# Barclays CEO Energy-Power Conference

Tim Leach, Chairman and Chief Executive Officer

September 2018

# Forward-Looking Statements and Other Disclaimers

**Forward-Looking Statements and Cautionary Statements**

The foregoing 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 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 relating to benefits of the acquisition of RSP Permian, Inc. (“RSP”). The words “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “enable,” “foresee,” “plan,” “will,” “guidance,” “drive,” “outlook,” “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 and other information discussed or referenced in the Company’s most recent Annual Report on Form 10-K and other filings with the SEC. 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 and free cash flow. 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 definitions of such measures and reconciliations to the nearest comparable measures in accordance with GAAP, please see the appendix.

The 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.

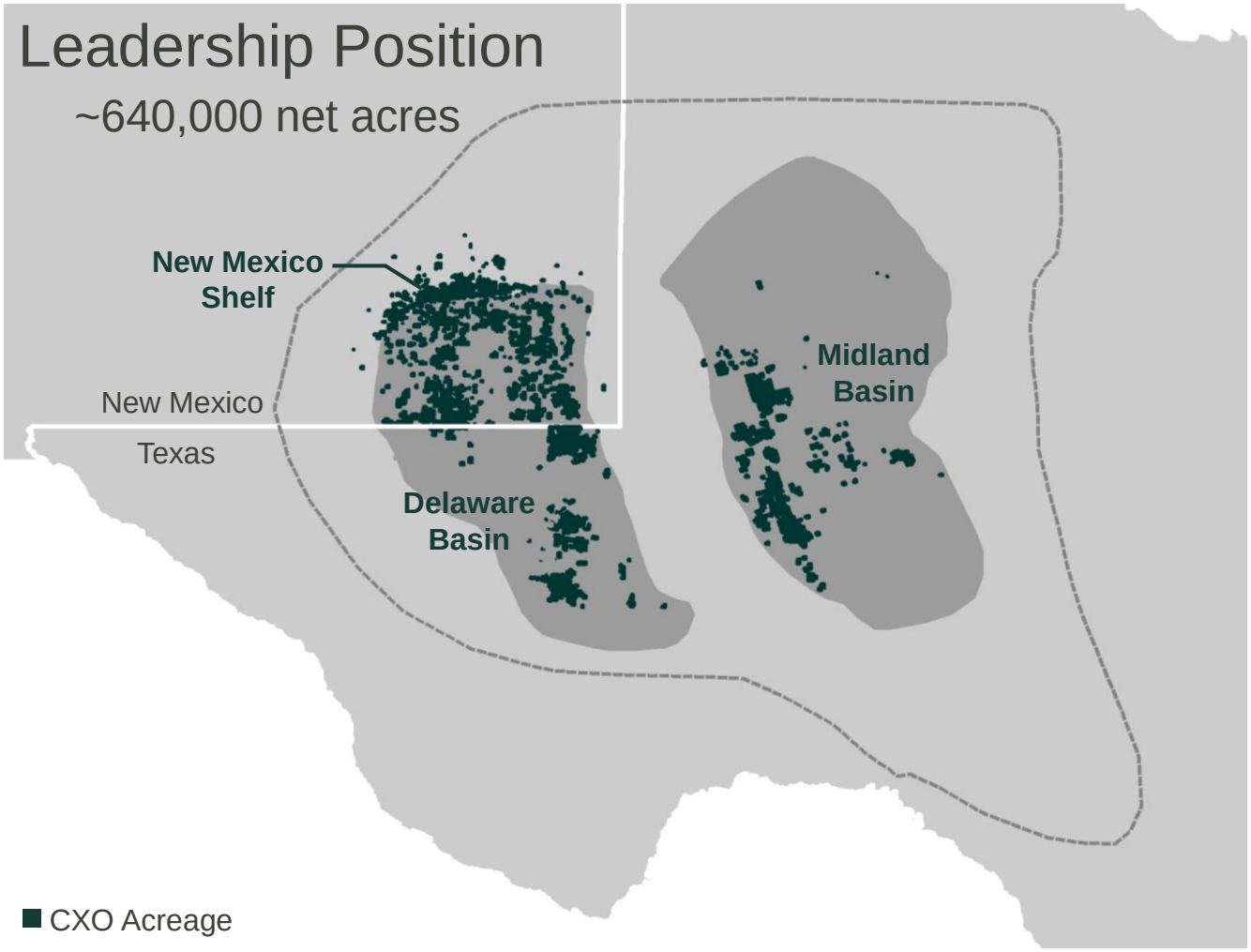
In this presentation, proved reserves attributable to the Company at December 31, 2017 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $47.79 per Bbl of oil and $2.98 per MMBtu of natural gas. The Company’s estimate of its total proved reserves at December 31, 2017 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,” “resources” and similar phrases 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. Such estimates 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 from these estimates. There is no commitment by the Company to drill all of the drilling locations that 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. Such estimates 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 or other factors that are beyond the Company’s control.

**Cautionary Statements Regarding Resource**

Concho may use the term “resource potential” and similar phrases to describe estimates of potentially recoverable hydrocarbons that SEC rules prohibit from being included in filings with the SEC. These are based on analogy to Concho’s existing models applied to additional acres, additional zones and tighter spacing and are Concho’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. Such estimates and identified drilling locations have not been fully risked by Concho management and are inherently more speculative than proved reserves estimates. Actual locations drilled and quantities that may be ultimately recovered from Concho’s interests could differ substantially from these estimates. There is no commitment by Concho to drill all of the drilling locations that have been attributed to these quantities. Factors affecting ultimate recovery include the scope of Concho’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. Such estimates may change significantly as development of Concho’s oil and natural gas assets provide additional data. Concho’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 or other factors that are beyond Concho’s control. Concho’s use of the term “premium resource” refers to assets with the capacity to produce at an internal rate of return that is greater than thirty-five percent based on fifty-five dollar oil and three dollar gas.

# Concho Resources

## Leading Development of the Permian Basin




## The Permian Basin

Our home for 30+ years

Home-field advantage with HQ in Midland, Texas

## The pillars of our strategy

Building a great **team**

Investing in high-margin **assets**

Generating high-quality **returns**

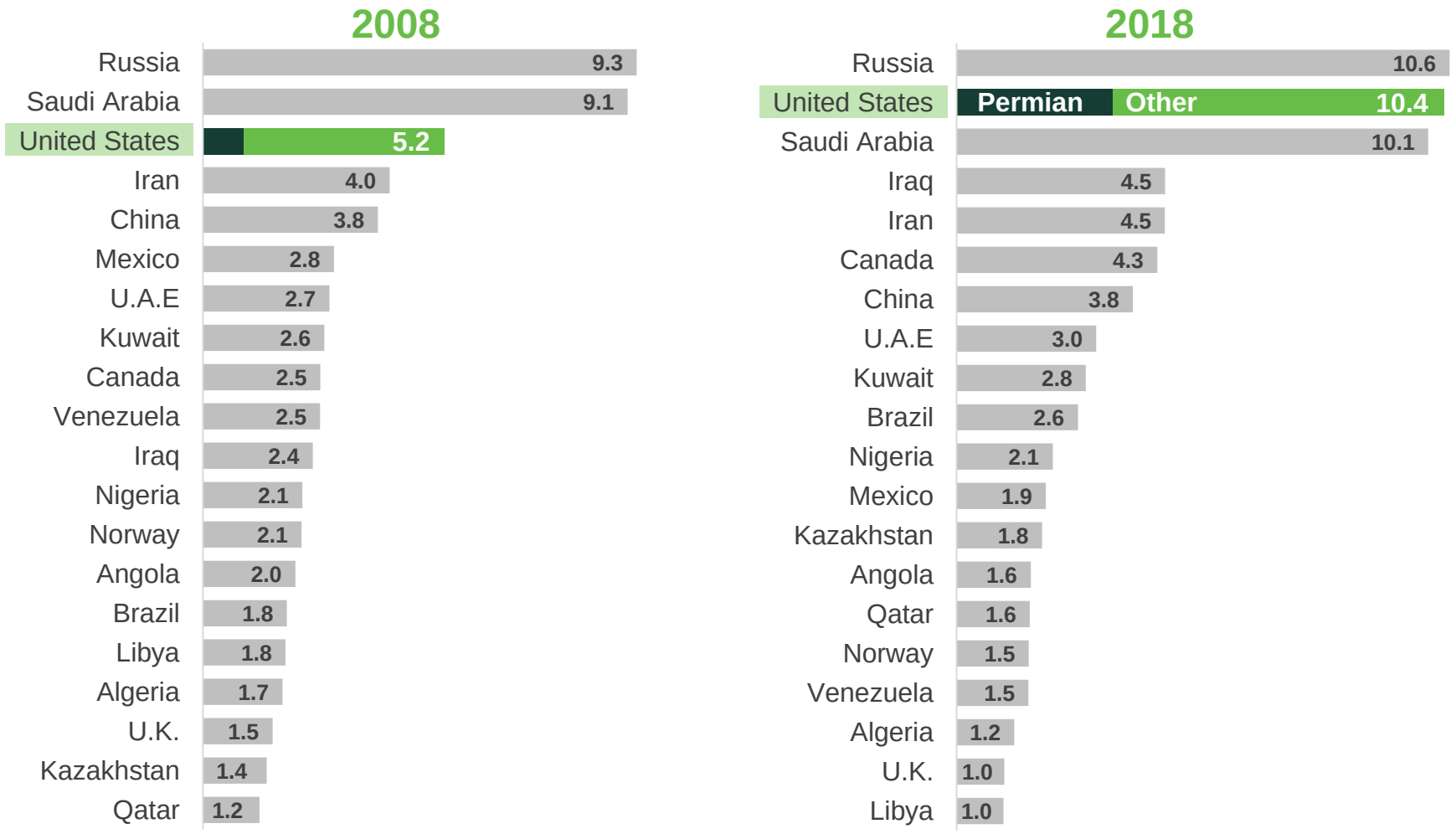
Maintaining a strong **balance sheet**

Note: Concho acreage as of December 31, 2017, pro forma for transactions announced to date.

# Global Context

## Innovation and Technology Game Changers for U.S. Oil Growth

### Millions of Barrels of Crude Oil Produced Per Day




**The U.S. Oil Growth Story Is a Permian Oil Growth Story**

- From 2008 to 2018, U.S. oil production more than doubled
- Permian key driver of U.S. oil growth
- Permian expected to lead growth for the next decade and beyond

Source: EIA for May 2018

# Well Positioned with Unique Competitive Advantages

**Leveraging Our Advantages to Deliver Growth *and* Value**

## Our Advantages

### Execution Strength and Scale

- Running one of the largest rig programs
- Largest shale producer
- Leader in horizontal development

### Breadth and Depth of High-Quality Portfolio

- Balanced portfolio within the Permian
- ~30 years of premium resource at current development pace

### Superior Capital Efficiency

- Delivering production growth *and* free cash flow
- Leading production growth per debt-adjusted share performance

### Financial Strength

- Low leverage provides substantial flexibility
- <1.5x target leverage ratio
- Investment grade credit ratings

Note: Leverage ratio determined using total long-term debt and the non-GAAP measure EBITDAX. See appendix for definition of EBITDAX.

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# Execution Strength and Scale

## What It Means to Us and Why It Matters

| What It Means to Us | Why It Matters |
|---|---|
| • Allocating capital to high-return projects | **Drives production growth and free cash flow** |
| • Running a large, manufacturing-like program | **Maximizes resource recovery and economics** |
| • Leveraging technology and data | **Accelerates innovation with real-time feedback loop** |
| • Building for the future | **Enhances platform for sustainable performance** |
| • Managing risk | **Mitigates headwinds; well positioned to win in any environment** |

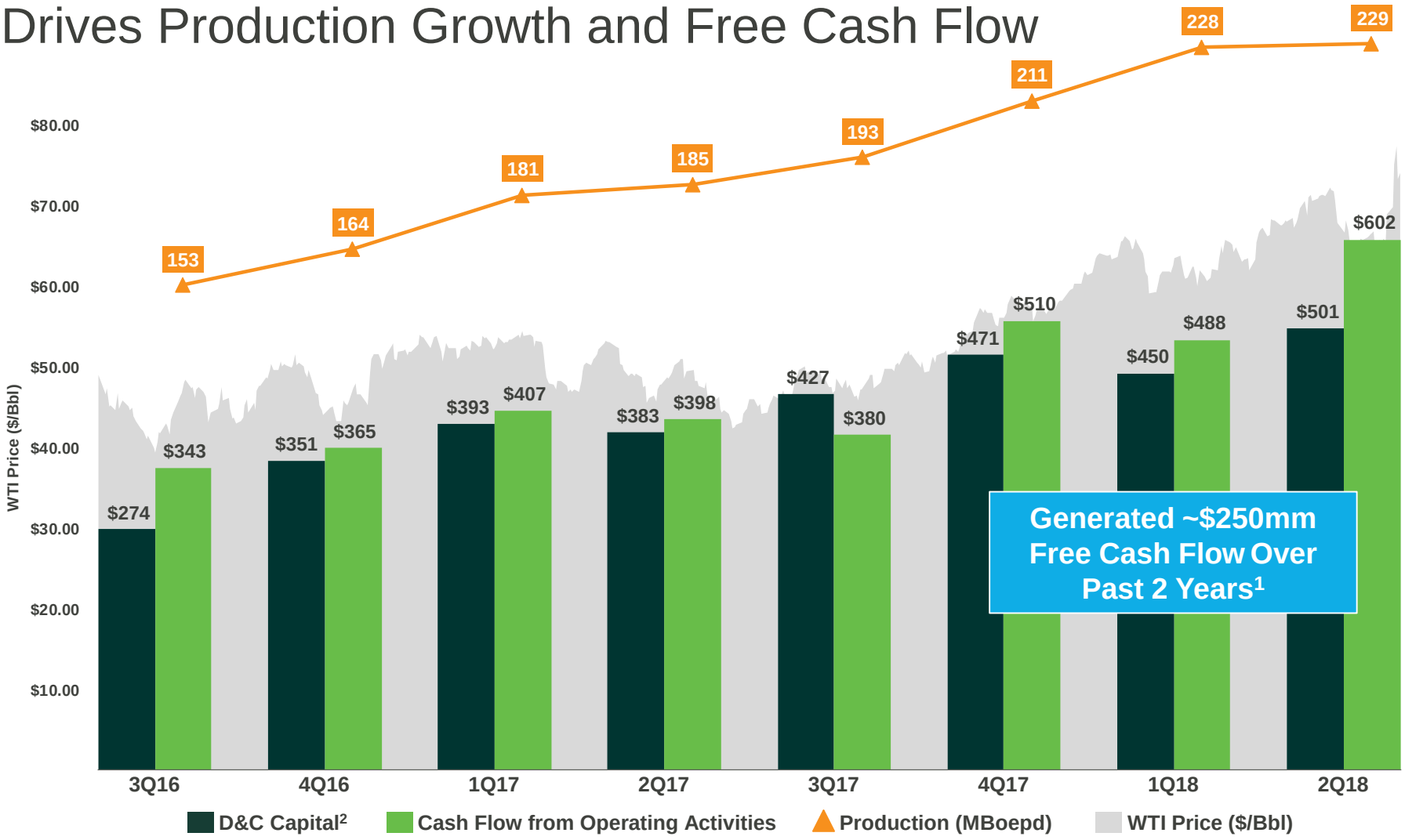
# Allocating Capital to High-Return Projects

## Track Record of Efficient Capital Allocation

## Execution Strength and Scale

- **Allocating capital to high-return projects**
- Running a large, manufacturing-like program
- Leveraging technology and data
- Building for the future
- Managing risk

## Drives Production Growth and Free Cash Flow




**Generated ~$250mm Free Cash Flow Over Past 2 Years[1]**

[1]Free cash flow is a non-GAAP measure. See appendix for definition and reconciliation to GAAP measure.
[2]Drilling & Completion (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.

# Running a Large, Manufacturing-Like Program

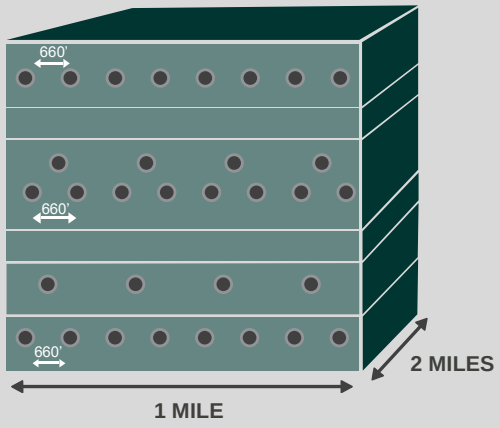
**Leading Large-Scale Development in the Permian Basin**

## Execution Strength and Scale

- Allocating capital to high-return projects
- **Running a large, manufacturing-like program**
- Leveraging technology and data
- Building for the future
- Managing risk

## Maximizes Resource Recovery and Economics

**Four Dimensions of Full-Field Development:**




1. **Vertical Spacing**
2. **Horizontal Spacing**
3. **Sequencing** (order in which zones are completed)
4. **Timing**

## Manufacturing Mode Accounts for All Four Dimensions and…

- ✓ Mitigates parent/child well degradation and downtime for offset activity
- ✓ Captures supply chain and logistics advantages
- ✓ Accelerates learning and adaptation

# Moving Acquired Assets into Manufacturing Mode

**Project Spotlight – Midland Basin Ted Johnson Project**

## Midland Basin Ted Johnson Project


- Thirteen, 2-mile wells targeting 5 zones
- Lateral placement and completion design leverages:
  - Proprietary geocellular model
  - Mabee Ranch fiber optic project
  - RSP's well spacing pilots
- Plan to utilize 2 frac crews and stage wells online over 2 months, optimizing facilities build
- Improves resource recovery and development economics (payout, ROR and NPV)

Note: Concho acreage as of December 31, 2017, pro forma for transactions announced to date.

# Leveraging Technology and Data

**Learning More, Faster and Quickly Transferring Across the Portfolio**

## Execution Strength and Scale

- Allocating capital to high-return projects
- Running a large, manufacturing-like program
- **Leveraging technology and data**
- Building for the future
- Managing risk

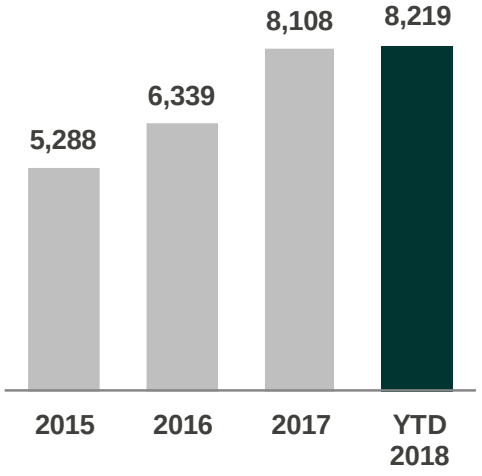
## Accelerating Innovation

**Drilling**
*Proprietary geocellular model fine-tuning lateral placement*

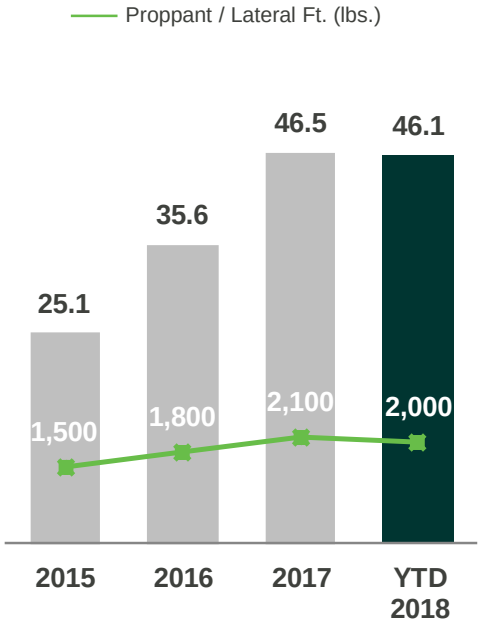
**Completions**
*Technology and data driving design changes and cost improvement*

**Productivity**
*Design refinements generating strong well performance*

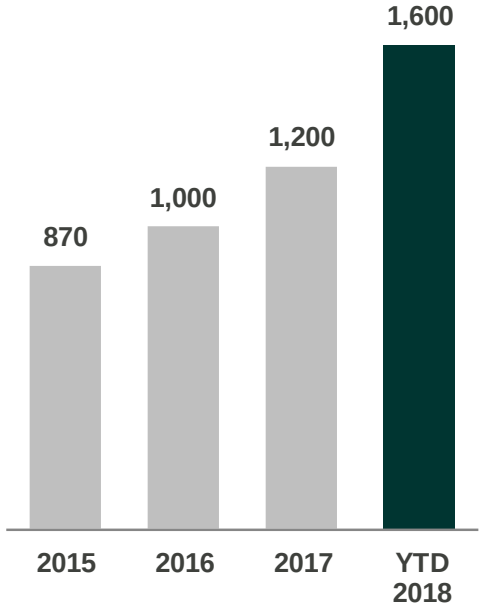
**Avg. Lateral Length (ft.)**




**Stages / Well**




**Avg. 30-Day Peak Rate (Boepd)**




Note: YTD well results represent wells with >60 days of production data at June 30, 2018.

# Manufacturing Precision

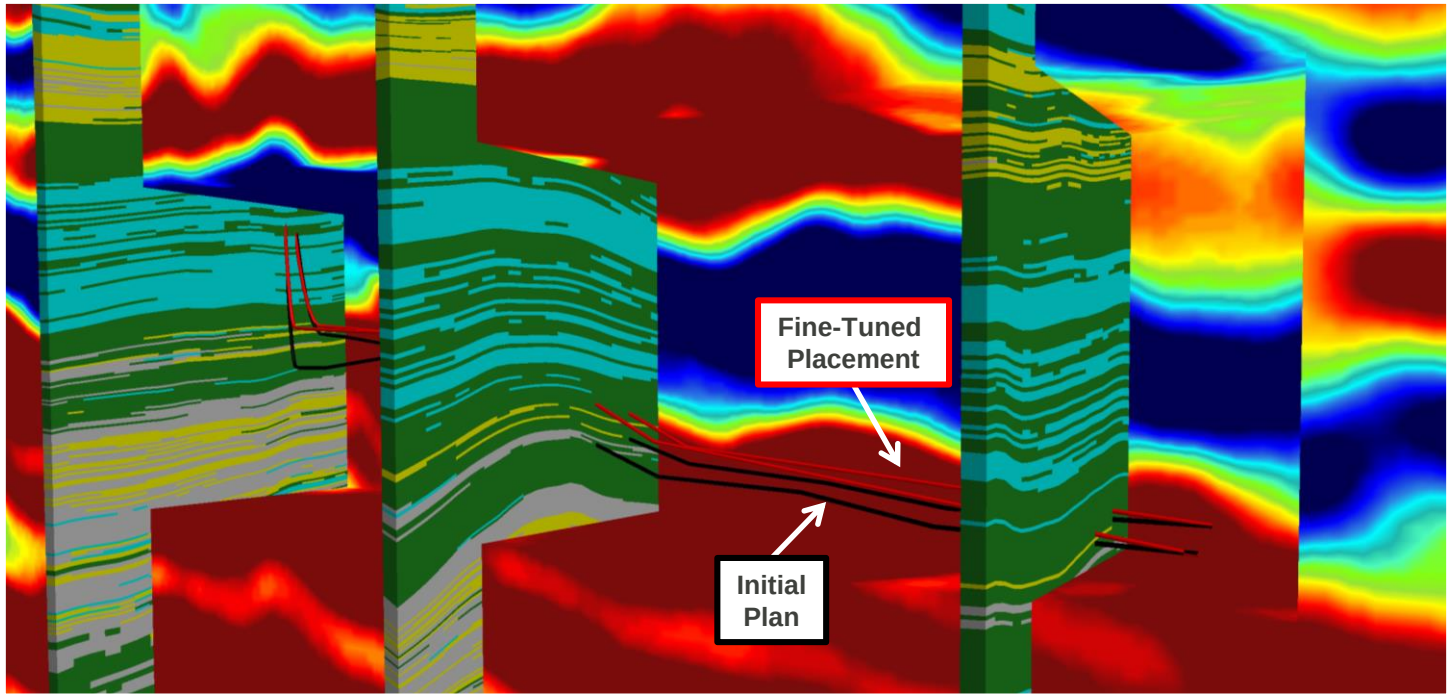
**Rapidly Optimizing Development with Large-Scale Projects and Technology**

## Manufacturing Mode Contributes to Our Most Efficient Feedback Loop

- ✓ Using tailored designs rather than pattern drilling
- ✓ Real-time adaptation to refine drilling and completion designs
- ✓ Accelerates learning and knowledge transfer across portfolio

## Example: Proprietary Geocellular Model

- Incorporates new technology, legacy data and proprietary interpretation
- Targets most productive zone
- Delivers record-setting performance: 12,859’ lateral with one drill bit



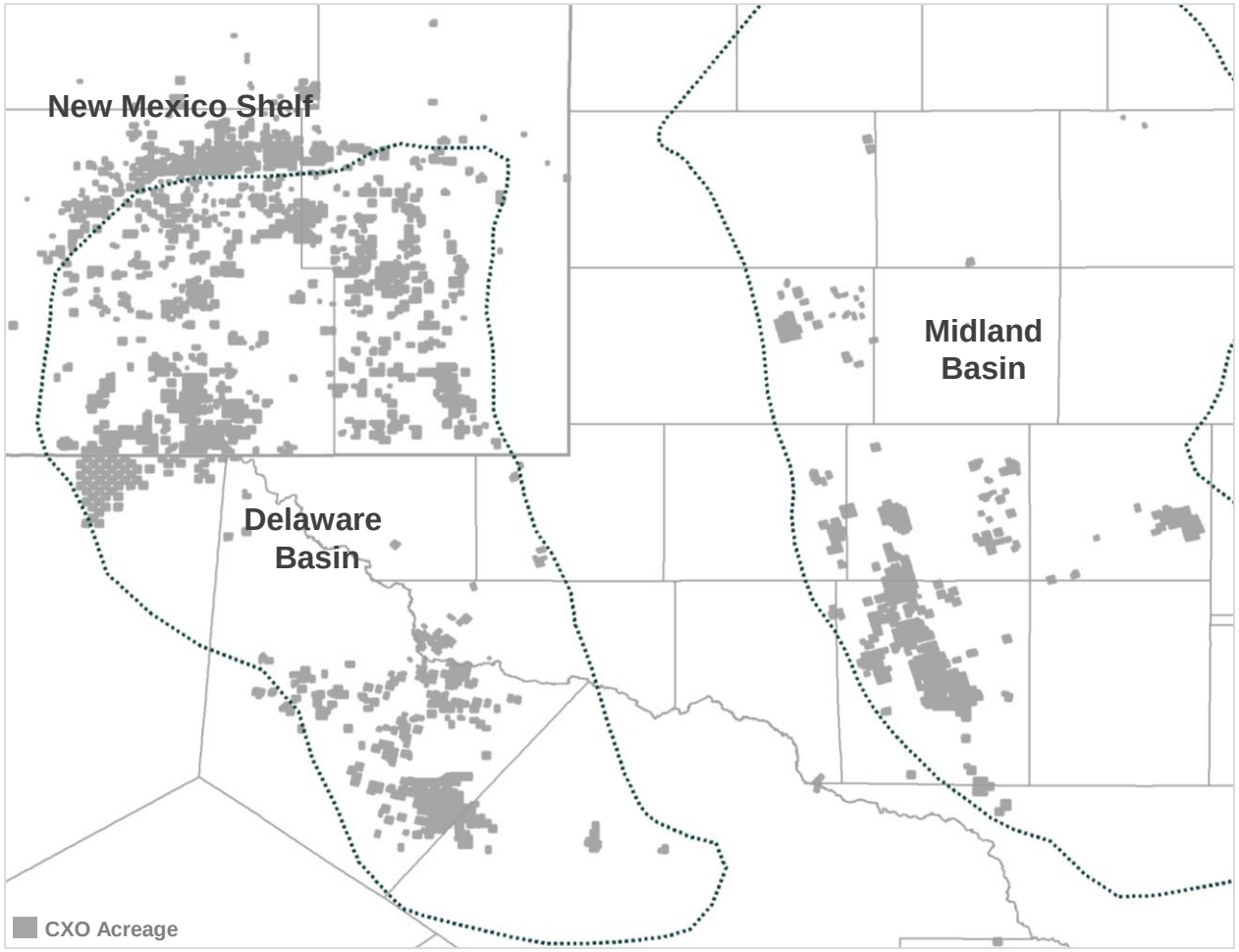
# Building for the Future

## High-Grading Assets Through Continuous Portfolio Management

### Execution Strength and Scale

- Allocating capital to high-return projects
- Running a large, manufacturing-like program
- Leveraging technology and data
- **Building for the future**
- Managing risk

### Concho Acreage Then: 2016




Note: Concho acreage as of January 31, 2016.

# Building for the Future

## High-Grading Assets through Continuous Portfolio Management

### Execution Strength and Scale

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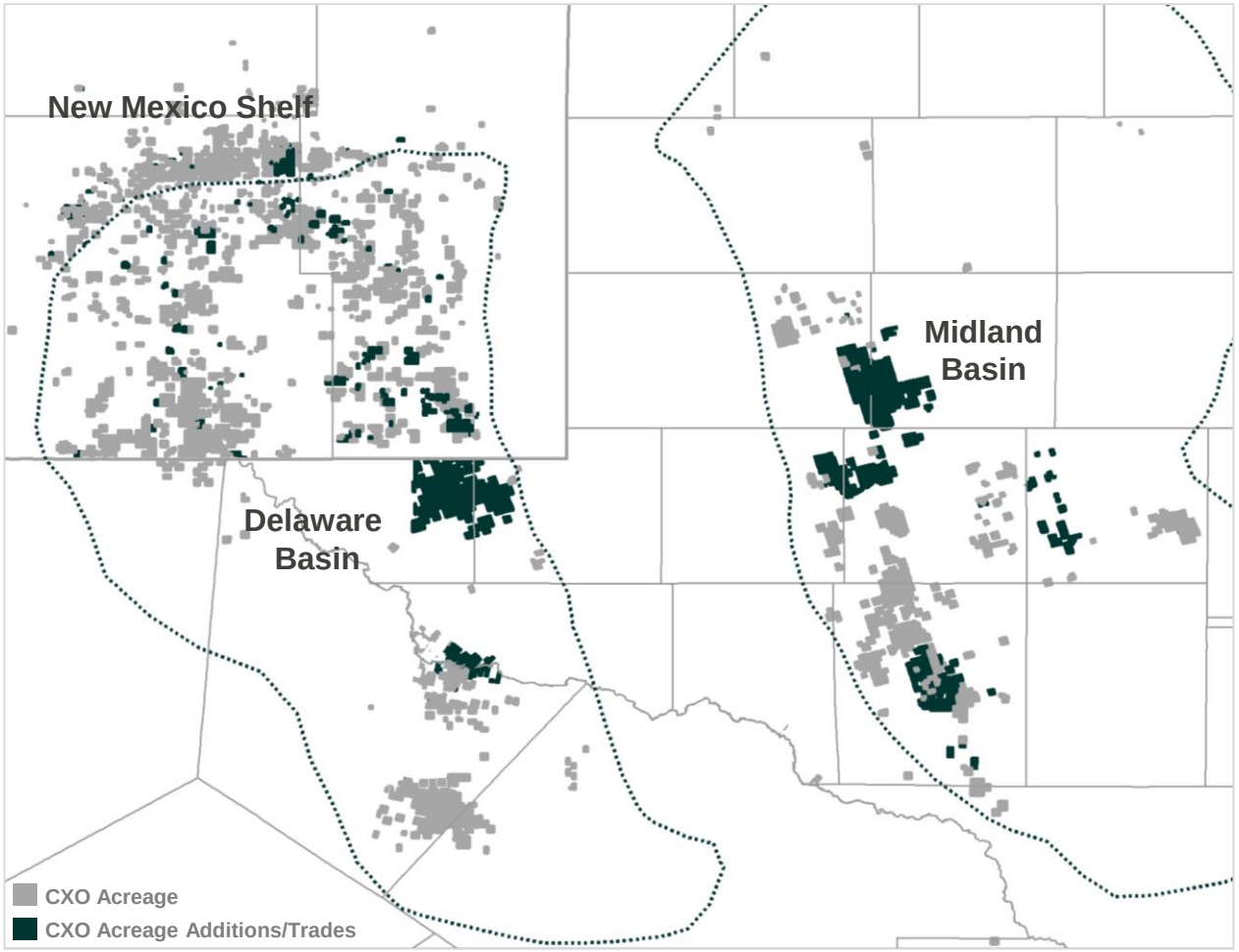
- **Building for the future**
- Managing risk

### Concho Acreage Now




- ✓ Balanced portfolio within the Permian
- ✓ Big, blocky position with high working interest that is amenable to large-scale development
- ✓ Strategic, complementary additions
- ✓ Trades enhance core positions
- ✓ Divestment of non-core leasehold and assets

Note: Concho acreage as of December 31, 2017, pro forma for transactions announced to date.

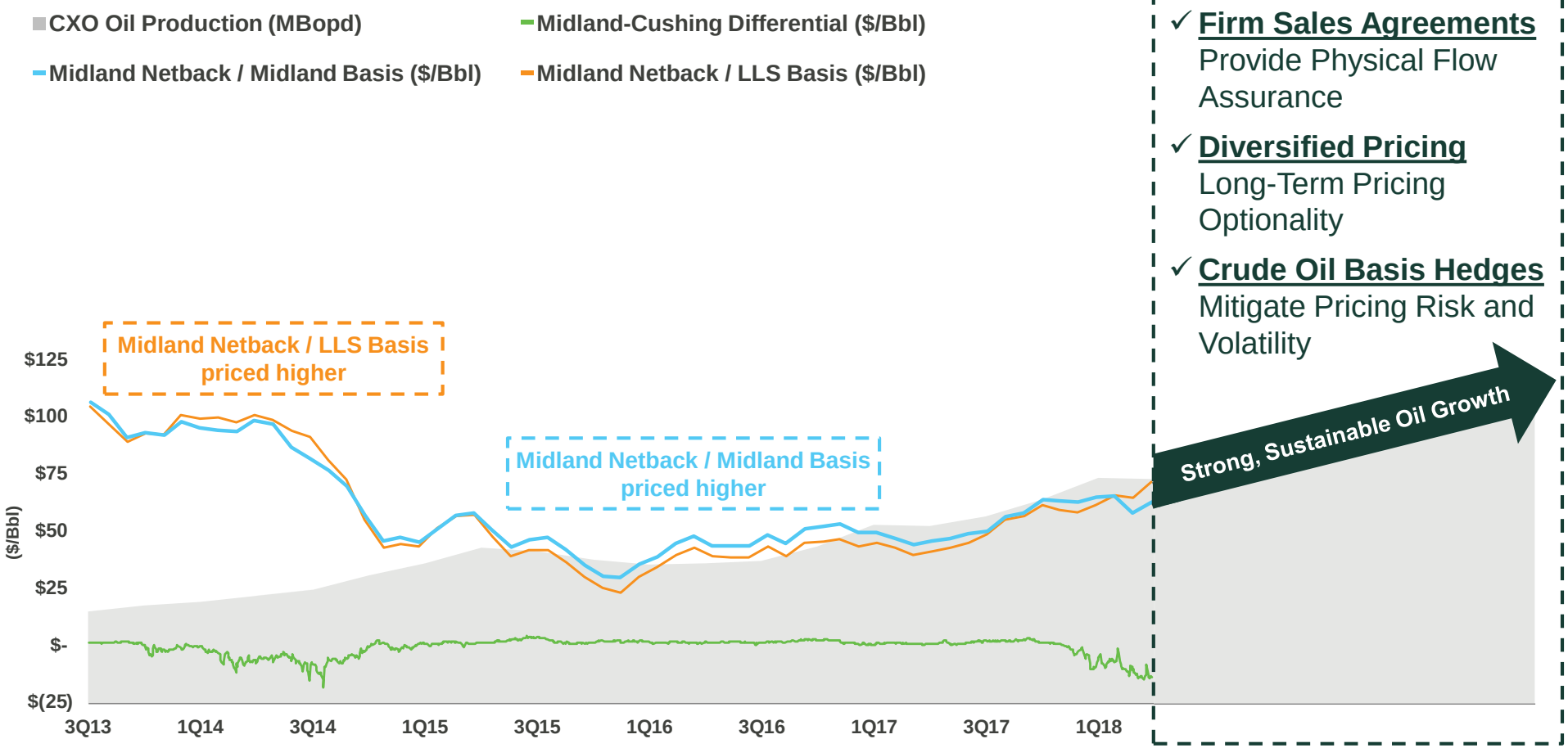
# Managing Risk

## Mitigating Volatility

## Execution Strength and Scale

- Allocating capital to high-return projects
- Running a large, manufacturing-like program
- Leveraging technology and data
- Building for the future
- **Managing risk**

## Oil Takeaway: The Basin Has Been Here Before



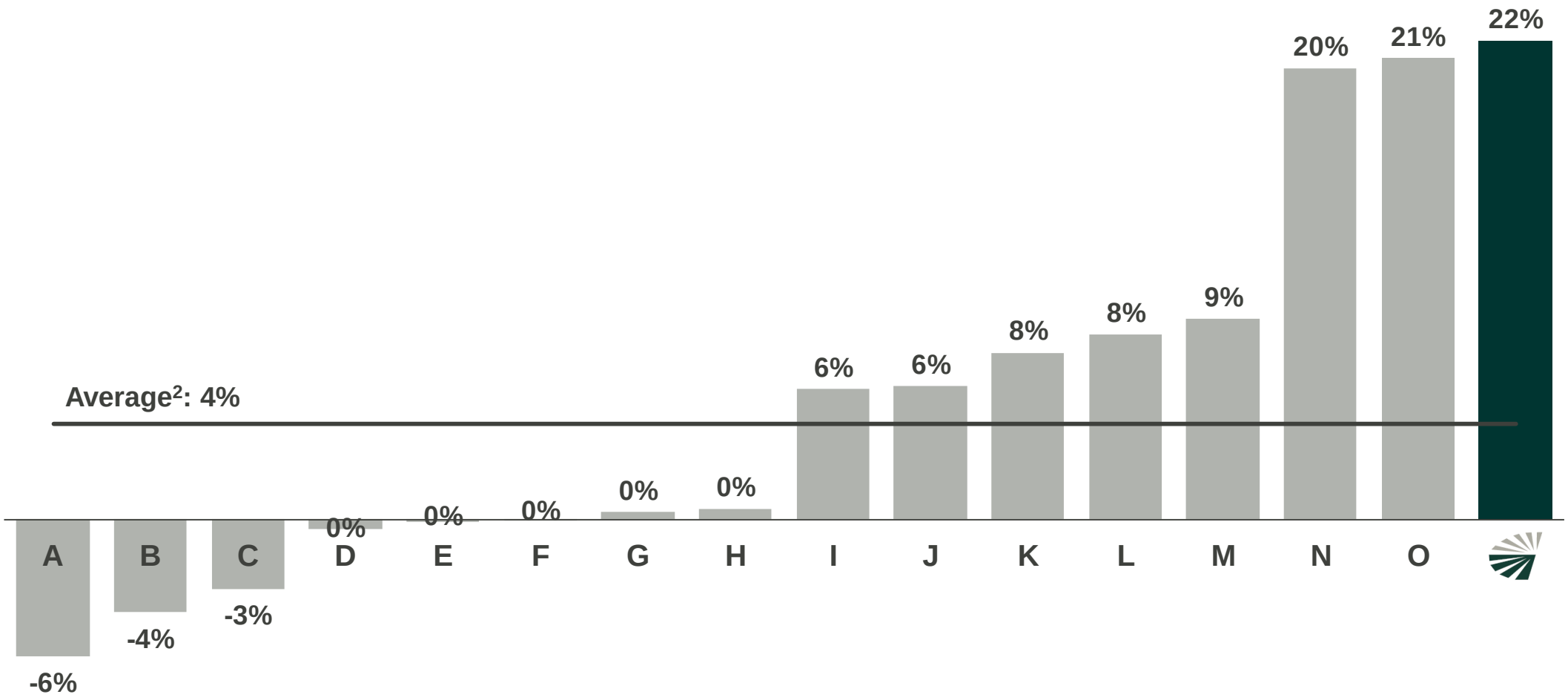

- ✓ **Firm Sales Agreements** Provide Physical Flow Assurance
- ✓ **Diversified Pricing** Long-Term Pricing Optionality
- ✓ **Crude Oil Basis Hedges** Mitigate Pricing Risk and Volatility

Source: Argus; Bloomberg

# Track Record of Execution Strength

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

**Peers**




Source: Bloomberg.
[1]Reflects 10-year CAGR ended June 30, 2018.
[2]Average does not include CXO.

# An Attractive Investment Thesis

## Leveraging Competitive Advantages to Deliver Sustainable Performance

- **Delivering production growth and free cash flow**
  - Peer leading oil growth and ~$250mm free cash flow[1] over past two years
- **Maximizing resource recovery and economics**
  - Leading manufacturing-style development in the Permian
- **Accelerating innovation with real-time feedback loop**
  - Leveraging technology to drive strong performance across portfolio
- **Mitigating efficiency risks**
  - Prioritize flexibility; protect cash flow with hedges
- **Investing in local communities for long-term development outlook**
  - Permian Strategic Partnership focused on critical infrastructure to support long-term economic development

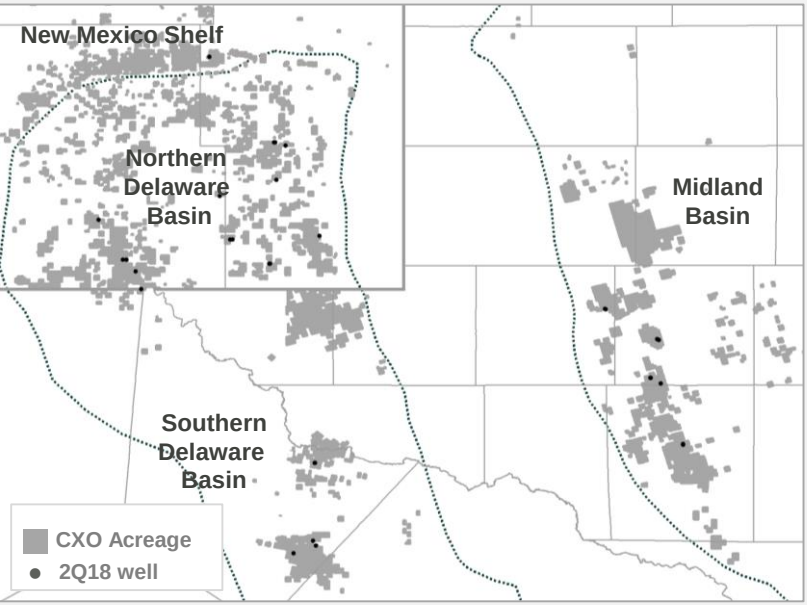
[1]Free cash flow is a non-GAAP measure. See appendix for definition and reconciliation to GAAP measure.

CONCHO

# Appendix

# 2Q18 Operational Highlights

## Scaling Development to Maximize Returns & Recoveries




### Key Operating Stats

**Operated Rigs**

- 2Q18 average: 21 rigs

**Completion Crews**

- 2Q18 average: 6 crews
- Utilizing 50% in-basin sand

### Northern Delaware Basin

- Added 16 horizontal wells (avg. lateral length 7,326')
  - Avg. 30-day peak rate: 1,987 Boepd (73% oil)
  - Avg. 60-day peak rate: 1,859 Boepd (72% oil)

### Southern Delaware Basin

- Added 5 horizontal wells (avg. lateral length 7,461')
  - Avg. 30-day peak rate: 1,463 Boepd (80% oil)
  - Avg. 60-day peak rate: 1,297 Boepd (80% oil)

### Midland Basin

- Added 21 horizontal wells (avg. lateral length 9,800')
  - Avg. 30-day peak rate: 1,294 Boepd (86% oil)
  - Avg. 60-day peak rate: 1,137 Boepd (86% oil)

### 2H18 Activity Outlook

- Plan to run 32 horizontal rigs and 10 completion crews
- Focus on large-scale development projects
- 4Q18 weighted activity due to timing of ongoing projects & moving acquired assets to manufacturing mode

Note: Well results represent wells with >60 days of production data in 2Q18.

# 2Q18 Northern Delaware Basin

## Quickly Advancing Large-Scale Development

### 2Q18 Project Highlight

#### 1 Columbus

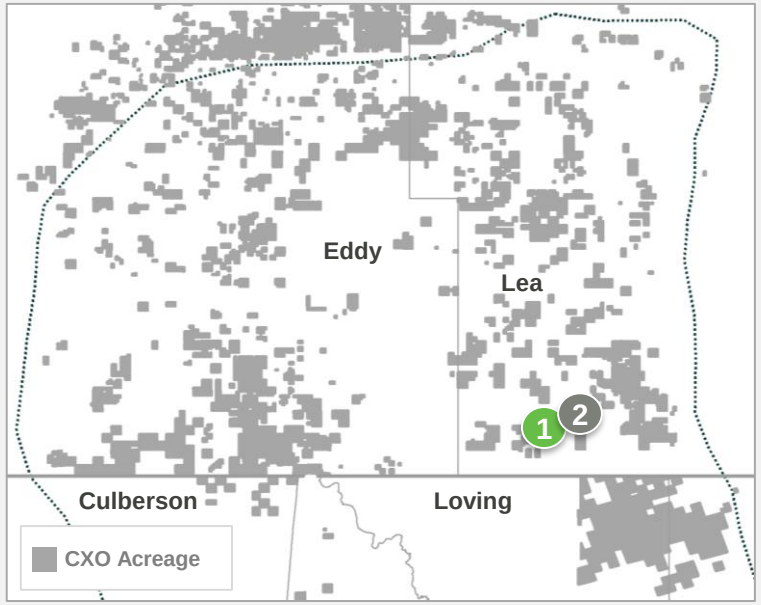
- 4-well development project targeting the Wolfcamp A zone
  - 660’ spacing
- Avg. per well 30-day peak rate 3,163 Boepd (77% oil)
- Avg. lateral length 9,550’

### 2018-2019 Project

#### 2 Dominator

- Commenced drilling operations on the planned 23-well Dominator project in 2Q18
- Stacked-staggered test across 5 landings
- Currently running 6 rigs; peak rig count will be 7 rigs
- Plan to run as many as 5 completion crews
- Coordinated with midstream partners 1 year+ in advance of first production

**Northern Delaware Basin**



# 2Q18 Midland Basin

## Maximizing Scale Advantage

## 2Q18 Project Highlights

### 1 PFU 102/103

- 5-well, multi-zone development project
  - Targets include: Spraberry, Wolfcamp A and Wolfcamp B
- Avg. per well 30-day peak rate 1,170 Boepd (87% oil)
  - Avg. per well 60-day peak rate 1,108 Boepd (87% oil)
- Avg. lateral length 9,370’

### 2 + 3 Vanessa & Karen Project

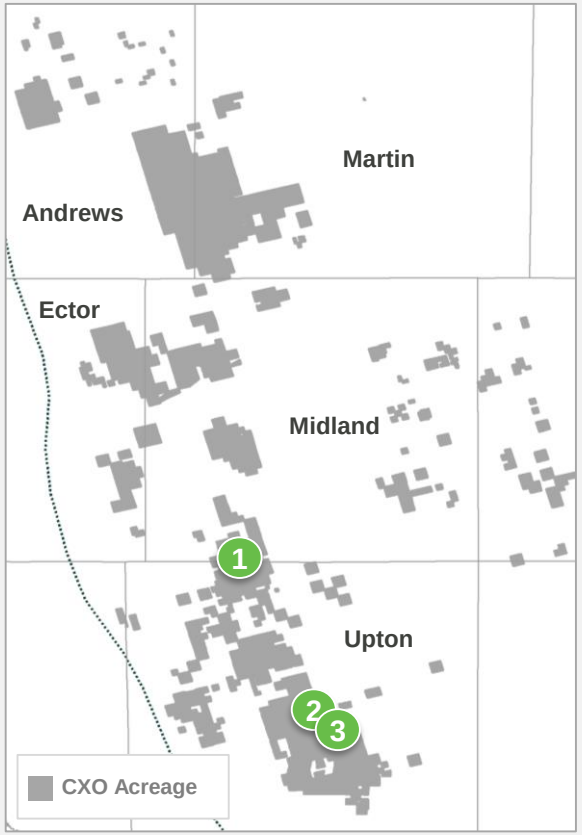
- 2, 3-well development projects with adjacent surface locations and shared infrastructure
  - Staggered test in the Wolfcamp B
- Avg. per well 30-day peak rate 1,250 Boepd (87% oil)
  - Avg. per well 60-day peak rate 1,076 Boepd (86% oil)
- Avg. lateral length 10,261’

**Right-sizing key completion variables to enhance well economics & performance**

Stage spacing + Cluster density & spacing + Fluid & proppant volumes + In-basin sand

**Driving solid per-well savings**

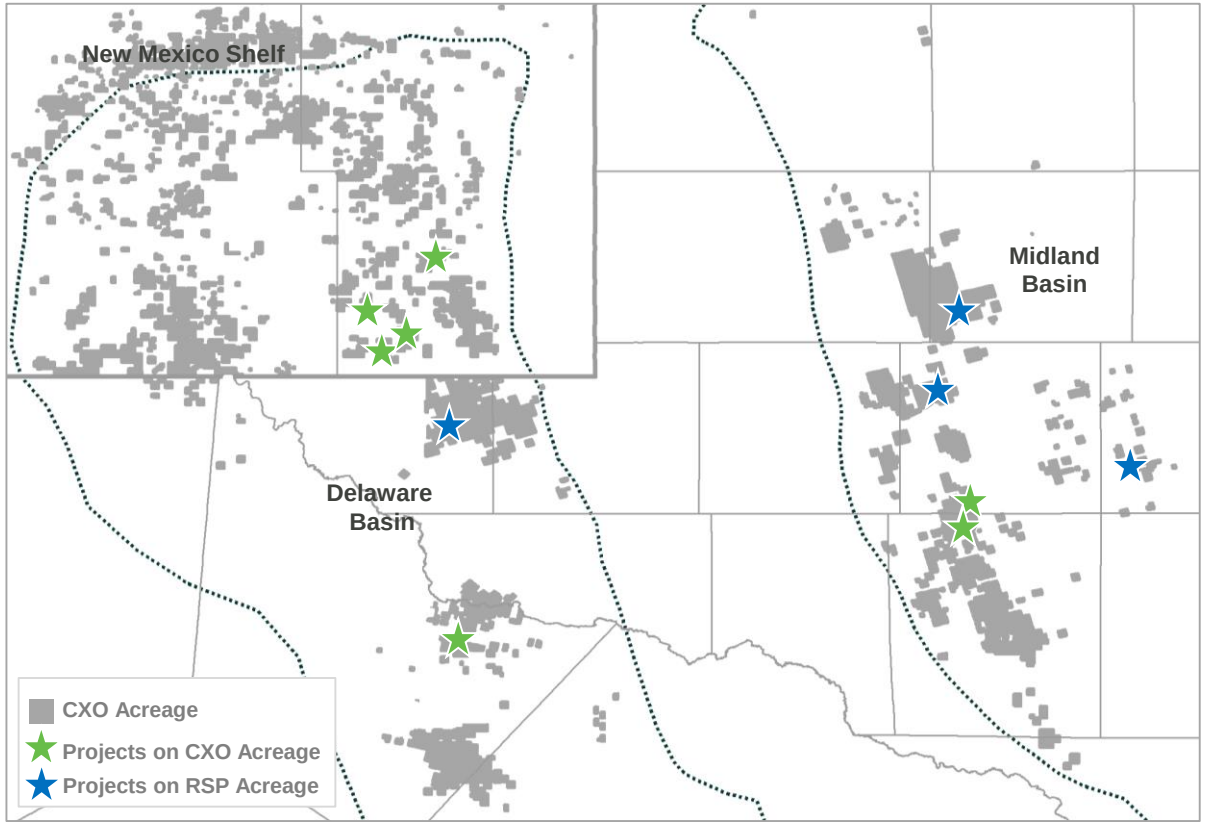
**Midland Basin**



# Jumpstarting Large-Scale Development on RSP Assets

**Key Value Levers Unlock Significant Value *on Day 1***

## Directing Capital & Resources to Key Large-Scale Projects Across *Entire* Portfolio




### Delaware Basin

| | |
|---|---|
| › Dominator | 23 wells |
| › Eider | 10 wells |
| › Jack | 6 wells |
| › Gettysburg | 5 wells |
| › Tiger Cat | 4 wells |
| › Taylor | 5 wells |

### Midland Basin

| | |
|---|---|
| › Windham TXL | 11 wells |
| › Pegasus | 6 wells |
| › Ted Johnson | 13 wells |
| › Calverley | 6 wells |
| › Spanish Trail | 5 wells |

**Manufacturing Mode…**

- ✓Long-lateral development
- ✓Large-scale, multi-zone projects
- ✓Shared infrastructure

**…Unlocks Significant Value**

- ✓Lowers capital intensity
- ✓Optimizes well performance & increases resource recovery
- ✓Minimizes downtime
- ✓Accelerates payout
- ✓Increases NPV per drilling unit

# Reconciliation of Net Income to EBITDAX (Unaudited)

EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator.

The Company defines EBITDAX as net income, plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion of discount on asset retirement obligations expense, (4) non-cash stock-based compensation expense, (5) (gain) loss on derivatives, (6) net cash receipts from (payments on) derivatives, (7) gain on disposition of assets, net, (8) interest expense, (9) loss on extinguishment of debt, (10) gain on equity method investment distribution and (11) federal and state income tax expense. EBITDAX is not a measure of net income 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. 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 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. 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.

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

| (in millions) | Three Months Ended June 30, | | Twelve Months Ended June 30, |
|---|---|---|---|
| | 2018 | 2017 | 2018 |
| **Net Income** | **$ 137** | **$ 152** | **$ 1,126** |
| Exploration and abandonments | 8 | 20 | **50** |
| Depreciation, depletion and amortization | 310 | 281 | **1,209** |
| Accretion of discount on asset retirement obligations | 2 | 2 | **8** |
| Non-cash stock-based compensation | 18 | 14 | **69** |
| (Gain) loss on derivatives | 133 | (209) | **789** |
| Net cash receipts from (payments on) derivatives | (82) | 68 | **(211)** |
| Gain on disposition of assets, net | (1) | - | **(748)** |
| Interest expense | 27 | 39 | **124** |
| Loss on extinguishment of debt | - | 1 | **65** |
| Gain on equity method investment distribution | - | - | **(103)** |
| Income tax expense | 40 | 93 | **(245)** |
| **EBITDAX** | **$ 592** | **$ 461** | **$ 2,133** |

# Reconciliation of Net Cash Provided by Operating Activities to EBITDAX (Unaudited)

EBITDAX is presented herein and reconciled to the GAAP measure of net cash provided by operating activities because the Company believes EBITDAX is a widely accepted financial indicator of a company's ability to internally fund exploration and development activities and to service or incur debt without regard to financial or capital structure. EBITDAX should not be considered an alternative to net cash provided by operating activities, as defined by GAAP.

The following table provides a reconciliation of the GAAP measure of net cash provided by operating activities to EBITDAX (non-GAAP) for the period presented:

| (in millions) | Twelve Months Ended June 30, 2018 |
|---|---|
| **Net cash provided by operating activities** | **$ 1,980** |
| Exploration and abandonments, including dry holes | 33 |
| Cash income tax benefit | (14) |
| Interest expense | 124 |
| Changes in working capital | 16 |
| Other | (6) |
| **EBITDAX** | **$ 2,133** |

# Reconciliation of Net Cash Provided by Operating Activities to Free Cash Flow (Unaudited)

The Company's presentation of free cash flow is a non-GAAP financial measure. Free cash flow is defined as net cash provided by operating activities less exploration and development costs incurred. Free cash flow is presented herein and reconciled from the GAAP measure of net cash provided by operating activities because the Company believes that it provides useful information to analysts and investors. For example, free cash flow can be used to assess the Company's ability to internally fund its capital expenditures and service or incur debt. Free cash flow should not be considered in isolation or as a measure of net income or net cash provided by operating activities, as defined by 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 cash provided by operating activities to free cash flow (non-GAAP), for the periods indicated:

| | Three Months Ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (in millions) | June 30, 2018 | March 31, 2018 | December 31, 2017 | September 30, 2017 | June 30, 2017 | March 31, 2017 | December 31, 2016 | September 30, 2016 |
| Net cash provided by operating activities | $ 602 | $ 488 | $ 510 | $ 380 | $ 398 | $ 407 | $ 365 | $ 343 |
| Less: Exploration and development costs incurred | (501) | (450) | (471) | (427) | (383) | (393) | (351) | (274) |
| **Free Cash Flow** | **$ 101** | **$ 38** | **$ 39** | **$ (47)** | **$ 15** | **$ 14** | **$ 14** | **$ 69** |

# Costs Incurred (Unaudited)

The table below provides the costs incurred for oil and natural gas producing activities for the periods indicated:

| (in millions) | Three Months Ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | June 30, 2018 | March 31, 2018 | December 31, 2017 | September 30, 2017 | June 30, 2017 | March 31, 2017 | December 31, 2016 | September 30, 2016 |
| Property Acquisition Costs: | | | | | | | | |
| Proved | $ - | $ - | $ 2 | $ 162 | $ 12 | $ 127 | $ 725 | $ 1 |
| Unproved | 5 | 13 | 40 | 472 | 87 | 306 | 982 | 14 |
| Exploration | 335 | 243 | 296 | 252 | 238 | 235 | 189 | 177 |
| Development | 166 | 207 | 175 | 175 | 145 | 158 | 162 | 97 |
| **Total Costs Incurred** | **$ 506** | **$ 463** | **$ 513** | **$ 1,061** | **$ 482** | **$ 826** | **$ 2,058** | **$ 289** |

# Hedge Position

## Includes RSP Commodity Derivative Positions

**REMAINING 2018 OIL BASIS SWAPS**

**113 MBopd**

| | 2018 | | | 2019 | 2020 |
|---|---|---|---|---|---|
| | Third | Fourth | Total | Total | Total |
| **Oil Price Swaps[1]:** | | | | | |
| Volume (Bbl) | 12,574,318 | 11,666,007 | 24,240,325 | 38,768,000 | 16,726,000 |
| Price per Bbl | $ 56.76 | $ 56.63 | $ 56.70 | $ 55.48 | $ 56.76 |
| **Oil Three-Way Collars[1]:** | | | | | |
| Volume (Bbl) | 1,319,000 | 1,227,000 | 2,546,000 | - | - |
| Ceiling price per Bbl | $ 60.56 | $ 60.96 | $ 60.75 | $ - | $ - |
| Floor price per Bbl | $ 47.79 | $ 48.00 | $ 47.89 | $ - | $ - |
| Short put price per Bbl | $ 37.79 | $ 38.00 | $ 37.89 | $ - | $ - |
| **Oil Costless Collars[1]:** | | | | | |
| Volume (Bbl) | 1,212,000 | 1,058,000 | 2,270,000 | 4,741,500 | - |
| Ceiling price per Bbl | $ 60.10 | $ 60.11 | $ 60.11 | $ 63.83 | $ - |
| Floor price per Bbl | $ 46.33 | $ 46.52 | $ 46.42 | $ 55.96 | $ - |
| **Oil Basis Swaps[2]:** | | | | | |
| Volume (Bbl) | 10,295,000 | 10,517,000 | 20,812,000 | 44,676,500 | 31,110,000 |
| Price per Bbl | $ (0.77) | $ (0.77) | $ (0.77) | $ (2.99) | $ (0.78) |
| **Natural Gas Price Swaps[3]:** | | | | | |
| Volume (MMBtu) | 19,420,000 | 18,458,000 | 37,878,000 | 28,790,992 | 12,808,000 |
| Price per MMBtu | $ 3.01 | $ 3.00 | $ 3.00 | $ 2.81 | $ 2.70 |

**Updated as of August 1, 2018**

[1]The oil derivative contracts are settled 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.

# 2018 Operational & Financial Outlook

## Includes RSP Beginning on the Acquisition Closing Date (July 19, 2018)

**3Q18 PRODUCTION**

**280-285 MBoepd (65% oil)**

**4Q18 PRODUCTION**

**305-310 MBoepd (65% oil)**

| | 2018 Guidance |
|---|---|
| **Production** | |
| Production (MBoepd) | 260 - 263 |
| Crude oil production mix | 64% |
| **Price realizations, excluding commodity derivatives** | |
| Crude oil[1] (per Bbl) (Relative to NYMEX - WTI) | ($1.50) - ($2.00) |
| Natural gas (per Mcf) (% of NYMEX - Henry Hub) | 100% - 110% |
| **Operating costs and expenses ($ per Boe, unless noted)** | |
| Lease operating expense and workover costs | $6.00 - $6.50 |
| Gathering, processing and transportation | $0.50 - $0.60 |
| Oil and natural gas taxes (% of oil & natural gas revenues) | 7.75% |
| General and administrative ("G&A") expense: | |
| Cash G&A expense | $2.40 - $2.60 |
| Non-cash stock-based compensation | $0.80 - $1.00 |
| DD&A | $15.00 - $16.00 |
| Exploration and other | $0.25 - $0.75 |
| Interest expense ($mm): | |
| Cash | $150 - $160 |
| Non-cash | $6 |
| Income tax rate (%) | 25% |
| Capital program ($bn)[2] | $2.5 - $2.6 |

**Updated as of August 1, 2018**

Note: 3Q18, 4Q18 & FY18 guidance includes production (on a 2-stream basis) and capital from RSP beginning on the acquisition closing date of July 19, 2018.
[1]FY18 guidance of ($1.50) – ($2.00) excludes regional Midland-Cushing price differential.
[2]The Company's capital program guidance excludes acquisitions and is subject to change without notice depending upon a number of factors, including commodity prices and industry conditions.