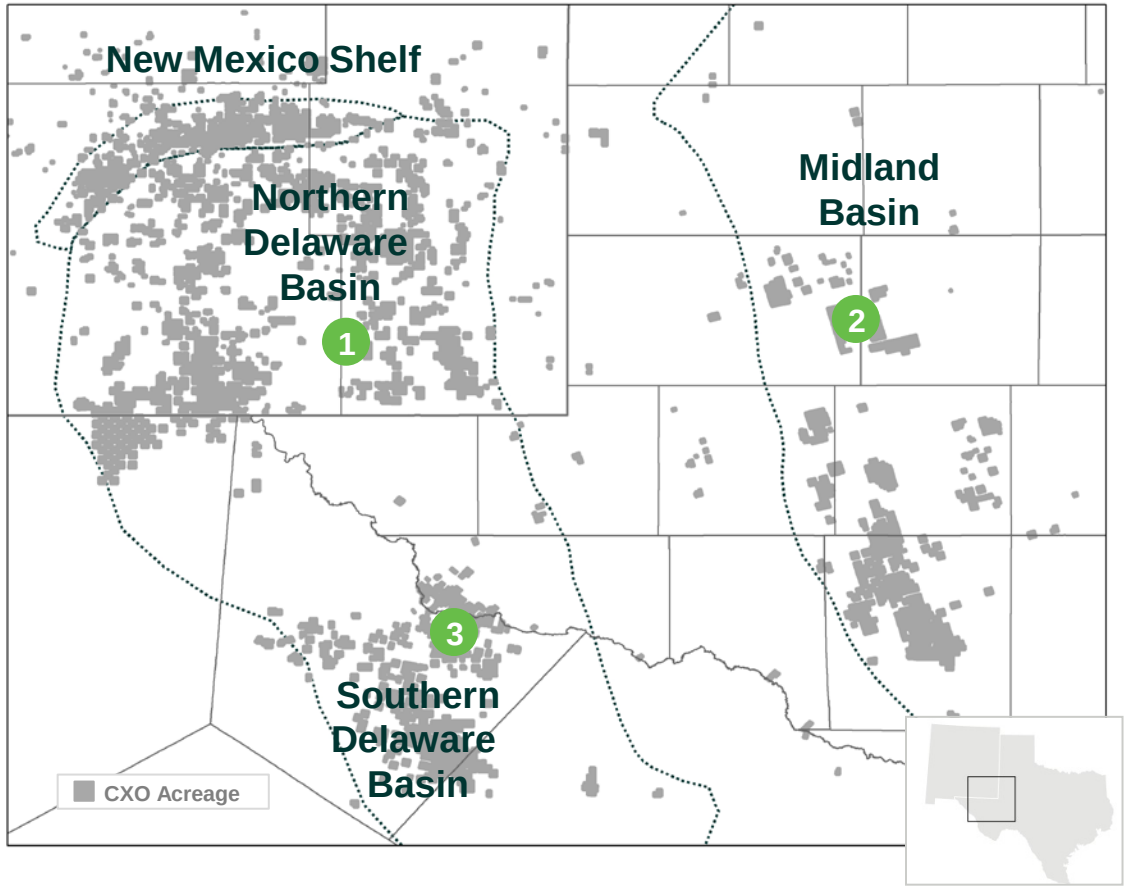
- Peer-leading balance sheet
- Strong financial position provides ultimate flexibility

Manufacturing Growth

Maximizing Returns & Recoveries of High-Quality Resource

Manufacturing Mode is Transforming Our Business

- Large-scale projects
- Multi-target access
- Batch completions
- Capital cost and LOE efficiencies
- Technology / data analytics to drive better outcomes



Manufacturing Across the Portfolio: Key Projects

1. ***Northern Delaware Basin:*** 8-well Windward project with 2-mile laterals
2. ***Midland Basin:*** 13-well Mabee Ranch project with 2-mile laterals
3. ***Southern Delaware Basin:*** 8-well Brass Monkey project with 2 & 2.5-mile laterals

Shifting to Manufacturing Mode Represents an Inflection in Our Business & Enhances Concho's Platform to Deliver Long-Term Value

First-Quarter 2017 Highlights

Focus in on Execution

Operational

- Quarterly production of 181.4 MBoepd exceeded guidance range
  - ***13% organic crude oil growth quarter-over-quarter***
- Record well performance in the Delaware Basin and New Mexico Shelf

Financial

- Per-unit production and interest expenses decreased 27% and 42%, respectively, year-over-year
- ***Cash flows exceeded capital expenditures for seventh consecutive quarter***
- Closed sale of Alpha Crude Connector; net proceeds of $803mm
- Net income of $650mm, or $4.37 per diluted share; adjusted net income[1] of $72mm, or $0.49 per diluted share
- EBITDAX of $461mm[1]

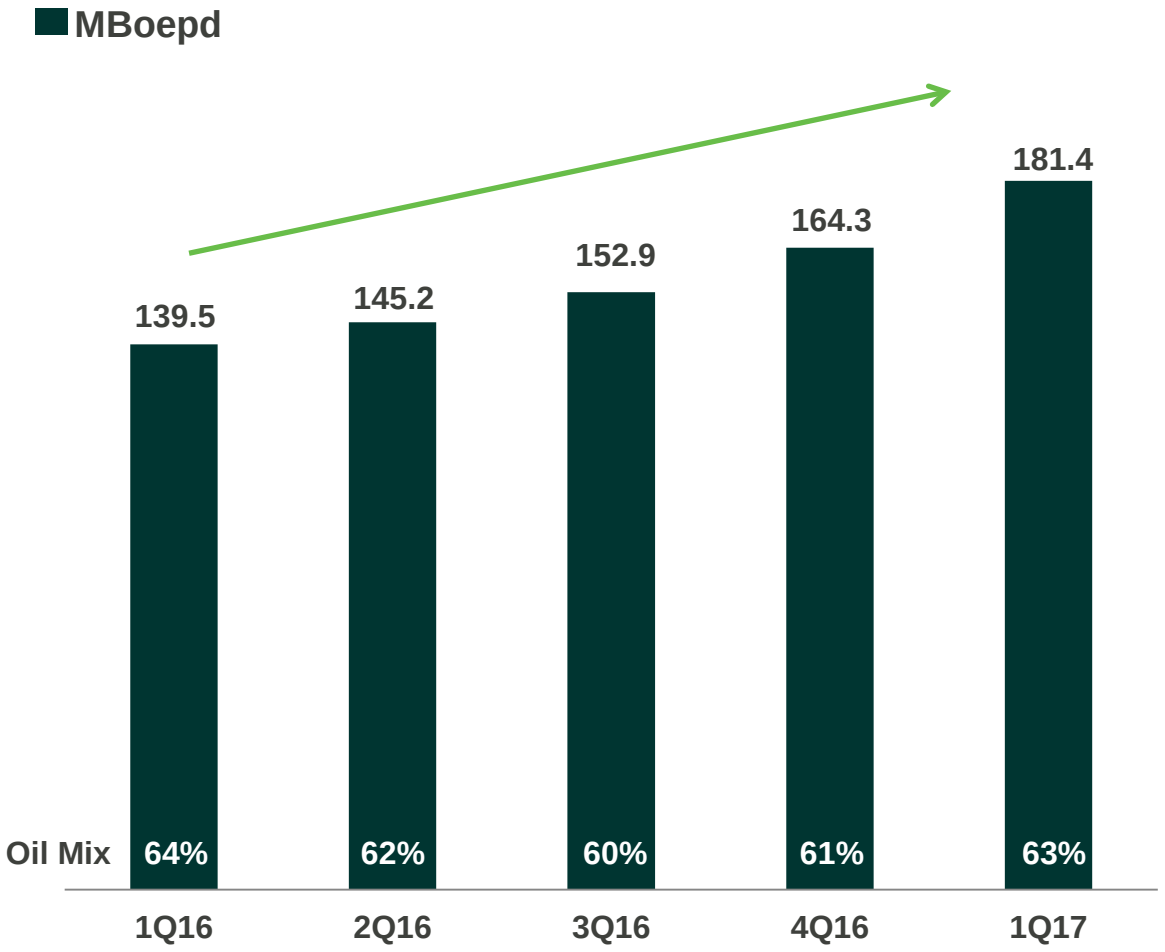
Outlook

- ***Raised FY17 production outlook to a range of 21% - 25% annual growth***
- Reduced FY17 cost guidance for per-unit production and DD&A expense
- Shift to manufacturing mode to power development efficiencies
  - Large-scale development projects underway across portfolio

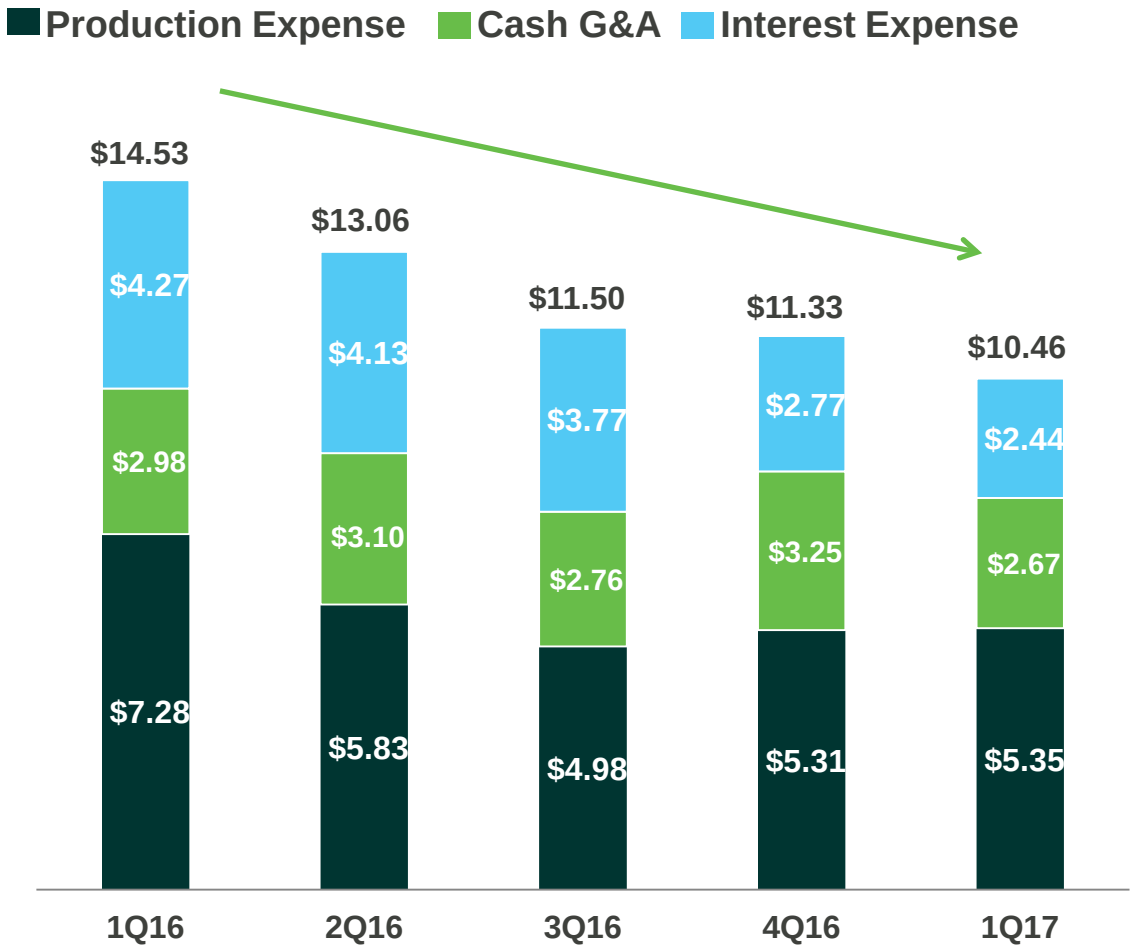
[1]Adjusted net income, adjusted EPS and EBITDAX are non-GAAP measures. See appendix for reconciliation to GAAP measures.

Growing Production and Controlling Costs

Increasing Quarterly Production



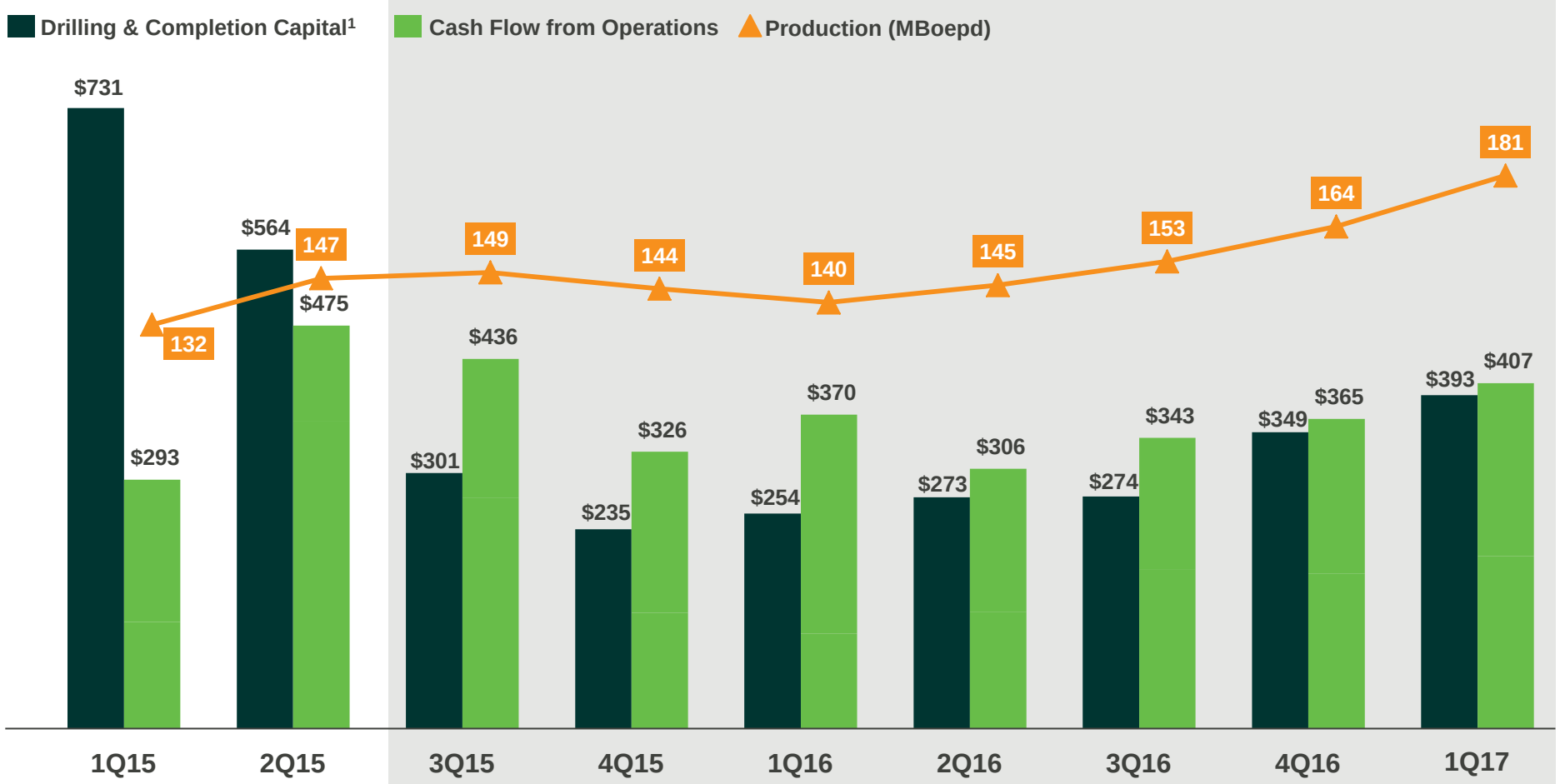
Controlling Costs ($/Boe)



Executing a Disciplined Capital Program

Operating Cash Flows *Exceeded* D&C Capital for Past *Seven Quarters*

D&C Capital vs. Cash Flows ($mm)



	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17
Avg. HZ Rigs	30	18	15	12	10	13	17	18	21

[1]D&C capital represents exploration and development costs incurred for oil and natural gas producing activities for each quarter shown. See appendix for a summary of costs incurred.

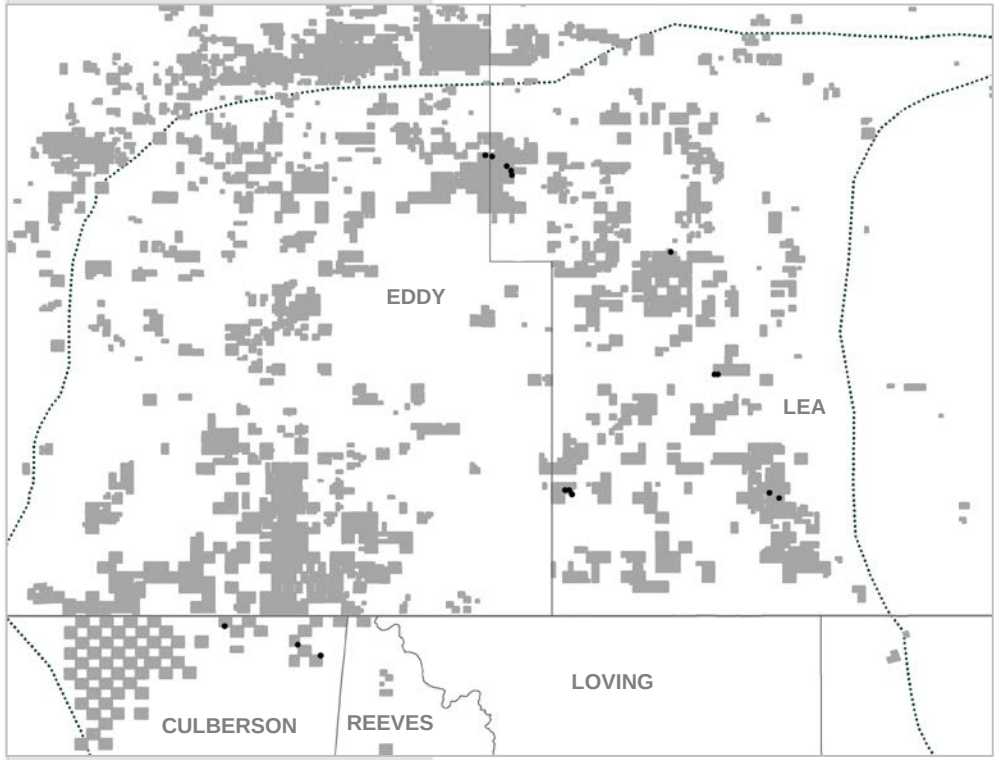
Northern Delaware Basin

Industry-Leading Exposure to Prolific Stacked Resource

~380,000 gross (260,000 net) acres

12,000 Horizontal Drilling Inventory (Gross)

8 Horizontal Rigs



CXO Acreage ● CXO 1Q17 HZ well

1Q17 Results

› **Added 16 horizontal wells (avg. lateral length 5,084')**
- Avg. 30-day peak rate: 1,473 Boepd (75% oil)
- Avg. 24-hour peak rate: 1,825 Boepd

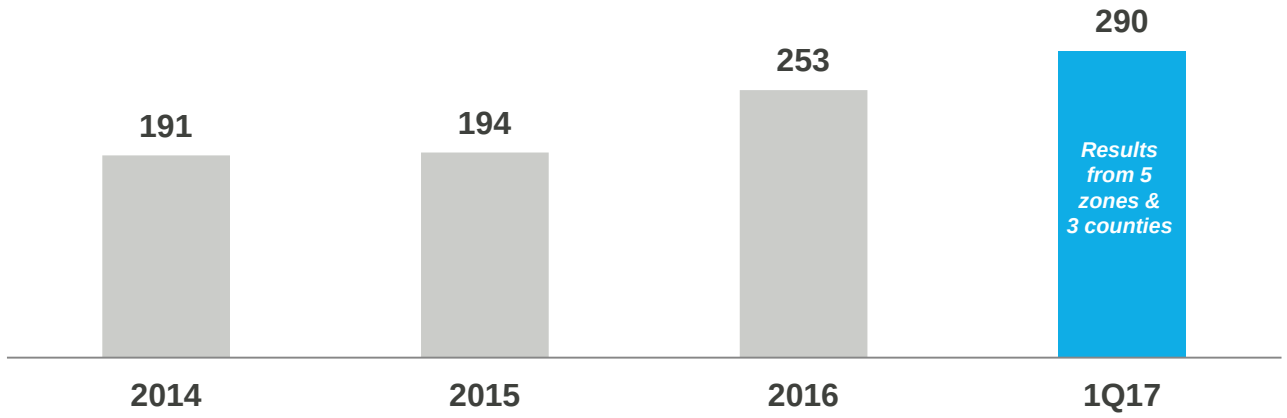
★ ***Record Performance: 30-day peak rate; 30-day peak rate per 1K'***

2017 Plans

› **Shift to manufacturing mode**

› **Exciting zone-delineation and well spacing projects**

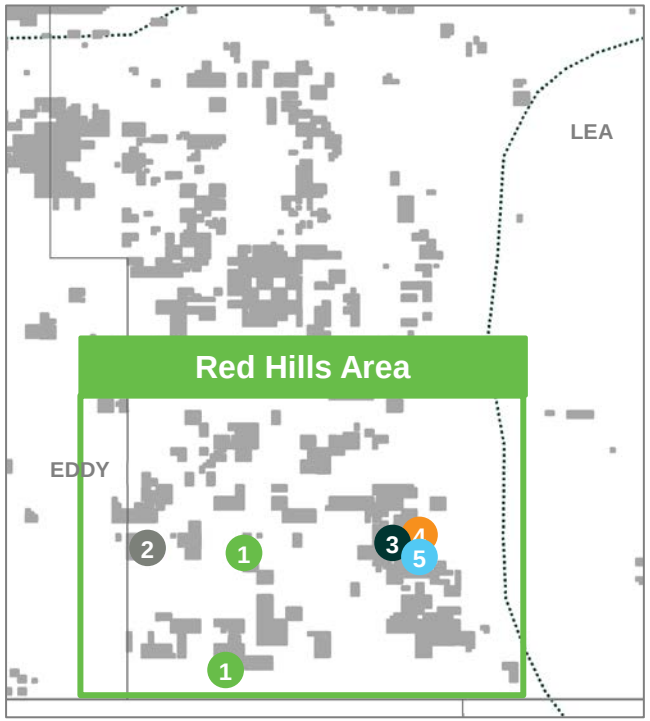
Avg. Peak 30-Day Rate per 1K'



Note: Acreage as of December 31, 2016 pro forma for recent ~24,000 gross (16,400 net) acquisition. 1Q17 results represent wells with >30 days of production data in 1Q17.

Northern Delaware Basin: Red Hills Area

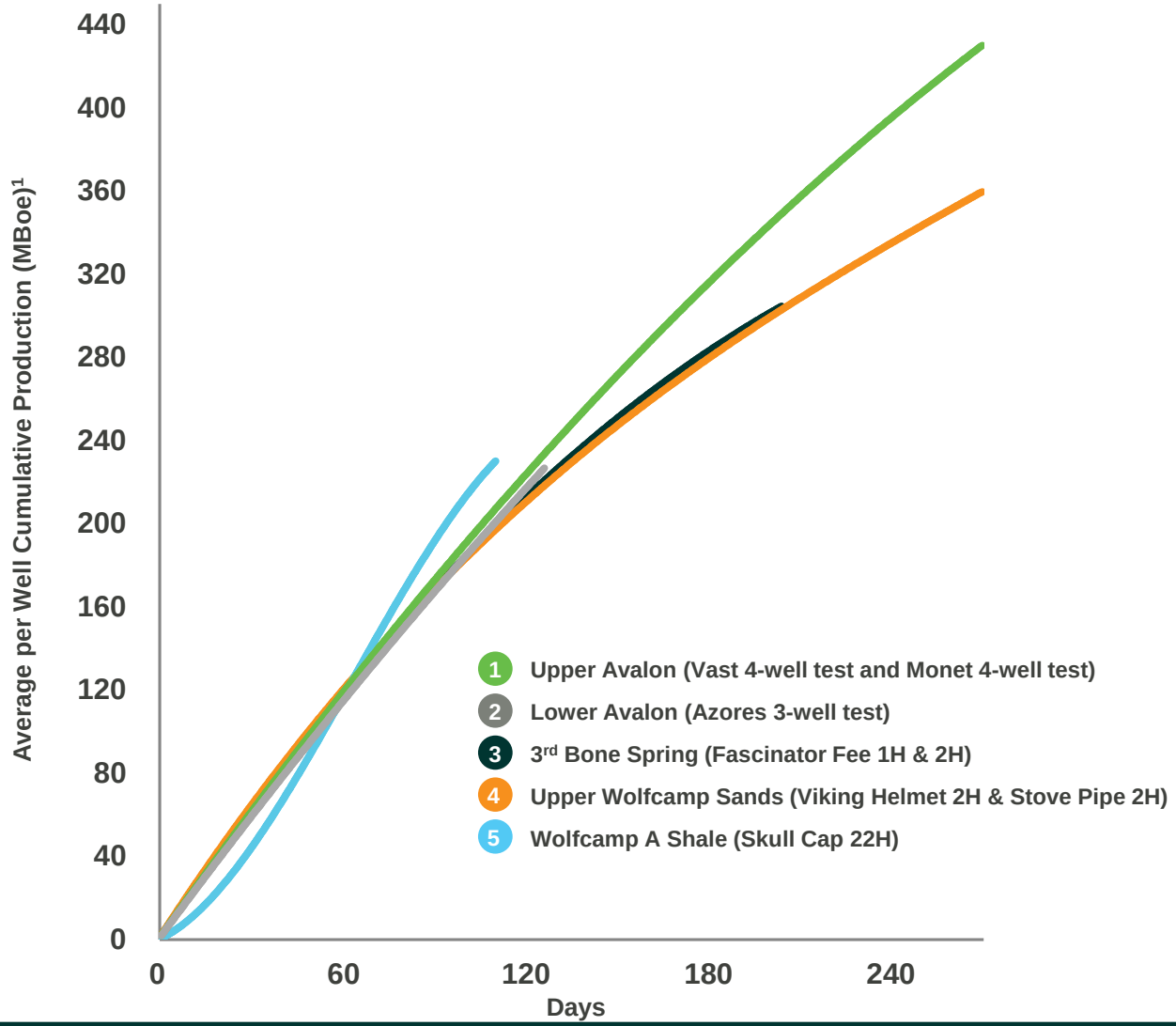
Oil-Rich, Multi-Zone Development



Scalable Growth

- **Big, blocky acreage position**
- **Shift to manufacturing mode & long-lateral development**
- **Key Projects:**
  - Windward: 8-well, 2-mile lateral Avalon project
  - Vast: 7-well Wolfcamp project
  - Columbus: 4-well Wolfcamp project

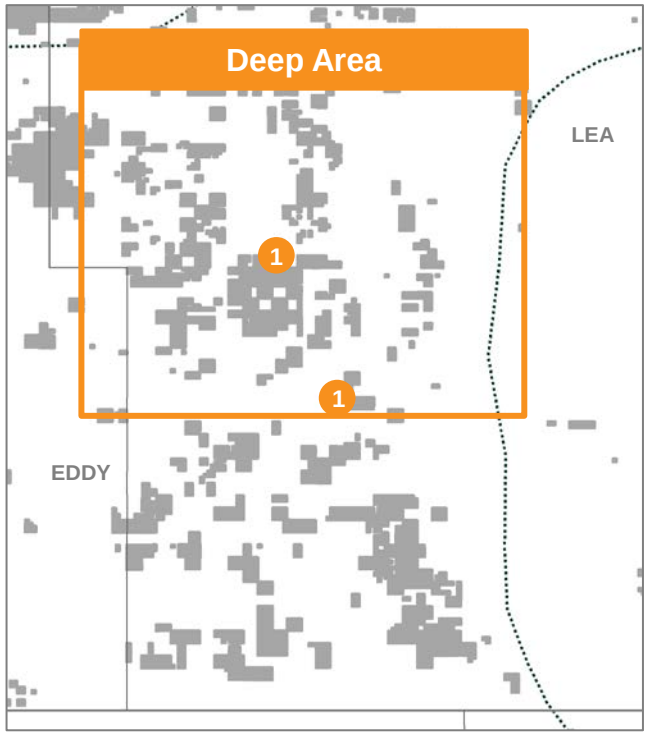
Red Hills Multi-Zone Well Performance



[1]Production normalized for a 7,000' lateral.

Northern Delaware Basin: Deep Area

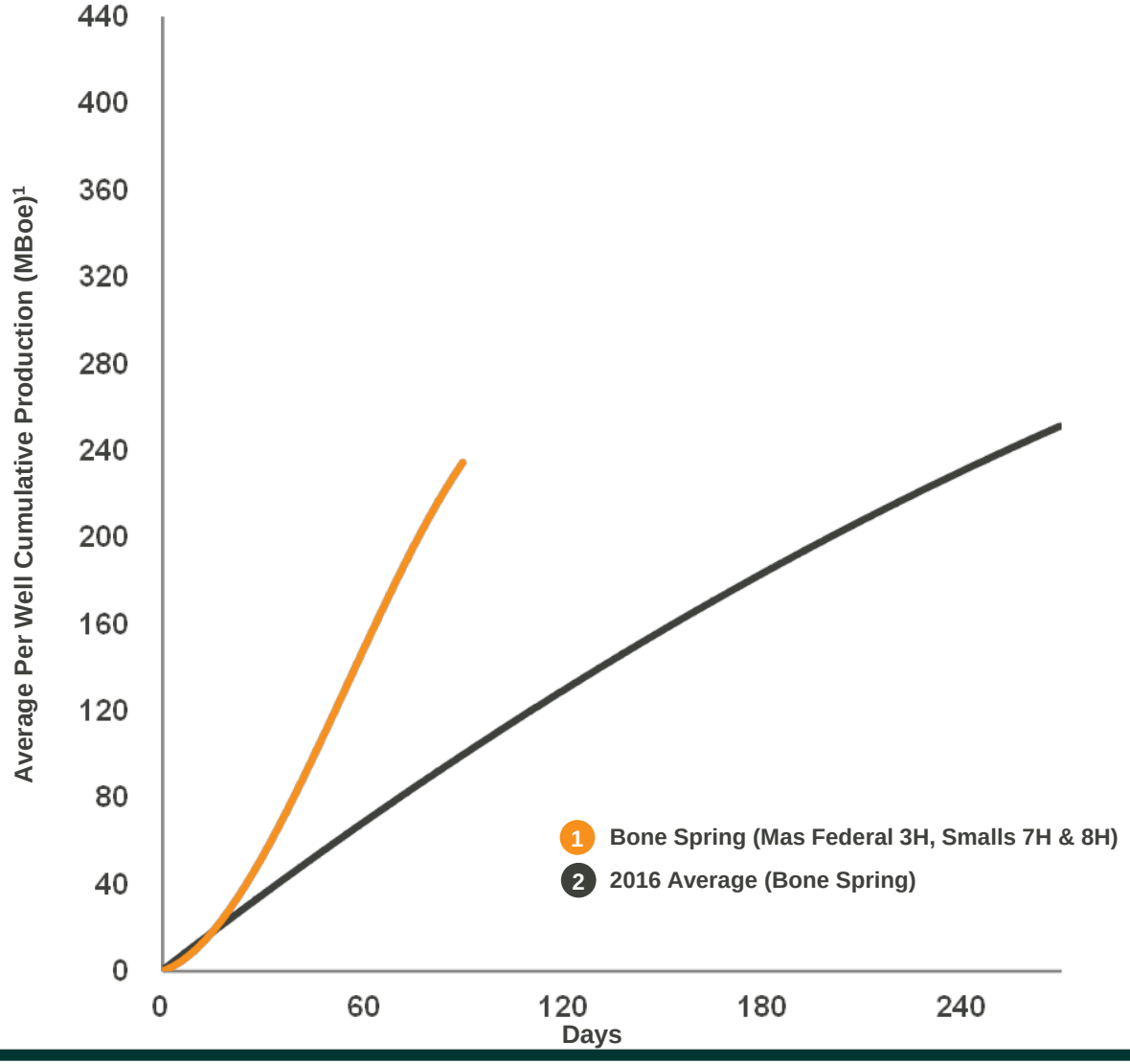
Extending the Oil-Rich Fairway North



Outstanding Bone Spring Performance

- 3 wells produced at an avg. 30-day peak rate of 2,112 Boepd (81% oil) (avg. lateral length 4,274')
- Actively developing Bone Spring and Wolfcamp zones in the Deep area

Deep Area Bone Spring Well Performance



[1]Production normalized for a 7,000' lateral.

Southern Delaware Basin

Core Position in Rapidly Advancing Oil Play

~160,000 gross (100,000 net) acres

1,300 Horizontal Drilling Inventory (Gross)

6 Horizontal Rigs

1Q17 Results

- **Added 9 horizontal wells (avg. lateral length 8,184')**
  - Avg. 30-day peak rate: 1,632 Boepd (73% oil)
  - Avg. 24-hour peak rate: 2,156 Boepd

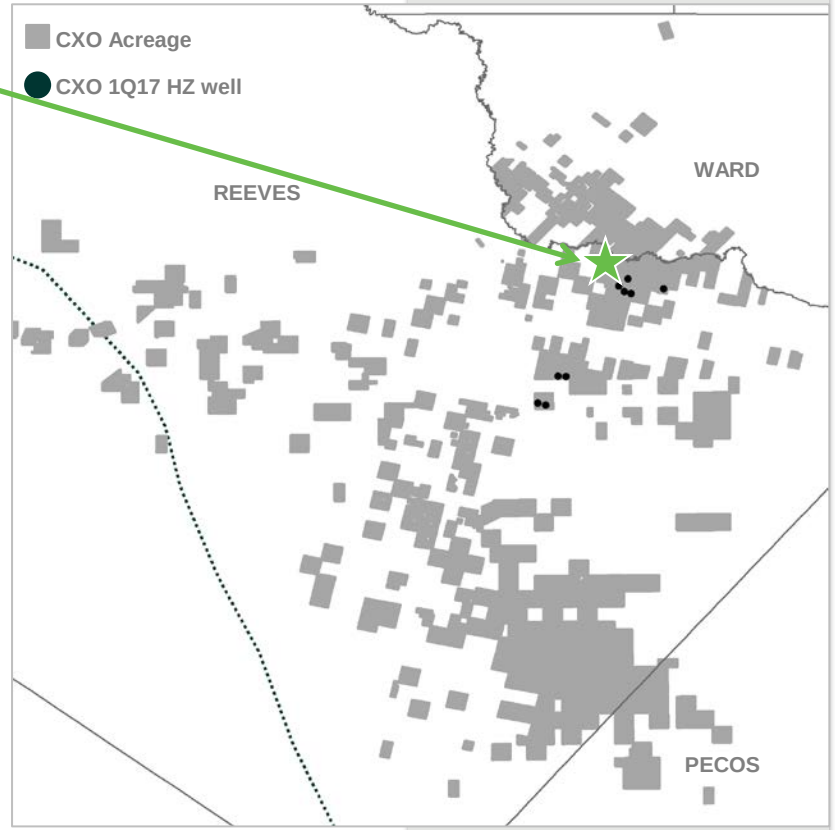
★ ***Record Performance: 30-day peak rate; lateral length***

Multi-Interval, Spacing Project:

- **Brass Monkey: 8 two-mile+ wells targeting 3rd Bone Spring and Wolfcamp zones**
- **Development within a half section**

2017 Plans

- **~90% extended length laterals**
- **~70% multi-well pad development**
- **Optimize development of the Wolfcamp and 3rd Bone Spring**



Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 1Q17.

Midland Basin

Building Momentum with Large-Scale Development Projects

1Q17 Results

- **Added 21 horizontal wells (avg. lateral length 9,910')**
  - Avg. 30-day peak rate: 1,164 Boepd (88% oil)
  - Avg. 24-hour peak rate: 1,453 Boepd

Multi-Interval, Spacing Project:

- **Mabee Ranch: 13 two-mile wells targeting 5 landings across the Spraberry & Wolfcamp zones**
- **Development pattern implies 32 wells per section**

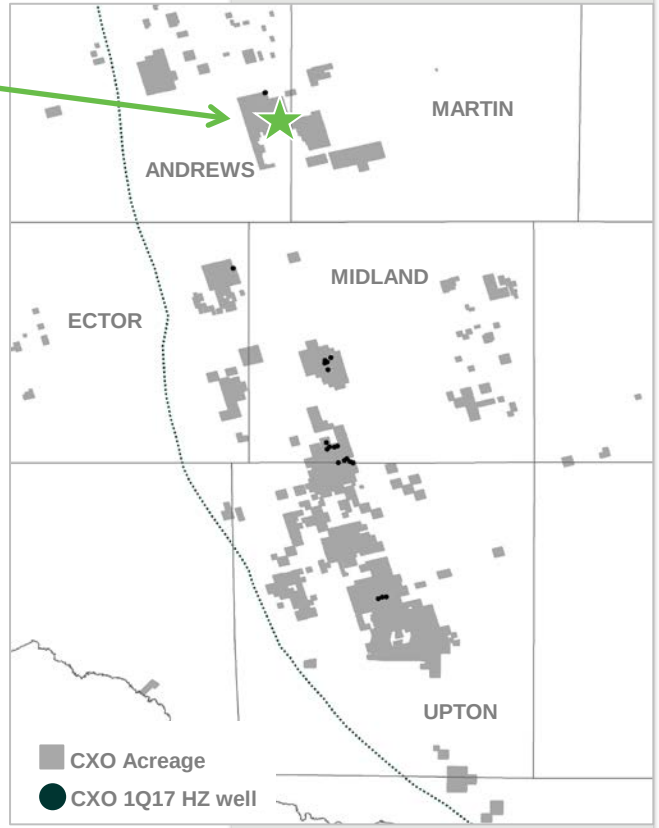
2017 Plans

- **~100% ≥ 10,000' laterals**
- **~100% multi-well pad development**
- **Optimize well spacing and development pattern**

~260,000 gross (160,000 net) acres

4,000 Horizontal Drilling Inventory (Gross)

5 Horizontal Rigs



Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 1Q17.

New Mexico Shelf

Improving Recoveries in Legacy Oil Play

~130,000 gross (80,000 net) acres

2,100 Horizontal Drilling Inventory (Gross)

2 Horizontal Rigs

1Q17 Results

- **Added 7 horizontal wells (avg. lateral length 4,517')**
  - Avg. 30-day peak rate: 546 Boepd (84% oil)
  - Avg. 24-hour peak rate: 701 Boepd

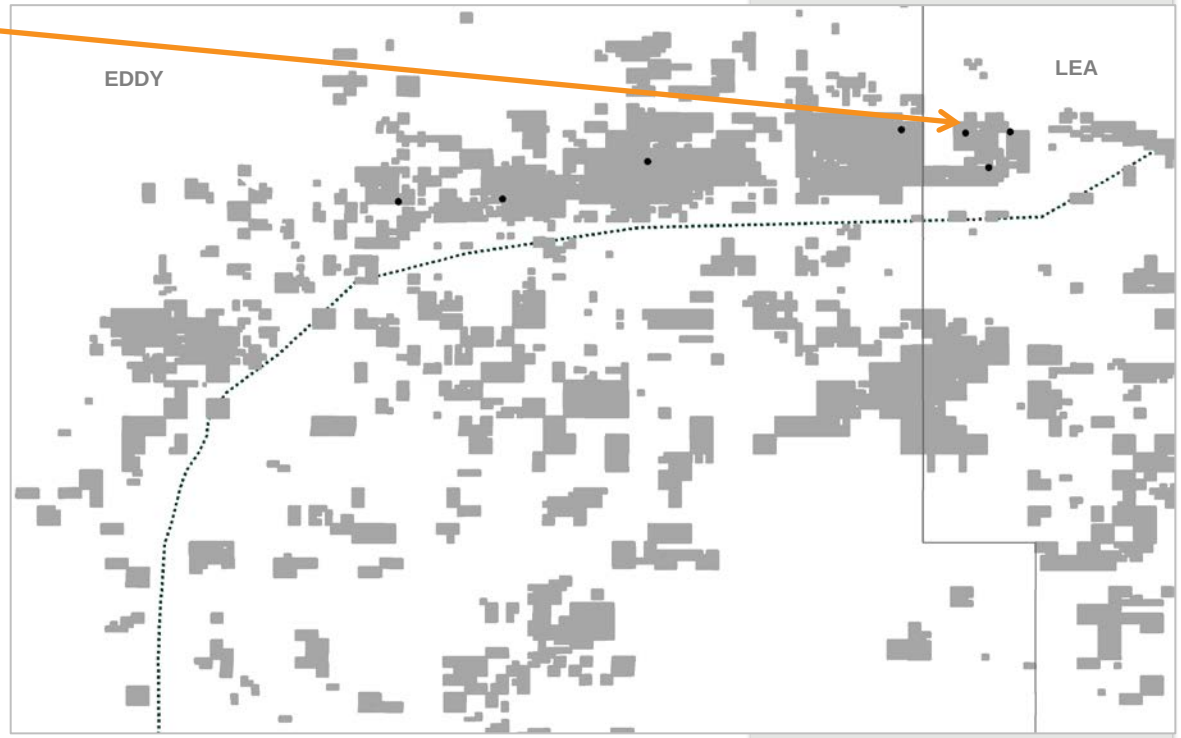
★ ***Record Performance: 30-day peak rate per 1K'***

Record Setting Horizontal Well:

- **1-mile lateral well in the Paddock formation**
- **Peak 30-day rate of 1,039 Boepd (84% oil)**

2017 Plans

- **Rate-of-return competitive at low oil prices**
- **Optimize well spacing, lateral length and completion techniques**



CXO Acreage ● CXO 1Q17 HZ well

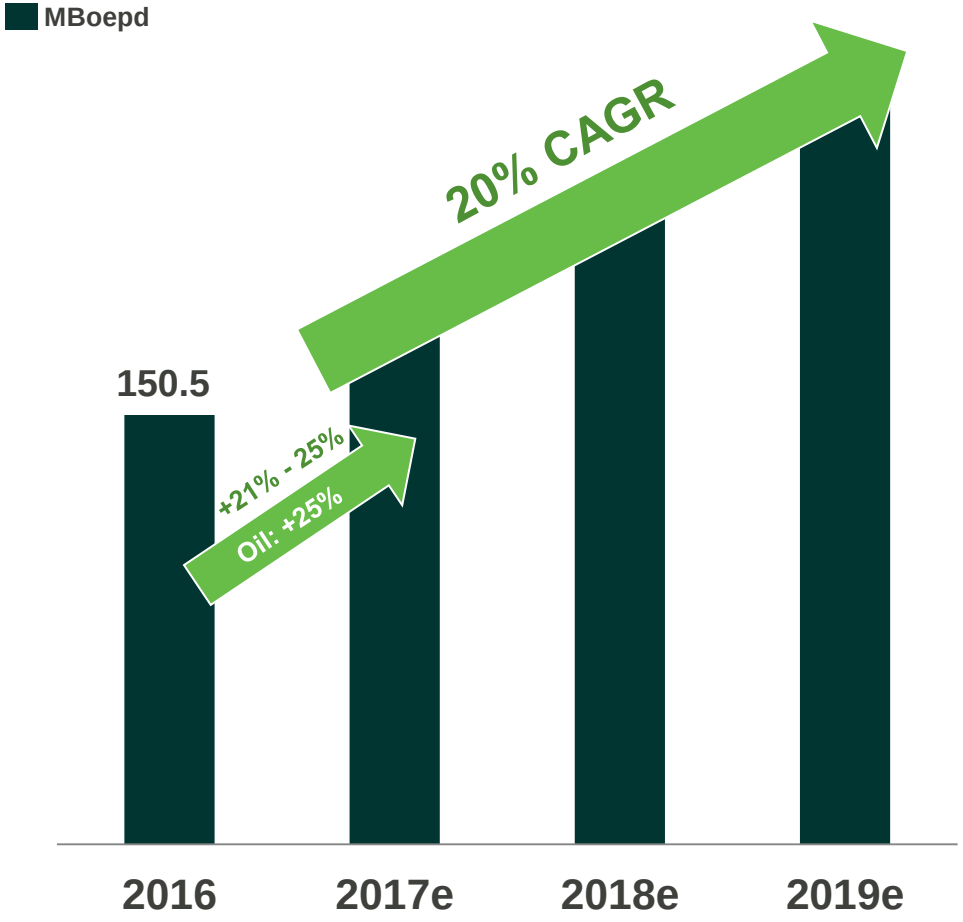
Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 1Q17.

Performance Track Record, Robust Outlook

Delivering Differentiated Growth

- **Expect 2017 annual production growth of 21% - 25% within cash flow**
  - ✓ *Crude oil production expected to grow 25%*
- **Performance track record demonstrates ability to deliver differentiated growth within cash flows in current commodity price environment**
- **Growth drivers:**
  - ✓ *High-quality inventory*
  - ✓ *Operational excellence*
  - ✓ *Cost control*
  - ✓ *Prudent capital management*

Visible Growth from High-Quality Assets



Differentiated Growth within Cash Flows

Appendix

2017 Capital Program

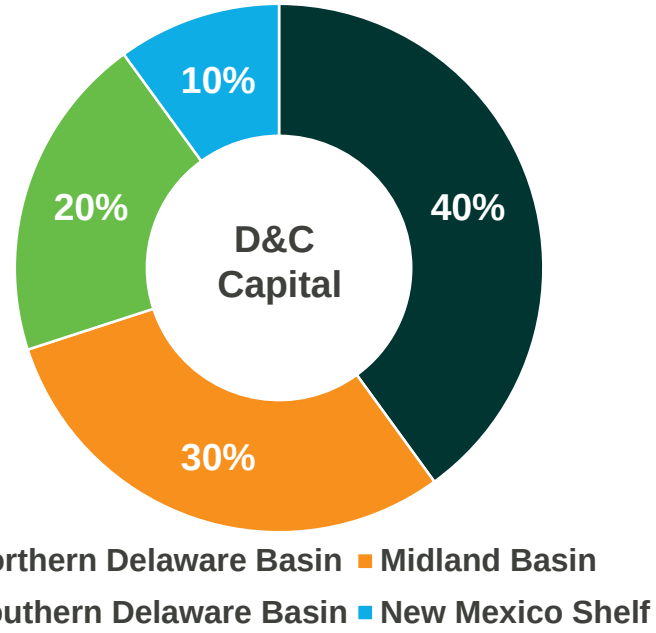
Capital-Efficient Growth & Value Creation

Maximizing Scale Advantage through Diversified Capital Allocation

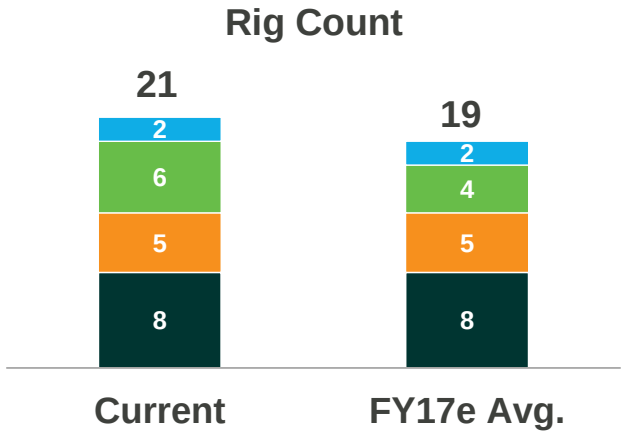
- Expect to fund within cash flows
- Directing capital to high-ROR projects
- Realizing benefits of portfolio high grading

2017 Capital Program Allocation

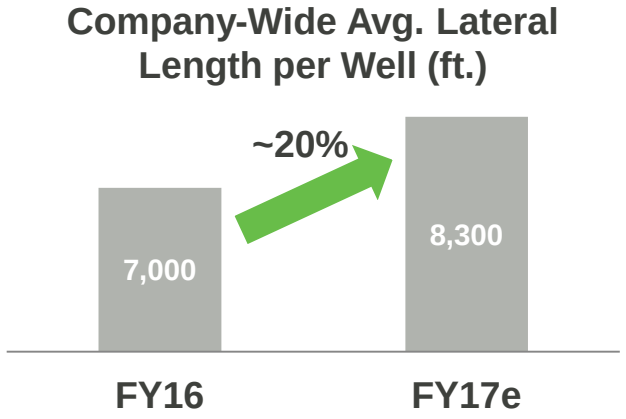
- **Total capital program: $1.6bn to $1.8bn[1]**
- **~90% of capital directed to drilling and completion activity**
  - Remaining ~10% for infrastructure and other



Extending Efficiency Gains



- *Rigs in place to deliver on 2017 growth target*
- *Consolidation increases program WI, led by Midland Basin*



- *Drilling longer laterals across portfolio*
- *70%+ of program to utilize multi-well pads*

Targeting 21% to 25% Production Growth and 25% Oil Production Growth

[1]Capital program excludes acquisitions.

Hedge Position

2017 OIL HEDGES
86.7 MBopd

	2017				2018	2019
	Second	Third	Fourth	Total	Total	Total
Oil Swaps[1]:						
Volume (Bbl)	8,679,480	7,966,370	7,188,080	23,833,930	21,537,124	8,854,000
Price per Bbl	$ 56.46	$ 51.69	$ 51.87	$ 53.48	$ 51.86	$ 55.14
Oil Basis Swaps[2]:						
Volume (Bbl)	6,141,500	5,290,000	5,290,000	16,721,500	15,695,000	2,555,000
Price per Bbl	$ (1.03)	$ (0.49)	$ (0.49)	$ (0.69)	$ (1.00)	$ (1.25)
Natural Gas Swaps[3]:						
Volume (MMBtu)	14,814,642	14,665,441	14,043,000	43,523,083	33,370,000	-
Price per MMBtu	$ 3.08	$ 3.10	$ 3.09	$ 3.09	$ 3.04	$ -

UPDATED AS OF MAY 3, 2017

[1]The index prices for the oil price swaps are based on the New York Mercantile Exchange (NYMEX) – West Texas Intermediate (WTI) monthly average futures price.
[2]The basis differential price is between Midland – WTI and Cushing – WTI.
[3]The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

2017 Operational & Financial Outlook

2Q17 GUIDANCE
182 - 186 MBoepd

	2017 Guidance
Production	
Annual growth	21% - 25%
Oil mix	62% - 64%
Price realizations, excluding commodity derivatives	
Crude oil differential to NYMEX (per Bbl)	($3.00) - ($3.50)
Natural gas (per Mcf) (% of NYMEX)	90% - 100%
Operating costs and expenses (per Boe, unless noted)	
Oil and natural gas production expense	$5.50 - $6.00
Production and ad valorem taxes (% of oil & natural gas revenues)	8.00%
G&A:	
Cash G&A	$2.60 - $2.90
Non-cash stock-based compensation	$1.00 - $1.20
DD&A	$17.00 - $19.00
Exploration and other	$1.00 - $1.50
Interest expense ($mm):	
Cash	$160 - $170
Non-cash	$10
Income tax rate	38%
Current taxes ($mm)	$10 - $20
Capital program ($bn)[1]	$1.6 - $1.8

UPDATED AS OF MAY 3, 2017

[1]Capital program excludes acquisitions.

Reconciliation of Net Income (Loss) to Adjusted Net Income (Loss) and Adjusted Earnings per Share (Unaudited)

The Company's presentation of adjusted net income (loss) and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted net income (loss) and adjusted earnings per share represent earnings and diluted earnings per share determined under GAAP without regard to certain non-cash and unusual items. The Company believes these measures provide useful information to analysts and investors for analysis of its operating results on a recurring, comparable basis from period to period. Adjusted net income (loss) and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with GAAP and may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation from the GAAP measure of net income (loss) to adjusted net income (loss) (non-GAAP), both in total and on a per diluted share basis, for the periods indicated:

(in millions, except per share amounts)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net income (loss) - as reported	**$ 650**	**$ (1,020)**
Adjustments for certain non-cash and unusual items:		
Gain on derivatives	(286)	(81)
Net cash receipts from derivatives	28	259
Impairments of long-lived assets	-	1,525
Leasehold abandonments	6	21
Gain on disposition of assets and other	(654)	(109)
Tax impact	336	(601)
Excess tax benefit	(8)	-
Adjusted net income (loss)	**$ 72**	**$ (6)**
Net Income (loss) per diluted share - as reported	$ 4.37	$ (7.95)
Adjustments for certain non-cash and unusual items per diluted share:		
Gain on derivatives	(1.92)	(0.62)
Net cash receipts from derivatives	0.18	2.01
Impairments of long-lived assets	-	11.88
Leasehold abandonments	0.04	0.16
Gain on disposition of assets and other	(4.40)	(0.86)
Tax impact	2.27	(4.67)
Excess tax benefit	(0.05)	-
Adjusted net income (loss) per diluted share	**$ 0.49**	**$ (0.05)**
Adjusted earnings per share:		
Basic net income (loss)	$ 0.49	$ (0.05)
Diluted net income (loss)	$ 0.49	$ (0.05)

Reconciliation of Net Income (Loss) to EBITDAX (Unaudited)

EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income (loss) because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund exploration and development activities.

The Company defines EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) gain on derivatives, (7) net cash receipts from derivatives, (8) gain on disposition of assets, net, (9) interest expense and (10) federal and state income tax expense (benefit). EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

The Company's EBITDAX measure provides additional information which may be used to better understand the Company's operations, and it is also a material component of one of the financial covenants under the Company's credit facility. EBITDAX is one of several metrics that the Company uses as a supplemental financial measurement in the evaluation of its business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by the Company, may not be comparable to similarly titled measures reported by other companies. The Company believes that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by the Company's management team and by other users of the Company's consolidated financial statements, including by lenders pursuant to a covenant in the Company's credit facility. For example, EBITDAX can be used to assess the Company's operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of the Company's assets and the Company without regard to capital structure or historical cost basis. Further, under the Company's credit facility, an event of default could arise if it were not able to satisfy and remain in compliance with its specified financial ratio, defined as the maintenance of a quarterly ratio of total debt to consolidated last twelve months EBITDAX of no greater than 4.25 to 1.0. Non-compliance with this ratio could trigger an event of default under the Company's credit facility, which then could trigger an event of default under its indentures. At March 31, 2017, the Company was in compliance with the covenants under all of its debt instruments.

The following table provides a reconciliation of the GAAP measure of net income (loss) to EBITDAX (non-GAAP) for the periods indicated:

(in millions)	Three Months Ended March 31,	
	2017	2016
Net income (loss)	**$ 650**	**$ (1,020)**
Exploration and abandonments	15	23
Depreciation, depletion and amortization	283	310
Accretion of discount on asset retirement obligations	2	2
Impairments of long-lived assets	-	1,525
Non-cash stock-based compensation	12	16
Gain on derivatives	(286)	(81)
Net cash receipts from derivatives	28	259
Gain on disposition of assets, net	(654)	(111)
Interest expense	40	54
Income tax expense (benefit)	371	(594)
EBITDAX	**$ 461**	**$ 383**

Costs Incurred (Unaudited)

The following table summarizes costs incurred for oil and natural gas producing activities for the periods indicated:

(in millions)		Three Months Ended							
	March 31, 2017	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
Property Acquisition Costs:									
Proved	$ 127	$ 725	$ 1	$ 4	$ 252	$ (2)	$ 57	$ 2	$ -
Unproved	306	982	15	19	139	10	162	18	16
Exploration	235	188	177	166	171	149	202	343	429
Development	158	161	97	107	83	86	99	221	302
Total Costs Incurred	**$ 826**	**$ 2,057**	**$ 289**	**$ 295**	**$ 645**	**$ 244**	**$ 520**	**$ 585**	**$ 747**