Scotia Howard Weil
2016 Energy Conference

MARCH 21, 2016

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, 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 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 the prices the Company receives, or sustained depressed prices the company receives, for its oil and natural gas; uncertainties about the estimated quantities of oil and natural gas reserves; drilling 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 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.

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, 2015 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $46.79 per Bbl of oil and $2.59 per MMBtu of natural gas. The Company’s estimate of its total proved reserves at December 31, 2015 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.

Agenda

Market Perspectives

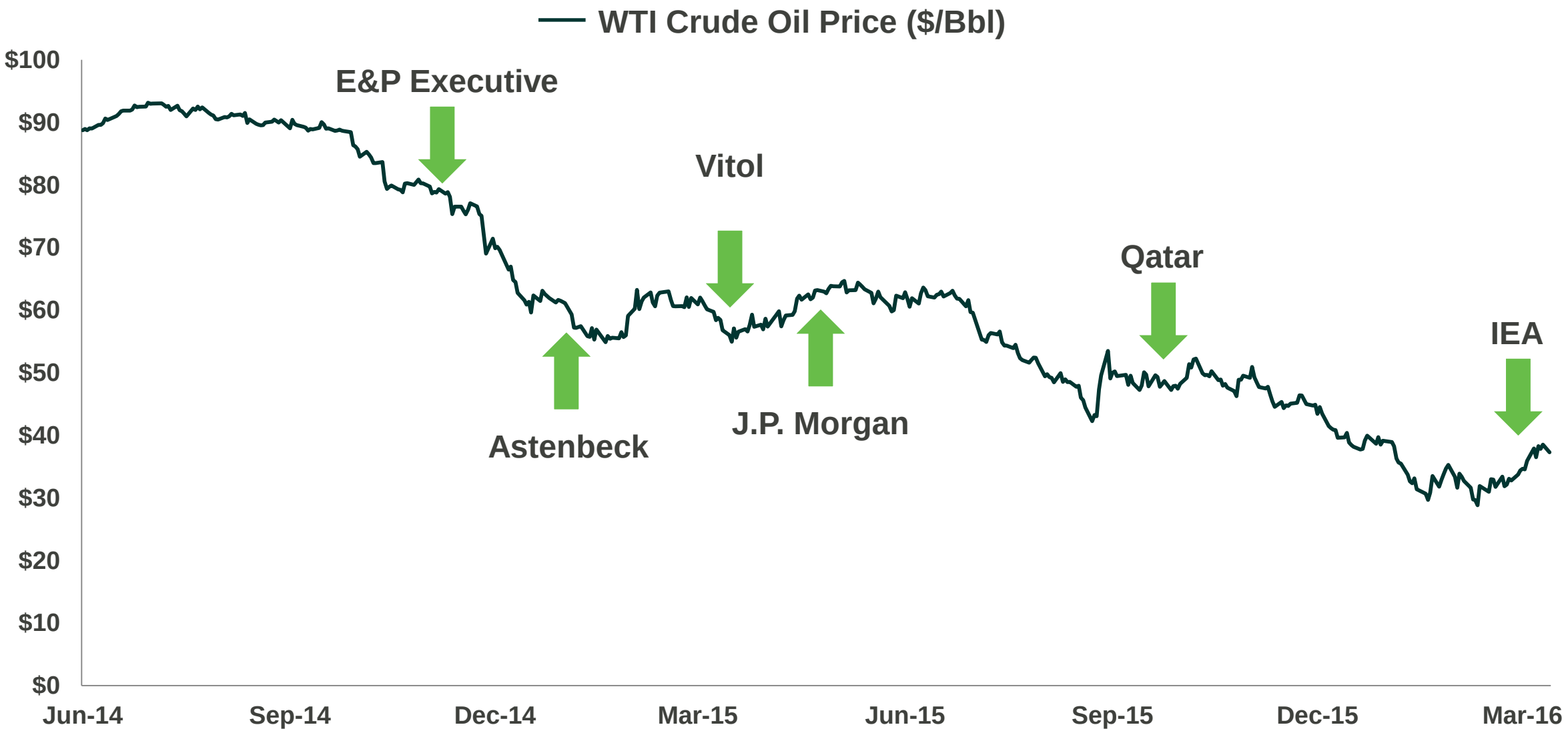
Strategy to Build Value Through Cycles

Performance Track Record

2016 Outlook, Development Efficiencies

Strong Balance Sheet

Many Experts Have Attempted to “Call the Bottom”

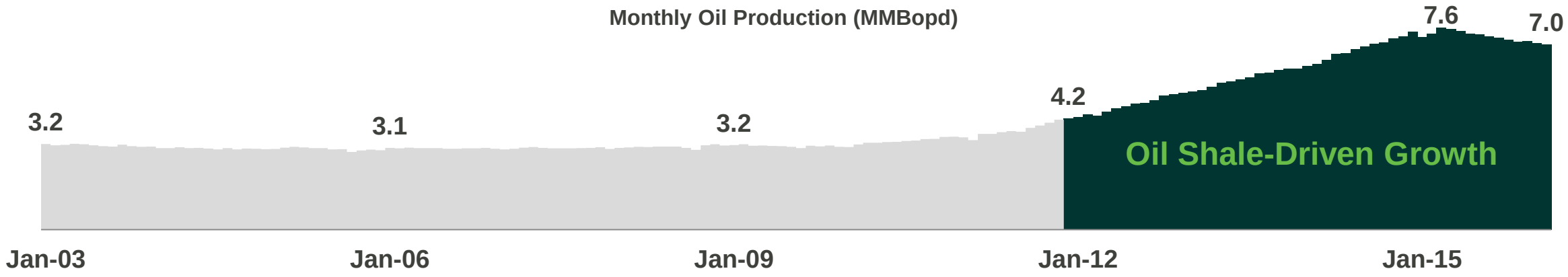


Source: Bloomberg.

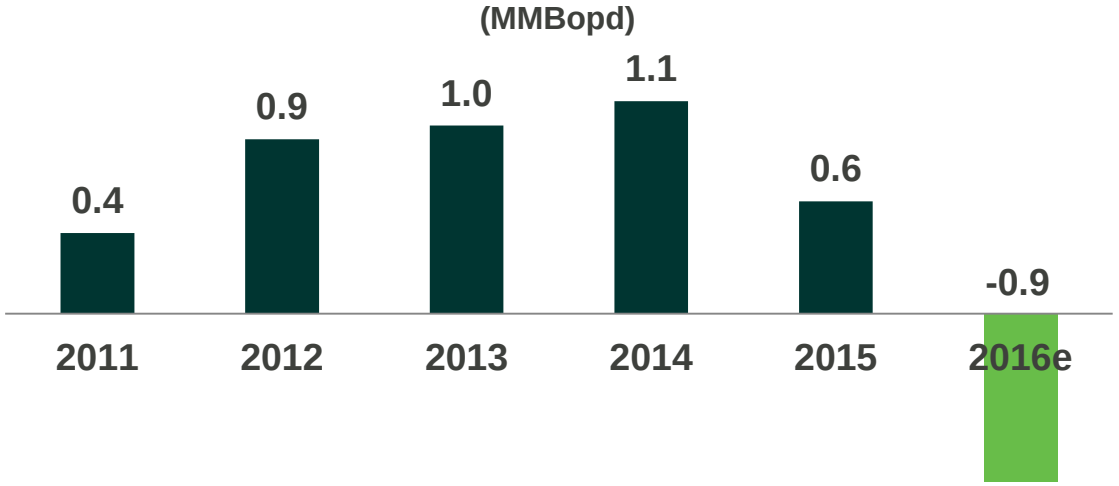
U.S. Lower 48 Crude Oil

Supply is Responding to Lower Oil Prices, Investment

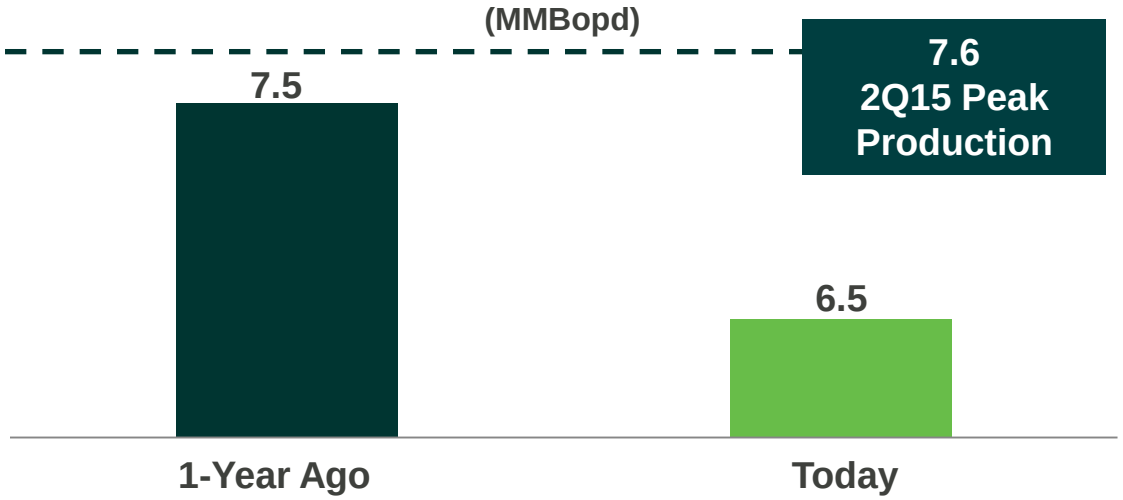
U.S. L48 Production



U.S. L48 Supply Growth (Y-o-Y)



EIA 2016 U.S. L48 Production Forecast

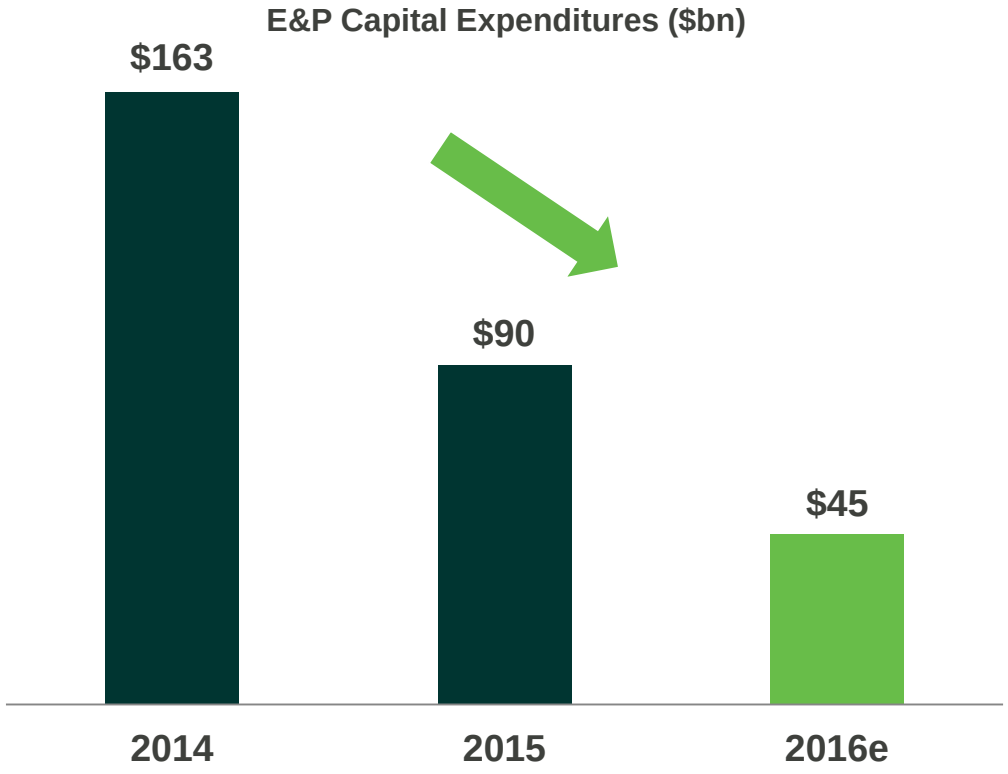


Source: EIA Short-Term Energy Outlook, Bloomberg.

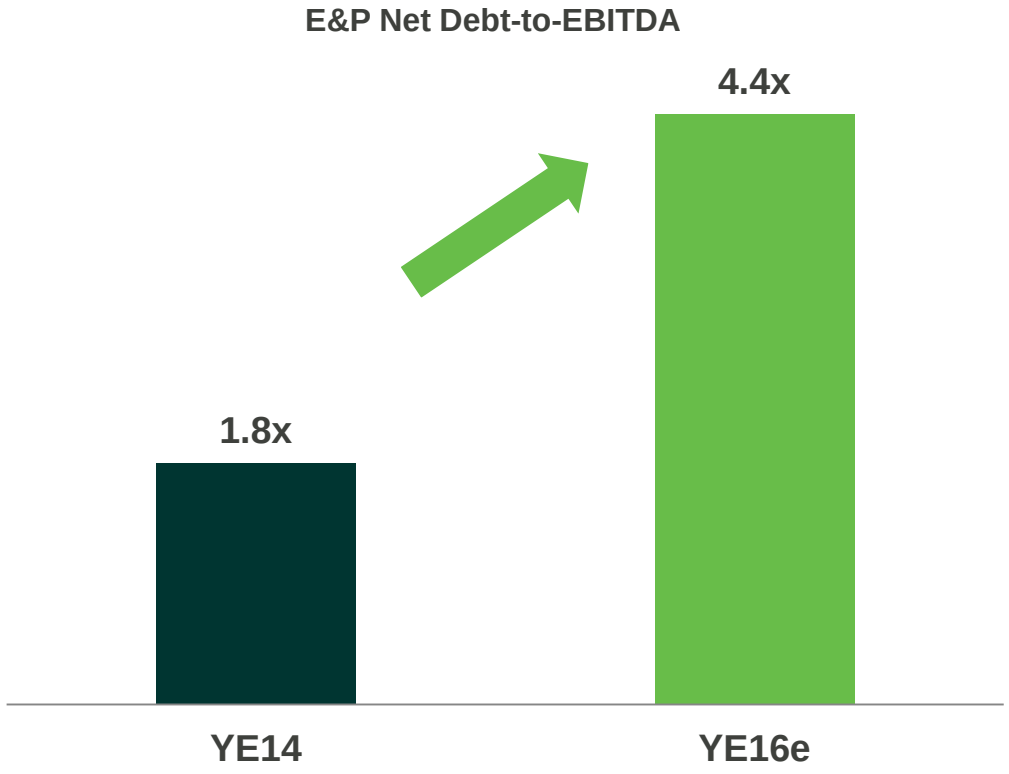
U.S. E&Ps Adapt to Crude Reality

Lower CapEx, High Financial Leverage Limit Shale's Ability to Serve as "Swing Producer"

Significant U.S. E&P Investment Reduction



E&P Leverage at Historical Highs



Concho is uniquely positioned with financial and operational strength to navigate low commodity prices, while retaining substantial flexibility to respond to an upcycle

Source: EIA, Bloomberg and company filings.

Concho Strategy

Creating Value Through the Cycles

Proven strategy, experienced team and high-quality assets to weather commodity price cycles

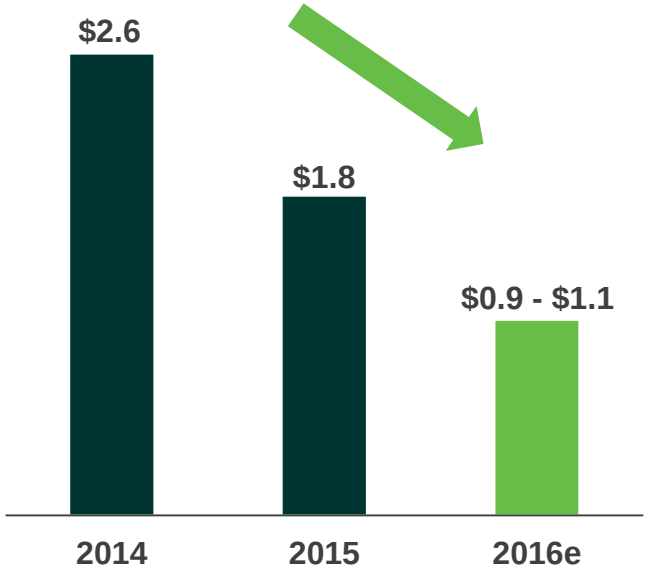
People	• Highly technical, motivated team • Legacy of successful consolidation in the Permian Basin
Assets	• High-quality assets in the Delaware Basin, Midland Basin and New Mexico Shelf • Development efficiencies improving well performance across portfolio
Returns	• Executing a returns-based, disciplined capital program • High grading drilling locations • Focusing on driving down costs
Balance Sheet	• Maintaining financial strength is a priority • Disciplined hedge program to protect cash flows

Capital Discipline

Preserving Financial Strength & High-Quality Resource

Reducing Capital

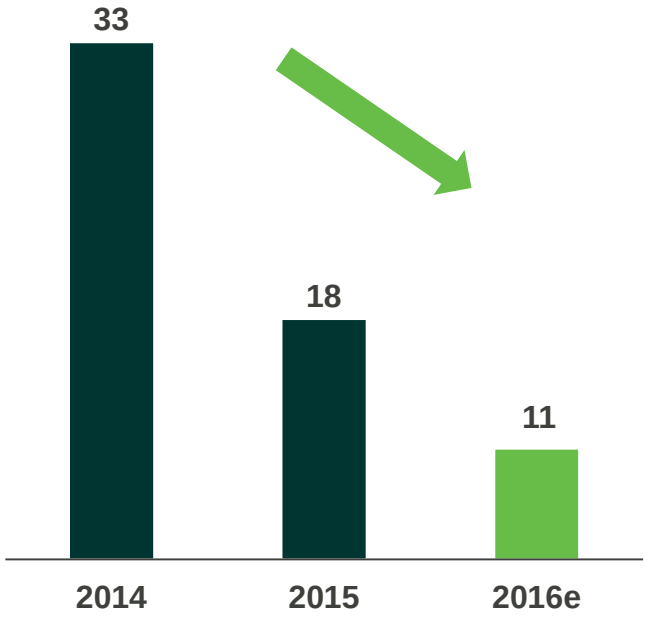
Exploration & Development Costs Incurred ($bn)



- Hedges and minimum drilling commitments maximize flexibility
- Maintain financial strength

Slowing Activity

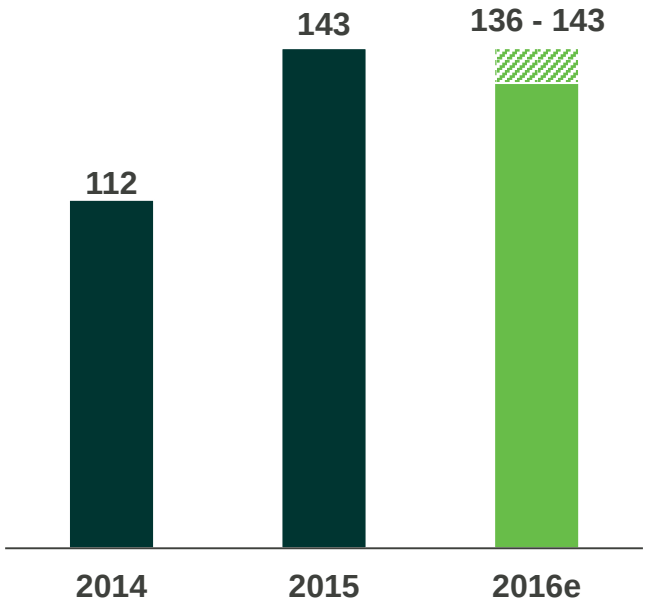
Rig Count



- Scale back capital plan, rigs and growth
- Preserve high-quality resource

Resilient Production

Avg. Daily Production (MBoepd)

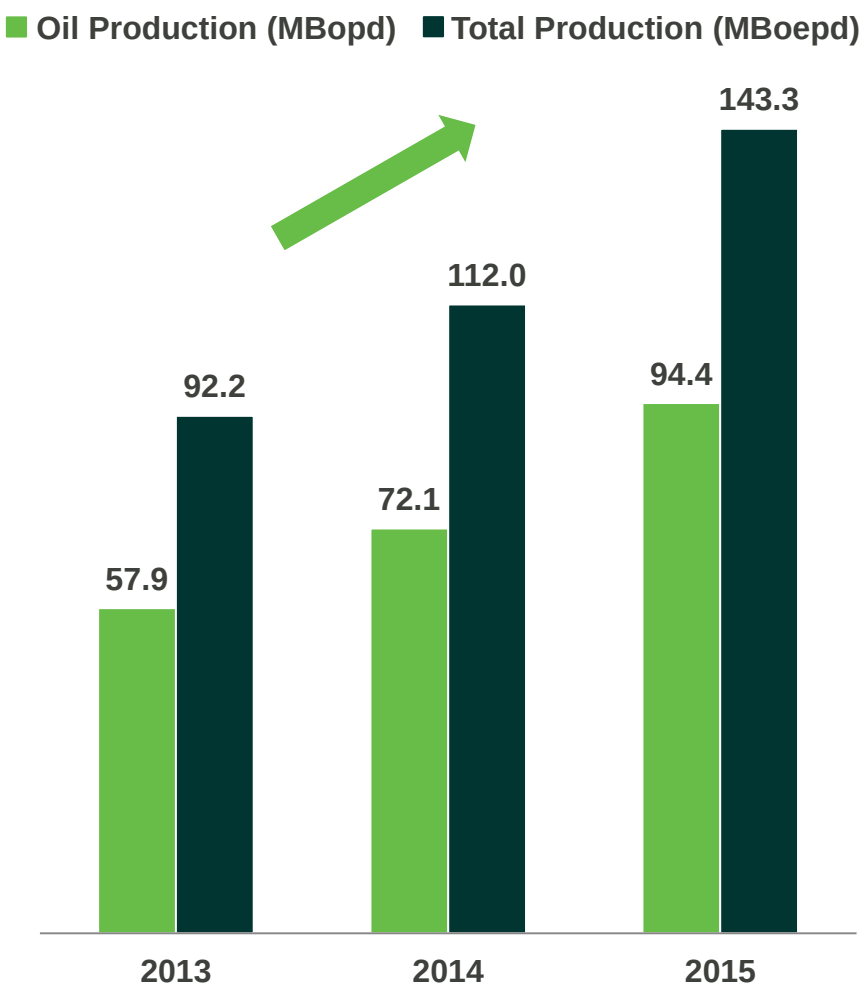


- Optimize development
- Shallower PDP decline year-over-year

Performance Track Record

Delivering Growth in a Price-Supportive Environment

Production



Leading Permian production growth

- 2015 production up 28% over 2014, exceeding initial expectations of 16%-20% growth
- 2-year production CAGR 25%

Capital efficient oil growth

- 2015 oil production up 31% over 2014
- 2-year oil production CAGR 28%
- Per-unit LOE stable over 3-year period

Performance track record demonstrates ability to deliver future growth in a better commodity price environment

Resource Capture

Expanding Resource Provides Solid Platform for Future Growth

Asset	Total Horizontal Drilling Inventory (Gross)	Economic Resource (>20% ROR) $40/Bbl & $2.50/Mcf		Primary Sources of Expansion
		Horizontal Drilling Inventory (Gross)	Inventory Life (Years)	
Northern Delaware Basin	11,700	2,700	46	Avalon Oil Shale & Wolfcamp
Southern Delaware Basin	1,200	350	10	Wolfcamp
Midland Basin	3,100	1,300	29	Wolfcamp & Lower Spraberry
New Mexico Shelf	2,000	520	12	Yeso

~5 BILLION BOE
Horizontal resource potential (net)

HIGH-QUALITY RESOURCE CAPTURE

- Inventory high grading
- Transitioned vertical drilling inventory to horizontal
- Zone delineation
- Tighter well spacing

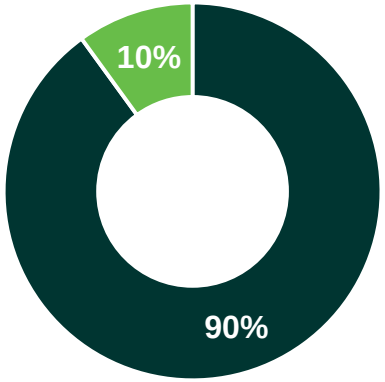
Total Horizontal Drilling Inventory of ~18,000 Locations
~30% of Inventory Generates >20% ROR at $40 Oil

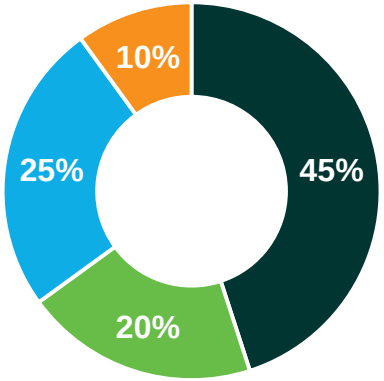
Note: Economic resource >20% ROR assumes $40/Bbl of oil and $2.50/Mcf of gas; years of drilling inventory based on 2016e drilling activity.

2016 Capital Plan

Protecting Future Optionality with Capital Discipline

2016 Capital Allocation





2016 capital plan $1.1bn to $1.3bn[1]

- Reduced from initial $1.4bn base budget
- ~35% less capital year-over-year[1]
- Balancing capital and cash flow

Production outlook flat-to-down ~5% vs. 2015

- Production outlook driven by reducing activity, shifting to pad development and timing of completion activity

Average 11 rigs in 2016

- ~100% horizontal development

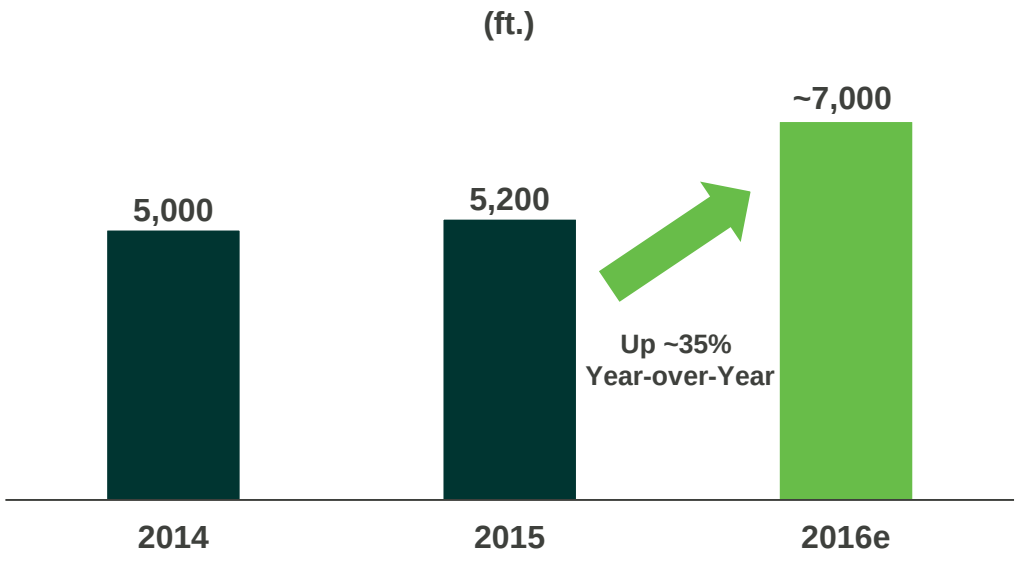
Continued focus on maximizing resource recovery

- Optimizing well spacing and completion techniques throughout core areas

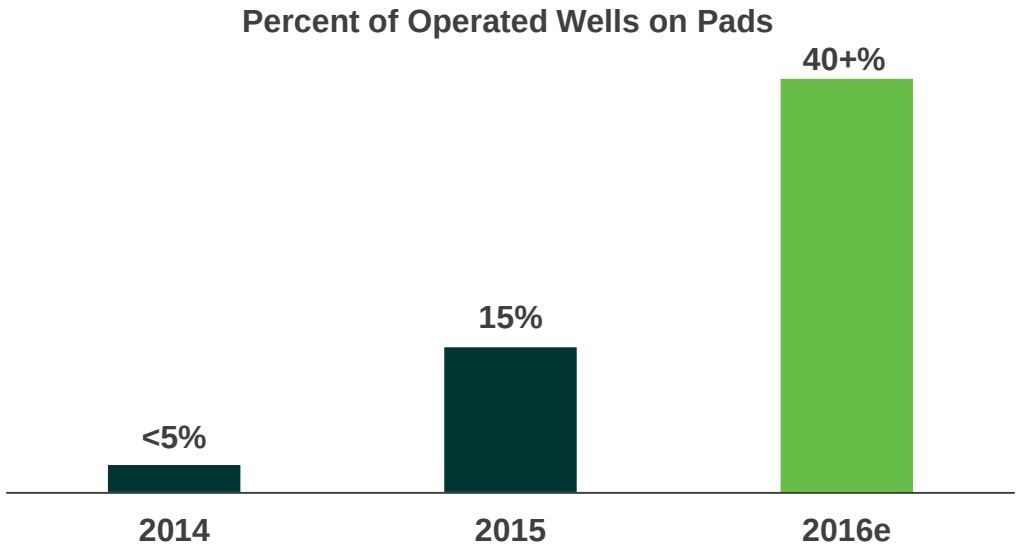
[1]2016 capital plan excludes acquisitions. Infrastructure and other capital includes facilities, midstream investments, G&G and other. Year-over-year capital comparison excludes acquisitions and is based on midpoint of 2016 capital plan guidance of $1.2bn.

Improving Capital Productivity

Average Lateral Length



Pad Development



- Capital and development efficiencies from extended laterals
- Transition to pad development generates cost and timing savings
- Continued improvement in base PDP decline year-over-year

Development efficiencies and timing of 2015 and 2016 capital sets up robust 2017 production outlook while continuing to balance cash flow and capital expenditures

Strong Financial Position

STRONG FINANCIAL POSITION
Recent transactions reduce leverage metrics & increase liquidity

RATING AGENCIES AFFIRM RATINGS
S&P and Moody's recently reaffirmed Concho's corporate credit ratings (BB+/Ba1)

Pro Forma Balance Sheet as of 12/31/2015 (Unaudited)

($ in millions)	Actual 12/31/2015	Adjustments: North Harpoon Acquisition[1]	Adjustments: Loving County Divestiture[2]	Pro Forma 12/31/2015
Cash	$ 229	$ (150)	$ 290	$ 369
Long-term debt:				
Credit facility[3]	$ -			$ -
Senior notes	$ 3,350			$ 3,350
Unamortized original issue premium & deferred loan costs, net	$ (18)			$ (18)
Total long-term debt	$ 3,332			$ 3,332
Stockholders' equity	$ 6,943	$ 193		$ 7,136
Total capitalization	$ 10,275			$ 10,468
Liquidity	$ 2,729			$ 2,869
Net debt	$ 3,103			$ 2,963
Net debt / net capitalization	31%			29%

[1]North Harpoon acquisition purchase price includes 2.2mm shares of CXO common stock and $150mm cash. Value of equity consideration based on CXO closing price on 2/15/2016 of $87.15.
[2]Anticipated Loving County divestiture proceeds total $290mm cash.
[3]Credit facility has a borrowing base of $3.25bn and commitments of $2.5bn.

Creating Value Through the Cycle

Proven strategy, experienced team and high-quality assets to weather commodity price cycles

- ☑ **Low-cost operator with high-quality assets and healthy financial position**
- ☑ **Exercising patience and discipline**
  - › **Looking for commodity price stability before increasing activity**
  - › **Focusing on consolidating the right assets at the right time and at the right price**
- ☑ **Improving capital productivity**
- ☑ **Maintaining superior positioning for growth acceleration**

Appendix

CONCHO

Northern Delaware Basin

Industry-Leading Position with Multi-Zone Potential

ACREAGE POSITION

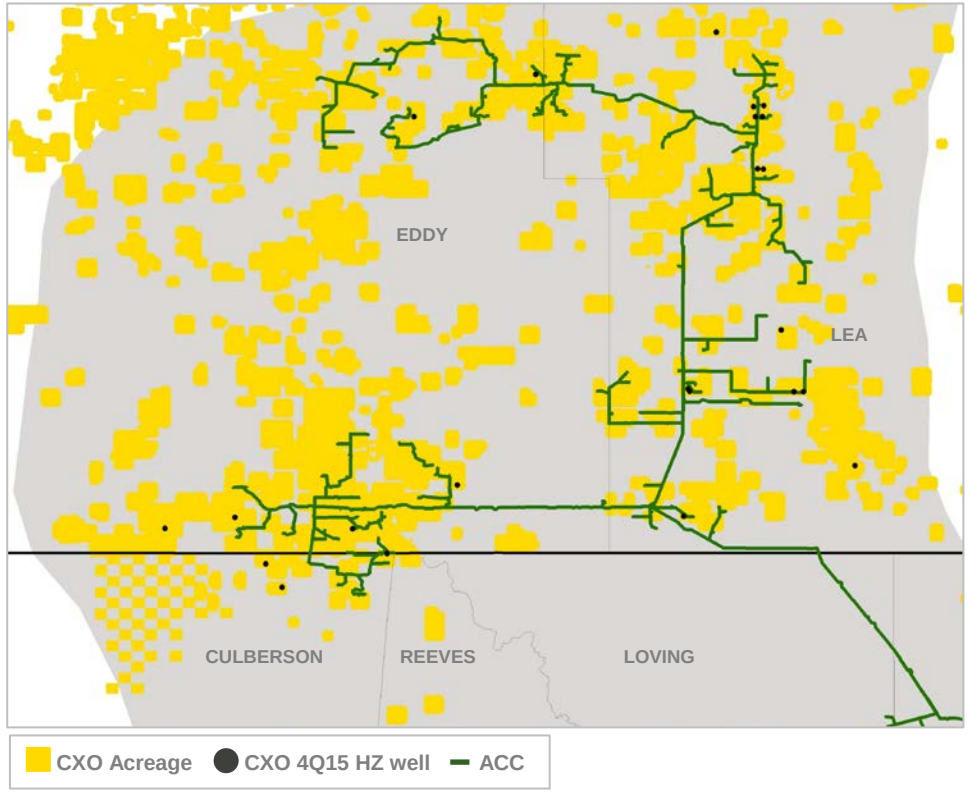
~355,000 gross (250,000 net) acres

CURRENT RIG COUNT

6 Horizontal Rigs

ALPHA CRUDE CONNECTOR (ACC)

- **400-mile pipeline system**
- **100+ MBopd capacity**
- **Improves upstream price realizations**



4Q15 Well Results

Added 24 horizontal wells (avg. lateral length 4,785')

- Avg. 30-day peak rate: 957 Boepd (74% oil)
- Avg. 24-hour peak rate: 1,445 Boepd

Resource Expansion

- Avalon Shale and Wolfcamp multi-zone delineation and downspacing primary resource growth contributors

2016 Plans

- Pad drilling to drive operational efficiencies
- Primary targets include 2nd Bone Spring, Avalon and Wolfcamp
- Continue Avalon well-spacing evaluation

Note: Acreage as of December 31, 2015, pro forma for acreage divestiture. Well results represent wells with >30 days of production data in 4Q15.

Southern Delaware Basin

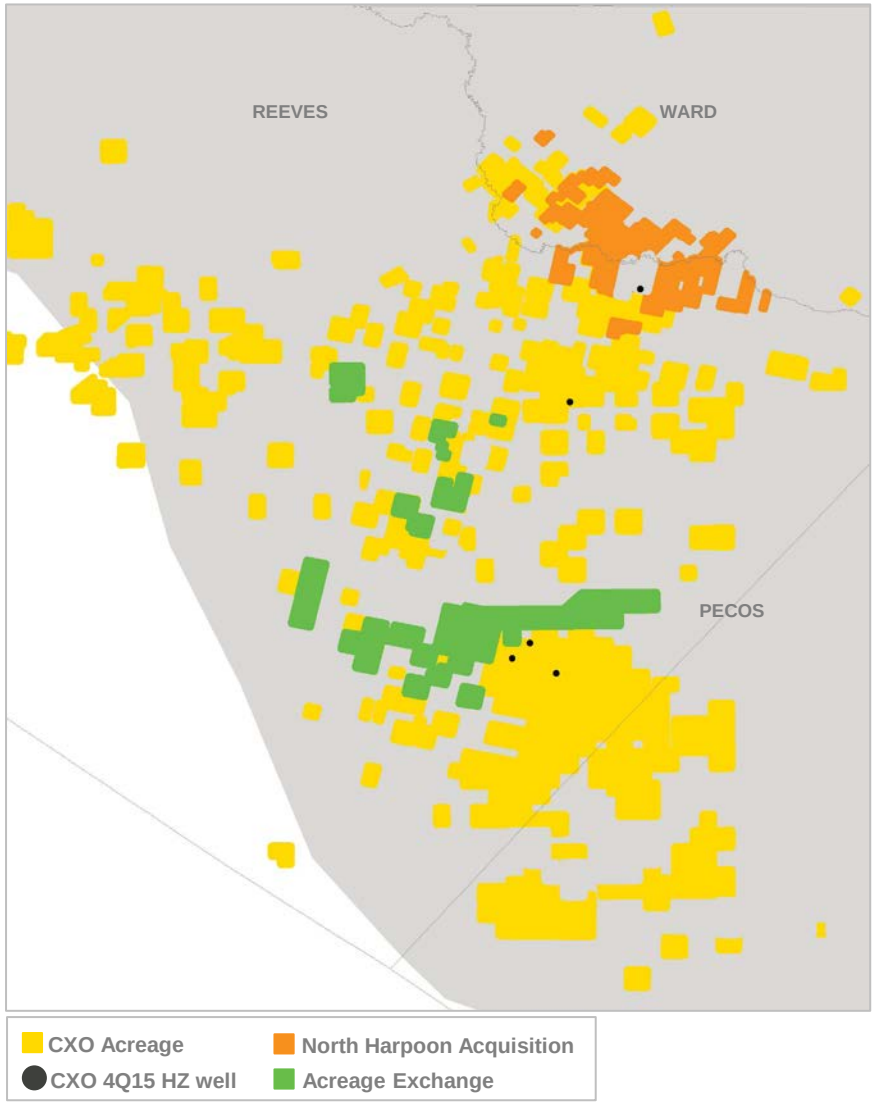
Consolidating High-Quality Acreage

ACREAGE POSITION

~200,000 gross (125,000 net) acres

CURRENT RIG COUNT

2 Horizontal Rigs



Resource Expansion

- Optimizing field development and well spacing
- High grading inventory and increasing long-lateral drilling opportunities

2016 Plans

- Focused development on Wolfcamp

Recently Announced Transactions

- North Harpoon acquisition adds ~12,000 net acres of core leasehold
- Acreage exchange consolidates ~21,000 net acres, increasing operated acreage

4Q15 Well Results

Added 5 horizontal wells (avg. lateral length 6,867')

- Avg. 30-day peak rate: 1,199 Boepd (78% oil)
- Avg. 24-hour peak rate: 1,498 Boepd

Note: Acreage as of December 31, 2015, pro forma for North Harpoon acquisition. Well results represent wells with >30 days of production data in 4Q15.

Midland Basin

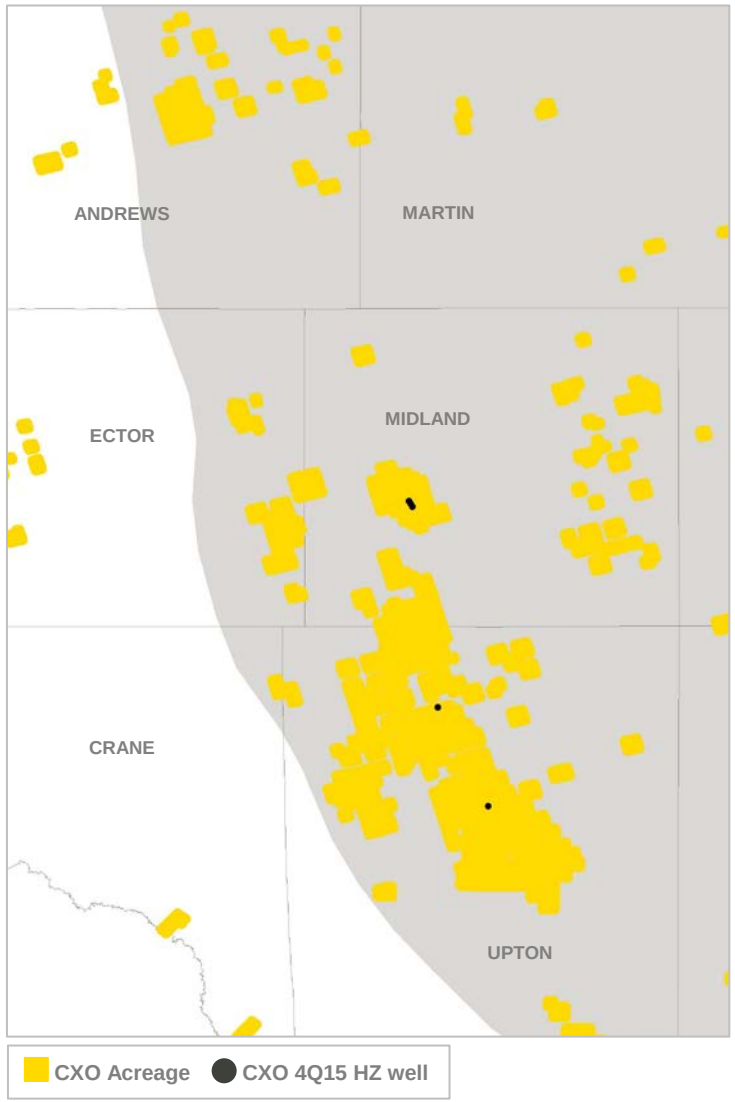
Optimizing Development

HORIZONTAL CORE ACREAGE POSITION

~200,000 gross (110,000 net) acres

CURRENT RIG COUNT

1 Horizontal Rig



Resource Expansion

- Inventory quality improving – converted vertical drilling locations to horizontal
- Optimizing Wolfcamp well spacing
- Successful Lower Spraberry testing

2016 Plans

- Build on long-lateral success: substantially all development will be 2-mile laterals and utilize pad drilling
- Optimize completion technique
- Advance Lower Spraberry program
- Test well spacing, development pattern

4Q15 Well Results

Added 5 horizontal wells (avg. lateral length 6,634')

- Avg. 30-day peak rate: 835 Boepd (85% oil)
- Avg. 24-hour peak rate: 1,099 Boepd

Note: Acreage as of December 31, 2015. Well results represent wells with >30 days of production data in 4Q15.

New Mexico Shelf

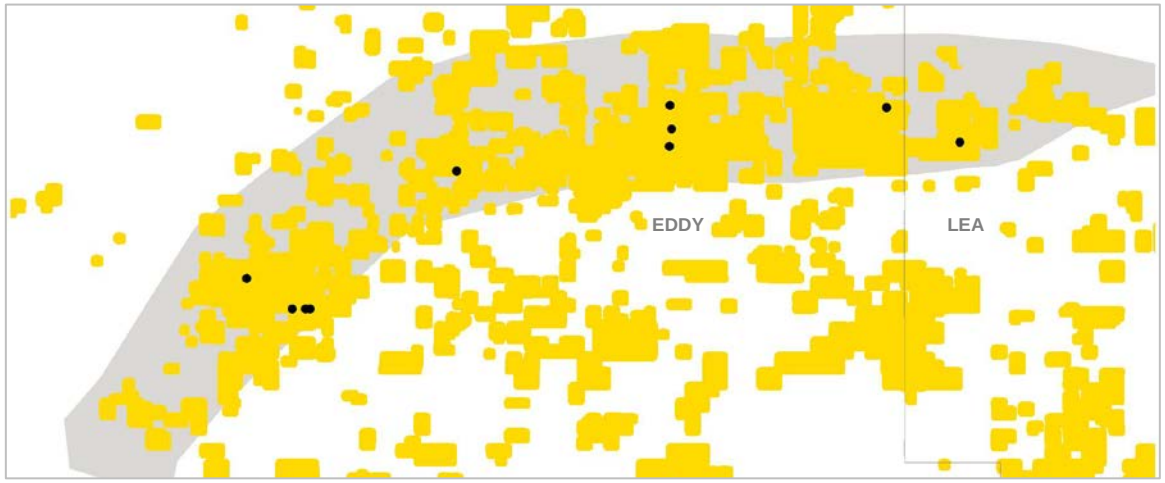
Enhancing Value in Legacy Oil Play

ACREAGE POSITION

~150,000 gross (100,000 net) acres

CURRENT RIG COUNT

1 Horizontal Rig



CXO Acreage ● CXO 4Q15 HZ well

4Q15 Well Results

Added 10 horizontal wells (avg. lateral length 4,246')

- Avg. 30-day peak rate: 354 Boepd (81% oil)
- Avg. 24-hour peak rate: 497 Boepd

Resource Expansion

- Horizontal drilling improving resource recovery

2016 Plans

- Rate-of-return competitive at low oil prices
- Focus on Upper Blinebry and Paddock
- Optimize well spacing and completion techniques

Note: Acreage as of December 31, 2015. Well results represent wells with >30 days of production data in 4Q15.

Hedge Position

2016 OIL HEDGES
63.4 MBopd

	2016					
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	2017
Oil Swaps: (a)						
Volume (Bbl)	6,722,000	5,985,000	5,460,000	5,054,000	23,221,000	15,642,000
Price per Bbl	$ 71.99	$ 73.38	$ 74.21	$ 59.38	$ 70.13	$ 57.39
Oil Basis Swaps: (b)						
Volume (Bbl)	6,155,000	5,914,000	5,520,000	5,060,000	22,649,000	14,276,000
Price per Bbl	$ (1.46)	$ (1.46)	$ (1.46)	$ (1.48)	$ (1.46)	$ (0.90)
Natural Gas Swaps: (c)						
Volume (MMBtu)	7,280,000	7,280,000	7,360,000	7,360,000	29,280,000	
Price per MMBtu	$ 3.02	$ 3.02	$ 3.02	$ 3.02	$ 3.02	

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

UPDATED AS OF FEBRUARY 24, 2016

2016 Operational & Financial Outlook

FIRST QUARTER & FULL-YEAR 2016 OUTLOOK

	1Q16 Guidance
Production (MBoepd)	130 - 134
Crude oil differential to NYMEX ($/Bbl)	($4.50) - ($4.70)
LOE ($/Boe)	$7.75 - $8.00

	2016 Guidance
Production	
Annual growth	-5% - 0%
Oil mix	60% - 64%
Price realizations, excluding commodity derivatives	
Crude oil differential to NYMEX ($/Bbl)	($3.75) - ($4.25)
Natural gas (per Mcf) (% of NYMEX)	80% - 85%
Operating costs and expenses ($/Boe, unless noted)	
LOE	$7.50 - $8.00
Oil & gas taxes (% of oil & gas revenues)	8.25%
G&A:	
Cash G&A	$3.10 - $3.50
Non-cash stock-based compensation	$1.35 - $1.45
DD&A	$24.00 - $26.00
Exploration and other	$1.00 - $2.00
Interest expense ($mm):	
Cash	$205 - $215
Non-cash	$10
Income tax rate (%)	38%
Current taxes ($mm)	$0 - $10
Capital plan ($bn)[1]	$1.1 - $1.3

UPDATED AS OF FEBRUARY 24, 2016

[1]Capital plan excludes acquisitions.