ENCANA CORPORATION

Q3 2016 Results Conference Call

November 3, 2016

ENCANA

Quality Returns & Leading Growth Potential (2016 – 2021)

Delivering quality returns

- >300% cash flowᵼ* growth
- >60% production* growth
- Corporate marginᵼ doubles

World class asset portfolio

- 5 year plan consumes small fraction of premium inventory locations
- Core four well returns >35% ATRORᵼ**

Resilient business model

- Competitive cost structures
- Balanced commodity mix
- Strengthened financial capacity

*Assumes flat $55/bbl WTI and $3/MMBtu NYMEX; **Assumes flat $50/bbl WTI and $3/MMBtu NYMEX. ᵼ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

ENCANA

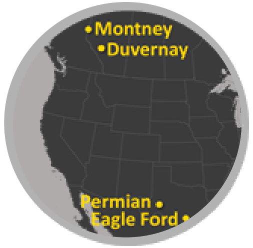
Beating 2016 Targets and Positioned for Growth

- Very strong Q3 cash flow[Ŧ] driven by operational efficiency
- Well productivity increases driven by completion design
- Matched or beat pacesetter well costs in core four assets
- Core four 4Q15 to 4Q16 on pace for 4% decline
- Reduced net debt[Ŧ] and secured funding capacity for 2017
- At close to 2017 activity levels today
- Positioned to maintain or improve costs in 2017

Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

OPERATIONAL EXCELLENCE

Maximizing Capital & Operating Efficiency



PORTFOLIO ADVANTAGE

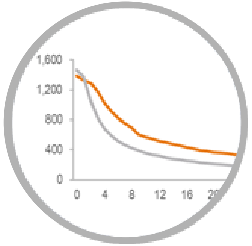
Multi-basin company creates enormous flexibility and value

INNOVATION

R&D lab is the field

CONTINUOUS IMPROVEMENT

Structured approach to change



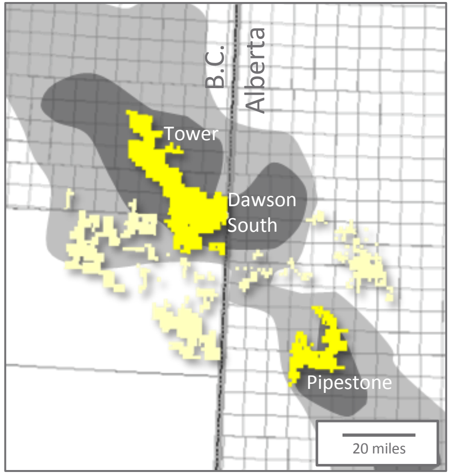
COMPETITOR BENCHMARKING

Rapid adoption of best ideas & technology in industry

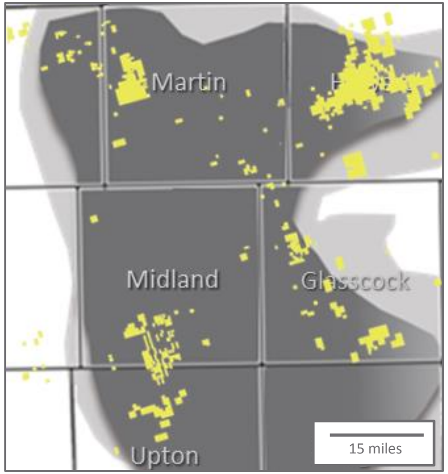
PORTFOLIO ADVANTAGE

Core Positions Within the Best Basins

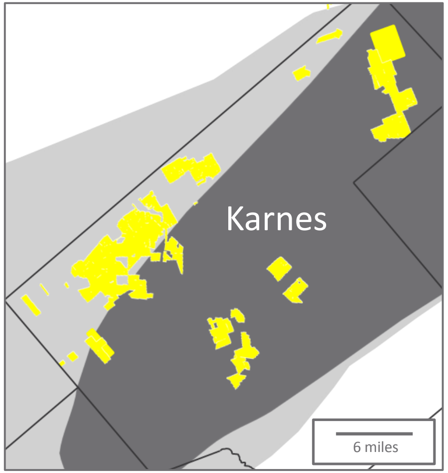
Montney



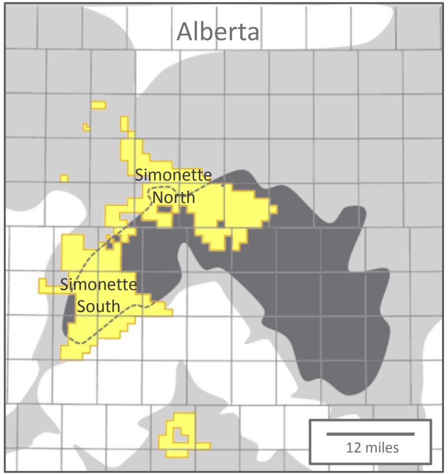
Permian



Eagle Ford



Duvernay



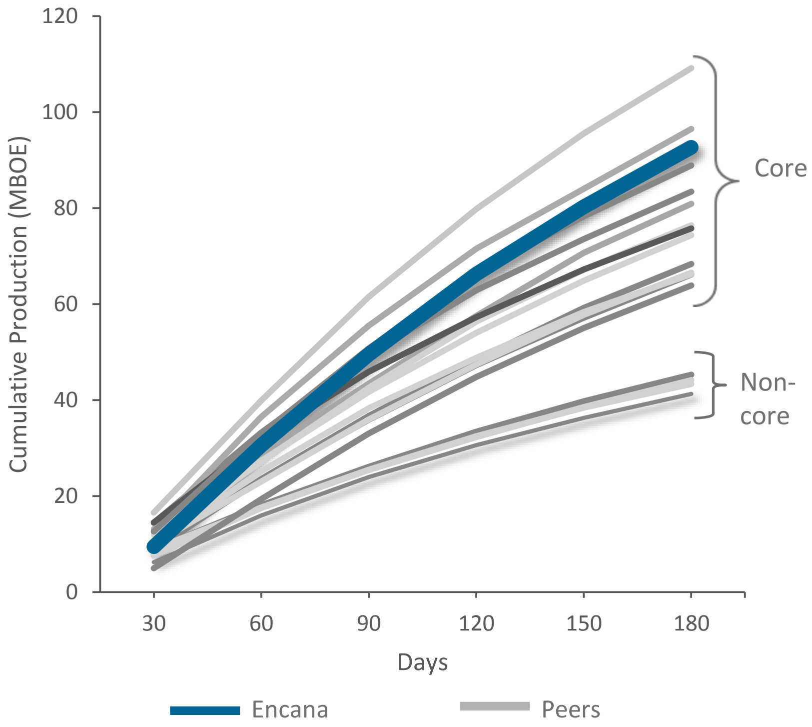
Encana Land
Basin Core

PERMIAN COMPETITOR BENCHMARKING

Leading Acreage & Completion Design

- **Encana wells among the top performers in Midland Basin**
  - Encana average IP180 of >500 BOE/d
- **Data from >2,000 horizontal wells since 2014 normalized to 7,500’ lateral length**
- **Core acreage matters**
  - Defined break between results from the core versus non-core
- **Completion design matters**
  - 40% spread in results from best to worst in the core

Permian Production* vs Peers



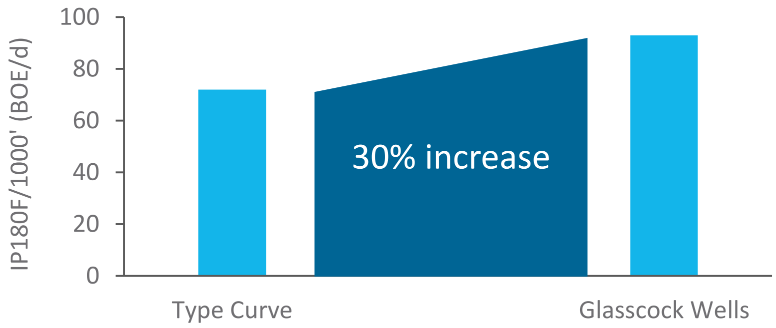
*Data sourced from IHS, Inc. Results normalized to 7,500’, includes all wells from 2014 onward. Peers include APA, AREX, CPE, CVX, CXO, DVN, EGN, END, EOG, EPE, FANG, LPI, OXY, PE, PXD, QEP, RSPP, SM, and XOM

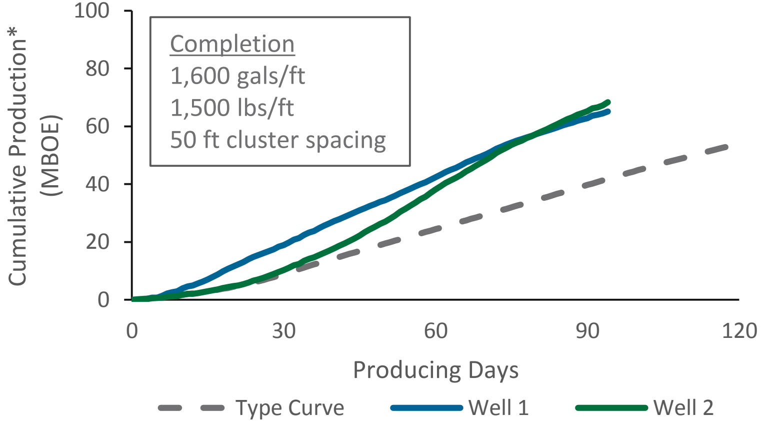
PERMIAN CONTINUOUS IMPROVEMENT

Well Performance Increasing

- **Optimal completion design matters**
  - Precision targeting
  - Frac geometry
  - Fluid and sand volumes
- **Two new Glasscock wells on-stream in Q3**
  - Forecasted IP180s of ~700 BOE/d
  - 30% above type curve
- **Minimized offset operator frac interruption**
  - 2,000 bbls/d impact in Q3 at Davidson pad
  - At full production in Q4

New Glasscock County Wells Outperforming





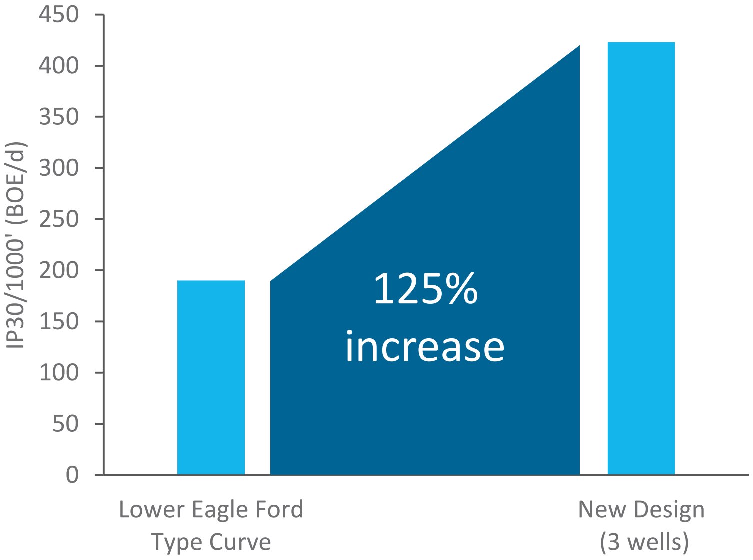
*All data normalized to 7,500' lateral length

EAGLE FORD CONTINUOUS IMPROVEMENT

Well Performance Increasing

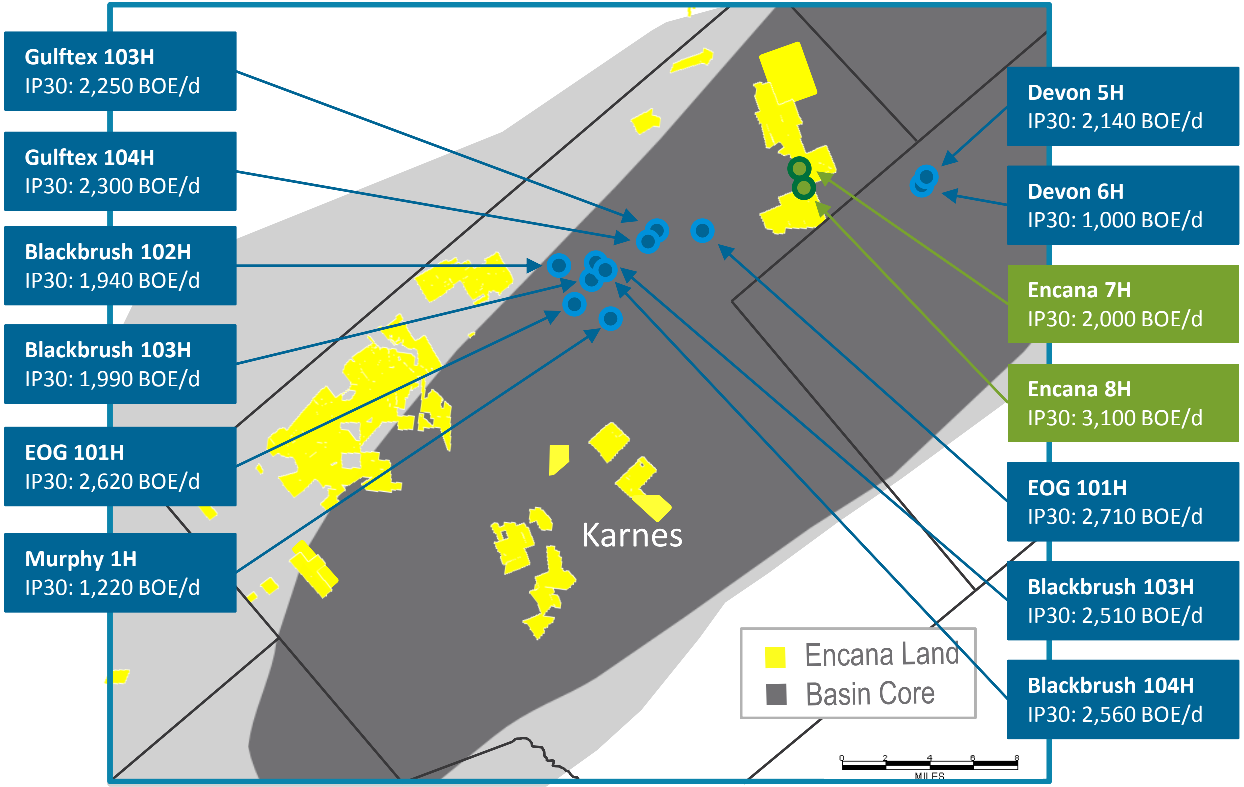
- **Optimizing completion design**
  - Latest design utilizes a thin fluid with <25 foot cluster spacing
  - Result is a complex fracture system with propped secondary fissures
- **Three new completion design Eagle Ford wells on-stream in the quarter**
  - Thin-fluid tight-cluster completion design
  - No stress shadowing
  - >2,000 lbs/ft sand concentration
  - After 30 days, 125% above type curve

Improved Fracture Complexity



PORTFOLIO ADVANTAGE

Top Austin Chalk Results



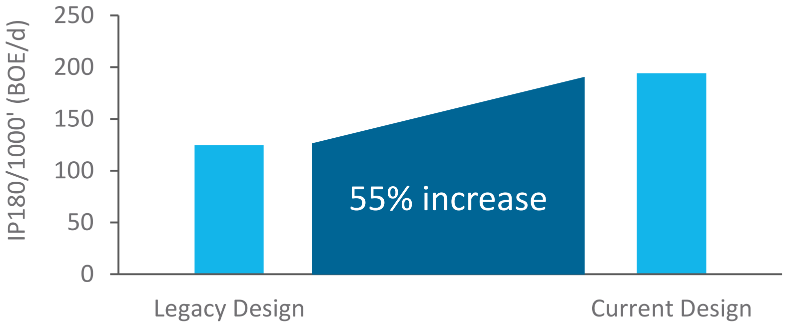
Source: IHS Energy, Inc., peer corporate presentations and publicly available information.

MONTNEY CONTINUOUS IMPROVEMENT

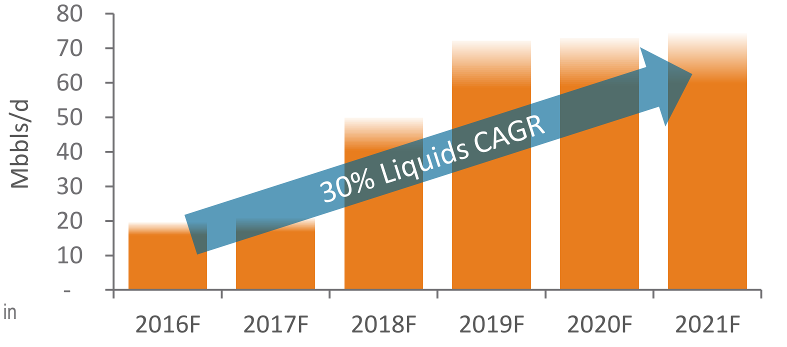
Well Performance and Margins Increasing

- **Optimizing completion design**
  - Up to 55% increase in IP180 since 2014
  - < 65 foot cluster spacing
- **Four new Pipestone wells on-stream in Q3**
  - Average IP30 1,900 BOE/d with 1,050 bbls/d of condensate
- **Montney margin growth through increasing condensate production**
  - Legacy Montney averaged <10 bbls/MMcf
  - 2017 program ~85 bbls/MMcf
  - 30% liquids CAGR** through 2021
  - Premium inventory operating margin[Ŧ] of $14/BOE***

Well Productivity Increase* – IP180



Potential Liquids Growth Profile



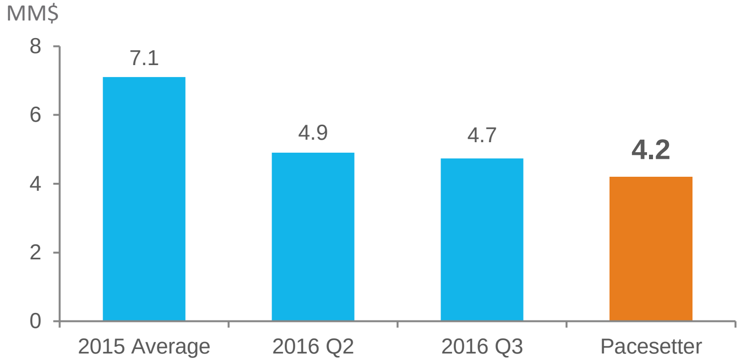
*Normalized to 9,000'; **Compound annual growth rate; ***Assuming $55 WTI and $3.00 NYMEX; ŦNon-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

INNOVATION

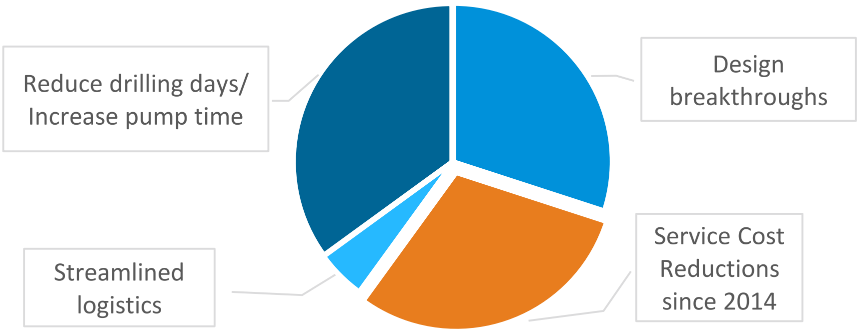
Well Costs Still Dropping

- New pacesetters achieved in Permian & Duvernay
- Repeated pacesetters in Montney & Eagle Ford
- Pipestone average D&C costs down to $4.4MM/well

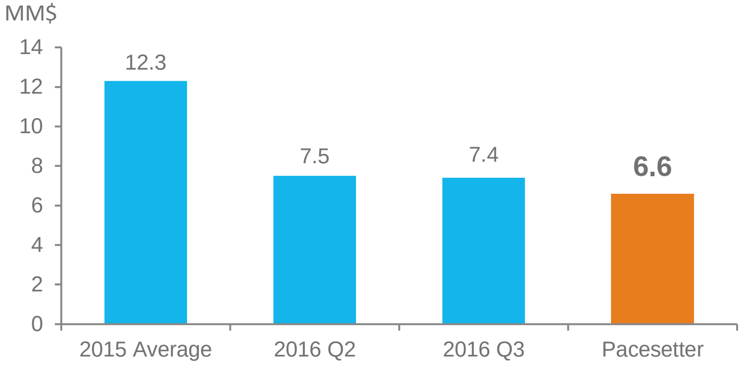
Permian D&C Costs*



Structural Changes Driving Sustainable Cost Savings Since 2014



Duvernay D&C Costs**



*Normalized to 7,500' **Simonette North only, normalized to 8,200'

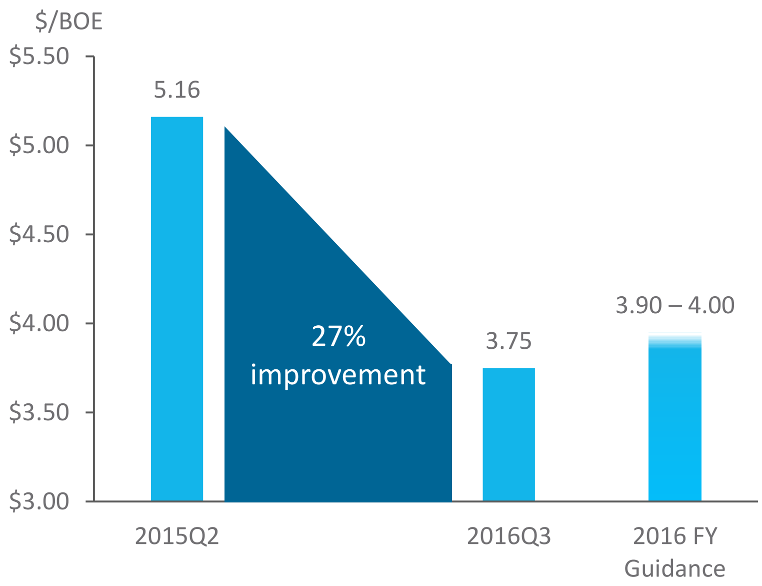
CONTINUOUS IMPROVEMENT

Met Operating Cost Reduction Target One Year Early

- **Beat 20% per unit operating cost target**
  - One year ahead of target
  - Permian horizontal opex under $4/BOE

- **Continuous drive to reduce costs**
  - Executing on over 1,000 unique opportunities identified through multi-basin task force
  - Savings in water handling, trucking, artificial lift, workovers, chemicals

Driving Down Operating Costs*



*Excluding long-term incentive costs

STRONG FINANCIAL & OPERATIONAL PERFORMANCE

Q3 Highlights

- **Higher Q3 cash flowŦ driven by operational efficiency**
  - Lower cash costsŦ and strong performance contribute to higher cash flowŦ
  - Operating costs and T&P down 5% from Q2
- **Highly disciplined and efficient capital program**
  - Core four 4Q15 to 4Q16 on pace for 4% decline – down from 10%
  - Matched or beat pacesetter D&C costs
- **Net debtŦ reduced by $2 billion in Q3**
  - Long-term debt reduced by $3.1 billion since year-end 2014
- **2017 hedge position adds greater cash flowŦ certainty**
  - Reduce capital program execution risk

	Q2 2016	Q3 2016
Upstream Operating Cash FlowŦ* Excluding Hedging ($MM)	204	319
Upstream Operating Cash Flow* Including Hedging ($MM)	330	374
Transportation & Processing ($/BOE)	6.80	5.77
Operating ($/BOE)	3.63	4.19
PMOT ($/BOE)	0.89	0.64
Total Cash FlowŦ ($MM)	182	252
- $ per share, diluted	0.21	0.29
Operating Earnings (Loss)Ŧ ($MM)	89	32
- $ per share, diluted	0.10	0.04
Capital Investment ($MM)	215	205
Net DebtŦ ($MM)	5,397	3,432
Natural Gas (MMcf/d)	1,418	1,326
Total Liquids (Mbbls/d)	132.0	117.0
Total Production (MBOE/d)	368.3	338.0
Core Four Production (MBOE/d)	268.3	242.8

*Upstream operating cash flow is defined as revenues, net of royalties, less production, mineral and other taxes, transportation and processing and operating expenses for each of the respective Canadian and USA operations.

Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

BEATING 2016 TARGETS AND POSITIONED FOR GROWTH

- Very strong Q3 cash flow[Ŧ] driven by operational efficiency
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- Matched or beat pacesetter well costs in core four assets
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One. Agile. Driven.

A culture of success

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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 MD&A as filed on SEDAR and EDGAR. Non-GAAP measures include:

- **Cash Flow, Cash Flow Per Share (CFPS) and Corporate Margin** – 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 cash tax on sale of assets. CFPS is Cash Flow divided by the weighted average number of common shares outstanding. Corporate Margin is Cash Flow per BOE of production. 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 are used, along with other measures, in the calculation of certain performance targets for the company's management and employees.
- **Net Debt** – is defined as long-term debt, including the current portion, less cash and cash equivalents. Management uses this measure as a substitute for total long-term debt in certain internal debt metrics as a measure of the company's ability to service debt obligations and as an indicator of the company's overall financial strength.
- **Operating Earnings (Loss)** – is defined as Net Earnings (Loss) excluding non-recurring or non-cash items that management believes reduces the comparability of the company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures, gains on debt retirement, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.
- **Upstream Operating Cash Flow, excluding Hedging** – Upstream Operating Cash Flow, excluding Hedging is a measure that adjusts the Canadian and USA Operations revenues, net of royalties for production, mineral and other taxes, transportation and processing expense, operating expense and the impacts of realized hedging. Management monitors Upstream Operating Cash Flow, excluding Hedging as it reflects operating performance and measures the amount of cash generated from the Company's upstream operations.
- **Cash Costs** – are defined as the summation of production, mineral and other taxes, transportation and processing expense, operating expense, administrative expense and interest expense.
- **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.
- **Operating Margin** – is defined as revenues, net of royalties, less production, mineral and other taxes, transportation and processing and operating expenses. When presented on a per BOE basis, Operating Margin is defined as indicated divided by average barrels of oil equivalent production volumes. Operating 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 future growth and returns over the next five years (including compound annual growth rate)
- anticipated capital program, including focus of development, amount of sustaining capital, the amount allocated to its core four assets, number of wells on stream and expected return
- well performance, completions intensity, location of acreage and costs relative to peers and within plays
- anticipated production, cash flow, rates of return, operational efficiency, commodity mix and operating and corporate margins
- estimated well locations (including identification of premium return locations), well spacing, decline rate, focus of drilling and timing, commodity composition, rates of returns, and operating performance compared to type curves
- pacesetting operational metrics being indicative of average future well performance and costs, including success of technological innovation and sustainability thereof
- ability to scale or redirect capital program and innovation and asset quality to drive capital productivity
- expected capacity and transportation and processing commitments and restrictions
- anticipated reserves and resources, including product types
- competitiveness and pace of growth of Encana’s plays within North America and against its peers
- anticipated capital and cost efficiencies, including drilling and completion, operating, corporate, transportation and processing costs, associated staffing levels, and sustainability of costs thereof
- expected net debt, associated interest expense savings and quarterly run rate on interest and G&A
- growth in long-term shareholder value and timing thereof
- expected rig count and rig release metrics
- commodity price outlook
- anticipated hedging and outcomes of risk management program, including amount of hedged production
- management of Encana’s balance sheet and credit rating, including access to and commitment of credit facilities and upcoming debt maturities
- expectation to continue to strengthen Encana's balance sheet and create additional financial flexibility
- intended use of proceeds from the public share offering
- running room and scale of Encana’s plays and anticipated vertical and horizontal drilling
- anticipated dividends
- amount of well inventory versus long-term plan and consumption thereof

Readers are cautioned against unduly relying on FLS which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or for results to differ materially from those expressed or implied. These assumptions include:

- assumptions contained in Encana’s 2016 corporate guidance and in this presentation
- data contained in key modeling statistics
- availability of attractive hedges and enforceability of risk management program
- results from innovations
- expectation that counterparties will fulfill their obligations under gathering, midstream and marketing agreements
- access to transportation and processing facilities where Encana operates
- effectiveness of Encana’s resource play hub model to drive productivity and efficiencies
- enforceability of transaction agreements
- 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 these business outcomes include: commodity price volatility; timing and costs of well, facilities and pipeline construction; ability to secure adequate product transportation and potential pipeline curtailments; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; fluctuations in currency and interest rates; risk and effect of a downgrade in credit rating, including below an investment-grade credit rating, and its impact on access to capital markets and other sources of liquidity; variability and discretion of Encana’s Board to declare and pay dividends, if any; the ability to generate sufficient cash flow to meet Encana’s obligations; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; Encana’s ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; changes in or interpretation of royalty, tax, environmental, accounting and other laws; risks associated with past and future divestitures of certain assets or other transactions or receive 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 MD&A, financial statements, Annual Information Form and Form 40-F, 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 future oriented financial information or financial outlook information is included in this presentation to communicate current expectations as to Encana’s performance. Readers are cautioned that it may not be appropriate for other purposes. Rates of return for a particular play or well are on a before-tax basis and are based on 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. Pacesetter well costs for a particular play are a composite of the best drilling performance and best completions performance wells in the current quarter in such play and are presented for comparison purposes. Drilling and completions costs in the Permian, Eagle Ford, Duvernay and Montney have been normalized based on lateral lengths of 7,500 feet, 5,000 feet, 8,200 feet and 9,000 feet, respectively. Premium return locations are defined as locations with expected after tax returns greater than 35% at $50/bbl WTI and $3/MMBtu NYMEX.

For convenience, references in this presentation to “Encana”, the “Company”, “we”, “us” and “our” may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (“Subsidiaries”) of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADVISORY REGARDING RESERVES DATA & OTHER OIL & GAS INFORMATION

National Instrument ("NI") 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. Encana complies with NI 51-101 requirements in its most recently filed annual information form ("AIF"). Detailed Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" of the AIF. Certain disclosure is also prepared in accordance with U.S. disclosure requirements as set forth in Appendix D of the AIF. A description of the primary differences between the disclosure requirements under Canadian and U.S. standards is set forth under the heading "Reserves and Other Oil and Gas Information" in the AIF. Additional detail regarding Encana's economic contingent resources disclosure is in the Supplemental Disclosure Document filed concurrently with the AIF. All estimates are effective as of December 31, 2015, are derived from reports prepared by independent qualified reserves evaluators ("IQREs) engaged by Encana and are prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), NI 51-101 and SEC regulations, as applicable. Information on the forecast prices and costs used in preparing the estimates are contained in the AIF. For additional information relating to risks associated with the estimates of reserves and resources, see "Risk Factors" in the AIF.

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 technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. 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 discovered, and as such have been assigned a 100% chance of discovery, but have however been risked for the chance 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 those contingent resources 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 a large areal expanse and/or thick vertical section, 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 resource 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") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, 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 certain of its plays and emerging opportunities which is "analogous information" as defined in NI 51-101. This analogous information includes estimates of PIIP, NGIP, COIP or EUR, all as defined in the COGEH or by the SPE-PRMS, and production type curves. This analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Encana's internal sources, as well as from 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 half of all locations in our core four plays are booked as either reserves or resources, as prepared by IQREs using forecast prices and costs as of December 31, 2015. 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 applicable geologic, 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 or 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 applicable 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.