Permian Update

June 20, 2017
DELIVERING QUALITY RETURNS

• **Objective is to make money at the company bottom line**
  – Robust growth for less capital means our business is resilient at lower prices
• **Growing premium return inventory**
  – Adding premium locations 5x faster than drilling
• **Boosting productivity**
  – Type curve IP180s up 20%
• **Industry leading innovation**
  – Developing the cube
• **Industry leading capital efficiency**
  – Delivering top tier corporate returns
• **Managing risk**
  – Multi-basin portfolio advantage, supply chain management, market access, hedging
• **Further upside expected**
  – Advanced completions, converting additional benches to premium, continuing to core-up acreage
**PERMIAN BASIN**

Premier North American Basin

- **Developing the cube**
  - Critical to creating value at industrial scale
  - Reservoir & above-ground benefits
  - Natural extension of our experience & capabilities

- **Premium inventory increased by 700 locations to 3,450**
  - Increase of five times 2017 drilling pace
  - Premium generates >35% ATROR at flat $50 WTI & $3 NYMEX

- **Premium inventory type curves increased**
  - IP30s & IP180s up by ~20%
  - Innovation and technology driving performance

- **Managing risk**
  - Execution efficiency offsetting inflation
  - Just-in-time water infrastructure ensures availability & avoids over-capitalization
  - Sophisticated supply-chain & logistics
  - Market access secure

- **Stacked pay & completions upside**
  - New benches & advanced completions
  - Coring up acreage boosts long lateral inventory

---

*Estimated inventory based on 450-660 ft spacing*
ENCANA’S PERMIAN ACREAGE
Core Position in Midland Basin

- In the Permian, execution efficiency at massive industrial scale is going to be critical
- North American unconventionals is all we do
- 100% short cycle capital business
- Industry leader in driving efficiency at scale

Cowden Pad Multi-Spread Operations
BEST ROCKS APPROACH
Deliberate and Disciplined Evaluation

Basin Focus
Resource potential
Geologic setting
Market access

Play Focus
Resource in place
Hydrocarbon phase
Highest deliverability

Position Focus
Best rocks
Scale with upside
Operational excellence

Geoscience, Engineering & Data Driven Approach
Geology
Petrophysics
Rock Mechanics
Engineering
RESERVOIR CHARACTERIZATION TOOLBOX
Structured Approach to Maximizing Value

Well Performance

Physical Reservoir Measurement

Modeling

Oil Production

GOR

Water Cut

Bottom Hole Pressure

Microseismic & Repeat Dipole

Fluid Geochemistry

Interface & Resource Analysis

Fiber Optics

Rate-Pressure Analysis

Earth Model

Frac Model

Reservoir Model
INNOVATION & DISCIPLINE DRIVE EFFICIENCY

Leveraging Technology To Create Value

• Structured innovation across the portfolio with real-time knowledge transfer
  – Multi-discipline chief organization engaged through planning and execution
  – Leveraging massive proprietary analytics dataset (core, logs, seismic, micro-seismic, fracture diagnostics, production)
  – Data & analytics accessible across organization through operations control centers and mobile apps
  – Real-time production data capture & analysis

• Integrated team with on-the-fly modeling capabilities
  – Geo-cellular reservoir modeling
  – Geosteering control center utilizes rock mechanics-while-drilling to precision target wells into the best rocks
  – Accelerated learning through active consortia participation

• Internal proprietary drilling & completions design
  – Advanced completions
  – Fibre-optic real-time pressure/completions design analytics

Geocellular Reservoir Model
Hydrocarbon Filled Porosity within the Stimulated Rock Volume
BOOSTING PRODUCTIVITY
Leading Acreage & Completion Design

- Rocks matter
- Our well performance is improving rapidly
- Deep understanding of the physics of the reservoir is critical to improving productivity
- Combined with rapidly applying successful ideas from other basins and other competitors

---

*Data sourced from IHS, Inc. Results normalized to 7,500’, includes all wells from 2014-2016. Peers include APA, AREX, CPE, CVX, CXO, DVN, EGN, END, EOG, EPE, FANG, LPI, OXY, PE, PXD, QEP, RSPP, SM, and XOM
DEVELOPING THE CUBE

Differentiated Execution

• Reservoir benefits
  – Optimizes resource recovery
  – Minimizes inter-wellbore communication
    • Minimizes downtime on existing wells
  – Eliminates “parent-child” in-fill drilling
  – No poor performing “child” wells in depleted reservoir

• Over 50 parent-child case studies reviewed across the Midland Basin
  – Industry and ECA data
  – Majority of results indicate child wells significantly underperform parents

Parent-Child Productivity Case Study
CUBE DEVELOPMENT RESULTS

Boosting Permian Productivity

- Development approach at premium returns
- Emphasis on well performance
- Accelerated learning
  - Each pad producing stronger wells
  - Abbie Laine wells outperforming Davidson Phase 1 by 25% after 90 days
- 45 ECA cube wells on production
  - Abbie Laine and RAB Davidson Phase 2 leading industry
  - RAB Davidson Phase 1 among the best results
- Industry dataset is all wells at >10 total wells per section
  - ~900 wells, 24 operators, 6 counties

<table>
<thead>
<tr>
<th>Pad</th>
<th>Benches</th>
<th>Wells per Bench</th>
<th>Wells per Section</th>
<th>Well Spacing (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RAB Davidson Phase 1</td>
<td>3</td>
<td>14</td>
<td>70</td>
<td>385</td>
</tr>
<tr>
<td>Abbie Laine</td>
<td>5</td>
<td>12</td>
<td>60</td>
<td>450</td>
</tr>
<tr>
<td>RAB Davidson Phase 2</td>
<td>5</td>
<td>12-14</td>
<td>60-70</td>
<td>385 – 450</td>
</tr>
</tbody>
</table>

*Well results normalized to 7500' lateral

Large Scale Development Performance Comparison

ECA leading performance in large scale development

Average Cumulative Production/Well (BOE*)

Days

- Abbie Laine
- RAB Davidson Phase 1
- RAB Davidson Phase 2
- Peer Large Pads
**BOOSTING PREMIUM RETURNS**

Outperformance Driving Type Curve Update

- Wells in all counties consistently outperforming type curves
  - Optimized completions
  - Improved targeting
- Premium return type curves increased to reflect improved productivity
  - Average 20% improvement in IP180
  - Average 25% improvement in IP30

*Well results normalized to 7500' lateral*
CORING UP ACREAGE

Drilling Longer Laterals

- By coring up our acreage, we can drill longer laterals
- 14 transactions since entering the basin
- 40% of premium locations expected to be drilled with 10,000 ft laterals
- Actively pursuing future opportunities
## PERMIAN RESERVOIR

Massive Potential with Stacked Benches

<table>
<thead>
<tr>
<th>Zone</th>
<th>Martin</th>
<th>Midland/Upton</th>
<th>Glasscock</th>
<th>Howard</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clear Fork</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>M. SPBY</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jo Mill</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>L. SPBY</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>L. SPBY- 2&lt;sup&gt;nd&lt;/sup&gt;</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>WCMP A</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>WCMP A- 2&lt;sup&gt;nd&lt;/sup&gt;</td>
<td>✓</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>WCMP B</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>WCMP C</td>
<td></td>
<td>✓</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>WCMP D / Cline</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Deep Targets</td>
<td>✓</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td><strong>Total Inventory</strong></td>
<td>2,200</td>
<td>5,200</td>
<td>1,300</td>
<td>3,600</td>
</tr>
<tr>
<td><strong>Premium</strong></td>
<td>750</td>
<td>1,450</td>
<td>350</td>
<td>900</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

~12,000

### Key Points:
- Massive potential with stacked benches
- Permian Reservoir focus zones
- Inventory and premium highlights
- Total inventory and premium totals provided.
# PREMIUM INCREASE OUTPACING DRILLING

**Gross Premium Return Inventory**

<table>
<thead>
<tr>
<th>County</th>
<th>Midland/Upton</th>
<th>Martin</th>
<th>Howard</th>
<th>Glasscock</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP30 (BOE/d)</td>
<td>985</td>
<td>950</td>
<td>825</td>
<td>800</td>
</tr>
<tr>
<td>IP180 (BOE/d)</td>
<td>700</td>
<td>650</td>
<td>600</td>
<td>550</td>
</tr>
<tr>
<td>EUR/Well (Mbbls)</td>
<td>610</td>
<td>675</td>
<td>550</td>
<td>530</td>
</tr>
<tr>
<td>EUR/Well (MBOE)</td>
<td>1,020</td>
<td>1,000</td>
<td>875</td>
<td>765</td>
</tr>
<tr>
<td>GOR (Mcf/bbl)</td>
<td>2,800</td>
<td>2,000</td>
<td>2,450</td>
<td>1,960</td>
</tr>
<tr>
<td>Gross Premium Return Inventory</td>
<td>1,450</td>
<td>750</td>
<td>900</td>
<td>350</td>
</tr>
</tbody>
</table>

- **3,450 premium return inventory locations**
  - Increase of 700 locations
  - 40% from tighter well density
  - 30% from increased type curve
  - 30% from longer laterals
  - 410 more in Martin/Midland/Upton
  - 200 more in Howard
  - 90 more in Glasscock

- **3.3 billion BOE premium EUR**
  - Increase of 1 billion BOE since October update

Estimated inventory based on 450-660 ft spacing, 7,500' lateral length.
• Rapid knowledge transfer across our assets
  – Advanced completions creating stronger wells in Montney & Eagle Ford
  – Thin fluid, tight cluster design
  – Results expected later in 2017 in Permian

• Converting zones to premium inventory
  – Jo Mill, Clear Fork
  – Wolfcamp C, Wolfcamp D/Cline

• Continuing to core up acreage
  – Build on already significant 10,000’ lateral inventory
INNOVATION BEYOND TECHNOLOGY
Highly Sophisticated Planning & Logistics

• Seasoned operator with >4,500 horizontals drilled
  – Leading EHS performance across industry
  – Top D&C performance across portfolio
  – Integrated supply chain with operations
    • Self-sourced key consumables with logistics management
  – Load leveled programs drive efficiency

• Multi-well pad design
  – Site access & traffic control
  – Reduced infrastructure costs (including oil batteries, water, and gathering)
  – Reduced footprint

• Unique multi-rig & multi-spread approach to D&C
  – Higher equipment and crew utilization
  – Cycle time optimization

• Integrated infrastructure design
  – Water recycling system to reduce completion and disposal costs
  – Pipe-based oil & gas gathering
  – Flexible takeaway arrangements
DEVELOPING THE CUBE
Differentiated Execution

• Multi-well pads centralizes development
  – Optimized infrastructure
  – Reduced costs through stockpiling, logistics
  – Minimized footprint
• Multi-rig/spread approach increases efficiencies
  – Faster drill times from repeated execution
  – Increased pumping horsepower utilization
  – Shared services at higher utilization

~$1.2 MM Savings/Well vs Single Well Development

RAB Davidson Phase 1 Cube Development

• Minimized offset well frac hits
  – Up to an additional $300K/well
  – Reduced clean-out requirement
  – Minimized production losses
• Intangible efficiency gains
  – Pace of learning is accelerated with multi-rig/spread approach
  – Natural competition from drilling/completing the same wells side-by-side
CONTINUED EFFICIENCY GAINS
Maintaining Well Costs Flat in 2017

• Expected 2017 average D&C cost of ~$5 MM
  – Flat versus 2016 average
• RAB Davidson Phase 2 highlights continued drilling efficiencies
  – Drilled 5 more wells and 8 more miles in 1 less day than Phase 1
  – Overall rate of penetration increased ~20%
• Averaging 12 days to drill a well in 2017
• Maximizing completions efficiencies
  – Detailed tracking of pumping hours and a strict maintenance schedule has dramatically reduced non-productive time
  – Optimized frac manifold allows for continued pumping while maintenance occurs
  – Achieving consistent high performance from multiple service providers
WATER INFRASTRUCTURE SOLUTION
Improving Efficiency & De-risking Supply

• Integrated water infrastructure improves capital intensity and de-risks supply
  – Capacity to support 3 frac crews per county in Midland and Martin
  – Simple and effective catch basin design
  – Water hubs payout in less than 12 months
  – Mitigates risk of water supply restrictions

• County-by-County solution
  – Recent Howard County water infrastructure transaction minimizes non-well capital
  – Water provider can service broader market for a lower fee

• All-in water costs of ~$1/bbl
  – Up to $1/bbl lower cost than market pricing
  – Expect to average 25% recycled water use in 2017
    • Expect to average 40% in 2018

• D&C cost savings up to $300k/well
• LOE savings up to ~$0.80/BOE
PRODUCTION OPERATION HIGHLIGHTS

Competitive LOE Performance

- Operating expense below $7/BOE
  - Efficiency gains through multi-well pad development
  - Reduced workover costs
  - Remote monitoring and control
  - Optimized artificial lift
  - Pipe gathered production
  - Average well runtime exceeds 95%

- 35% reduction since entering the basin in 2014
  - Down from $11/BOE when we entered the play

- Water recycling/piping has reduced operating expenses up to $0.80/BOE

D&C Sim-Ops on RAB Davidson 27 Pad
MANAGING INFLATION
Maintaining Well Costs Flat in 2017

• Holding the line on inflation and working on greater intensity at similar total well costs
  – RAB Davidson Phase 2 highlights continued drilling efficiencies
  – Efficiencies offset inflation to keep total well costs flat
    • Self-sourcing sand, water, OCTG, chemicals, drilling mud
      – Expanding use of non-API sand, reducing rail costs
      – ~90% of sand used is non-API
      – New domestic source located in Monahans, Texas
    • Recycling water, optimizing trucking and fuel
      – Averaged 60% recycled water use on recent 3-well pad
    • Locked-in rates for several rigs and frac crews for full year with potential to extend

• Challenging industry norms
  – Increasing pump time per day
  – Reducing non-productive time through optimized frac manifold and pump maintenance
  – Integrated water/sand delivery logistics reducing truck times

ECA D&C Cost Breakdown

40% of well cost is drilling
60% of well cost is completions

D&C Key Component Cost Breakdown

• 30-35% sand & water
• 10-12% casing
• 10-12% pressure pumping
• 9-11% drilling rig
• 6-8% cement and mud
MIDSTREAM AND MARKETING OVERVIEW

Permian Basin

Proximity to market and environment of responsive infrastructure development

Medallion pipeline provides midstream reliability and interconnects to market hubs

Encana has secured capacity on the Enterprise Midland to Sealy Pipeline (Houston Market)

<table>
<thead>
<tr>
<th>Permian Basin</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Production</td>
<td>2.3 MMbbls/d</td>
</tr>
<tr>
<td>Gas Production</td>
<td>~7.5 BCF/d</td>
</tr>
<tr>
<td>Oil Export Capacity/Demand</td>
<td>2.5 MMbbls/d</td>
</tr>
<tr>
<td>2017/18 New Oil Infrastructure</td>
<td>700 Mmbbls/d</td>
</tr>
<tr>
<td>Gas Export Capacity/Demand</td>
<td>~10 BCF/d</td>
</tr>
</tbody>
</table>

- Reliable Access to downstream oil markets
  - ~80% of oil gathered (Medallion Pipeline)
  - Secured basin takeaway capacity on Enterprise Midland to Sealy pipeline

- Diversified oil price exposure
  - Houston, WTI, Midland

- Active oil differential and gas basis hedging programs
**PERMIAN BASIN FUNDAMENTALS**

Past & Future Pipeline Capacity Expansions Align with Growth

- Over 700 Mbbls/day of pipelines are under construction to address anticipated growth through to 2018
- Infrastructure development has been proactive, and to date, has generally paced volume growth

Source: Wells Fargo Securities
PERMIAN RISK MANAGEMENT PROGRAM
Market Access & Price Risk Management

2017F

~15%

35 Mbbls/d ($0.61)/bbl

2018F - 2020F

~20%

17 Mbbls/d ($0.83)/bbl

25 Mbbls/d to Houston

Option for up to 25 Mbbls/d to Houston

Midland Exposure

EPD* Midland to Houston

WTI-Midland Differential Hedges + Transport Option

* Enterprise Products Partners L.P.
PERMIAN
5 Year Growth Profile

- >50% of Encana’s capital directed to the Permian
- Permian production expected to grow 3-4x
  - 5 year CAGR* 30%
- Quality inventory with scale
- No infrastructure or midstream limitations
- Eliminated vertical program

*Compound annual growth rate
DE DELIVERING QUALITY CORPORATE RETURNS
Growing Value & Adding Resiliency

• Our goal is to generate quality corporate returns while managing risk
  – Strategy, organization, process, & culture must be aligned

• Compelling wellhead returns are a must, but are just the beginning
  – Biggest driver is quality of the rocks
  – Targeting and completions design can make up to 40% difference
  – Innovation is vital

• Quality corporate returns
  – Result from aggregate performance of all of our wells
  – Includes all non-well capital (largely geoscience & infrastructure)
  – Includes all overheads (largely interest & G&A)

• Managing risk
  – Commercial ingenuity
  – Sophisticated planning & supply chain
  – Preserving agility
PERMIAN BOOSTING PRODUCTIVITY
Leading Acreage & Completion Design

• Best Rocks Matter
  – Defined break between results from the core versus non-core
  – Exclusive focus on premium return locations

• Operational Excellence Matters
  – Innovation leader
  – Developing the cube
  – Advanced completions
  – Multi-basin advantage

• Commercial Mindset
  – Sophisticated planning & supply chain
  – Lowest overhead costs
  – Realized price optimization
  – Preserving agility

Midland Basin Well Productivity* vs Peers

ECA 2017 program
45 wells YTD
665 BOE/d IP90
25% improvement

>40% spread within the core

Cumulative Production (MBOE)

Delivering quality returns while managing risk

*Data sourced from IHS, Inc. Results normalized to 7,500’, includes all wells from 2014-2016. Peers include APA, AREX, CPE, CVX, CXO, DVN, EGN, END, EOG, EPE, FANG, LPI, OXY, PE, PXD, QEP, RSPP, SM, and XOM
INDUSTRY LEADING CAPITAL EFFICIENCY

Impact of Operational Excellence

- **Best Rocks Matter**
  - Defined break between results from the core versus non-core
  - Exclusive focus on premium return locations

- **Operational Excellence Matters**
  - Innovation leader
  - Developing the cube
  - Advanced completions
  - Multi-basin advantage

- **Commercial Mindset**
  - Sophisticated planning & supply chain
  - Lowest overhead costs
  - Realized price optimization
  - Preserving agility

*Data sourced from current company disclosures. Peers include APA, CPE, EGN, FANG, LPI, PE, PXD, OEP, RSPP, and SM. Data normalized to 7500'.

Midland D&C Costs by Operator*
INDUSTRY LEADING VALUE CREATOR

Delivering Quality Well Returns

- Best Rocks Matter
  - Defined break between results from the core versus non-core
  - Exclusive focus on premium return locations

- Operational Excellence Matters
  - Innovation leader
  - Developing the cube
  - Advanced completions
  - Multi-basin advantage

- Commercial Mindset
  - Sophisticated planning & supply chain
  - Lowest overhead costs
  - Realized price optimization
  - Preserving agility

*Data sourced from RS Energy Group, Inc. "Permian Activity Map – April 2017". Peers include AJAX, AREX, BROAD OAK, CPE, CROWNQUEST, CVX, CXO, DISCOVERY, ECA, EGN, ENDEAVOR, EPE, FANG, LGCY, LPI, OXY, PE, PERMIAN RESOURCES, PXD, QEP, RSPP, SM, and SURGE.
PERMIAN INCOME MARGIN

Premium Returns at the Corporate level

- ATAX well returns of >35% deliver corporate return\(^\dagger\) of >15%
- Permian delivers ~$30/BOE operating margin*
  - NRI F&D ~$8.00/BOE
  - Non-well capital of $0.60/BOE
  - G&A and interest expense ~$3.00/BOE
- Permian income margin\(^\dagger\) of over $18.00/BOE

\(^\dagger\)Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website; *Assumes flat $55/bbl WTI and $3/MMBtu NYMEX
\(^\dagger\)Assumes flat $50/bbl WTI and $3/MMBtu NYMEX.
5 YEAR CAPITAL, PRODUCTION & CASH FLOW OUTLOOK
Self-Funding Capital Program Post 2017

• Projected >300% cash flow\textsuperscript{T*} growth
  — Focus on high margin production amplifies cash flow\textsuperscript{T} growth

• Self funding post 2017
  — Cash flow\textsuperscript{T} exceeds capital program at $55 WTI and $3 NYMEX

• Corporate margin\textsuperscript{T} doubles
  — Core assets become >90% of total company production
  — Commodity mix becomes balanced between liquids and natural gas

• Resilient to lower prices
  — As a result of our recent improvements, we now expect we can deliver the same growth as our five-year-plan at flat $50 WTI within cash flow\textsuperscript{T}
  — With mid-40s WTI we expect to still grow within cash flow\textsuperscript{T} (15-20% liquids CAGR)
  — With low-40s WTI we expect to stay flat within cash flow\textsuperscript{T}

\*Assumes flat $55/bbl WTI and $3/MMBtu NYMEX; \textsuperscript{T}Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company’s website.
DELIVERING QUALITY RETURNS

- **Objective is to make money at the company bottom line**
  - Robust growth for less capital means our business is resilient at lower prices

- **Growing premium return inventory**
  - Adding premium locations 5x faster than drilling

- **Boosting productivity**
  - Type curve IP180s up 20%

- **Industry leading innovation**
  - Developing the cube

- **Industry leading capital efficiency**
  - Delivering top tier corporate returns

- **Managing risk**
  - Multi-basin portfolio advantage, supply chain management, market access, hedging

- **Further upside expected**
  - Advanced completions, converting additional benches to premium, continuing to core-up acreage
ENCANA’S POTENTIAL PREMIUM RETURN INVENTORY
Only Premium Inventory Consumed in Growth Plan

Permian Basin
- 12,000 well inventory
- 3,450 premium locations
- ~1,000 wells drilled in 5 year plan
- Premium assumption:
  - 450-660’ spacing on average of 2.5 zones across basin

Montney
- 9,300 well inventory
- 5,900 premium locations
- ~850 wells drilled in 5 year plan
- Premium assumption:
  - 440’ spacing in very rich gas condensate
  - 660’ spacing in rich gas condensate

Eagle Ford
- 650 well inventory
- 180 premium locations
- ~130 wells drilled in 5 year plan
- Premium assumption:
  - 330’ spacing

Duvernay
- 1,000 well inventory
- 500 premium locations
- ~200 wells drilled in 5 year plan
- Premium assumption:
  - 1,000’ spacing

*Premium locations are >35% ATROR\(^\text{\textdegree}\) at $50 WTI & $3.00 NYMEX; \(^\text{\textdegree}\) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see Company’s website.
PERMIAN

2017 Program

<table>
<thead>
<tr>
<th>FY 2017 Plan</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Acreage (net acres)</td>
<td>124,000</td>
</tr>
<tr>
<td>Average Working Interest (%)</td>
<td>91%</td>
</tr>
<tr>
<td>Average Royalty Rate (%)</td>
<td>20 – 25%</td>
</tr>
<tr>
<td>Development Capital (net) ($MM)</td>
<td>$775 – 850</td>
</tr>
<tr>
<td>Rig Count</td>
<td>5</td>
</tr>
<tr>
<td>HZ Wells Drilled (net)</td>
<td>135 – 145</td>
</tr>
<tr>
<td>HZ Wells On-stream (net)</td>
<td>120 – 130</td>
</tr>
<tr>
<td>D&amp;C Cost* ($MM/well)</td>
<td>~$5.0</td>
</tr>
<tr>
<td>Average Lateral Length (ft)</td>
<td>8,100</td>
</tr>
</tbody>
</table>

Production Split
- Oil/condensate** % | 65%
- NGLs % | 19%
- Natural gas % | 16%

2017 Program
- Maximize value through optimized completion design
- ~50% production growth Q4 2016 to Q4 2017
- Program on schedule
  - As of May 2017, ~40% of 2017 wells drilled and on-stream

4 Drilling Rigs Reoccupying the Davidson Pad

*Normalized to 7,500' lateral length **Includes plant and field condensate; Encana reports plant condensate as NGL
Encana Holds Core Positions in Premier Basins

Horizontal Rig Activity* by Play

ECA portfolio focused entirely on unconventional plays utilizing similar technology

Source: RigData, IHS, GeoScout, and RS Energy, Inc as of Sept 2016
CORE POSITIONS IN THE BEST ROCKS

Building of a Premium Return Inventory

**Montney**
10 - 45 MMBOE/sec
Up to 6 stacked laterals

**Permian**
>200 MMBOE/sec
Up to 8 stacked laterals

**Duvernay**
Up to 25 MMBOE/sec

**Eagle Ford**
30 - 50 MMBOE/sec
Up to 3 stacked laterals
FULLY INTEGRATED ANALYTICAL PLATFORM
Utilized Through All Phases of Development

Data
• Centralized, Dynamic Database for all Clients
• Automated Geotechnical Workflows
• Real Time Data

Customized Environment
• 3D Pad Planning and Evaluation
• Volumetric Integration
• Physics-Based Resource Delineation

Co-Visualization and Integration
• Integrated Environment
• Advanced and Automated Workflows
• Analytical scalability
GEOCELLULAR RESERVOIR MODEL

Defines the Resource

- Physics based geologic model
- Integrated from entire proprietary catalog of core, logs, petrophysics, geophysics, and completions diagnostic data (including data trades)
- Parameters sampled directly to the well
- Direct input into advanced simulations
FULLY INTEGRATED ANALYTICAL PLATFORM

PLATFORM GEOMECHANICAL MODELING

Mechanical Properties
Stress
Pore Pressure
Interfaces
Natural Fractures

Input

Tuning Geomechanical Iteration

Treating Pressure
Microseismic

Constraints

Frac Hits/VOX
Interference Test Geometry

Output

3D Stimulation

4D Pressure Depletion Simulations
FULLY INTEGRATED ANALYTICAL PLATFORM

Reservoir Modeling

Core-Tied Petrophysical Model

Log-Based Property Model

Physics-Based Understanding

Structural Model

Geomechanical Modeling

Development Scale Sensitivities

Single Well Models
NON-GAAP MEASURES

Certain measures in this presentation do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other companies. These measures have been provided for meaningful comparisons between current results and other periods and should not be viewed as a substitute for measures reported under U.S. GAAP. For additional information regarding non-GAAP measures, including reconciliations, see the Company’s website and Encana’s most recent Annual Report as filed on SEDAR and EDGAR. Non-GAAP measures include:

- **Non-GAAP Cash Flow, Non-GAAP Cash Flow Per Share (CFPS), Free Cash Flow and Corporate Margin** – Non-GAAP Cash Flow (or Cash Flow) is defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets. Non-GAAP CFPS is Cash Flow divided by the weighted average number of common shares outstanding. Corporate Margin is Non-GAAP Cash Flow per BOE of production. Free Cash Flow is defined as Non-GAAP Cash Flow in excess of capital investment, excluding net acquisitions and divestitures. Management believes these measures are useful to the company and its investors as a measure of operating and financial performance across periods and against other companies in the industry, and are an indication of the company’s ability to generate cash to finance capital programs, to service debt and to meet other financial obligations. These measures may be used, along with other measures, in the calculation of certain performance targets for the company’s management and employees.

- **After-Tax Rate of Return (ATROR)** – is defined as the discount rate at which the net present value of the after-tax cash flows is equal to zero. Encana uses nine percent as the discount rate for its standard investment decisions, which is intended to represent the Company’s long term cost of capital. For project evaluation, cost of capital includes land, drilling and completion costs (D&C), seismic, facilities and gathering. D&C costs include all capital outlay for activities related to drilling and completing the well in addition to permanent production equipment such as site compressors, separation equipment and liquid storage tanks.

- **Corporate Return** – is defined as the After-Tax Rate of Return (ATROR) including the impact of non-well capital costs and overhead costs, such as administrative and interest expenses.

- **Operating Margin/Operating Netback** – Product revenues less costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing and operating expenses. When presented on a per BOE basis, Operating Margin/Operating Netback is defined as indicated divided by average barrels of oil equivalent sales volumes. Operating Margin/Operating Netback is used by management as an internal measure of the profitability of a play(s).

- **Income Margin** – is defined as Operating Margin less finding and development costs, non-well capital costs and allocated overhead costs, such as administrative and interest expenses. When presented on a per BOE basis, Income Margin is defined as indicated divided by average barrels of oil equivalent production volumes. Income Margin is used by management as an internal measure of the profitability of a resource play.
FUTURE ORIENTED INFORMATION

This presentation contains certain forward-looking statements or information (collectively, “FLS”) within the meaning of applicable securities legislation. FLS include:

- expectation of meeting or exceeding the targets in Encana's corporate guidance
- anticipated capital program, including focus of development, amount of development capital, the amount allocated to its core assets, number of wells on stream, expected return and source of funding thereof
- well performance, completions intensity, location of acreage and costs relative to peers and within assets
- anticipated production, cash flow, capital coverage, payout, net present value, rates of return, production efficiency, commodity mix, operating, income and corporate margins, netbacksw, including expected timeframes
- number of well locations (including identification of premium well locations and ability to add wells to such category), well spacing, decline rate, focus of drilling and timing, commodity composition, and operating performance compared to type curves
- pacesetting operational metrics being indicative of future well performance and costs, and sustainability thereof
- timing, success and benefits from innovation, cude development approach, completed designs, technology advancements and asset quality, including to drive efficiency and capital productivity and the transferability of ideas across portfolio
- expected capital and transportation and processing commitments and restrictions
- anticipated reserves and resources, including products and stack resource potential
- capital intensity and pace of growth of Encana's assets within North America and against its peers
- anticipated third-party incremental and joint venture carry capital

FLS have been included to assist in the assessment of Encana’s business, the best of Encana's knowledge and experience, and should not be relied upon as representing an express or implied assurance of future results or an evaluation of the current financial position or expected results of operations of Encana. 

Readers are cautioned that forward-looking statements or information are necessarily based on certain assumptions. Future results may differ from these estimates due to the inherent uncertainty of such statements. 

These assumptions include: future commodity prices and differentials; foreign exchange rates; Encana's ability to access its revolving credit facilities and shelf prospectuses; assumptions contained in Encana's corporate guidance and in this presentation; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of Encana's drive to productivity and efficiencies; results from innovations; expectation that counter parties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; enforceability of transaction agreements, ability to satisfy closing conditions and regulatory approvals, successful closing of, and value of post-closing and other adjustments associated with announced sale of assets; and expectations and projections made in light of, and generally consistent with, Encana's historical experience and its perception of historical trends, including with respect to the pace of technological development, the benefits achieved and general industry expectations.

Risks and uncertainties that may affect the business outcomes include: the ability to generate sufficient cash flow to meet Encana's obligations; risks inherent to completing transactions on a timely basis or at all and adjustments that may impact expected proceeds or value to Encana; commodity price volatility; ability to sustain adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors to declare and pay dividends, if any, the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, and its impact on access to capital markets and other sources of liquidity; fluctuations in currency and interest rates; risks inherent in Encana's corporate guidance; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; 

Risks associated with technology; changes in or interpretation of regulatory, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; risks associated with existing and potential future lawsuits and regulatory actions made against Encana (by third parties, including the United States and Canada as a result of disputes arising with its partners, including the suspension by its partners of certain of their obligations and the inability to dispose of assets or interests in certain arrangements; Encana's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from plays and other areas not currently classified as proved, probable or possible reserves or economic or competitive resources, including future net revenue estimates; risks associated with past and present arrangements or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as “partnerships” or “joint ventures” and the funds received in respect thereof which Encana may refer to from time to time as “proceeds”, “deferred purchase price” and/or “carry capital”, regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana’s business, as described in its most recent Annual Report on Form 10-K and as described from time to time in Encana’s other periodic filings as filed on SEDAR and EDGAR.

Although Encana believes the expectations represented by such FLS are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. FLS are made as of the date of this presentation and, except as required by law, Encana undertakes no obligation to update publicly or revise any FLS. The FLS contained in this presentation are expressly qualified by these cautionary statements.

Certain forward oriented financial information or financial outlook information is included in this presentation to communicate current expectations as to Encana's future performance. Readers are cautioned that it may not be appropriate for other purposes.

Rates of return for a particular asset or group of assets are on a before-tax basis and are not adjusted for specified commodity prices with local pricing offsets, capital costs associated with drilling, completing and equipping a well, field operating expenses and certain type curve assumptions. Front end costs for a particular asset are a composite of the best drilling performance and best completions performance wells in the current quarter in such asset and are presented for comparison purposes. 

This presentation contains certain forward-looking statements or information that may involve risks and uncertainties that could cause actual results to differ materially from those expressed or implied by such statements.

The statements made in this presentation speak only as of the date hereof. Encana undertakes no duty to update any forward-looking statements or information, whether as a result of new information, future events or otherwise, except as required by law.
All proved and probable reserve and economic contingent reserve estimates in this presentation are effective as of December 31, 2016, prepared by qualified reserves evaluators in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), National Instrument ("NI") 51-101 and SEC regulations, as applicable, and are audited by independent qualified reserves auditors engaged by Encana. Detailed Canadian protocol disclosure will be contained in Encana’s Form 51-101F1 for the year ended December 31, 2016 ("Form 51-101F1") and detailed U.S. protocol disclosure will be contained in Encana’s Annual Report on Form 10-K for the year ended December 31, 2016 ("Annual Report on Form 10-K"). each of which Encana anticipates filing with applicable securities regulatory authorities on or about February 27, 2017. Additional detail regarding Encana’s economic contingent resources disclosure will be available in the Supplemental Disclosure Document filed concurrently with the Form 51-101F1. Information on the forecast prices and costs used in preparing the Canadian protocol estimates will be contained in the Form 51-101F1. For additional information relating to risks associated with such estimates, see “Item 1A. Risk Factors” in the Annual Report on Form 10-K.

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technologies, and specified economic conditions, which are generally accepted as reasonable and proved reserves are those reserves which an operator believes can be recovered, in all probability. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is uncertainty that it will be commercially viable to produce any portion of the resources. All of the resources classified as contingent are considered to be discoverable, and as a result, have been included in an 100% (based upon the presence of a known reservoir) estimate of development. The chance of development is defined as the likelihood of a project being commercially viable and development proceeding in a timely fashion. Determining the chance of development requires taking into consideration each contingency and quantifying the risks into an overall development risk factor at a project level. Contingent resources are categorized as economic if they have a positive net present value under currently forecasted prices and costs. In examining economic viability, the same fiscal conditions have been applied as in the estimation of Encana’s reserves. Contingencies include factors such as required corporate or third party (such as joint venture partners) approvals, legal, environmental, political and regulatory matters or a lack of infrastructure or markets.

Encana uses the terms play, resource play, total petroleum initially-in-place ("PIIP"), natural gas-in-place ("NGIP"), and crude oil-in-place ("COIP"). Play encompasses resource plays, geological formations and conventional plays. Resource play describes an accumulation of hydrocarbons known to exist over an large areal extent and/or vertical thickness, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. PIIP is defined by the Society of Petroleum Engineers - Petroleum Resources Management System ("SPE-PRMS") as that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total recoverable potential"), NGIP and COIP are defined in the same manner, with the substitution of "natural gas" and "crude oil" where appropriate for the word "petroleum". As used by Encana, estimated ultimate recovery ("EUR"), which Encana may refer to as recoverable resource potential, has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in 1999, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

Encana has provided information with respect to its assets which are "analogous information" as defined in NI 51-101, including estimates of PIIP, NGIP, COIP, EUR and production type curves. This analogus information is presented on a basin, sub-basin or area basis utilizing data derived from Encana’s internal sources, as well as a variety of publicly available information sources which are predominantly independent in nature. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, and as depicted in this presentation, is representative of Encana’s current program, including relative to current performance. Some of this data may not have been prepared by qualified reserves evaluators, may have been prepared based on internal estimates, and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Encana believes that the provision of this analogous information is relevant to Encana’s oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question, and such information has been updated as of the date hereof unless otherwise specified. Due to the early life nature of the various emerging plays discussed in this presentation, PIIP is the most relevant specific assignable category of estimated resources. There is no certainty that any portion of the resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the estimated PIIP, NGIP, COIP or EUR. Disclosure of estimated well locations include proved, probable, contingent and unbooked locations. These estimates are prepared internally based on Encana’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Approximately 40 percent of all locations specified in our core assets are booked as either reserves or resources, as prepared by internal qualified reserves evaluators using forecast prices and costs as of December 31, 2016. Unbooked locations do not have attributed reserves or resources and have been identified by management as an estimation of Encana’s multi-year drilling activities based on evaluation of economic, seismic, engineering, production and reserves information. There is no certainty that Encana will drill all unbooked locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources and production. The locations on which Encana will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of capital, regulatory and partner approvals, seasonal restrictions, equipment and personnel, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained, production rate recovery, transportation constraints and other factors. While certain of the unbooked locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of other unbooked locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

30-day IP and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery. The conversion of natural gas volumes to barrels of oil equivalent ("BOE") is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily used at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation.