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" or "Concho") expects, believes or anticipates will or may occur in the future are forward-looking statements. Forward-looking statements contained in this presentation specifically include statements, estimates and projections regarding the Company's future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditure budget, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and sources of financing. The words "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "program," "outlook" 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. The capital program guidance and outlook provided herein is based on the Company’s current expectations that may change. The Company does not undertake any obligation to update any statements related to the capital program, 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. The Company also discloses its reserves replacement ratio and finding and development ("F&D") cost in this presentation. Please see the appendix for an explanation of how the Company calculates 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 provide 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 analogies 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 with additional drilling or recovery techniques. These estimates 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 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.
Concho Resources
Largest Pure-Play Permian Company

Premier Permian Assets

Headquartered in Midland, Texas

Strategic acreage position in the Permian Basin

Prolific growth platform

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

- Operational focus on maximizing resource recovery and returns
- Strategic portfolio management to high grade inventory
- Outlook to deliver growth within cash flow over the long term

Note: Acreage as of December 31, 2017, pro forma for transactions to date.
Permian Basin Oil Production

Innovation and New Technology Game Changers for Permian Oil Growth

Source: Rig Data (current rig count as of 2/26/2018); EIA.
Note: January 2011 to January 2018 production data.
Concho’s Proven Strategy Yields Unique Advantages
People, Assets, Returns and Balance Sheet

Execution Strength & Scale
Most active driller in the Permian Basin

Depth of High-Quality Inventory
Prolific resource capture across the Permian Basin

Superior Capital Efficiency
ROR-driven & strong portfolio management track record

Financial Strength
Low leverage provides substantial flexibility

~1,350
Horizontal wells drilled in past 6 years – more than any other operator

~30 years
Premium resource runway at current development pace

20%
Three-year production CAGR outlook within cash flow

1.0x to 1.5x
Target leverage ratio

Note: Leverage ratio determined using total long-term debt and the non-GAAP measure EBITDAX. See appendix for definition of EBITDAX.
2017 Was A Great Year for Concho
Executing Near-Term Goals, Focusing on Long-Term Returns

Delivering Strong, Consistent Execution
• 29% crude oil production growth and 28% total production growth
• 17% increase in proved reserves, driven by a 26% increase in proved developed reserves at low proved developed finding costs

Prioritizing Capital Discipline
• $1.7bn capital program\(^1\) in-line with capital guidance
• $1.7bn operating cash flows fully fund capital program\(^1\); ~$0.5bn in free cash flow generation over past two and a half years

Actively Managing Portfolio
• Prudent portfolio management enhances capital allocation
• Non-core asset sales fund complementary leasehold acquisitions
• Strategic asset trades increase exposure to existing core areas

Strengthening Financial Position
• Fortified balance sheet, reduced interest expense, lowered cost of capital and expanded cash margin
• Investment grade credit rating

\(^1\)Capital program excludes acquisitions.
2017 Guidance

20%-24% total production growth

25% crude oil growth

$1.7bn capital program\(^1\) within cash flows from operations

2017 Results

28% total production growth

29% crude oil growth

$1.7bn capital program\(^1\) within cash flows from operations

Expanded resource base

Enhanced cash margin

Strengthened balance sheet

High-graded portfolio

Note: 2017 guidance as of February 21, 2017.

\(^1\)Capital program excludes acquisitions.
Delivering Strong, Consistent Execution

Delivering Differentiated Production Growth & Maintaining Low Cash Costs

Production (MBoepd)

<table>
<thead>
<tr>
<th>Year</th>
<th>Oil</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>92</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>112</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>143</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>151</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>193</td>
<td></td>
</tr>
</tbody>
</table>

20% crude oil CAGR

High-Margin Crude Oil Growth

- Delivered 29% crude oil growth y/y
- 28% total production growth y/y

Cash Cost Structure ($/Boe)

<table>
<thead>
<tr>
<th>Year</th>
<th>Production Expense</th>
<th>Cash G&amp;A</th>
<th>Interest Expense</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$14.62</td>
<td>$3.95</td>
<td>$2.61</td>
</tr>
<tr>
<td>2016</td>
<td>$12.36</td>
<td>$3.53</td>
<td>$2.02</td>
</tr>
<tr>
<td>2017</td>
<td>$10.40</td>
<td>$1.99</td>
<td>$2.61</td>
</tr>
</tbody>
</table>

Cost Control Expanding Cash Margin

- Cash costs 29% lower vs. 2015
- 2017 DD&A $16.29/Boe (non-cash) down 30% vs. 2015, underscoring capital efficiency improvement
Actively Managing Portfolio

Executing on Efficient Growth While Building for the Future
- Enhancing core positions for long-lateral and manufacturing-style development
- Aligning capital to best opportunities
- Unlocking significant value through non-core asset sales

2016 – 1Q18 Significant Additions

**1Q18 Closed Transactions**

**Non-Core Divestiture**
- Divested non-core leasehold in Ward and Reeves Counties, Texas for ~$280mm
- Sale included 40,000 gross (20,000 net) acres; minimal associated production
- $1.4bn in divestiture proceeds to date since January 2016

**Strategic Trade**
- Strategic trade with large integrated oil company – key highlights:
  - Acquired highly complementary core acreage in the Midland Basin
  - Conveyed checker-board acreage in Culberson County

Note: Acreage as of December 31, 2017 pro forma for transactions to date.
Growing Proved Reserves & Expanding Resource

Proved Reserves (MMBoe)

<table>
<thead>
<tr>
<th>Year</th>
<th>Proved Developed</th>
<th>Proved Undeveloped</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>503</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>637</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>623</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>720</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>840</td>
<td></td>
</tr>
</tbody>
</table>

2017 reserves: ~70% proved developed & 60% oil
- 17% proved reserves growth y/y, driven by 26% increase in proved developed reserves
- 275% reserves replacement ratio at $8.68/Boe proved developed finding and development cost

~10 BBoe of Captured Horizontal Resource

Premium resource: 60% of total horizontal resource
- Average IRR of 67%
- Directing capital to these locations
- ~30 years of premium resource at current development pace

Key Drivers:
- Better recovery per well (+21% y/y)
- Longer lateral length
- Higher working interest

Premium resource up 37% y/y

Note: Premium resource >35% IRR based on $55 oil and $3 gas.
Prioritizing Capital Discipline
Generating Free Cash Flow Over the Long Term

Operating Cash Flow vs. D&C Capital ($mm)

Performance Track Record

- Returns-focused capital program generating free cash flow and differentiated growth per debt-adjusted share
- Free cash flow provides optionality and long-term flexibility
  - Reinforce balance sheet
  - Absorb cost inflation
  - Invest in development program
  - Strategic consolidation

Sustainable Competitive Advantages

- High-quality assets
- Execution strength
- Scale advantage
- Disciplined capital allocation

1D&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.
Strengthening Financial Position

Fortified Balance Sheet Provides Significant Flexibility

**Long-Term Debt Profile ($mm)**

<table>
<thead>
<tr>
<th></th>
<th>2Q16</th>
<th>4Q17</th>
<th>4Q17 Pro Forma</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3,350</td>
<td>$600</td>
<td>$2,722</td>
<td>$2,471</td>
</tr>
<tr>
<td>$600</td>
<td>7.0%</td>
<td>$322</td>
<td>$600</td>
</tr>
<tr>
<td>2021</td>
<td></td>
<td></td>
<td>4.375% due 2025</td>
</tr>
<tr>
<td>$600</td>
<td>6.5%</td>
<td>$1,000</td>
<td>$1,000</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td>3.75% due 2027</td>
<td></td>
</tr>
<tr>
<td>$1,550</td>
<td></td>
<td>$800</td>
<td>$800</td>
</tr>
<tr>
<td>5.5%</td>
<td></td>
<td>4.875% due 2047</td>
<td></td>
</tr>
<tr>
<td>due</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$2,5bn in total long-term debt at December 31, 2017</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Key Highlights**

- Investment grade credit ratings
- Reduced long-term debt by ~$900mm since 2Q16
- Lowered annual interest expense by ~$90mm since 2Q16
- Prioritizing low leverage ratio of 1.0x-1.5x

1Leverage ratio determined using total long-term debt and the non-GAAP measure EBITDAX. See appendix for definition of EBITDAX.
2018 Capital Program & Activity Overview

- Targeting midpoint of $1.9bn - $2.1bn capital program guidance\(^1\)
  - ~93% for D&C activity and ~7% for other
- Expect to generate 20% crude oil growth and 16%-20% total production growth
  - Timing of large-scale projects to drive quarterly growth trajectory
- Rigs and completion crews in place to execute on 2018 program

Efficiencies

- ~80% multi-well pads
- ~65% large-scale projects

Expect to drill ~260 gross wells
Expect to complete ~11,000 gross stages

---

New Long-Term Outlook

**Prior Outlook**

- 20% total production CAGR within cash flow

**2016-2019**

- 20% total production CAGR within cash flow

**New Outlook**

- 20% total production CAGR within cash flow

**2017-2020**

- 20% total production CAGR within cash flow

**Key considerations**

- Delivers free cash flow at low-to-mid $50/Bbl WTI oil
- Cost inflation assumed; productivity gains not assumed
- Secured sand volumes and last-mile logistics

---

\(^1\)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.

Note: Large-scale projects include 4 or more wells.
2017 Key Operational Milestones

Execution Machine Firing on all Cylinders

**Long-Lateral Development**
Avg. Lateral Length (ft.)

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5,300</td>
<td>6,300</td>
<td>8,100</td>
</tr>
</tbody>
</table>

**Completion Optimization**
Gross Stages

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6,500</td>
<td>7,000</td>
<td>9,500</td>
</tr>
</tbody>
</table>

--

**Productivity Uplift**
Avg. Peak 90-Day Rate (Boepd)

<table>
<thead>
<tr>
<th>Year</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>700</td>
<td>850</td>
<td>1,000</td>
</tr>
</tbody>
</table>

Achieved Significant Productivity Gains from Long-Lateral Development and Completion Optimization
Manufacturing Mode
Scaling Development to Maximize Returns & Recoveries

Key Projects – 2018 & 2019
1. Dominator 20+ well multi-zone project
2. Eider 10+ well Avalon project
3. Little Bear 8+ well multi-zone project
4. Mabee 240A 10+ well multi-zone project
5. Windham TXL 10+ well multi-zone project
6. Whatcha Want 6+ well multi-zone project

Economic Benefits

Technology
- Accelerating innovation across assets with new technology and data analytics
- Benefiting from robust real-time feedback loop

Drilling
- High-grading lateral placement
- Walking rigs and concentrated development reduces drilling days

Completions
- Zipper completions result in more stages completed per day
- Maximizing cluster efficiency to promote near-wellbore complexity and optimize long-term well performance

Production Optimization
- Shared facilities and infrastructure reduce above-ground costs
- Managed flowback optimizes facilities design and investment

Note: Acreage as of December 31, 2017 pro forma for transactions to date.
Midland Basin – Mabee Ranch

Consolidating Core Acreage

October 2016
Acquired assets from a private-operator

July 2017
Bolted on additional leasehold

February 2018
Added in asset trade

Adding Scale & High-Quality Drilling Locations with Contiguous Leasehold

Relative Size Among Pure-Play Permian Operators

Midland Basin Net Acres
(in thousands)

- Peer 1: 168
- Peer 2: 83
- Peer 3: 47
- Peer 4: 40

60 Mabee Ranch

Note: Pure-play Permian operators include: CPE, FANG, PE, RSPP; pro forma for announced transactions.
Track Record of Peer-Leading Execution
10-Year Production Growth per Debt-Adjusted Share (CAGR)\(^1\)

**Peers**

**Average\(^2\): 6%**

Data per Bloomberg.
\(^1\)Reflects 10-year CAGR ending 12/31/2017.
\(^2\)Average does not include CXO.
Key Messages

Executing Clear, Cycle-Tested Strategy
› Hire the best
› Develop the best asset base
› Rate of return driven
› Prioritize financial strength

Disciplined Capital Allocation
› Capital spending on high-return projects
› Differentiated growth within cash flow
› Robust long-term outlook

Industry-Leading Scale and Execution
› Drive productivity gains
› Control costs
› Leverage new technology
› Mitigate efficiency risks

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

Industry-Leading Exposure to Prolific Stacked Resource

Premier Acreage Position

340,000 gross (230,000 net) acres

4Q17 Results

- Added 24 horizontal wells (record avg. lateral length 6,685’)
  - Record avg. 30-day peak rate: 1,805 Boepd (68% oil)
  - Avg. 60-day peak rate: 1,703 Boepd (67% oil)

2016-2017 Well Completions

<table>
<thead>
<tr>
<th>Formation</th>
<th>Well Count</th>
<th>Avg. Peak Rate (Boepd)</th>
<th>Lateral Length</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>30-Day</td>
<td>% Oil</td>
</tr>
<tr>
<td>Brushy Canyon</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Avalon Shale</td>
<td>40</td>
<td>1,624</td>
<td>72%</td>
</tr>
<tr>
<td>1st Bone Spring</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2nd Bone Spring</td>
<td>40</td>
<td>1,198</td>
<td>78%</td>
</tr>
<tr>
<td>3rd Bone Spring</td>
<td>16</td>
<td>1,387</td>
<td>80%</td>
</tr>
<tr>
<td>Wolfcamp Sands</td>
<td>3</td>
<td>1,916</td>
<td>81%</td>
</tr>
<tr>
<td>Wolfcamp A</td>
<td>20</td>
<td>1,536</td>
<td>68%</td>
</tr>
<tr>
<td>Wolfcamp C</td>
<td>2</td>
<td>1,060</td>
<td>37%</td>
</tr>
<tr>
<td>Wolfcamp D</td>
<td>19</td>
<td>1,375</td>
<td>35%</td>
</tr>
</tbody>
</table>

Continuous Improvement

Avg. Peak 90-Day Rate (Boepd)

- Avg. 90-Day Rate / 1K Lateral Ft.

<table>
<thead>
<tr>
<th>Avg. Peak Rate (Boepd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015: 800</td>
</tr>
<tr>
<td>2016: 1,040</td>
</tr>
<tr>
<td>2017: 1,280</td>
</tr>
</tbody>
</table>

1Wells with >30 days of production data as of January 1, 2016 through December 31, 2017.
Note: Acreage as of December 31, 2017 pro forma for transactions to date. Well results represent wells with >30 days of production data in 4Q17.
Southern Delaware Basin
Core Position in Rapidly Advancing Oil Play

Focused Position Ready for Full-Field Development
100,000 gross (70,000 net) acres

4Q17 Results
- Added 3 horizontal wells (record avg. lateral length 10,354’)
  - Avg. 30-day peak rate: 1,644 Boepd (71% oil)
  - Avg. 60-day peak rate: 1,474 Boepd (71% oil)

Infrastructure Supports Growth
- Oryx crude oil gathering and transportation system improves upstream price realizations
  - Concho owns a 23.75% membership interest

Large-Scale Project: Brass Monkey
- 2 wells added to original 8-well project to optimize development pattern
- Simultaneous development of 3rd Bone Spring, Wolfcamp A and Wolfcamp B
- Avg. lateral length ~9,700’

Note: Acreage as of December 31, 2017 pro forma for transactions to date. Well results represent wells with >30 days of production data in 4Q17.
Midland Basin
Building Momentum with Large-Scale Development Projects

Blocky Acreage Driving Growth
280,000 gross (170,000 net) acres

4Q17 Results
- Added 6 horizontal wells targeting the Wolfcamp A and Wolfcamp B
  (record avg. lateral length 11,656’)
  › Avg. 30-day peak rate: 1,272 Boepd (82% oil)
  › Avg. 60-day peak rate: 1,195 Boepd (83% oil)

Water Management System Facilitates Development
- 90-mile water system transports water for drilling and completion operations
- System can accommodate up to 125,000 barrels of water per day
- Regional disposal networks transport substantially all disposal volumes, minimizing trucking

★ Large-Scale Project: Mabee Ranch #24
- 13-well, two-mile project targeting 5 landings across the Spraberry & Wolfcamp zones
  › Development implies 32 wells per section
- Technology deployed and data interpretation to optimize completion design and drive savings
- All wells online with strong initial production rates

Note: Acreage as of December 31, 2017 pro forma for transactions to date. Well results represent wells with >30 days of production data in 4Q17.
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.

The Company defines EBITDAX as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) non-cash stock-based compensation, (6) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) gain on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt and (11) federal and state income tax 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 that 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 (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 depleteable 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 (loss) to EBITDAX (non-GAAP) for the periods indicated:

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended December 31,</th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income (loss)</td>
<td>$267</td>
<td>$(125)</td>
</tr>
<tr>
<td>Exploration and abandonments</td>
<td>17</td>
<td>23</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>298</td>
<td>277</td>
</tr>
<tr>
<td>Accretion of discount on asset retirement obligations</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Impairments of long-lived assets</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Non-cash stock-based compensation</td>
<td>17</td>
<td>16</td>
</tr>
<tr>
<td>Loss on derivatives</td>
<td>415</td>
<td>193</td>
</tr>
<tr>
<td>Net cash receipts from (payments on) derivatives</td>
<td>(47)</td>
<td>43</td>
</tr>
<tr>
<td>Gain on disposition of assets, net</td>
<td>(11)</td>
<td>(9)</td>
</tr>
<tr>
<td>Interest expense</td>
<td>28</td>
<td>42</td>
</tr>
<tr>
<td>Loss on extinguishment of debt</td>
<td>0</td>
<td>28</td>
</tr>
<tr>
<td>Income tax benefit</td>
<td>(473)</td>
<td>(94)</td>
</tr>
<tr>
<td><strong>EBITDAX</strong></td>
<td><strong>$513</strong></td>
<td><strong>$396</strong></td>
</tr>
</tbody>
</table>
Costs Incurred (Unaudited)

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

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Property Acquisition Costs:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proved</td>
<td>$2</td>
<td>$162</td>
<td>$12</td>
<td>$127</td>
<td>$725</td>
<td>$1</td>
<td>$4</td>
<td>$252</td>
<td>$57</td>
<td></td>
</tr>
<tr>
<td>Unproved</td>
<td>40</td>
<td>472</td>
<td>87</td>
<td>306</td>
<td>982</td>
<td>14</td>
<td>19</td>
<td>139</td>
<td>10</td>
<td>162</td>
</tr>
<tr>
<td>Exploration</td>
<td>296</td>
<td>252</td>
<td>238</td>
<td>235</td>
<td>189</td>
<td>177</td>
<td>165</td>
<td>170</td>
<td>149</td>
<td>202</td>
</tr>
<tr>
<td>Development</td>
<td>175</td>
<td>175</td>
<td>145</td>
<td>158</td>
<td>162</td>
<td>97</td>
<td>107</td>
<td>83</td>
<td>87</td>
<td>99</td>
</tr>
<tr>
<td>Total Costs Incurred</td>
<td>$513</td>
<td>$1,061</td>
<td>$482</td>
<td>$826</td>
<td>$2,058</td>
<td>$289</td>
<td>$295</td>
<td>$644</td>
<td>$244</td>
<td>$520</td>
</tr>
</tbody>
</table>
Reserves Replacement Ratio and Finding & Development Cost (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 275% was calculated by dividing net proved reserve additions of 194 MMBoe (the sum of purchases, extensions and discoveries and total revisions) by production of 70 MMBoe.

Proved Developed Finding and Development ("F&D") Cost

Proved developed 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. The Company’s proved developed F&D cost of $8.68 is calculated by dividing the sum of exploration and development costs incurred of $1.7 billion by the change in proved developed reserves year-over-year, excluding current year production, of 192 MMBoe. This calculation does not include the future development costs required for the development of proved undeveloped reserves.
## Hedge Position

**FY18 OIL HEDGES**  
**105 MBopd**

**UPDATED AS OF**  
February 20, 2018

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>First</td>
<td>Second</td>
<td>Third</td>
</tr>
<tr>
<td><strong>Oil Price Swaps 1:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volume (Bbl)</td>
<td>11,038,629</td>
<td>10,178,170</td>
<td>8,944,318</td>
</tr>
<tr>
<td>Price per Bbl</td>
<td>$53.01</td>
<td>$53.30</td>
<td>$52.98</td>
</tr>
<tr>
<td><strong>Oil Basis Swaps 2:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volume (Bbl)</td>
<td>10,674,000</td>
<td>9,492,000</td>
<td>8,465,000</td>
</tr>
<tr>
<td>Price per Bbl</td>
<td>$(0.75)$</td>
<td>$(0.81)$</td>
<td>$(0.85)$</td>
</tr>
<tr>
<td><strong>Natural Gas Price Swaps 3:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volume (MMBtu)</td>
<td>17,833,000</td>
<td>16,979,000</td>
<td>15,740,000</td>
</tr>
<tr>
<td>Price per MMBtu</td>
<td>$3.05</td>
<td>$3.04</td>
<td>$3.04</td>
</tr>
</tbody>
</table>

1 The index prices for the oil price swaps are based on the New York Mercantile Exchange (NYMEX) – West Texas Intermediate (WTI) monthly average futures price.  
2 The basis differential price is between Midland – WTI and Cushing – WTI.  
3 The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.
### 1Q18 GUIDANCE
**215 – 219 MBoepd**

**2018 Guidance**

<table>
<thead>
<tr>
<th>Category</th>
<th>2018 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production</strong></td>
<td></td>
</tr>
<tr>
<td>Total production growth</td>
<td>16% - 20%</td>
</tr>
<tr>
<td>Crude oil production growth</td>
<td>20%</td>
</tr>
<tr>
<td><strong>Price realizations, excluding commodity derivatives</strong></td>
<td></td>
</tr>
<tr>
<td>Crude oil differential to NYMEX (per Bbl)</td>
<td>($2.00) - ($2.50)</td>
</tr>
<tr>
<td>Natural gas (per Mcf) (% of NYMEX)</td>
<td>90% - 100%</td>
</tr>
<tr>
<td><strong>Operating costs and expenses ($ per Boe, unless noted)</strong></td>
<td></td>
</tr>
<tr>
<td>Lease operating expense and workover costs</td>
<td>$6.00 - $6.50</td>
</tr>
<tr>
<td>Gathering, processing and transportation</td>
<td>$0.50 - $0.60</td>
</tr>
<tr>
<td>Oil &amp; natural gas taxes (% of oil &amp; natural gas revenues)</td>
<td>7.75%</td>
</tr>
<tr>
<td>General and administrative (&quot;G&amp;A&quot;) expense:</td>
<td></td>
</tr>
<tr>
<td>Cash G&amp;A expense</td>
<td>$2.50 - $2.80</td>
</tr>
<tr>
<td>Non-cash stock-based compensation</td>
<td>$0.80 - $1.00</td>
</tr>
<tr>
<td>DD&amp;A</td>
<td>$15.00 - $16.00</td>
</tr>
<tr>
<td>Exploration and other</td>
<td>$0.25 - $0.75</td>
</tr>
<tr>
<td><strong>Interest expense ($mm):</strong></td>
<td></td>
</tr>
<tr>
<td>Cash</td>
<td>$110 - $120</td>
</tr>
<tr>
<td>Non-cash</td>
<td>$6</td>
</tr>
<tr>
<td>Income tax rate (%)</td>
<td>25%</td>
</tr>
<tr>
<td>Capital program ($bn)</td>
<td>$1.9 - $2.1</td>
</tr>
</tbody>
</table>

1 The Company’s capital program guidance for 2018 is subject to change without notice depending upon a number of factors, including commodity prices and industry conditions.