Howard Weil

45th Annual Energy Conference

MARCH 2017

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, 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 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 Form 10-K; 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 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 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; the impact of potential changes in the Company’s credit ratings; 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 related to the integration of acquired properties or businesses; uncertainties about the Company’s ability to successfully execute its business and financial plans and strategies; 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. Accordingly, you should not place undue reliance on any of the Company’s forward-looking statements. 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.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), including 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 EBITDAX to the nearest comparable measures in accordance with GAAP, please see the appendix.

We also disclose reserves replacement ratio and finding and development costs in this presentation. Please see the appendix for an explanation of how we calculate these metrics.

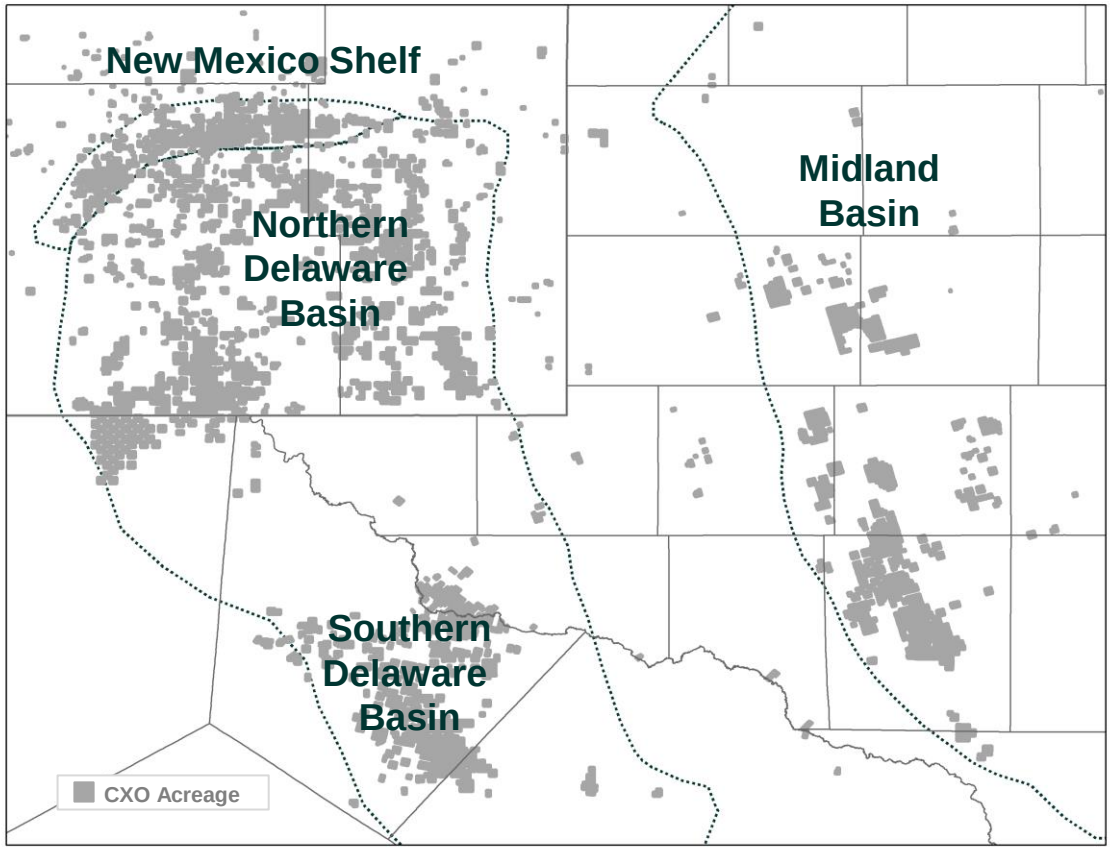
The Securities and Exchange Commission (“SEC”) requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be 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.

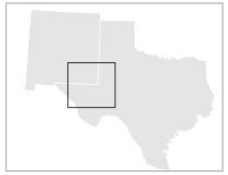
In this presentation, proved reserves attributable to the Company at December 31, 2016 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $39.25 per Bbl of oil and $2.48 per MMBtu of natural gas. The 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.

Concho Resources

Largest Pure-Play Permian Company

Premier Permian Assets





Leading exposure to the Permian Basin

- ~930,000 gross (600,000 net) acres
- Four core areas benefit capital flexibility

Prolific growth platform

- 720 MMBoe estimated proved reserves
- ~8 BBoe of total resource potential, including proved reserves, and >19,000 horizontal drilling locations

Delivering near-term performance, building for long-term value creation

- Operational focus on maximizing resource recovery and efficiencies
- Outlook to deliver exceptional long-term oil growth within cash flow
- Strategic portfolio management to high grade inventory

Note: Acreage as of December 31, 2016, pro forma for year-to-date announced acquisitions and dispositions. Proved reserves and resource potential as of December 31, 2016, and excludes year-to-date announced acquisitions.

2016 Was a Great Year for Concho

Well Positioned for Long-Term Value Creation

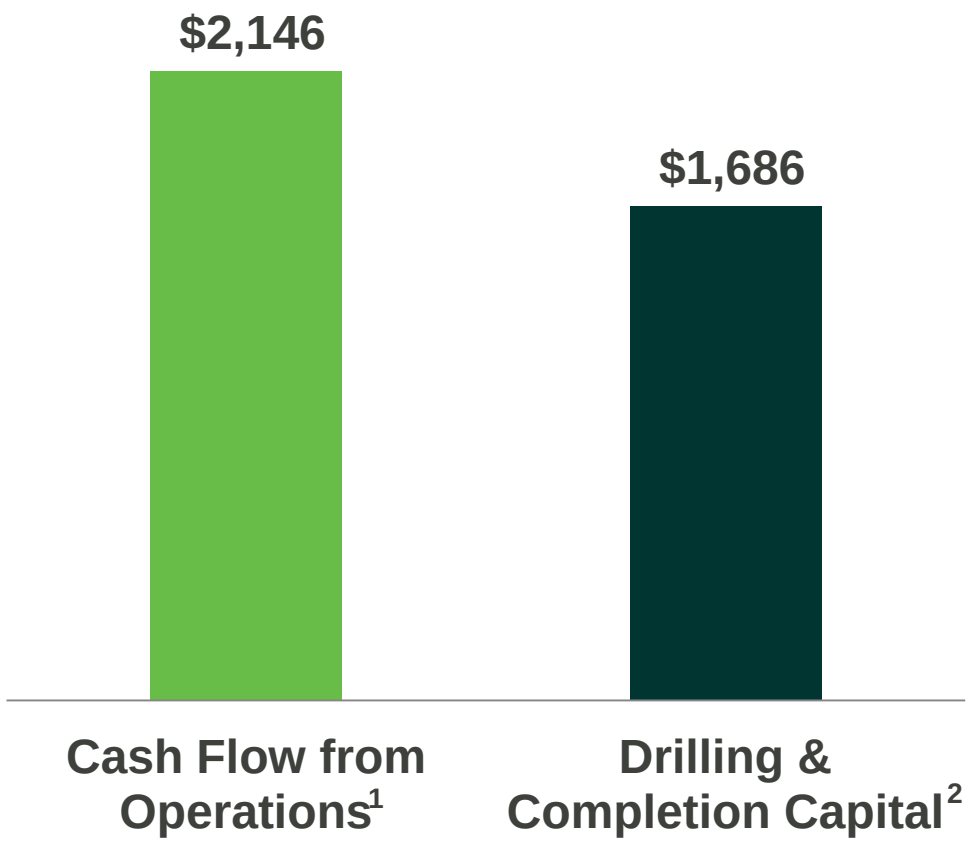
- ✓ ***Delivered 5% production growth year-over-year within cash flow***
- ✓ ***Expanded resource capture***
  - › Proved reserves grew 15% to 720 MMBoe, replacing 344% of production at a cost of $9.21 per Boe
  - › Net resource totals 8 BBoe with 19,000 identified drilling locations
- ✓ **Achieved significant, *sustainable capital efficiency improvements***
- ✓ **Reduced cash cost structure and reinforced balance sheet**
- ✓ **Executed strategic portfolio management**
  - › Increased core acreage by ~70,000 net acres
  - › Divested $325mm in non-core acreage
  - › Recently monetized ACC system for net proceeds of $803mm (6x ROIC)

Executing a Disciplined Capital Program

Preserving Financial Strength; Improving Capital Productivity

Cash Inflows vs. Outflows ($mm)

Prior 18 Months Ended December 31, 2016



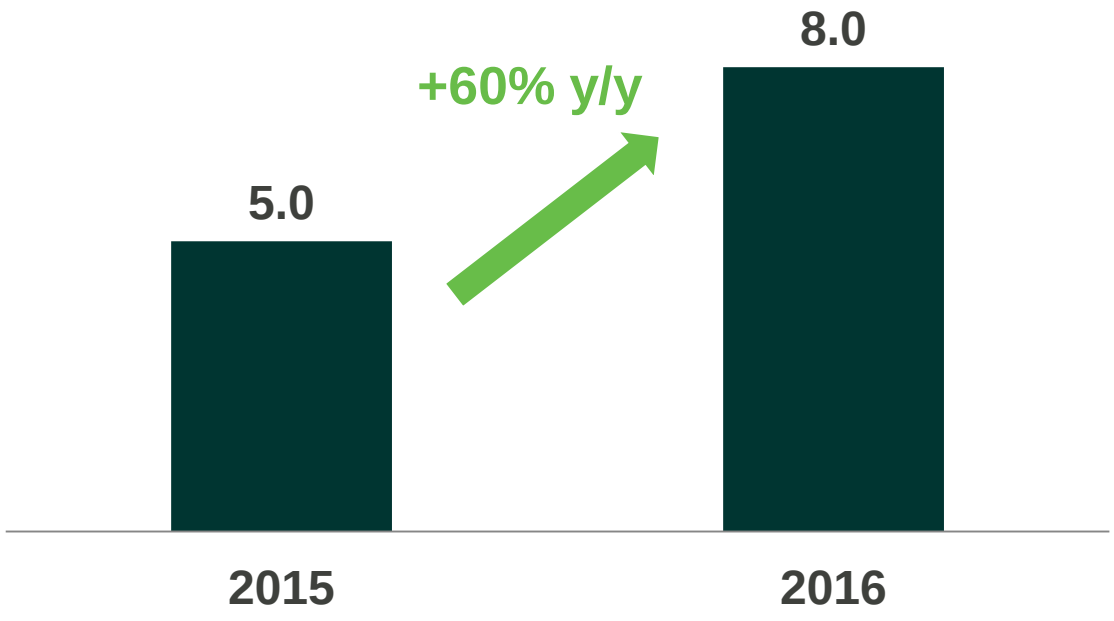
- **Over past 18 months, *operating cash flow exceeded D&C capital by ~$0.5bn***
- **Production up 10% over same time period**
- **Uniquely positioned to spend within cash flow and deliver long-term oil production growth**

[1]The six months ended 12/31/15 operating cash flow includes cash settlements from derivatives to be consistent with reclassifications included in the 2016 10-K.
[2]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.

Resource Expansion Reflects Sustainable Capital Efficiency Improvements

Resource Capture Provides Confident Growth Platform

Net Resource Potential Up ~3 BBoe

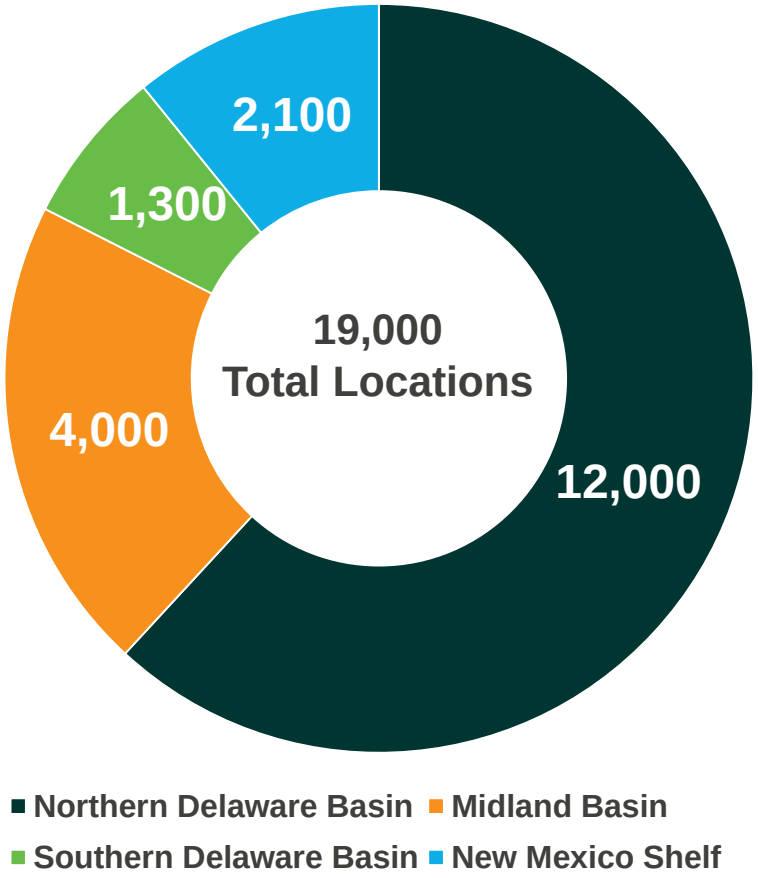


› **Key Drivers**

- ✓ *Longer laterals*
- ✓ *Acquisitions*
- ✓ *Zone delineation*
- ✓ *Tighter well spacing*
- ✓ *Model improvement*

Significant Inventory Depth

Identified Drilling Locations



Our Crystal Ball

We expect more…

Oil Price Volatility

So, we're sticking with our…

Strategy

Key Factors

High inventory levels

U.S. shale production & technology

OPEC supply trajectory

Uptick in long-cycle FIDs

Our Focus

Exercise capital discipline

Maximize resource recovery

Generate development efficiencies

Actively manage portfolio

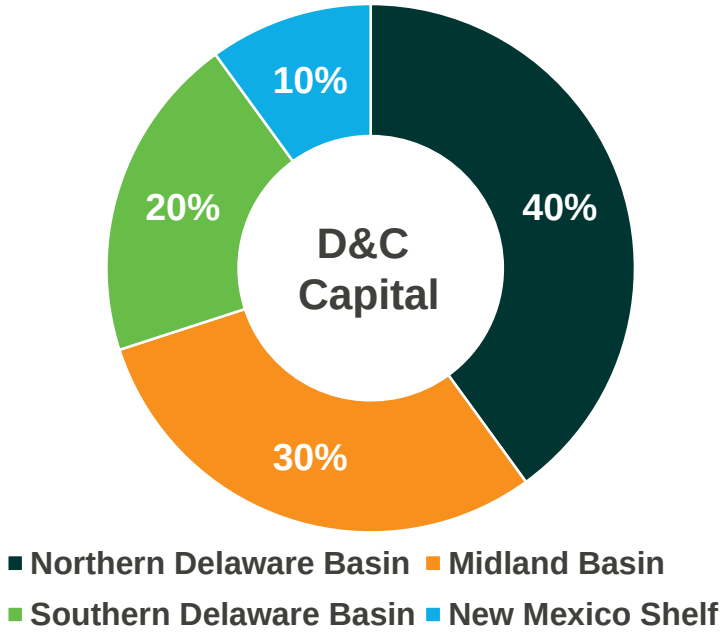
2017 Capital Program

Capital-Efficient Growth & Value Creation

2017 Capital Program Allocation

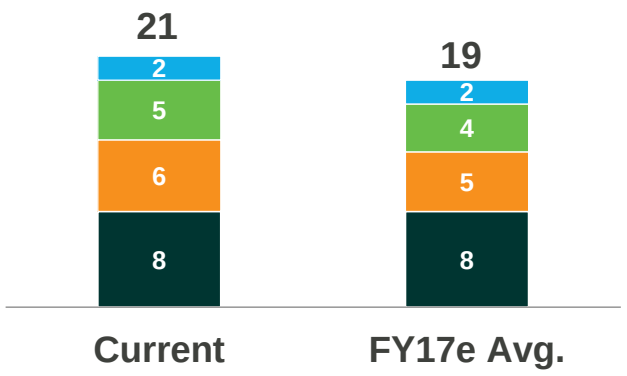
› **Total capital program range: $1.6bn – $1.8bn[1]**

- **~90% of capital directed to drilling and completion activity and ~10% for infrastructure and other**

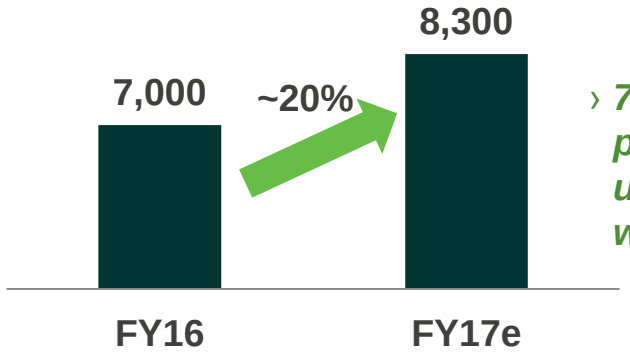


Extending Efficiency Gains

Rig Count



Company-Wide Avg. Lateral Length per Well (ft.)



› ***70%+ of program to utilize multi-well pads***

20% to 24% Production Growth and 25% Oil Production Growth within Cash Flow

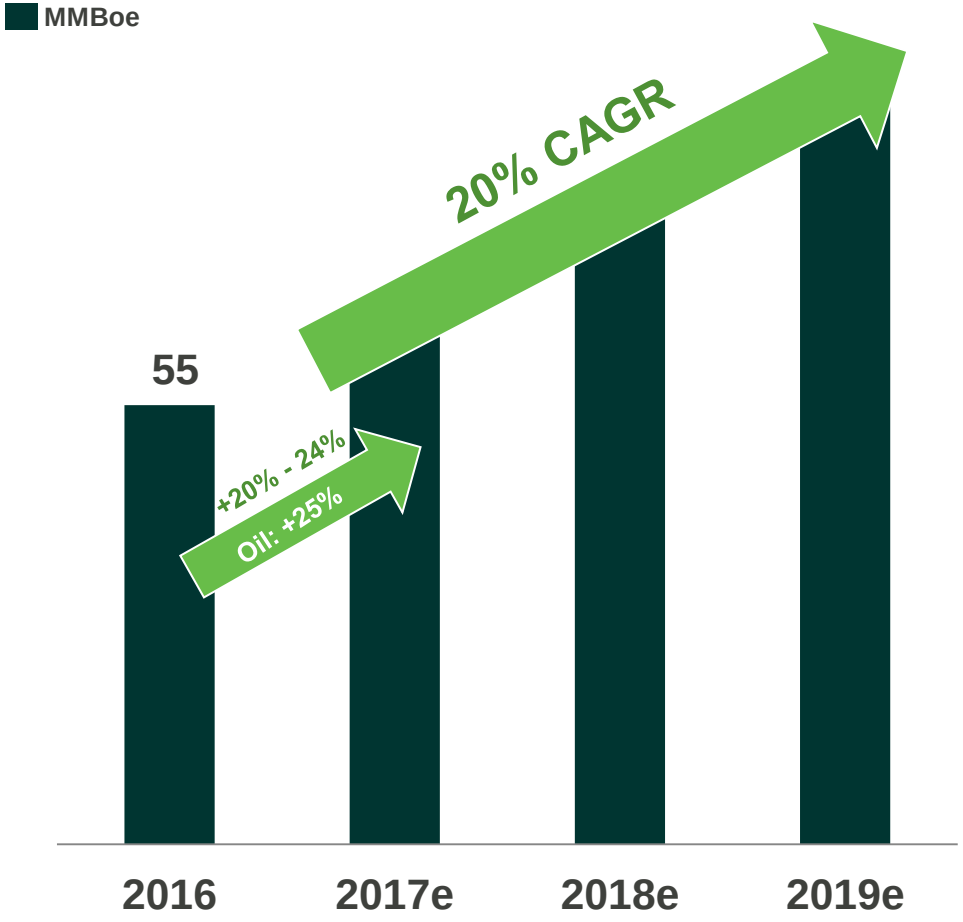
[1]Capital program excludes acquisitions.

Robust Long-Term Outlook

Delivering Differentiated Growth

- **Expect 2017 annual production growth of 20% - 24% within cash flow**
  - ✓ ***Crude oil production expected to grow 25%***
- **Performance track record demonstrates ability to deliver differentiated growth within cash flow 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

Proven Strategy Yields Unique Advantages

Execution Strength & Scale

Most active driller in the Permian Basin

~1,200

Horizontal wells drilled in past 5 years – More than any other operator

Depth of High-Quality Inventory

Prolific resource capture across the Permian Basin

19,000

Identified horizontal drilling locations

Superior Capital Efficiency

ROR-driven & strong portfolio management track record

20%

3-year production CAGR outlook

Financial Strength

Low leverage provides substantial flexibility

$800mm

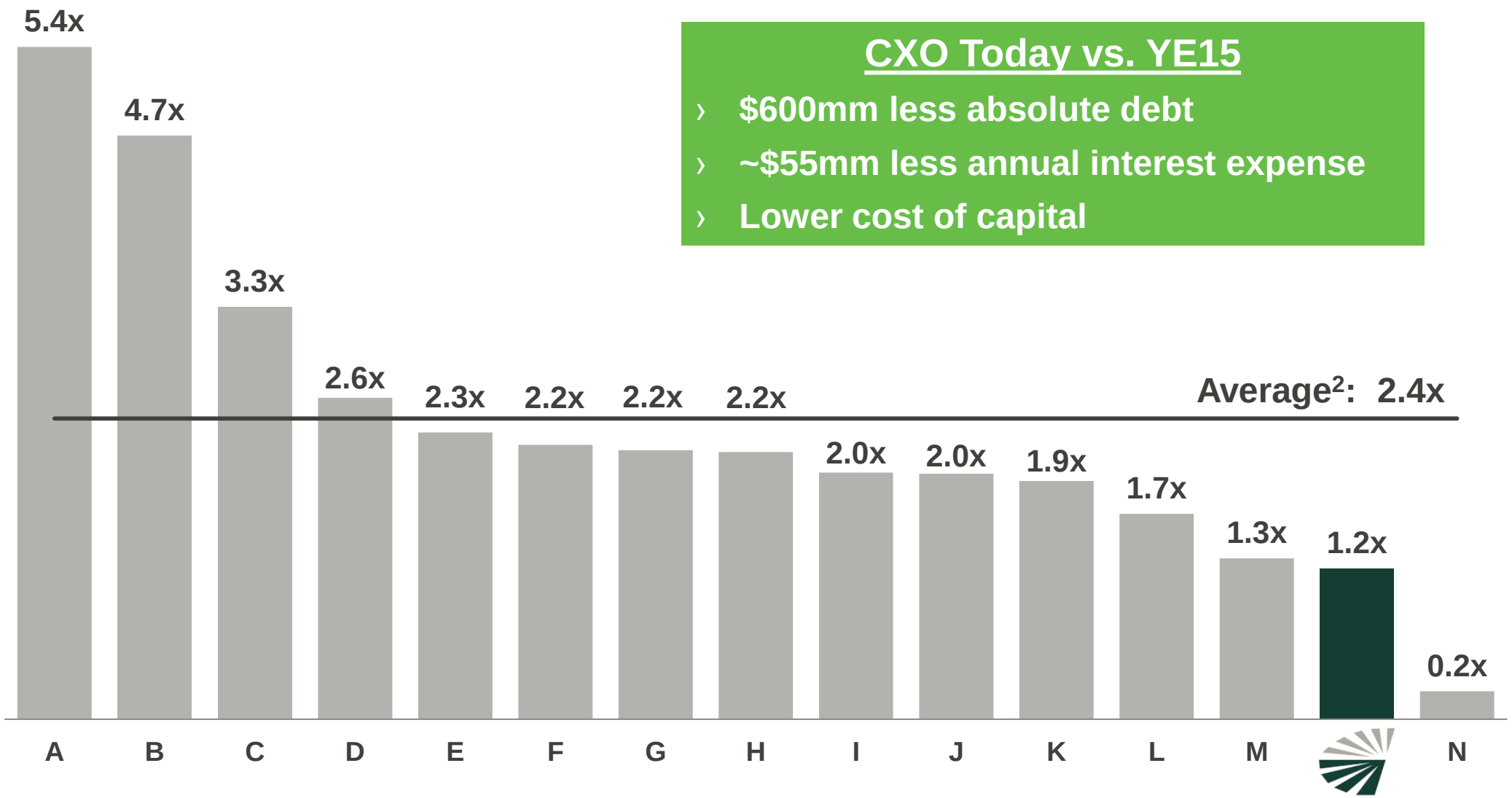
Net proceeds from ACC divestiture – further strengthens our balance sheet

Strong Balance Sheet Enhances Flexibility

YE16 Net Debt / EBITDAX[1]

Peers

Anadarko Petroleum Corporation
Apache
Cabot Oil & Gas
CIMAREX
devon
eog
HESS
Marathon Oil Corporation
NEWFIELD
noble energy
OXY
PIONEER NATURAL RESOURCES
RANGE RESOURCES
SWN Southwestern Energy



CXO Today vs. YE15

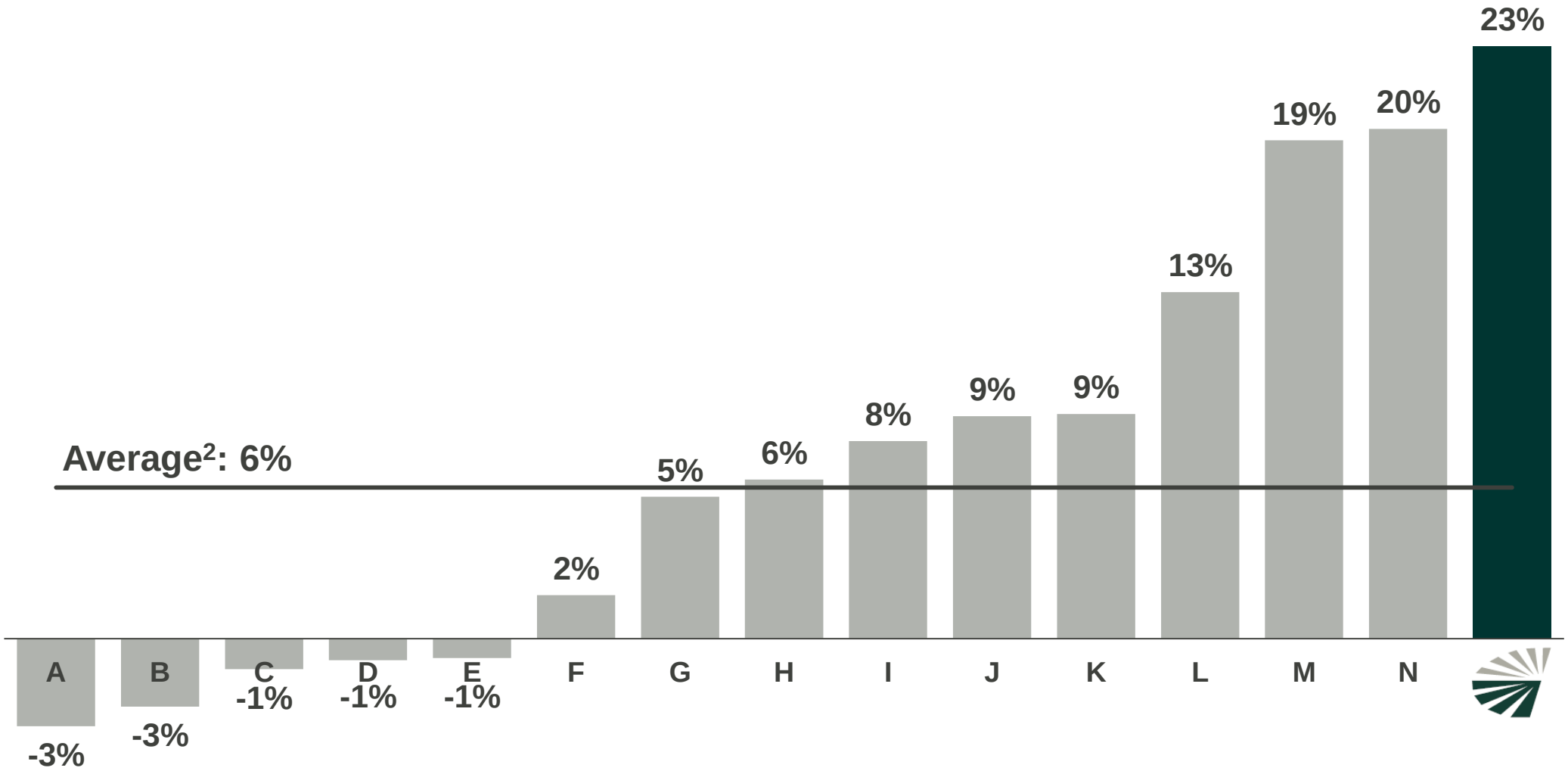
- $600mm less absolute debt
- ~$55mm less annual interest expense
- Lower cost of capital

Data per Bloomberg.
[1]CXO net debt adjusted for northern Delaware Basin acquisition and ACC divestiture. APC, MRO, NBL, PXD metrics have been adjusted for recently announced acquisitions/divestitures.
[2]Average does not include CXO.

Track Record of Peer-Leading Execution

10-Year Production Growth per Debt-Adjusted Share (CAGR)[1]

Peers



Data per Bloomberg.
[1]CXO 2006 debt-adjusted shares calculated using the IPO share price on 8/7/07 of $11.50.
[2]Average does not include CXO.

Key Messages

Consistent Execution of Our Strategy

- **High-quality, balanced asset base in the Permian with over 19,000 horizontal locations and ~8 billion barrels of net resource potential**
- **Disciplined capital program**
- **Enhancing capital efficiency with a relentless focus on operational excellence**
- **20% to 24% production growth target, led by 25% crude oil production growth, within cash flows for 2017**

Long-Term Outlook	
20% Three-Year Production CAGR	**Capital Expenditures within Cash Flows**
Maintain Strong Balance Sheet	

Appendix

Northern Delaware Basin

Industry-Leading Exposure to Prolific Stacked Resource

4Q16 Results

- **Added 16 horizontal wells (avg. lateral length 6,379')**
  - Avg. 30-day peak rate: 1,316 Boepd (71% oil)
  - Avg. 24-hour peak rate: 1,662 Boepd
- **Achieved record average lateral length**
- **Track record of outstanding results across multiple zones**
- **Have 600+ wells with > 30 days of production**

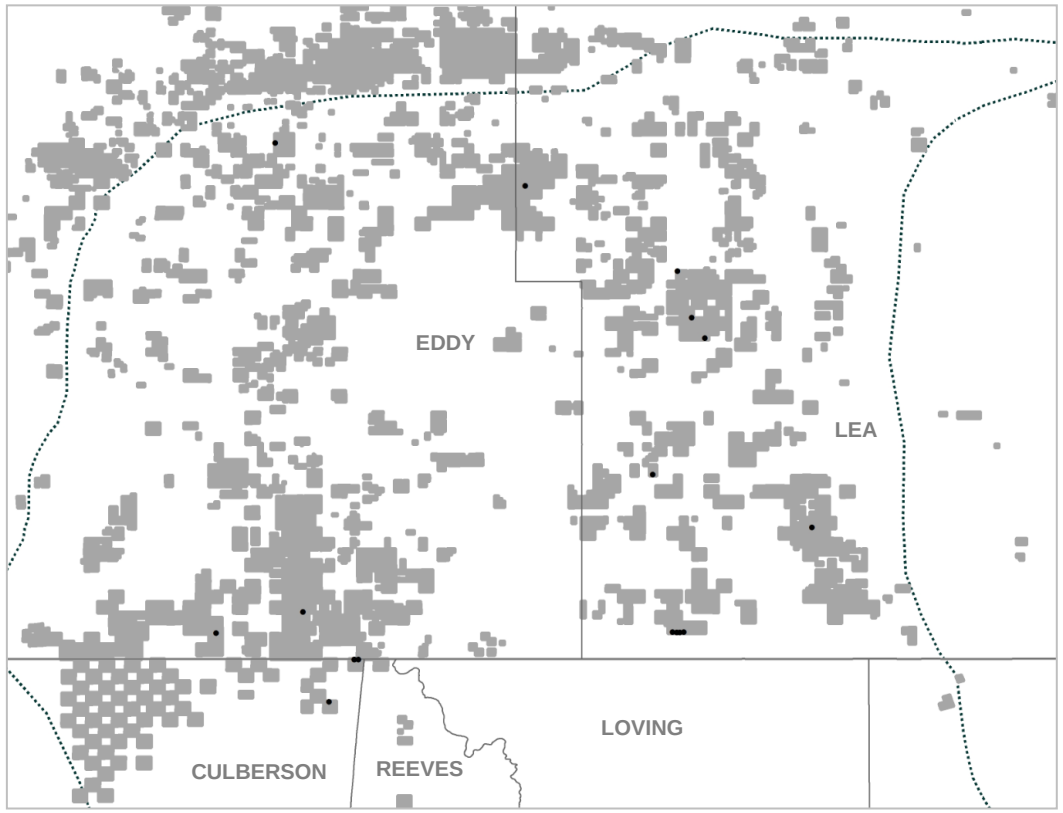
~380,000 gross (260,000 net) acres	12,000 Total Horizontal Drilling Inventory (Gross)	Running 8 Horizontal Rigs

2016 Well Completions[1]

~5,000'

FORMATION	WELL COUNT	AVG. PEAK RATE (Boepd)	
		30-DAY (% OIL)	24-HOUR
Brushy Canyon	-	-	-
Avalon Shale	24	1,441 (73%)	1,816
1st Bone Spring	-	-	-
2nd Bone Spring	25	1,076 (74%)	1,409
3rd Bone Spring	11	1,096 (80%)	1,488
Upper Wolfcamp Sands	3	1,916 (82%)	2,365
Upper Wolfcamp Shale	4	1,308 (67%)	1,558
Middle Wolfcamp	2	1,060 (35%)	1,491
Lower Wolfcamp	4	1,127 (36%)	1,553

★ *Emerging Target*



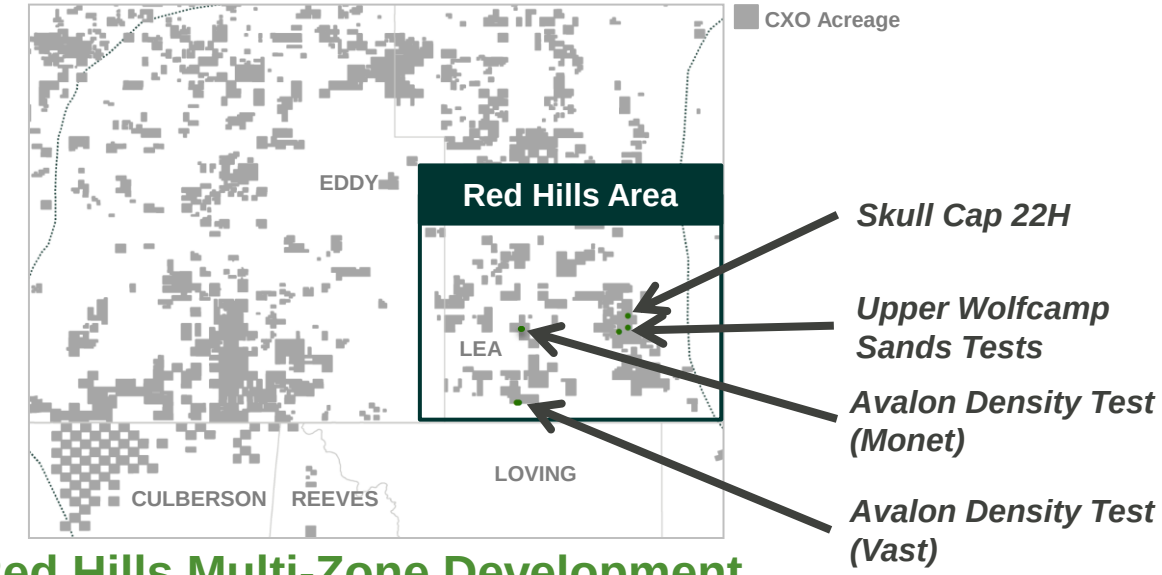
CXO Acreage ● CXO 4Q16 HZ well

Note: Acreage as of December 31, 2016 pro forma for recent ~24,000 gross (16,400 net) acquisition. 4Q16 results represent wells with >30 days of production data in 4Q16.
[1]Wells with >30 days of production data as of January 1, 2016 through December 31, 2016.

Northern Delaware Basin Red Hills Area

Oil-Rich, Multi-Zone Resource Potential

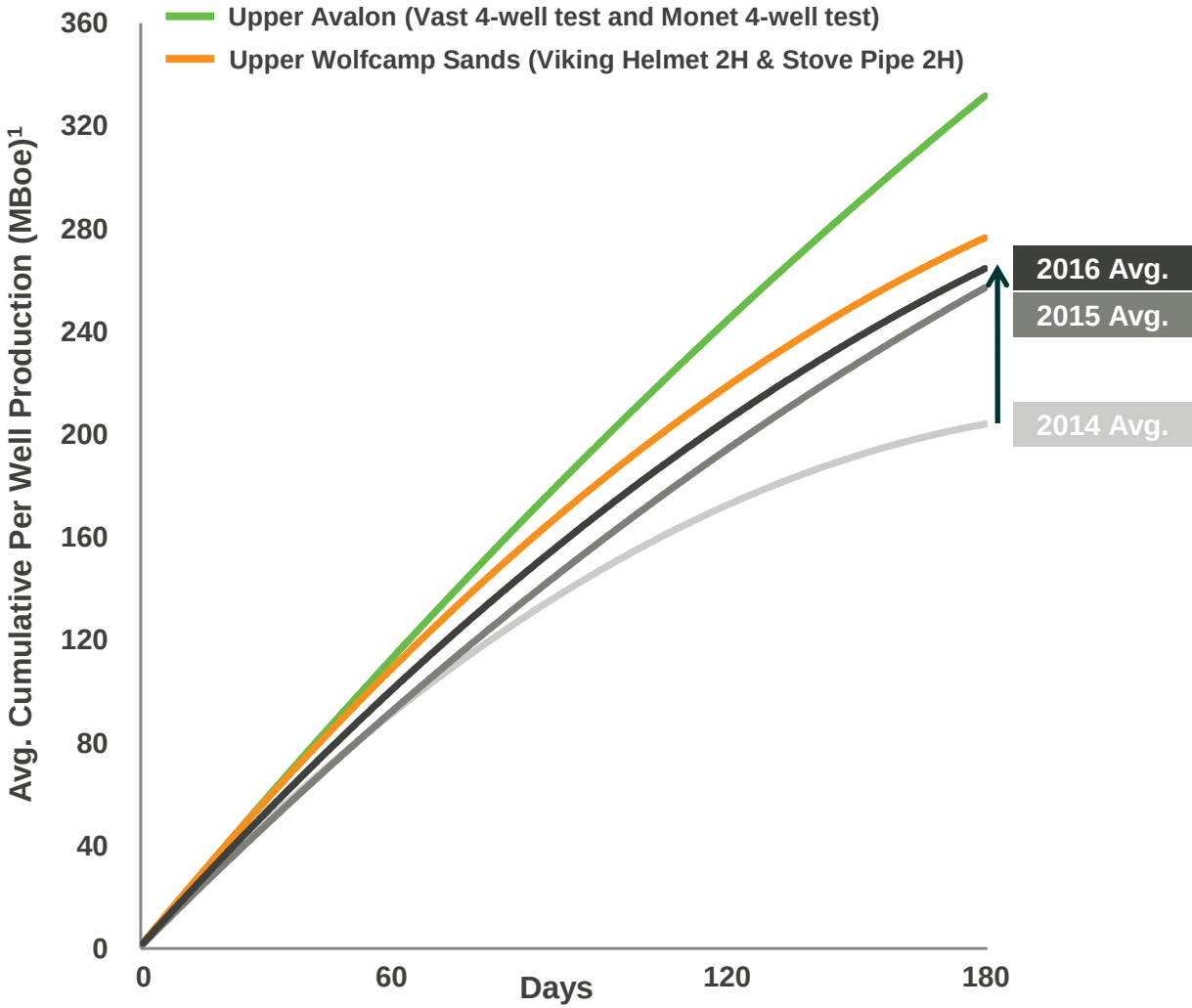
Northern Delaware Basin



Red Hills Multi-Zone Development

- **Avalon Shale (Upper and Lower)**
  - Four well Vast density test produced at a per well avg. 30-day peak rate of 1,491 Boepd (74% oil)
- **Upper Wolfcamp Sands**
  - Viking Helmet State 2H & Stove Pipe Federal 2H produced at a per well avg. 90-day peak rate of 1,878 Boepd (84% oil)
- **Wolfcamp A Shale**
  - Skull Cap 22H produced at an avg. 24-hour peak rate of 2,833 Boepd

Recent Red Hills Production Highlights



[1]Production normalized for a 7,000' lateral.
Note: 2014, 2015 and 2016 avg. production plots consist of Avalon wells only.

Southern Delaware Basin

Core Position in Rapidly Advancing Oil Play

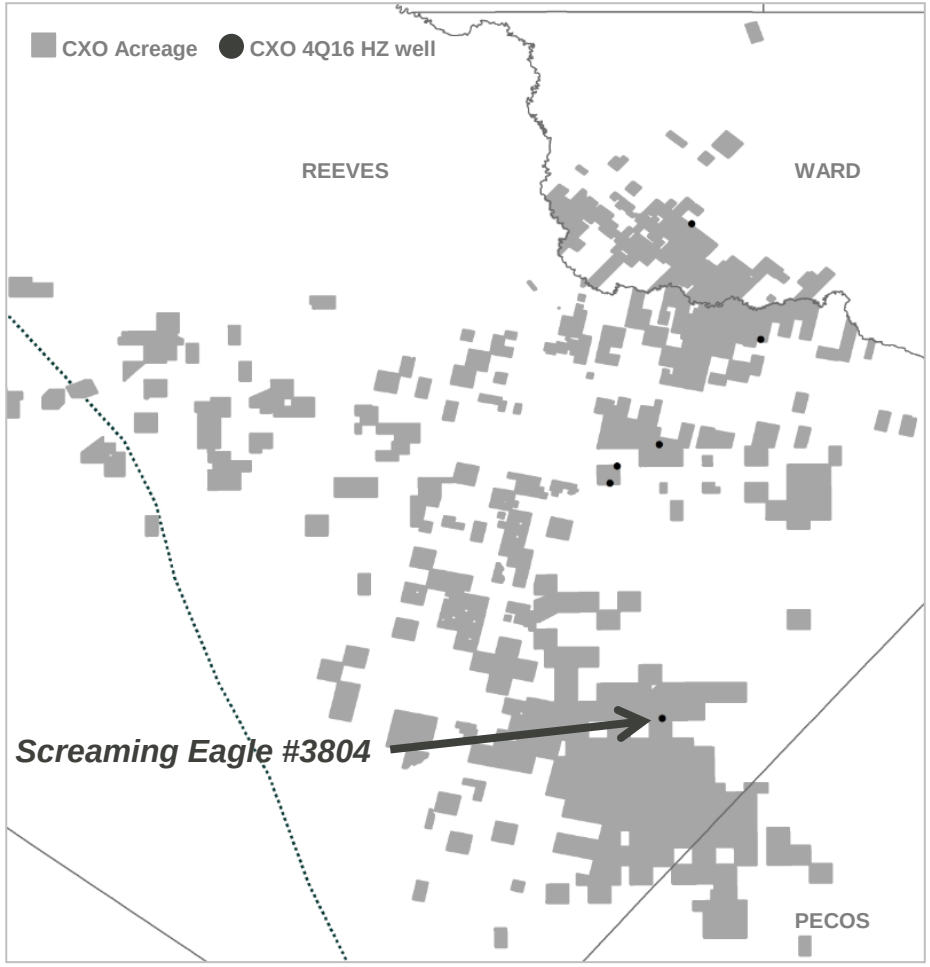
4Q16 Results

- **Added 6 horizontal wells (avg. lateral length 6,349')**
  - Avg. 30-day peak rate: 1,252 Boepd (73% oil)
  - Avg. 24-hour peak rate: 1,635 Boepd
- **Screaming Eagle #3804 completed as Concho's longest lateral (12,812')**
  - Avg. 30-day peak rate: 1,890 Boepd (83% oil)

2017 Plans

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

~160,000 gross (100,000 net) acres	1,300 Total Horizontal Drilling Inventory (Gross)	Running 5 Horizontal Rigs



Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 4Q16.

Midland Basin

Multi-Well Pad Development Driving Record Production

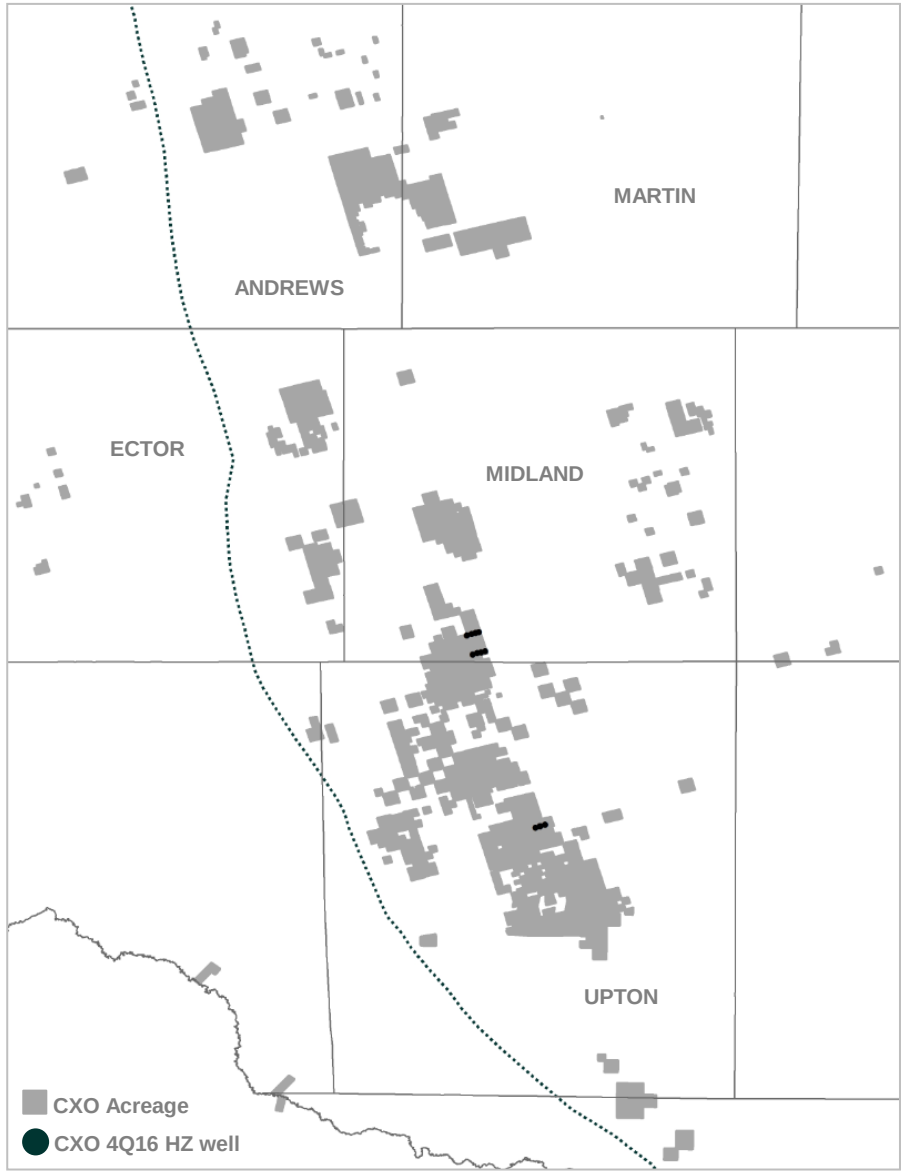
4Q16 Results

- **Achieved record average 30-day peak rate**
- **Added 11 horizontal wells (avg. lateral length 9,601')**
  - Avg. 30-day peak rate: 1,299 Boepd (85% oil)
  - Avg. 24-hour peak rate: 1,555 Boepd
- **Windham 8-well pad generated 1 MMBoe in just over 100 days**
  - All 10,000' laterals targeting Lower Spraberry and Wolfcamp B

2017 Plans

- **~100% ≥ 10,000' laterals**
- **~100% multi-well pad development**
- **Plan to run 2 rigs on recently acquired assets, average 5 rigs for the year**
- **Optimize well spacing and development pattern**

~260,000 gross (160,000 net) acres	**4,000 Total Horizontal Drilling Inventory (Gross)**	**Running 6 Horizontal Rigs**



Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 4Q16.

New Mexico Shelf

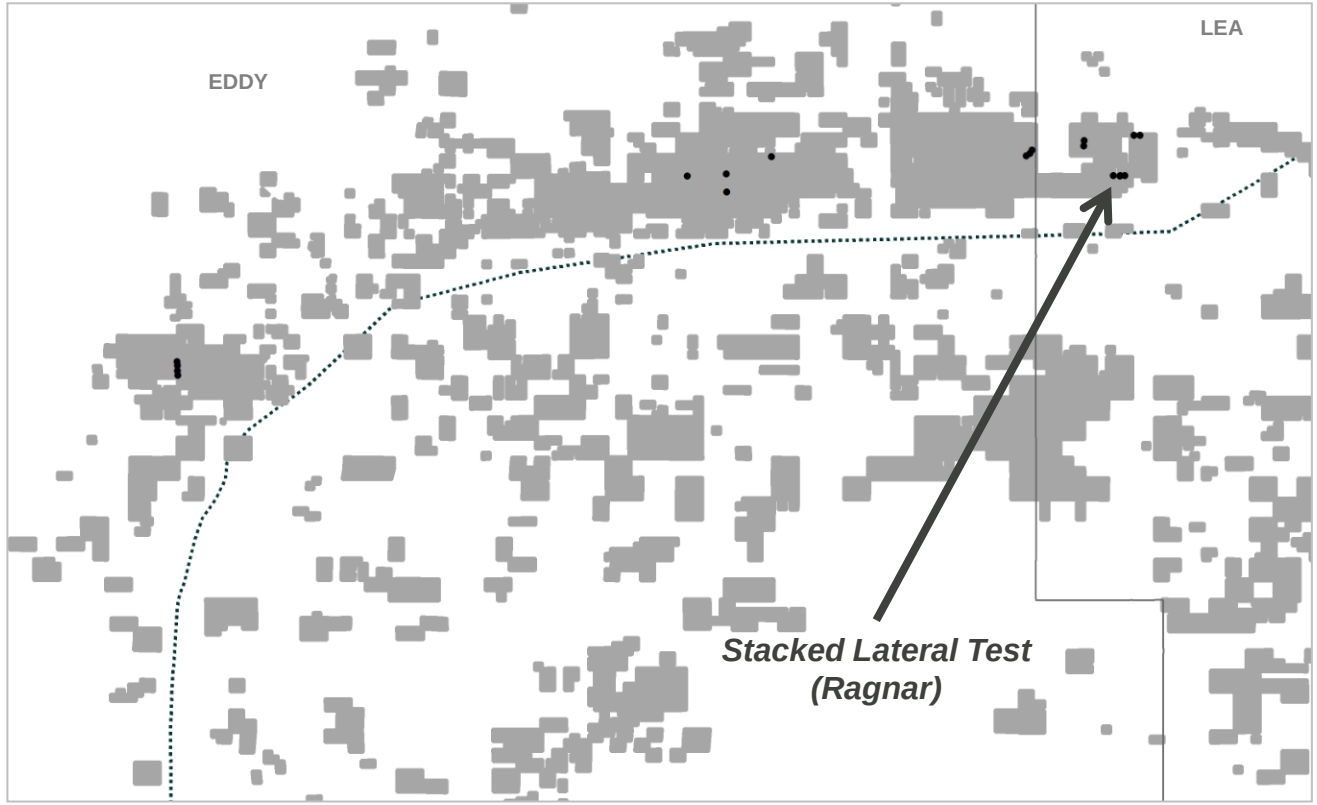
4Q16 Results

- **Achieved record average 30-day peak rate**
- **Added 18 horizontal wells (avg. lateral length 4,643')**
  - Avg. 30-day peak rate: 556 Boepd (84% oil)
  - Avg. 24-hour peak rate: 746 Boepd
- **Completed first stacked lateral test targeting the Paddock and Blinebry**
  - Avg. 30-day peak rate: 880 Boepd (83% oil)

2017 Plans

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

~130,000 gross (80,000 net) acres	2,100 Total Horizontal Drilling Inventory (Gross)	Running 2 Horizontal Rigs



CXO Acreage ● CXO 4Q16 HZ well

Note: Acreage as of December 31, 2016. Well results represent wells with >30 days of production data in 4Q16.

2017 Operational & Financial Outlook

1Q17 GUIDANCE
172 to 176 MBoepd

	2017 Guidance
Production	
Annual growth	20% - 24%
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)	
LOE and workover costs	$5.75 - $6.25
Oil and natural gas taxes (% of oil and 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	$18.00 - $20.00
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 FEBRUARY 21, 2017

[1]Capital program excludes acquisitions.

Hedge Position

2017 OIL HEDGES
77.7 MBopd

	2017					2018	2019
	First	Second	Third	Fourth	Total	Total	Total
Oil Swaps[1]:							
Volume (Bbl)	7,423,870	7,708,480	6,898,370	6,333,080	28,363,800	21,537,124	8,854,000
Price per Bbl	$ 56.91	$ 57.22	$ 51.87	$ 52.04	$ 54.68	$ 51.86	$ 55.14
Oil Basis Swaps[2]:							
Volume (Bbl)	6,603,000	6,141,500	5,290,000	5,290,000	23,324,500	9,490,000	-
Price per Bbl	$ (1.00)	$ (1.03)	$ (0.49)	$ (0.49)	$ (0.78)	$ (0.98)	$ -
Natural Gas Swaps[3]:							
Volume (MMBtu)	14,461,315	13,289,642	12,365,441	11,743,000	51,859,398	20,595,000	-
Price per MMBtu	$ 3.07	$ 3.05	$ 3.05	$ 3.04	$ 3.06	$ 3.03	$ -

UPDATED AS OF FEBRUARY 21, 2017

[1]The index prices for the oil contracts are based on the NYMEX – 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.

Pro Forma Capitalization – ACC Sale & Northern Delaware Basin Acquisition

Strong Financial Position
Recent transactions and liability management reduce leverage metrics and increase liquidity

Pro Forma Net Debt/EBITDAX
1.2x

($ millions)	As of 12/31/16	Endurance Acquisition Adj.[1]	ACC Sale Adj.	Pro Forma Balance Sheet
Cash	$ 53	$ (107)	$ 803	$ 749
Long-term debt:				
Credit facility	$ -			$ -
5.500% Senior Notes due 2022	600			600
5.500% Senior Notes due 2023	1,550			1,550
4.375% Senior Notes due 2025	600			600
Unamortized original issue premium	22			22
Senior notes issuance costs, net	(31)			(31)
Total long-term debt	$ 2,741			$ 2,741
Stockholders' equity	$ 7,623	$ 295		$ 7,918
Total capitalization	$ 10,364			$ 10,659
Operating Statistics				
LTM Net Loss[2]	$ (1,462)			$ (1,462)
LTM EBITDAX[2]	$ 1,633			$ 1,633
4Q16 Average Daily Production (MBoepd)	164			164
Credit Statistics				
Net Debt / LTM EBITDAX[2]	1.6x			1.2x
Net Debt / 4Q16 Average Daily Production ($/Boepd)	$ 16,390			$ 12,146
Net Debt / Capitalization	26.1%			20.1%

[1]Adjustment to stockholders' equity related to the northern Delaware Basin acquisition reflects payment of ~2.2mm shares based on the close price on 1/12/2017. Share price subject to change prior to deal closing.
[2]LTM as of 12/31/16.

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) loss on derivatives, (7) net cash receipts from derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt and (11) 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 December 31, 2016, 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 thousands)	Years Ended December 31, 2016	2015
Net income (loss)	**$ (1,462,446)**	**$ 65,900**
Exploration and abandonments	77,454	58,847
Depreciation, depletion and amortization	1,167,208	1,223,253
Accretion of discount on asset retirement obligations	7,133	7,600
Impariments of long-lived assets	1,524,645	60,529
Non-cash stock-based compensation	58,927	63,073
(Gain) loss on derivatives	368,684	(699,752)
Net cash receipts from derivatives	625,250	632,916
(Gain) loss on disposition of assets, net	(117,561)	53,789
Interest expense	203,518	215,384
Loss on extinguishment of debt	56,436	-
Income tax expense (benefit)	(876,090)	31,371
EBITDAX	**$ 1,633,158**	**$ 1,712,910**

Costs Incurred (Unaudited)

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

(in thousands)	Three Months Ended					
	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015
Property Acquisition Costs:						
Proved	$ 725,200	$ 546	$ 3,757	$ 252,352	$ (1,689)	$ 56,636
Unproved	981,937	15,079	18,767	138,640	10,243	161,921
Exploration	188,191	176,687	165,850	170,572	148,630	201,737
Development	161,289	96,977	107,039	83,104	86,444	99,490
Total Costs Incurred	**$ 2,056,617**	**$ 289,289**	**$ 295,413**	**$ 644,668**	**$ 243,628**	**$ 519,784**

Reserves Replacement Ratio and Finding & Development Costs (Unaudited)

Reserves Replacement Ratio

The Company uses the reserves replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. The reserves replacement ratio is a statistical indicator that is limited because it typically varies widely based on the extent and timing of discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not embed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The reserve replacement ratio of approximately 344% was calculated by dividing net proved reserve additions of 189.8 MMBoe (the sum of extensions, discoveries, revisions other than price-related revisions and purchases) by production of 55.1 MMBoe.

Drill-Bit Finding and Development ("F&D") Cost

Drill-bit F&D cost is an indicator used to assist in an evaluation of how much it costs the Company, on a per Boe basis, to add proved reserves. Drill-bit F&D cost is calculated by dividing the sum of exploration and development costs incurred of $1.15 billion by total reserve extensions and discoveries of 124.8 MMBoe. This calculation does not include the future development costs required for the development of proved undeveloped reserves.