Investor Presentation

SEPTEMBER 2016

CONCHO

Forward-Looking Statements and Other Disclaimers

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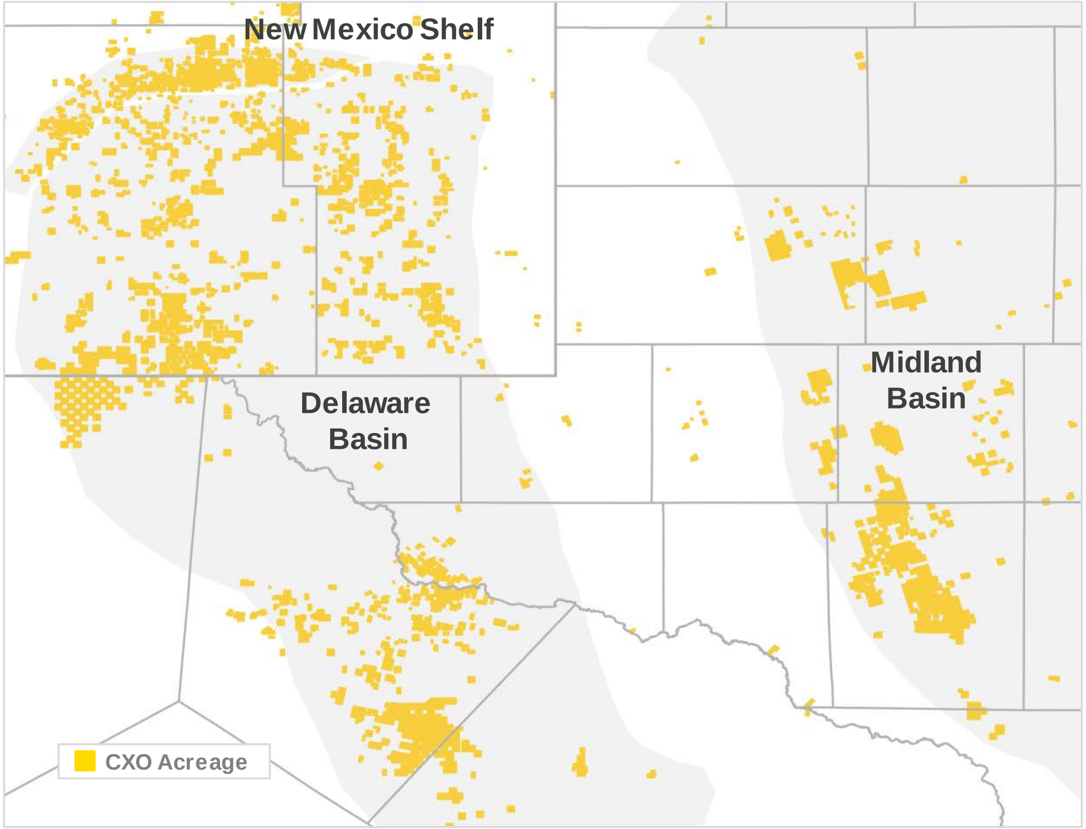
The words "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" or other similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements, which generally are not historical 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 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2016; 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, including the Company's acquisition of assets in the Midland Basin; 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.

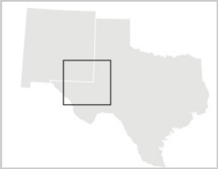
The Securities and Exchange Commission ("SEC") requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be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

Concho Resources

Premier Permian Basin Assets





Strategic acreage position in the Permian Basin

- ~1.1 million gross (690,000 net) acres
- Core areas in the Delaware Basin, Midland Basin and New Mexico Shelf

High-quality, long-life reserve base

- 623.5 MMBoe estimated proved reserves
- ~5 BBoe of total resource potential, including proved reserves
- ~18,000 horizontal drilling locations identified

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

- Maximizing resource recovery and reducing costs
- High grading portfolio with strategic bolt-on acquisitions and opportunistic asset sales
- Protecting financial strength and future optionality with capital discipline

Note: Acreage as of December 31, 2015, pro forma for year-to-date acquisitions and dispositions. Proved reserves and resource potential as of December 31, 2015.

Concho's Strategy

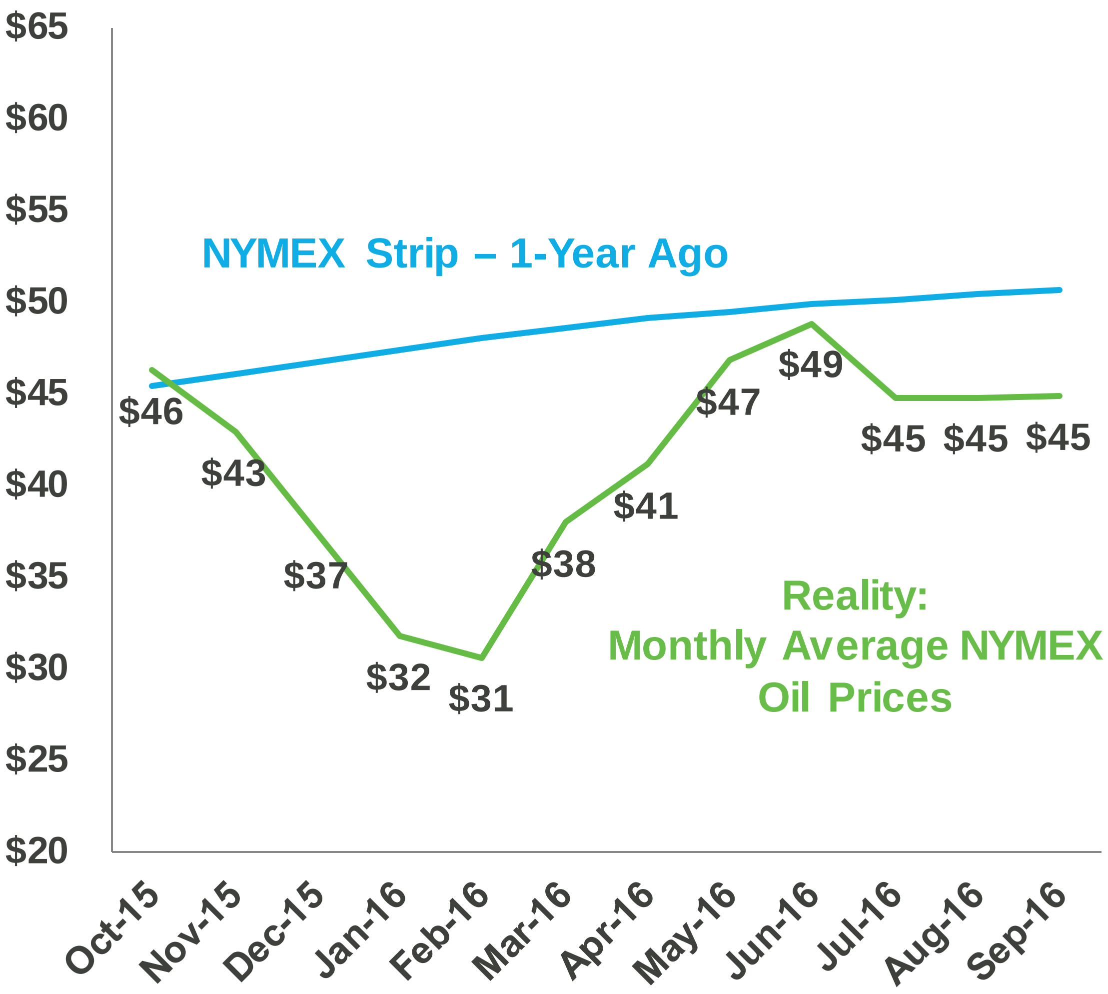
Focused on Creating Value

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

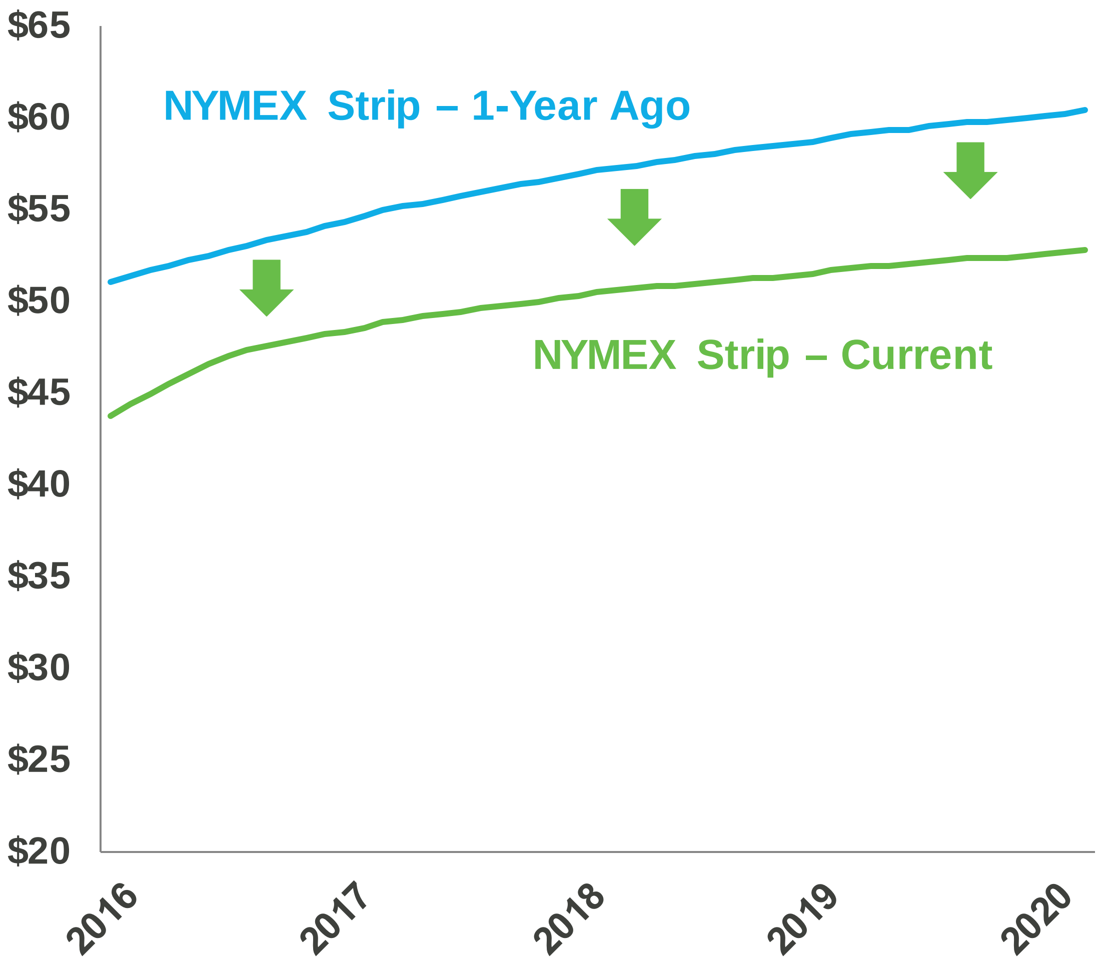
Consistent and proven strategy, experienced team and high-quality assets

Commodity Price Environment

Crude Oil Prices ($/Bbl)



Crude Oil Price Outlook ($/Bbl)



Note: NYMEX strip prices – 1-year ago as of 9/1/2015, and NYMEX strip prices – current as 9/1/2016.

Delivering on our Strategy

Positioning for Long-Term Growth

Improving Capital Efficiency

- **Executing a disciplined capital program within cash flows[1]**
- **Resilient production base**
- **Targeting >20% oil growth in 2017**

Reducing Cost Structure

LOE & Workover Costs per Boe

↓ 20% Y/Y

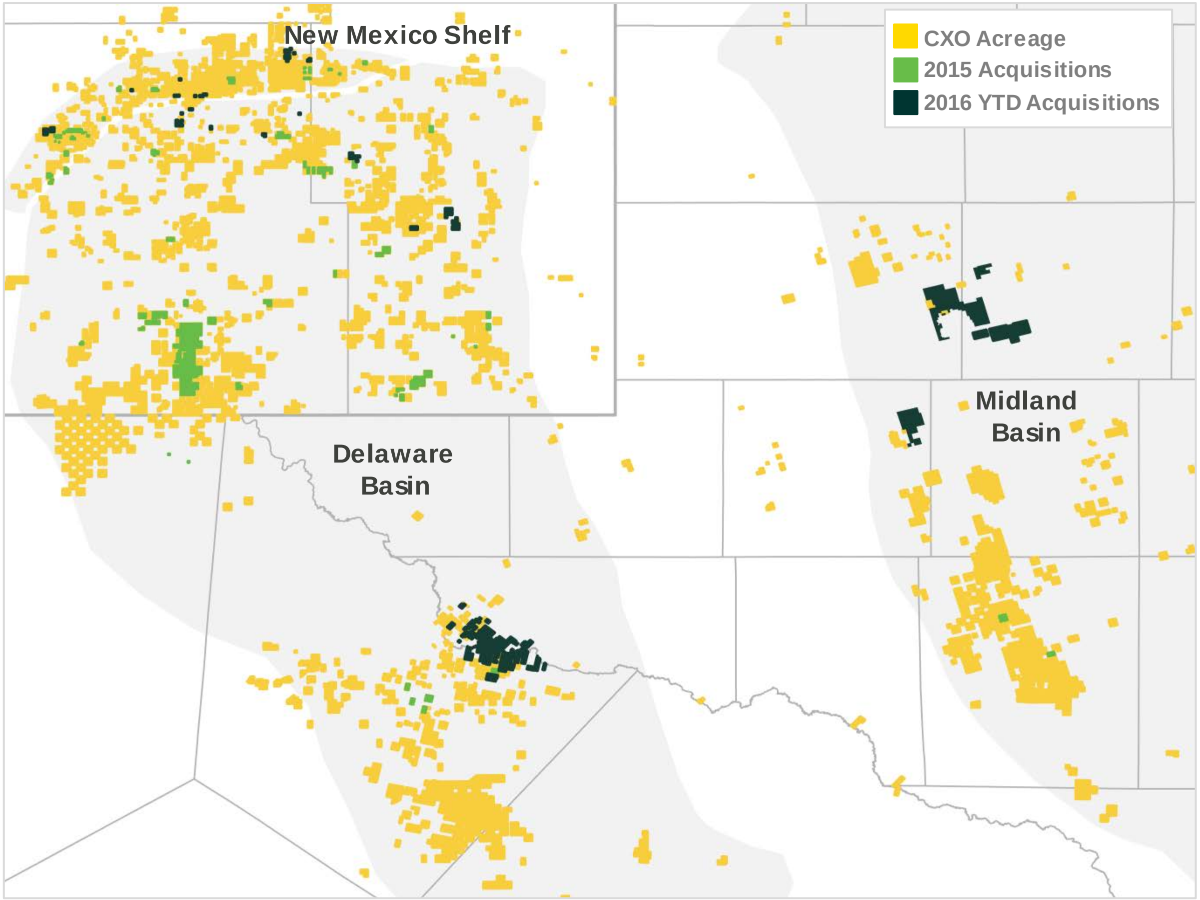
Cash G&A per Boe

↓ 10% Y/Y

Strengthening Balance Sheet

- **Maintaining low leverage ratio of <2x**
- **Reducing absolute leverage though senior notes redemption**
- **Lower interest expense burden improves cash margin**

Expanding Growth Platforms



[1]Capital program excludes acquisitions.

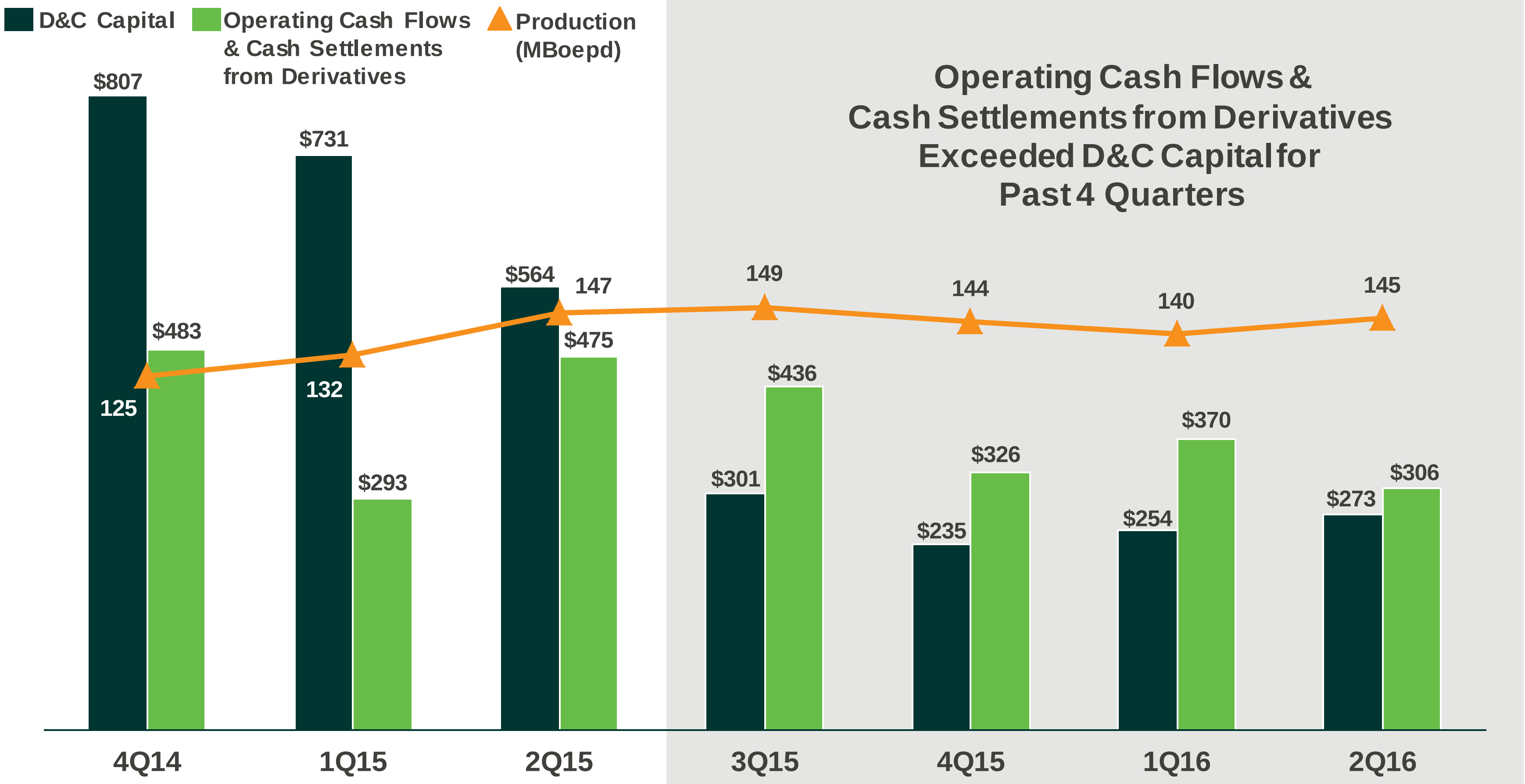
Executing a Disciplined Capital Program

Preserving Financial Strength; Improving Capital Productivity

Capital Discipline Uniquely Positions Concho

- D&C capital down ~65% since 4Q14
- Resilient production base
- Well positioned to reduce long-term debt through senior notes redemption

Spending Within Cash Flows ($mm)



Avg. HZ Rigs	37	30	18	15	12	10	13

Execution Strength

Concho's Development Machine Enhances Asset Value

1,040	17	>18,000
Total Horizontal Wells Drilled 2011-2Q16	Rigs Running Largest Rig Program in the Permian	Identified Horizontal Drilling Locations

- Large-scale, diversified asset base within the Permian provides competitive advantage
- Capital flexibility across assets
- Proven execution strength
- Infrastructure drives cost efficiencies and maximizes returns
- Development optimization enhances well productivity and capital efficiency

Note: Rig count as of September 1, 2016.

Improving Well Performance and Reducing Costs

- **Continuous improvement in well performance**
  - › Drilling & completion optimization driving strong well performance
  - › Advancing multi-zone delineation
  - › Transitioning to development mode with more efficient multi-well pads and long-laterals
- **Sharp focus on reducing well costs**
  - › Average well cost per lateral foot down 40%+ since 1Q15
- **Enhanced drilling efficiencies**
  - › Multi-well pads utilized for ~55% of the drilling program in 2Q16
  - › Set quarterly record for average drilling days in Northern Delaware Basin at 19 days in 2Q16
  - › 20% improvement Y/Y in feet drilled per day in Midland Basin

Decrease in Total Well Cost / Lateral Foot Since 1Q15

Midland Basin
↓ 48%

New Mexico Shelf
↓ 47%

Southern Delaware Basin
↓ 42%

Northern Delaware Basin
↓ 26%

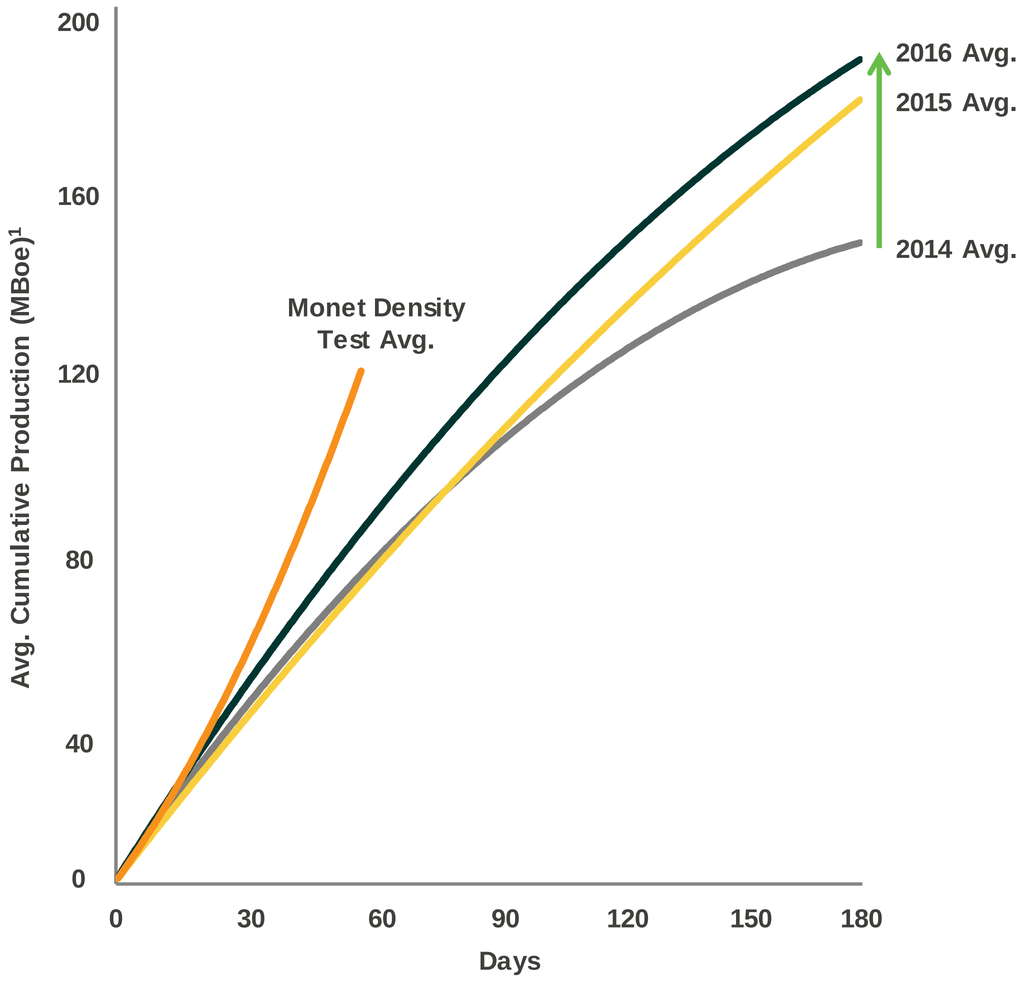
Oil-Rich Avalon Shale

Completion Optimization Enhancing Well Performance

NORTHERN DELAWARE BASIN

- **Completion optimization enhancing well performance**
- **Delineated Upper and Lower Avalon Shale zones**
- **Monet Density Test: recent well results outpacing prior well performance**
  - › **Red Hills Area (Lea County, New Mexico)**
  - › **4-well, 80-acre spacing test**
  - › **Fluid system and sand loading optimization**
- **Planning to drill several long-lateral Avalon Shale wells in 2H16**

Avalon Cumulative Production



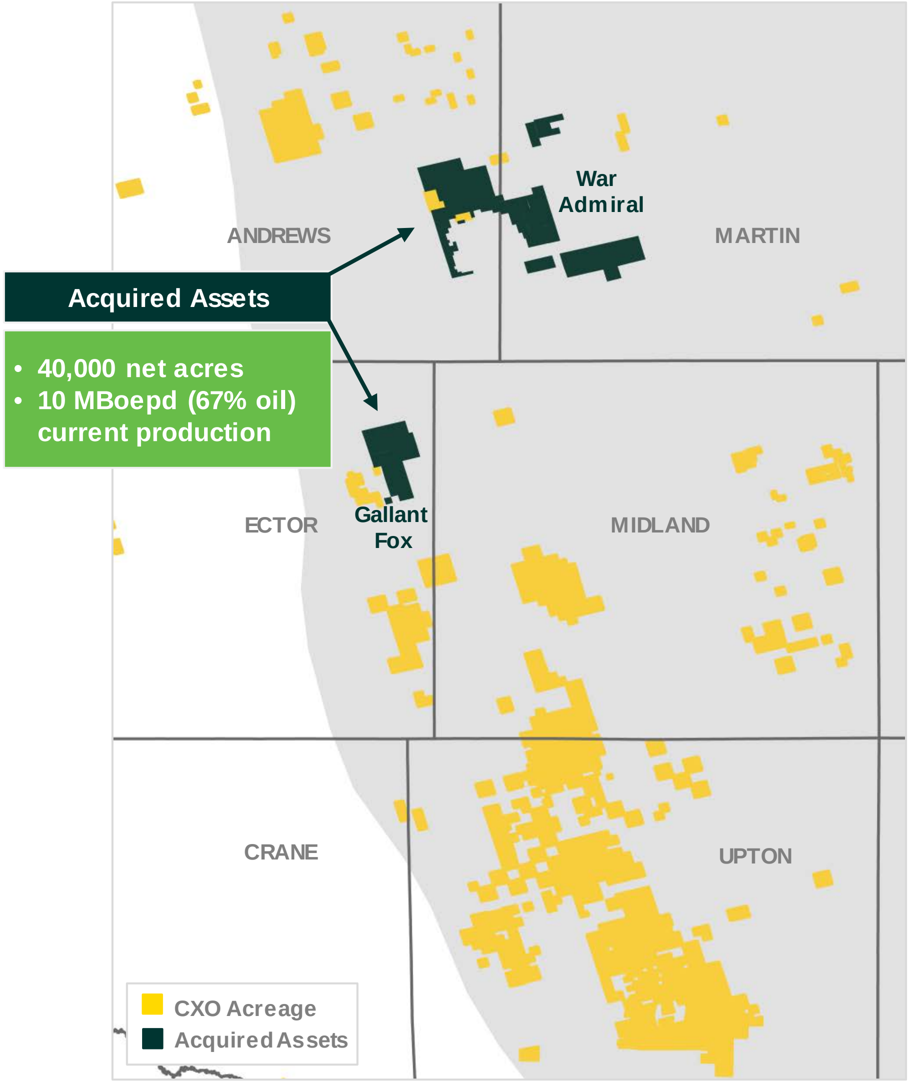
[1]Production data normalized for a 5,000' lateral.

CONCHO

Recent Acquisition Highlights

Expanding Core Midland Basin Position

- **Acquiring high-quality assets in the Midland Basin**
  - › Purchase price $1.625bn, consisting of approximately $1.1bn cash and 3.96mm shares of CXO common stock[1]
  - › Expected closing October 2016
- **Contiguous leasehold adds 40,000 net acres to core Midland Basin position[2]**
  - › Average 99% working interest and minimal leasehold obligations
  - › Stable, low-decline production base
- **Enhances drilling inventory with significant upside**
  - › Adds more than 530 long-lateral locations
  - › Upside potential through development optimization, tighter well spacing and additional zones

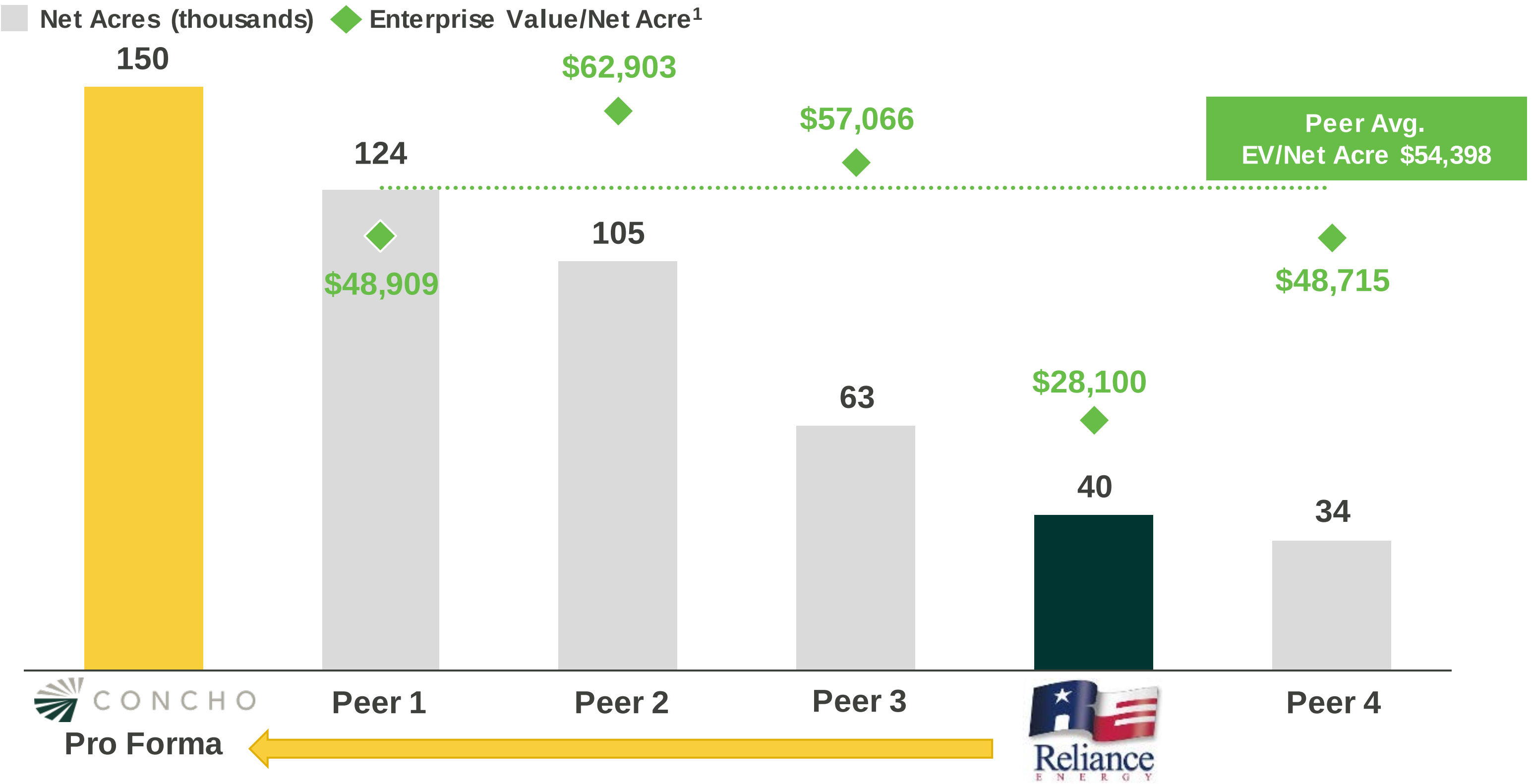


[1]Issuable pursuant to a stock payment option exercised by CXO.
[2]Approximately 8,500 net acres with rights below 10,000' only.

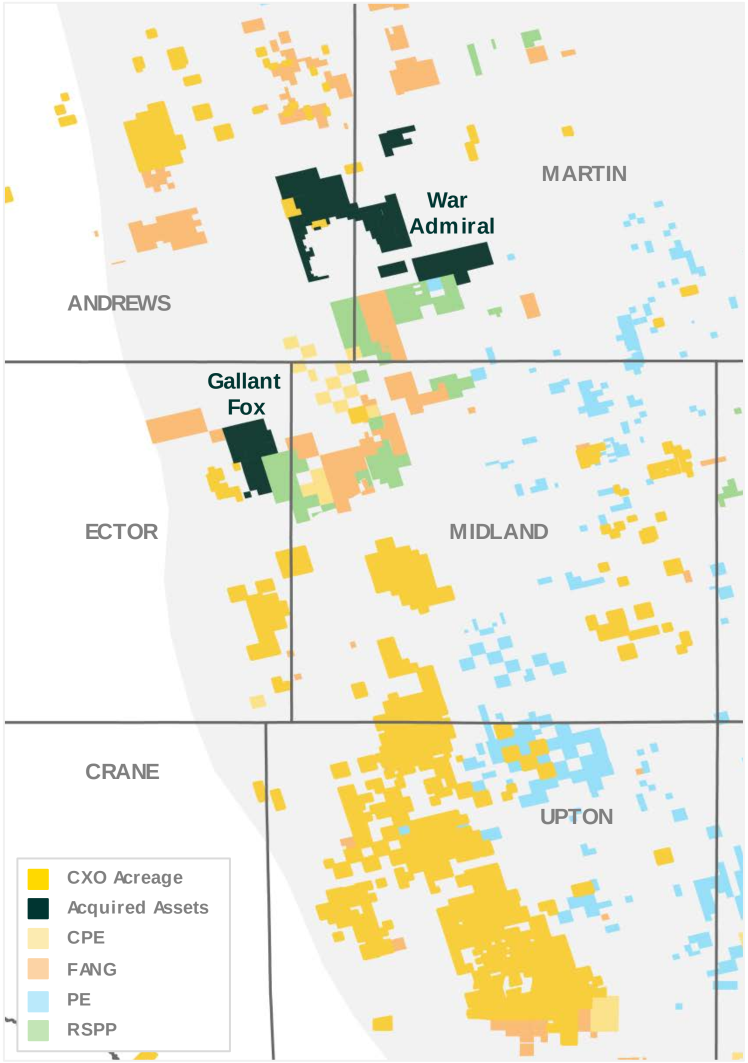
Building for Long-Term Value Creation in the Midland Basin

- **Expands core Midland Basin position by ~35% to more than 150,000 net acres**
  - Combined production totals ~30 MBoepd
- **Premier resource and returns proven by Concho and regional operators**

Relative Size & Valuation among Pure-Play Permian Operators



Regional Overview

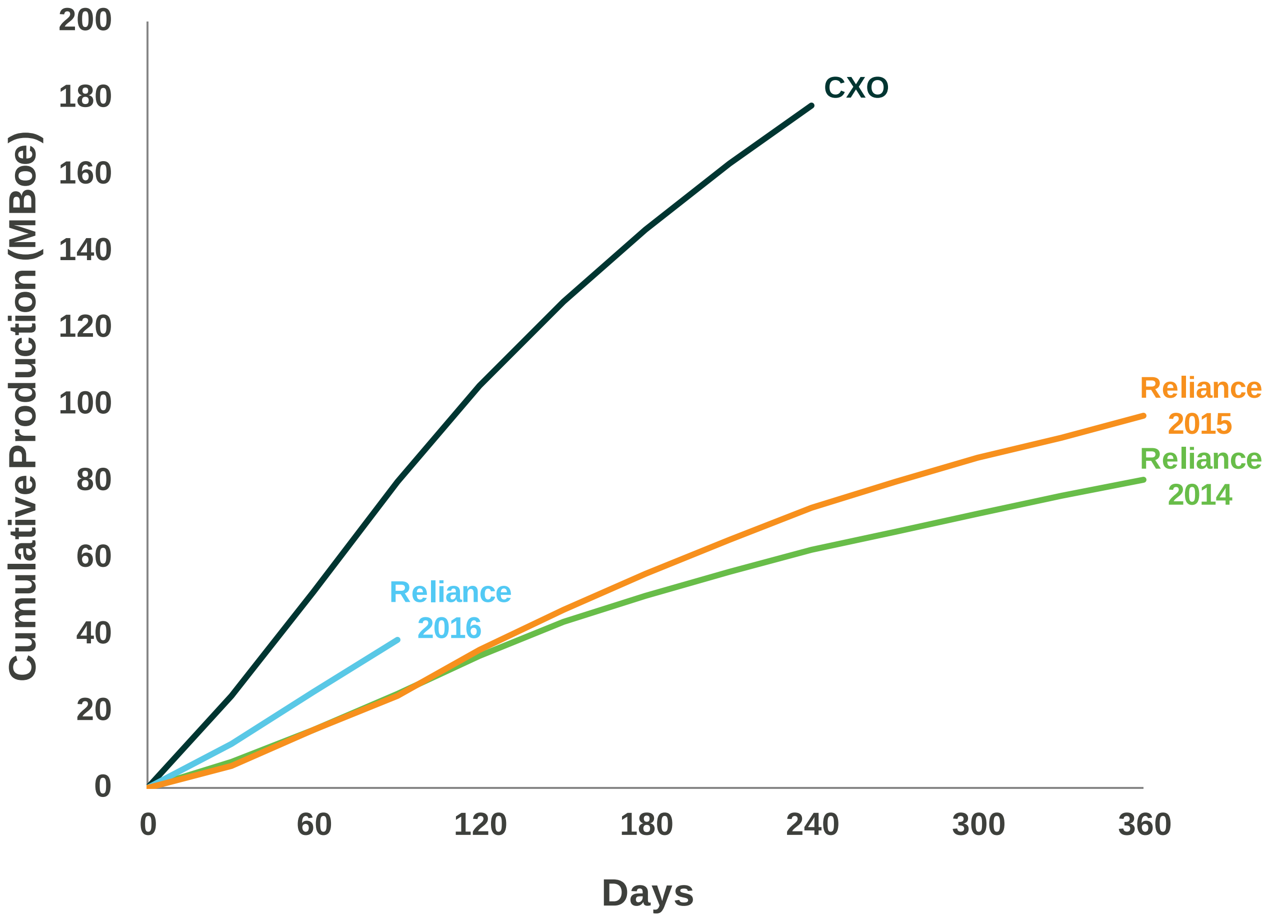


Note: Peer companies include CPE, FANG, PE and RSPP.

[1]Enterprise value for peer companies as of August 12, 2016, and adjusted for current production value at $35,000/Boepd. Value for Reliance based on transaction value of $1,625mm adjusted for current production value of $500mm, which represents the present value of proved developed producing volumes based on NYMEX strip pricing as of August 12, 2016.

Leveraging Our Execution Strength to Add Value

Lower Spraberry Well Performance



Completion Optimization Drives Better Performance

Lower Spraberry		
Vintage	Well Count	Proppant Loading (lbs/ft)
CXO	2	2,300
Reliance 2016	1	1,800
Reliance 2015	4	1,400
Reliance 2014	3	1,300

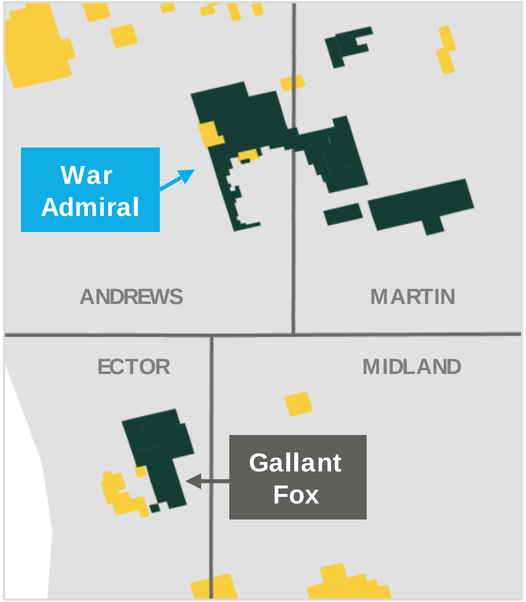
- Lower Spraberry zone a prolific target de-risked by Concho and industry activity
- Strong results from Concho's Lower Spraberry program
- 8 Lower Spraberry wells completed since 2014 on acquired assets

Immediate opportunity to enhance value through completion optimization

Note: Production normalized for a 5,000' lateral.

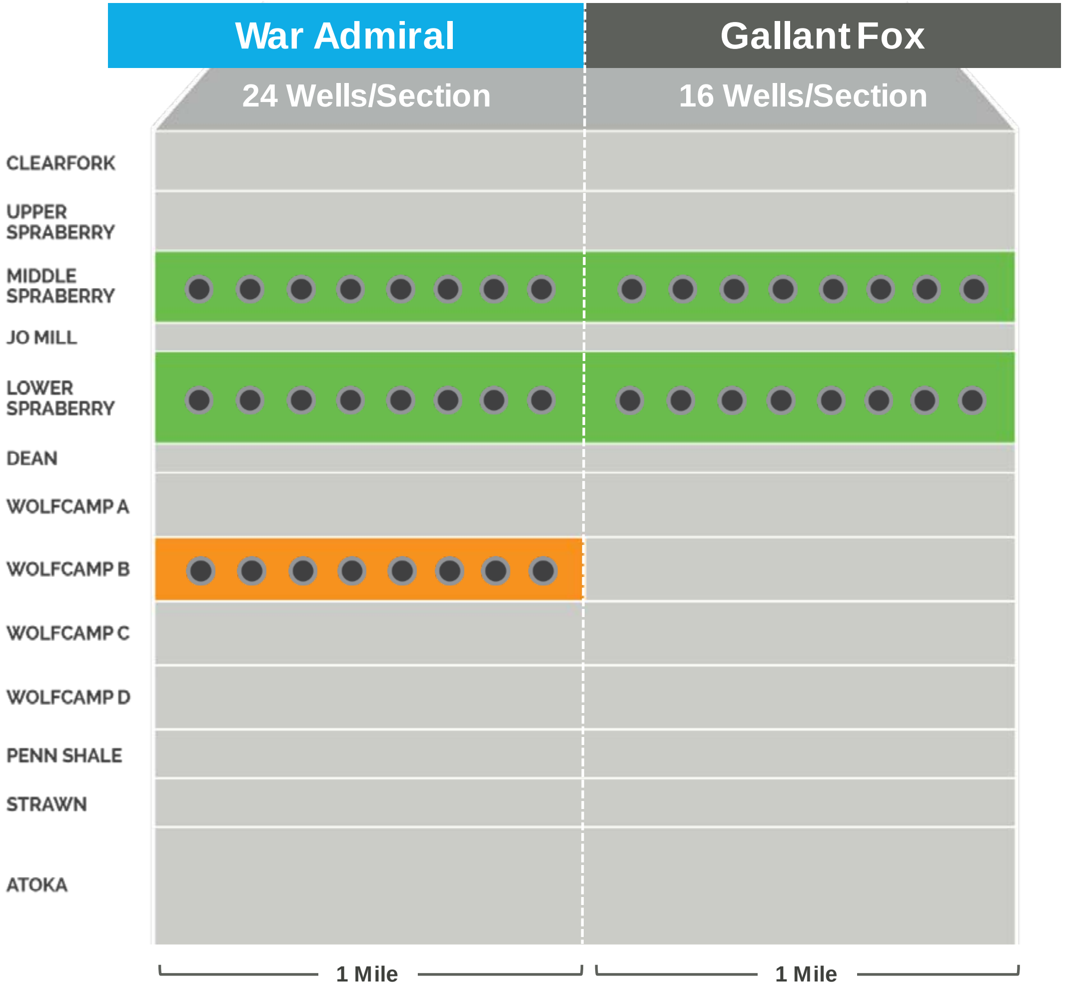
Low-Risk Inventory Assessment

Acquired Assets



Inventory Assessment

- **High-quality acreage position with multi-zone potential de-risked by consistently strong industry results**
- **Acquisition economics evaluated using conservative location booking based on two to three zones per DSU**
- **Plan to develop substantially all of the acquired acreage with long-lateral wells**
  - Adds more than 530 long-lateral wells to inventory
  - Two-thirds of these locations are 2-mile laterals, remaining third are 1.5-mile laterals



Development Upside

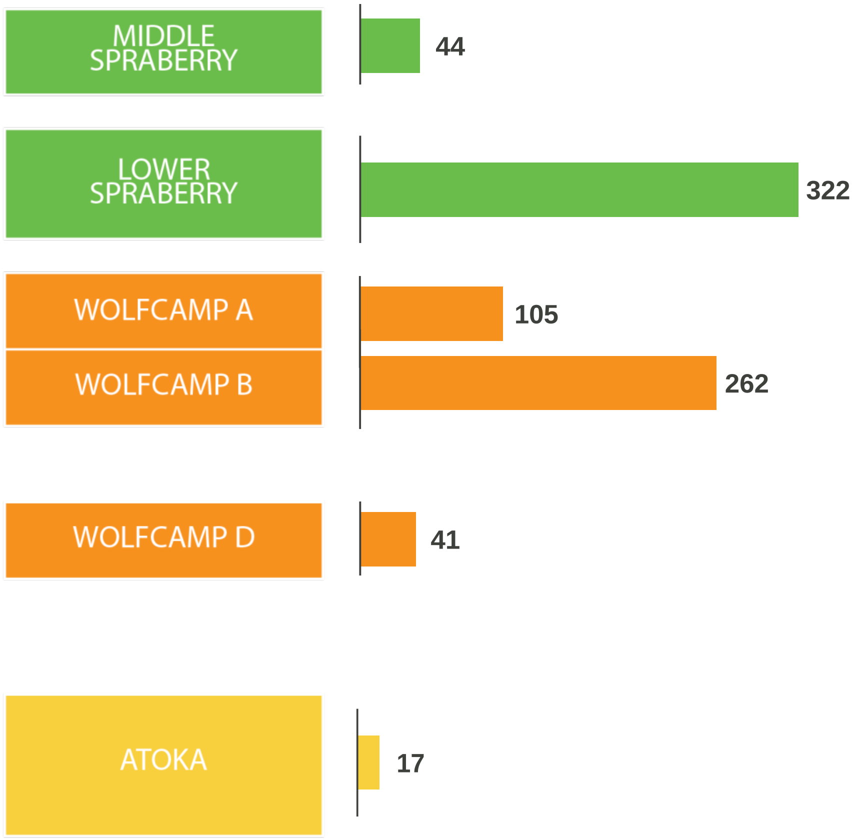
Substantial Multi-Bench and Increased Density Potential

Upside Potential

- Regional geology and industry activity suggests acquired acreage may support development in three additional zones as well as staggered development in the Lower Spraberry
- Potential versus evaluated locations per section implies over 2x inventory expansion

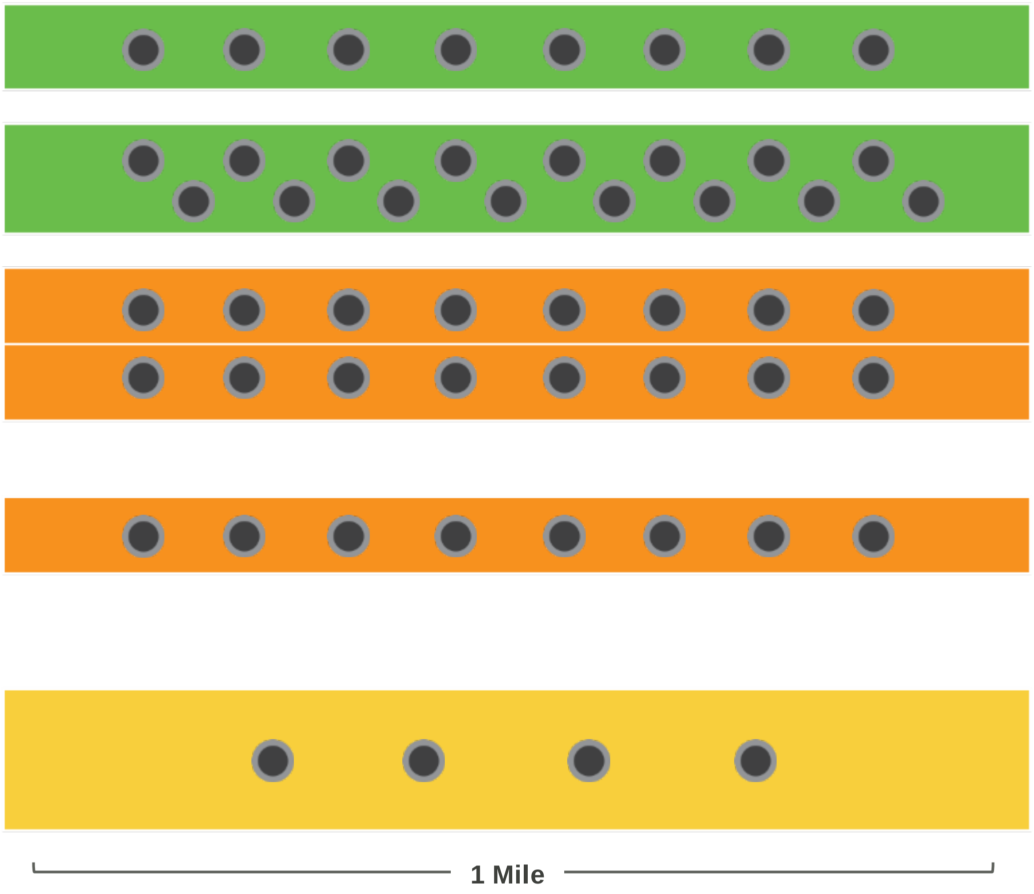
Regional Activity

of Industry Wells Drilled by Zone[1]



Development Upside

52 Wells/Section



[1]Data sourced from regulatory filings and IHS.

CONCHO

Key Messages

Concho's Development Optimization Enhances Asset Value

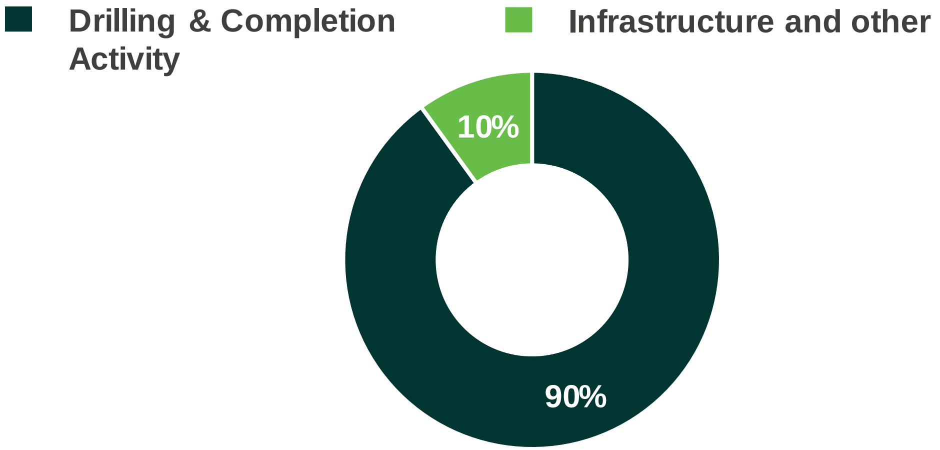
- **Consistent execution of our strategy**
- **Large-scale, diversified asset base within the Permian provides competitive advantage**
- **Capital flexibility across assets**
- **Intense focus on delivering operational excellence**
  - **Infrastructure drives cost efficiencies and maximizes returns**
  - **Development optimization enhances well productivity and capital efficiency**
- **Active portfolio management**

Long-Term Outlook	
Balance Cash Flow and Capital	Deliver Differentiated Growth
Maintain Strong Balance Sheet	Portfolio High-Grading

Appendix

2016 Capital Program

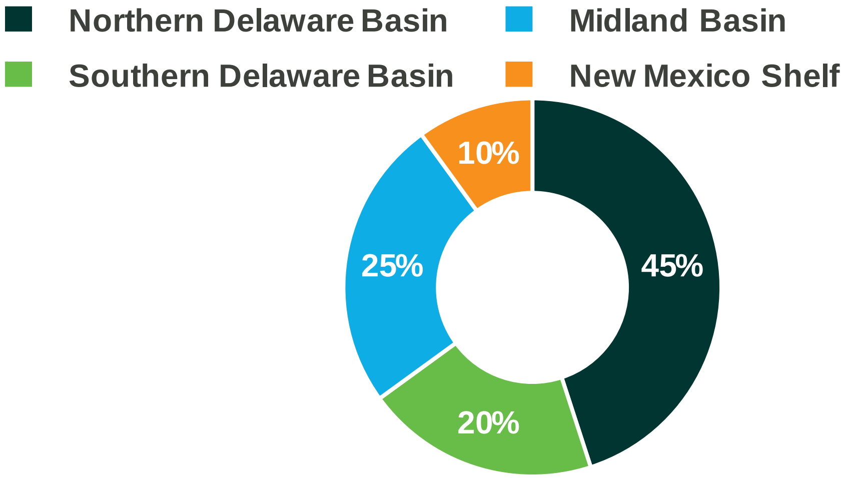
2016 Capital Allocation



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

- ~35% less capital year-over-year[1]
- Spending within cash flows

2016 production outlook 1% - 3% annual growth



~100% horizontal development

Continued focus on maximizing resource recovery

- Optimizing well spacing and completion techniques throughout core areas

2017 OUTLOOK

20% annual production growth, driven by >20% oil volume growth, within cash flows

[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.

Northern Delaware Basin

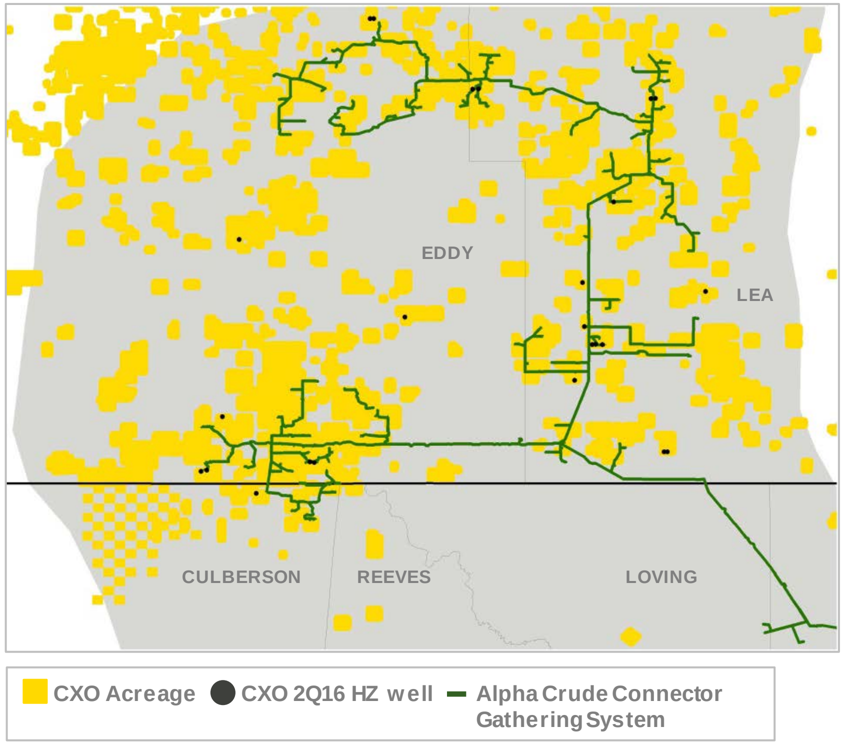
Industry-Leading Position with Multi-Zone Potential

ACREAGE POSITION

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

CURRENT RIG COUNT

4 Horizontal Rigs



2016 Plans

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

2Q16 Well Results

Added 24 horizontal wells (avg. lateral length 4,879')

- Avg. 30-day peak rate: 1,100 Boepd (73% oil)
- Avg. 24-hour peak rate: 1,470 Boepd

Alpha Crude Connector

- Strategic gathering system providing access to key markets and improving wellhead pricing

Note: Acreage as of December 31, 2015. Well results represent wells with >30 days of production data in 2Q16.

Southern Delaware Basin

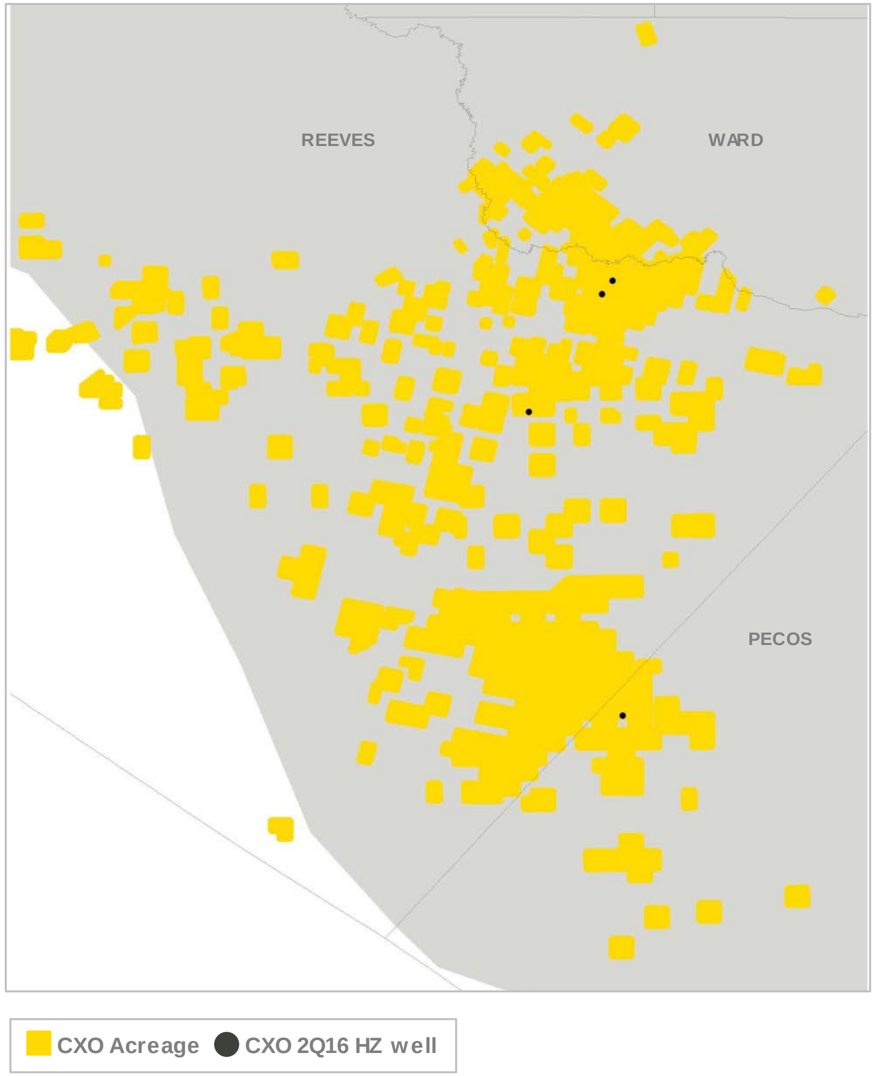
Core Position in Rapidly Advancing Oil Play

ACREAGE POSITION

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

CURRENT RIG COUNT

4 Horizontal Rigs



2016 Plans

- Focused development on Wolfcamp
- Delineating 3rd Bone Spring Sand zone

2Q16 Well Results

Added 4 horizontal wells (avg. lateral length 5,360')

- Avg. 30-day peak rate: 1,284 Boepd (77% oil)
- Avg. 24-hour peak rate: 1,772 Boepd

Achieved strong results from 3rd Bone Spring Sand well in North Harpoon area

Note: Acreage as of December 31, 2015, pro forma for 1Q16 acreage acquisition. Well results represent wells with >30 days of production data in 2Q16.

Midland Basin

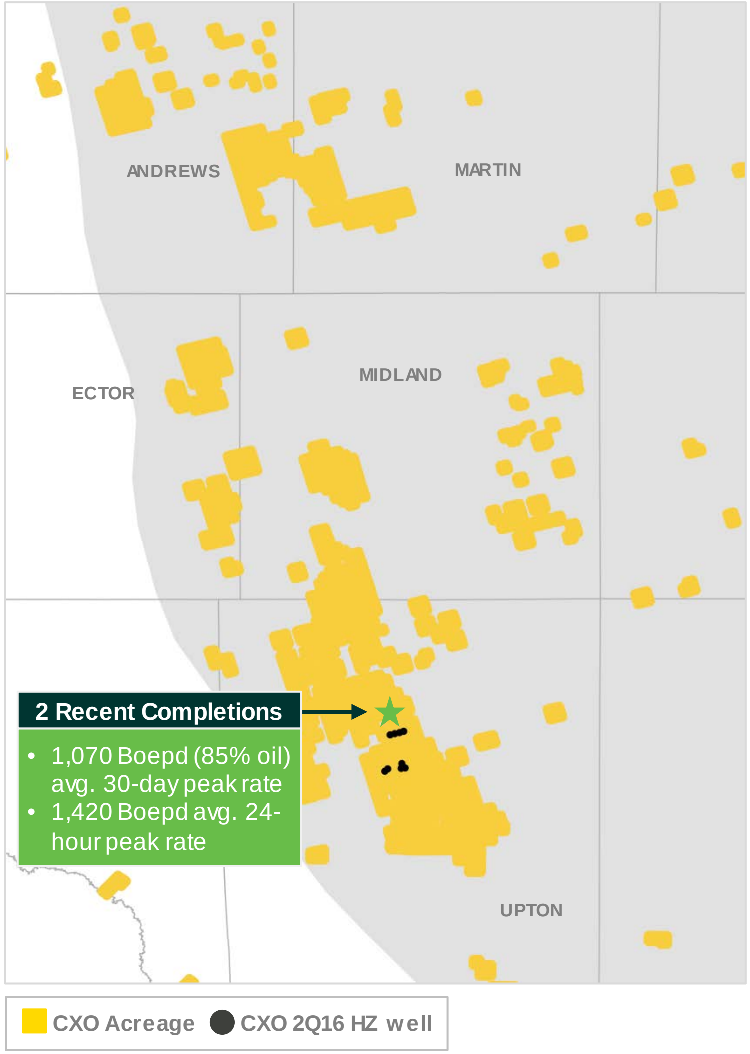
Optimizing Development

HORIZONTAL CORE ACREAGE POSITION

~240,000 gross (150,000 net) acres

CURRENT RIG COUNT

7 Horizontal Rigs



2016 Plans

- Build on long-lateral success and shift to multi-well pad drilling
- Optimize completion technique
- Advance Lower Spraberry program
- Test well spacing, development pattern

2Q16 Well Results

Added 9 horizontal wells (avg. lateral length 6,193')

- Avg. 30-day peak rate: 629 Boepd (85% oil)
- Avg. 24-hour peak rate: 925 Boepd
- Commenced drilling operations on these wells in 2015
  - › Plan to drill substantially all wells to ~10,000' in lateral length during 2016
- Experimented with lower sand volumes in completion design
  - › Plan to complete future wells with higher sand volumes

Currently completing an 8-well test, with 4 wells targeting the Lower Spraberry and 4 wells targeting the Wolfcamp B

Note: Acreage as of December 31, 2015, pro forma for Reliance acquisition. Well results represent wells with >30 days of production data in 2Q16.

New Mexico Shelf

Enhancing Value in Legacy Oil Play

ACREAGE POSITION

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

CURRENT RIG COUNT

2 Horizontal Rigs

2016 Plans

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

2Q16 Well Results

Added 4 horizontal wells (avg. lateral length 4,655')

- Avg. 30-day peak rate: 472 Boepd (82% oil)
- Avg. 24-hour peak rate: 592 Boepd

Note: Acreage as of December 31, 2015. Well results represent wells with >30 days of production data in 2Q16.

Operating Cash Flows & Cash Settlements from Derivatives (Unaudited)

The following table summarizes operating cash flows and cash settlements from derivatives for the periods indicated:

	Three Months Ended						
(in thousands)	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
Cash flows from operating activities	**$ 137,550**	**$ 112,275**	**$ 136,912**	**$ 271,659**	**$ 362,685**	**$ 126,249**	**$ 385,251**
Net settlements received from derivatives	168,749	257,930	189,475	164,033	112,252	167,156	98,157
Total	**$ 306,299**	**$ 370,205**	**$ 326,387**	**$ 435,692**	**$ 474,937**	**$ 293,405**	**$ 483,408**

Costs Incurred (Unaudited)

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

	Three Months Ended						
(in thousands)	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015	December 31, 2014
Property Acquisition Costs:							
Proved	$ 3,757	$ 252,352	$ (1,689)	$ 56,636	$ 2,243	$ -	$ 39,003
Unproved	18,767	138,640	10,243	161,921	18,037	16,013	184,378
Exploration	165,850	170,572	148,630	201,737	343,051	429,169	479,027
Development	107,039	83,104	86,444	99,490	221,410	301,744	327,711
Total Costs Incurred	**$ 295,413**	**$ 644,668**	**$ 243,628**	**$ 519,784**	**$ 584,741**	**$ 746,926**	**$ 1,030,119**

Reinforcing Financial Position

Significant Liquidity with Less Debt

BALANCE SHEET STRENGTH

Reducing leverage and consolidating core acreage during low price environment

Unaudited Pro Forma Balance Sheet (as of 6/30/2016)

($ in millions)	Actual 6/30/16	Adjustments: Reliance Acquisition	Adjustments: Equity Offering[1]	Adjustments: Bond Redemption[2,3]	Pro Forma 6/30/16
Cash	$ 481	$ -	$ 190	$ (621)	$ 50
Long-term debt:					
Credit facility	$ -	$ 1,137	$ (1,137)	$ -	$ -
CXO 7.000% Senior Notes due 2021	600			(600)	-
CXO 6.500% Senior Notes due 2022	600				600
CXO 5.500% Senior Notes due 2022	600				600
CXO 5.500% Senior Notes due 2023	1,550				1,550
Unamortized original issue premium	24				24
Senior notes issuance costs, net	(40)			7	(33)
Total long-term debt	$ 3,334				$ 2,741
Stockholder's equity	$ 5,904	$ 488	$ 1,327	$ (18)	$ 7,701
Total capitalization	$ 9,238				$ 10,442
Liquidity	$ 2,981				$ 2,550
Net debt	$ 2,853				$ 2,691
Net debt / net capitalization	33%				26%

[1]Includes underwriters' exercise of the greenshoe.
[2]Excludes impact of accrued interest expense upon redemption.
[3]Adjustment to stockholder's equity of $18mm reflects after-tax charges associated with the redemption of the 7.0% notes.

Hedge Position

2H16 OIL HEDGES
57.1 MBopd

	2016				
	Third Quarter	Fourth Quarter	Total	2017	2018
Oil Swaps[1]:					
Volume (Bbl)	5,460,000	5,054,000	10,514,000	20,865,500	12,000,000
Price per Bbl	$ 74.21	$ 59.38	$ 67.08	$ 54.91	$ 49.40
Oil Basis Swaps[2]:					
Volume (Bbl)	5,520,000	5,060,000	10,580,000	17,561,000	
Price per Bbl	$ (1.46)	$ (1.48)	$ (1.47)	$ (0.82)	
Natural Gas Swaps[3]:					
Volume (MMBtu)	7,360,000	7,360,000	14,720,000	45,217,398	
Price per MMBtu	$ 3.02	$ 3.02	$ 3.02	$ 3.02	

UPDATED AS OF SEPTEMBER 6, 2016

[1] The index prices for the oil contracts 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.

Operational & Financial Outlook

3Q16 OUTLOOK

Production:
144 to 148 MBoepd

	2016 Guidance
Production	
Annual growth	1% - 3%
Oil mix	60% - 64%
Price realizations, excluding commodity derivatives	
Crude oil differential to NYMEX (per Bbl)	($3.50) - ($4.00)
Natural gas (per Mcf) (% of NYMEX)	80% - 85%
Operating costs and expenses (per Boe, unless noted)	
LOE and workover costs	$6.50 - $7.00
Oil & gas taxes (% of oil & gas revenues)	8.25%
G&A:	
Cash G&A	$3.00 - $3.30
Non-cash stock-based compensation	$1.10 - $1.30
DD&A	$22.00 - $24.00
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 SEPTEMBER 6, 2016

[1]Capital plan excludes acquisitions.