ENCANA CORPORATION

Q3 2017
Results Conference Call

November 8, 2017

encana®

FOCUS ON QUALITY CORPORATE RETURNS

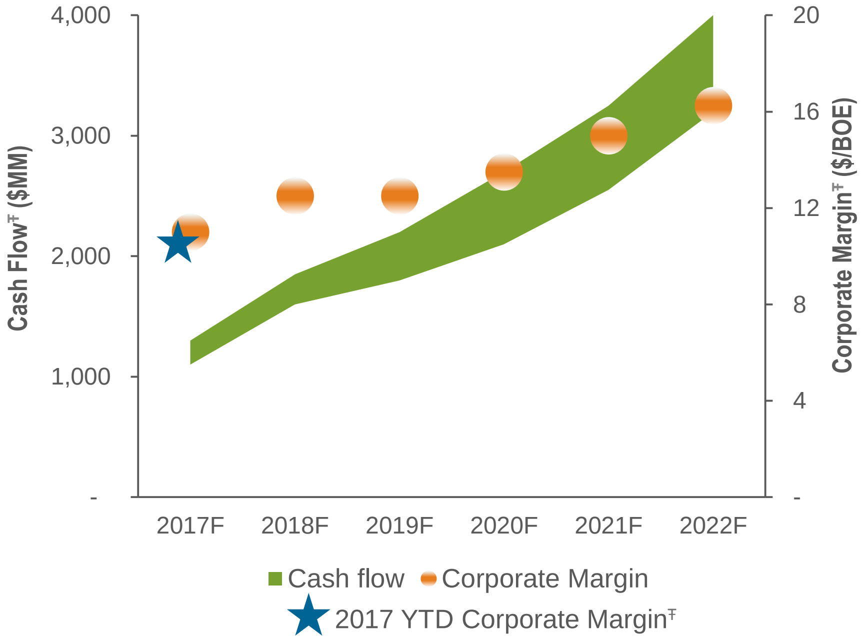
- **Demonstrating that our business works today**
  - Delivering quality corporate returns through the cycle
  - Strong liquids growth continuing to drive margin expansion
- **Set up to deliver on Q4 2017, confidence for 2018**
  - Core assets on track for ~30% Q4 2016 to Q4 2017 core asset production growth
  - All three Montney plants on-stream – liquids growth happening now
  - Permian production of 80 MBOE/d in October well ahead of Q4 target of ~75 MBOE/d
- **Innovation continues to drive upside**
  - Cube development maximizes value
  - Completion design innovation boosts productivity
- **Commercial mindset to grow value not just volumes**
  - Financial hedges, commercial agreements and physical transportation maximize margin
  - Key supply chain components secured for 2018 program

FUNDAMENTALS OF THE BUSINESS ARE WORKING

More Valuable & Resilient

- **Cash flow per share[Ŧ] of $0.28 in Q3**
- **On track to deliver $11/BOE corporate margin[Ŧ] in 2017**
  - YTD corporate margin[Ŧ] of $10.77/BOE
- **Results consistent with 5 year plan**
- **Significant cash flow[Ŧ] growth at flat commodity prices**

2017F - 2022F Cash Flow[Ŧ] ~25% CAGR*



* Assumes flat $50/bbl WTI oil price, flat $3/MMBtu NYMEX natural gas price.

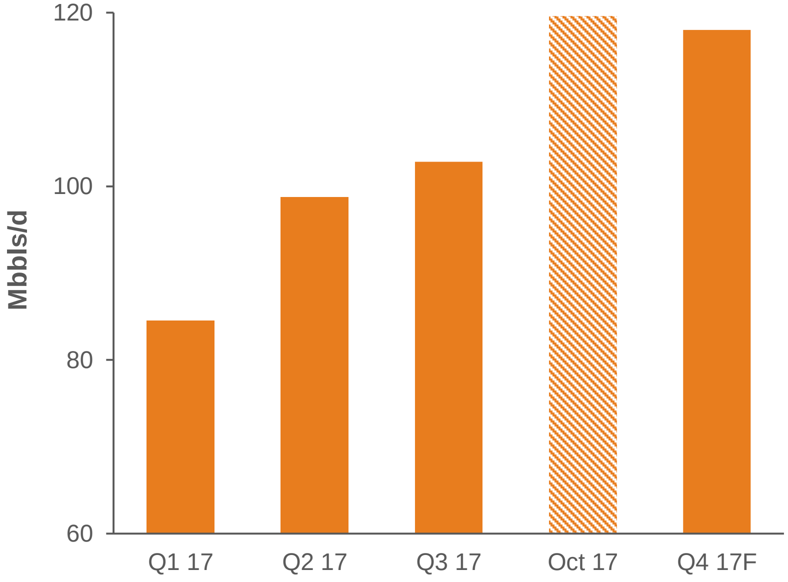
Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

DRIVING MARGIN EXPANSION

Delivering High Margin Production Growth

- **>35% growth in high value oil and condensate from Q416 to Q417**
  - Driven by growth in the Permian and Montney
- **Strong results Q4 to date**
  - October oil & condensate production of 120 Mbbls/d
- **Production weighting close to balanced between liquids and gas by YE 2017**

Oil & Condensate on Track to Grow >35%*



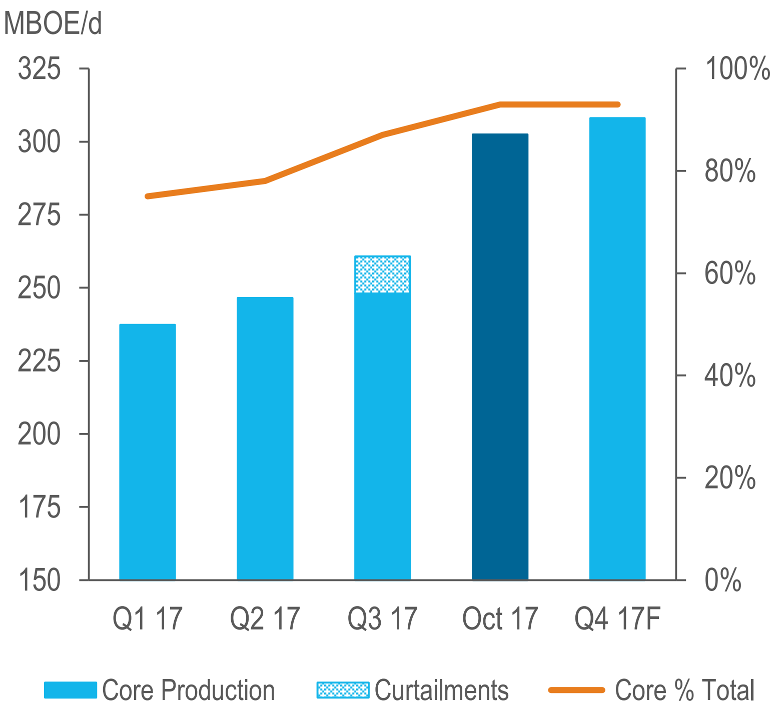
*Excludes volumes associated with assets sold during the year.

STRONGLY AHEAD IN YEAR 1 OF 5 YEAR PLAN

Core Assets on Track to Deliver Top End of Guidance

- **Robust corporate margin[Ŧ] expansion through higher value product mix and lower costs**
- **Core assets performing well**
  - On track to achieve ~30% growth Q416 to Q417
  - Expect Q4 production of 305-310 MBOE/d
  - Total core October production 302 MBOE/d
  - Permian October production 80 MBOE/d
  - Montney October production 147 MBOE/d with >25 Mbbls/d liquids
  - Core assets to make up >90% of total Q4F production
  - ~13 MBOE/d impact in Q3 due to curtailments

Core Production Expected to Grow ~30%



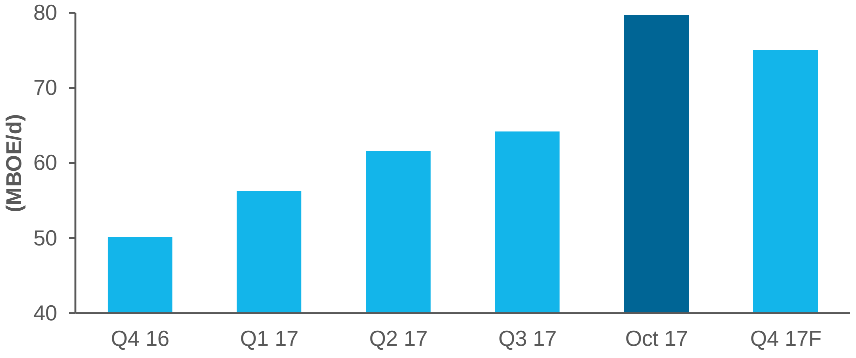
Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

PERMIAN TRACK RECORD OF DELIVERY

Advanced Completions Fueling 50% Permian Growth

- **2017 program delivering 50% growth Q416 to Q417**
  - Reinforced by strong Q4 results to date
  - October oil production 50 Mbbls/d
  - October production 80 MBOE/d
- **Highly efficient operations**
  - Large pads leverage economies of scale
  - Concurrent operations reduce cycle times
  - Advanced sand and water logistics
  - Re-occupied infrastructure
- **Frac services secured for 2018**

On Track to Grow Permian Production to ~75MBOE/d in Q4

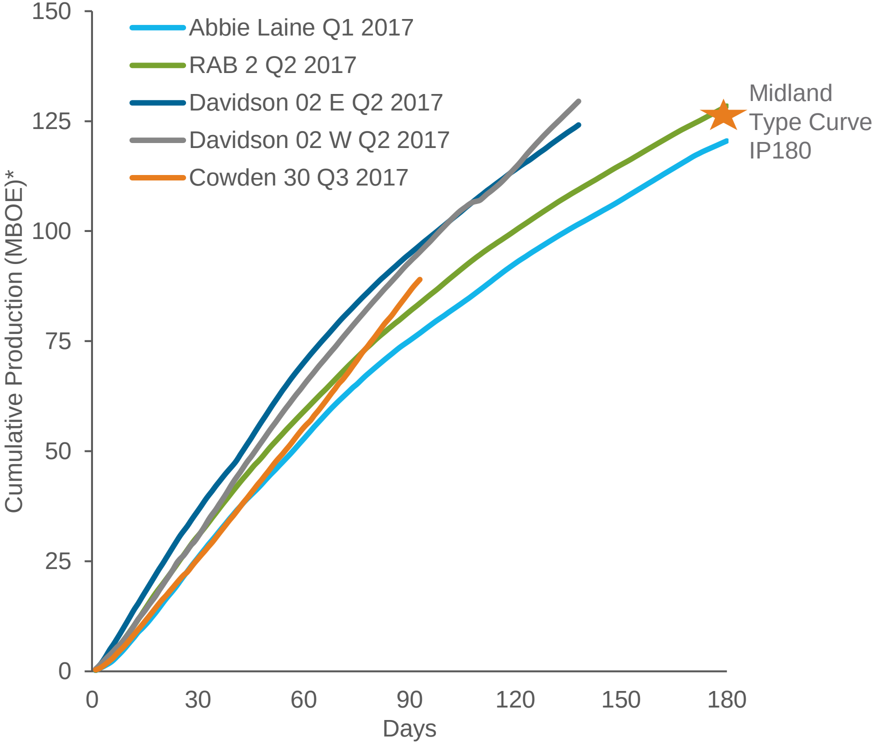


PERMIAN MAXIMIZING RETURNS AND RECOVERY

2017 Cube Development Results

- **Step-change productivity increases**
- **Cube development approach continues to evolve in 2017**
  - Data-driven innovation
  - Added new benches
  - Spacing and stacking trials
  - Implemented advanced completion designs
  - Evaluating emerging technologies
- **Recent Midland County 10-well cube on-stream**
  - First wells averaging >1,600 BOE/d over 14 days
- **Continue to lead industry in dense-well development**

Permian Cube Evolution



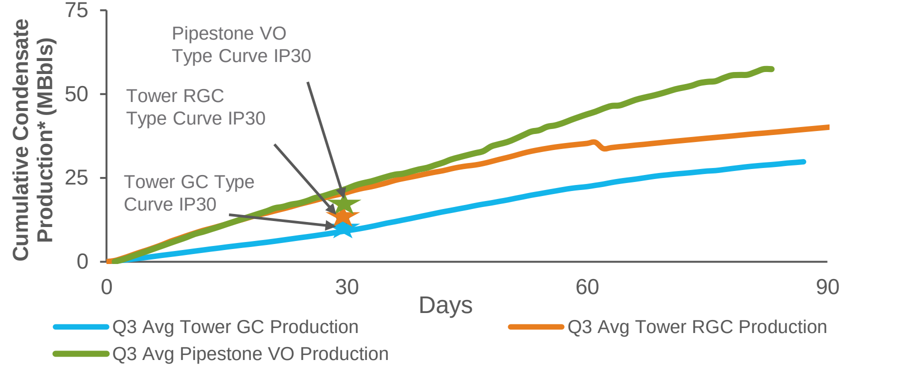
* 3-stream pad average, well results normalized to 7,500'

MONTNEY TRACK RECORD OF DELIVERY

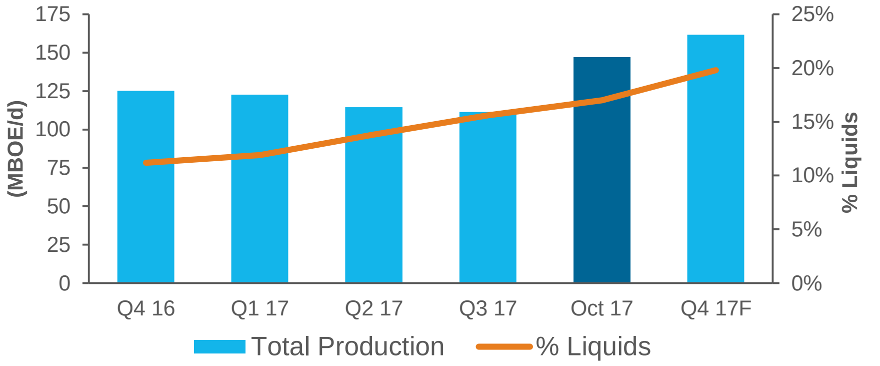
Delivering Condensate Growth

- **Well targeting and completion design driving well productivity**
  - 28 well Tower cube average IP30 of 700 bbls/d condensate
  - Recent Dawson South Upper Montney well stabilized on test at >700 bbls/d condensate and >11MMcf/d of gas
  - Q3 Pipestone two well pad average IP90 of 750 bbls/d condensate
- **All 3 plants are on-stream 1-6 months ahead of schedule and ~10% under budget**
  - Saturn plant started up November 1, 2017
- **October production of 147 MBOE/d, including >25 Mbbls/d liquids**
- **Dawn service began November 1st**

Significant Condensate Production Across Montney Acreage



Montney Liquids Production to Double Over Q416



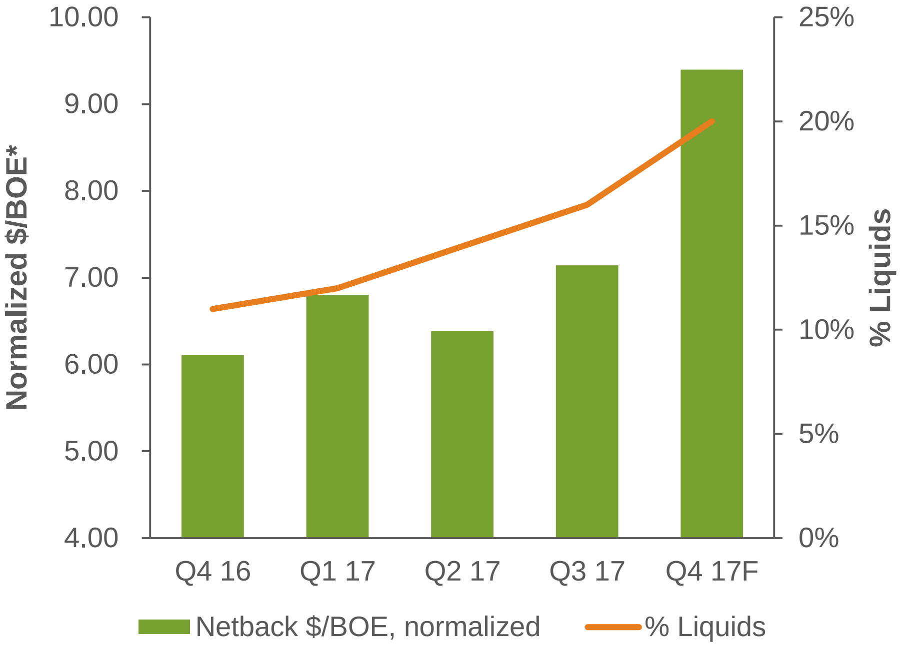
*Pipestone well results normalized to 9,000’ & Tower normalized to 8,200’

MONTNEY MARGIN EXPANSION

Driving Cash Flow[Ŧ] Growth

- **Montney liquids production set to more than double from Q4 2016 to Q4 2017**
- **Margin impact is significant**
  - Q4 2017 operating margin[Ŧ] expected to be up >50% versus Q4 2016 driven by greater liquids mix
  - This expansion equates to an incremental ~$200 million in annualized operating cash flow[Ŧ]

Montney Margin Expansion with Increased Liquids



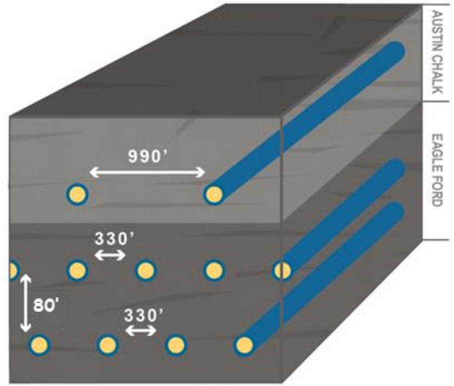
[Ŧ] Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

* Per unit Netback normalized to US$50.00 WTI Oil, US$3.00 NYMEX Gas and US$1.00 AECO Differential, no hedge impact & flat FX.

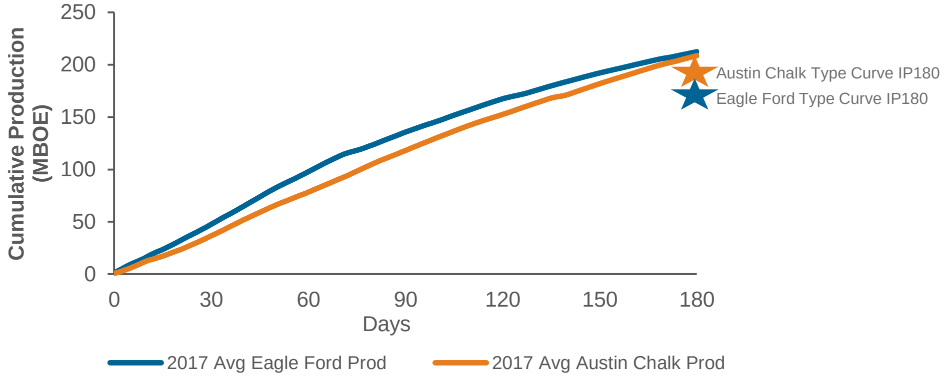
EAGLE FORD TRACK RECORD OF DELIVERY

Generating Free Cash Flow[Ŧ]

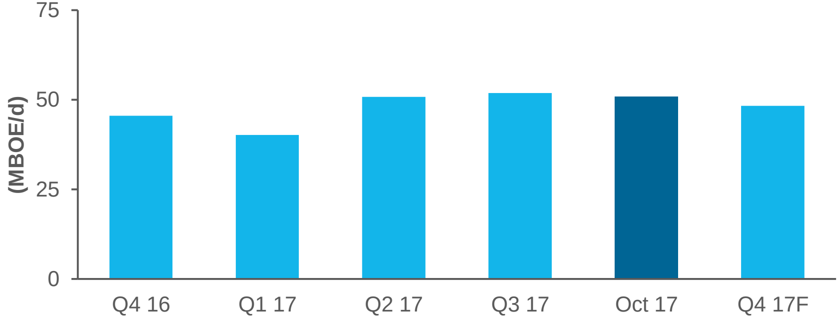
- **Strong performance from Eagle Ford and Austin Chalk**
  - Q3 production of 52 MBOE/d
- **Maintaining production while generating free cash flow[Ŧ]**
- **Focus on completions design evolution to increase productivity and optimize capital**
- **Evaluating spacing and stacking in Eagle Ford & Austin Chalk**
- **Safely and effectively managed through Hurricane Harvey with no damage and minimal impact**



Average 2017 Eagle Ford Program Productivity*



Eagle Ford Maintaining Plateau Production ~50 MBOE/d



*Well results normalized to 5,000'.

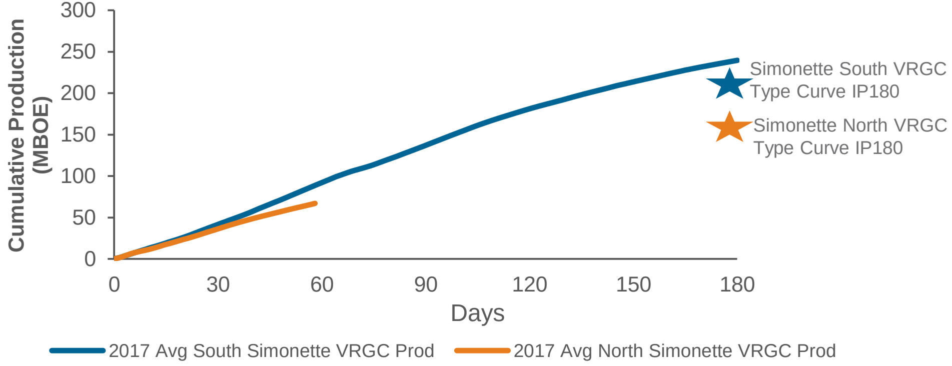
[Ŧ] Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

DUVERNAY TRACK RECORD OF DELIVERY

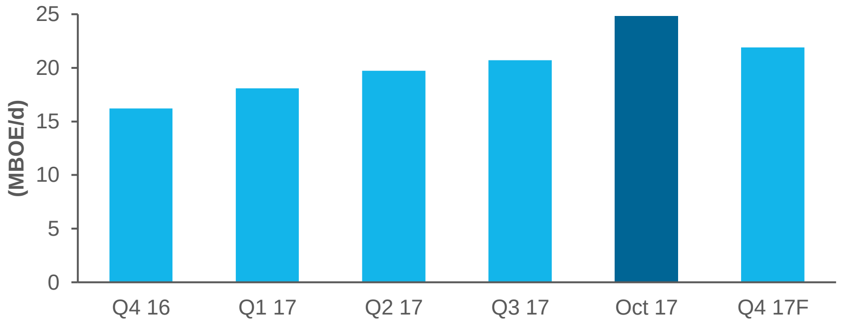
Delivering Record Performance

- **Strong production performance**
  - October production of >24 MBOE/d
  - Asset generating free cash flow[Ŧ]
- **Advanced completion design**
  - Encouraging early results
  - Industry leading costs and productivity
- **Efficient operations driving down LOE**
  - 70% reduction in operating cost since 2015

Average 2017 Duvernay Program Productivity*



Duvernay Production Growth in 2017



*Simonette North normalized to 8,200', Simonette South normalized to 8,900' lateral length

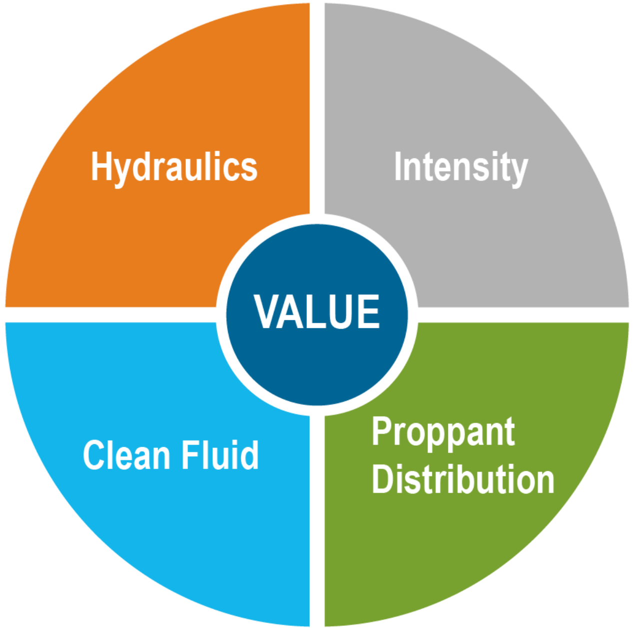
Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

INNOVATION SUCCESS

Identifying Optimal Completion Design and Geometry

- **Applying advanced completions to high-density, stacked development**
- **Key principles:**
  - Tight cluster spacing and optimal hydraulics maximize fracture surface area
  - Clean, non-guar based fluids lead to higher fracture conductivity
  - Fine grained proppant maximizes fracture complexity
- **Higher recovery from stacked pay reservoir**
  - Effective draw-down within cube
- **Evaluating emerging technology**
  - Continued evolution and data-driven refinement

Key Completion Design Factors



STRONG Q3 PERFORMANCE

On Track to Achieve 2017 Guidance

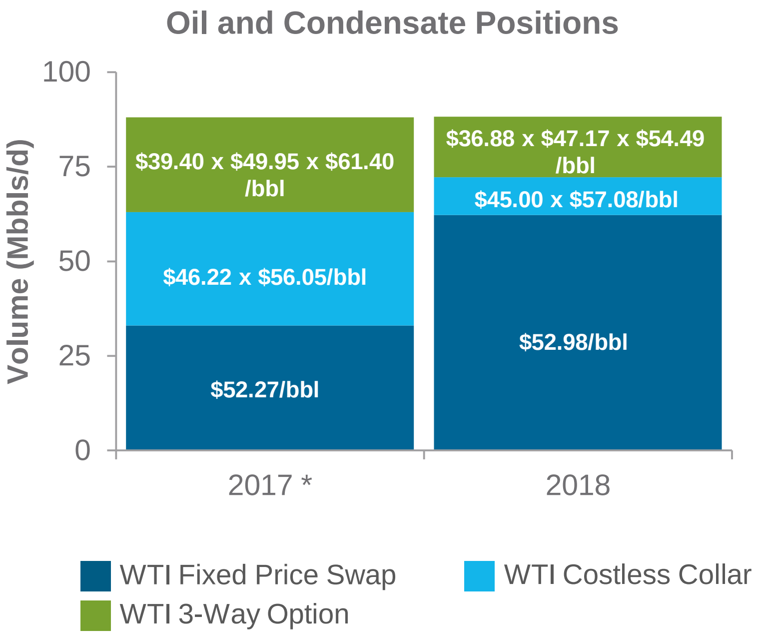
- **Corporate margin[Ŧ] ahead of plan**
  - $10.77/BOE YTD
  - ~$11.00/BOE expected full year 2017
- **Strong liquids growth YTD**
  - October Oil & C5+ production up 16% vs Q3
- **Core assets made up 87% of total production in Q3**
- **Cost performance in line with expectations**

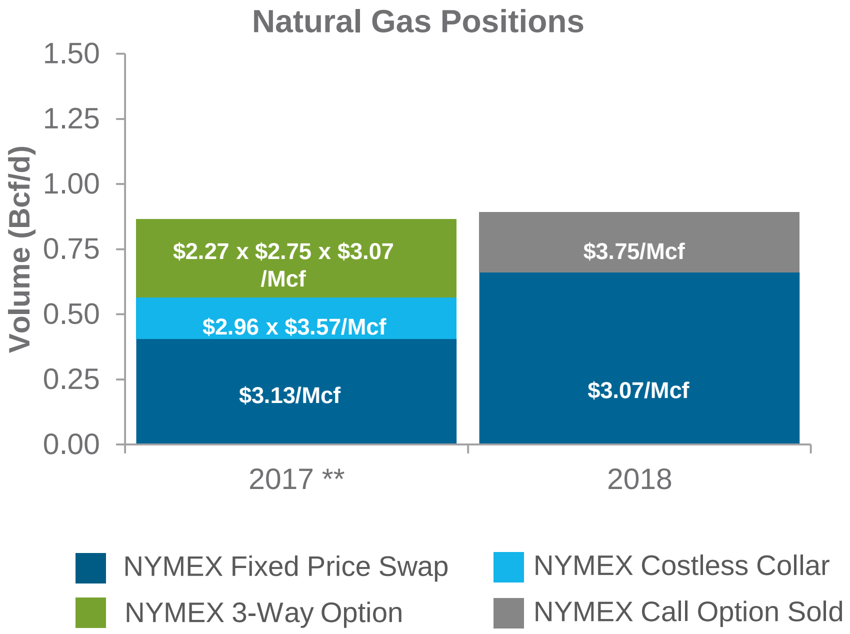
	Q3 2017	YTD Q3 2017
Net Earnings ($MM)	294	1,056
Cash Flow[Ŧ] ($MM)	270	899
Corporate Margin[Ŧ] ($/Boe)	10.34	10.77
Capital Investment ($MM)	473	1,287
Total Liquids (Mbbls/d)	128	121
Natural Gas (MMcf/d)	939	1,108
Total Production (MBOE/d)	284	306
Core Asset % of Total Production	87%	80%
Transportation & Processing ($/BOE)	6.50	6.52
Operating Expense* ($/BOE)	3.96	3.85
Administrative Expense* ($/BOE)	1.63	1.58

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

RISK MANAGEMENT PROGRAM

Adds Greater Certainty to Cash Flow and De-Risks Capital Program





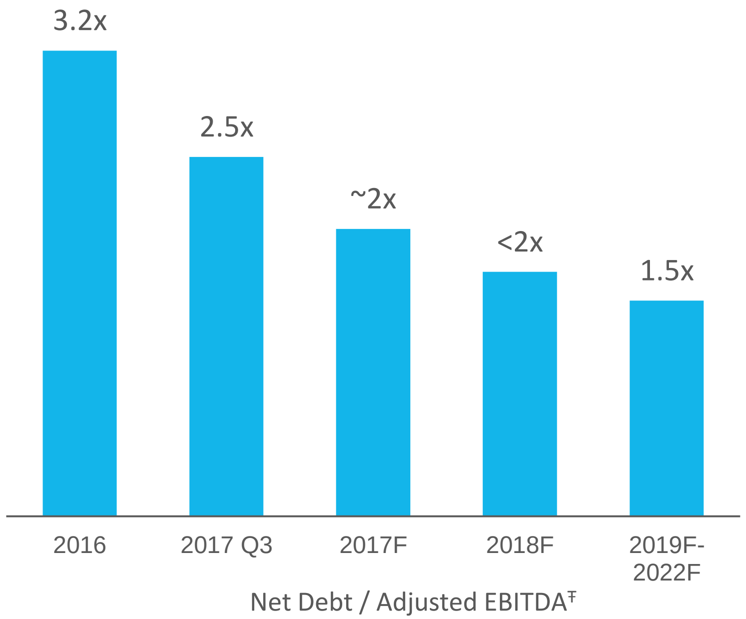
Risk management positions as at October 31, 2017. * November to December 2017 positions. ** December 2017 positions.

DISCIPLINED FINANCIAL MANAGEMENT

Balance Sheet Well Positioned for Price Volatility

- **Well positioned for price volatility**
  - Robust hedge position
  - Expect to have >$5 billion of liquidity at year-end 2017
- **Expect net debt to adjusted EBITDAŦ of ~2x by Y/E 2017**
- **Total debt reduced by ~$3 billion since Y/E 2014**
- **Significant financial flexibility with no debt maturities until 2019**
- **~75% of fixed rate long-term debt not due until 2030+**
- **Investment grade credit rating**
- **$4.5B fully committed, unsecured, revolving credit facilities**

Leverage Rapidly Dropping



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FOCUS ON QUALITY CORPORATE RETURNS

Our Business Works Today

Strategy

- World class portfolio of assets
- Execution excellence
- Market fundamentals
- Disciplined capital allocation
- Unconventionals are all we do

Execution

- Track record of delivery
- Culture of innovation both technical and commercial
- Leader in industrial scale development
- Integrated supply chain management
- Managing risk

Return on Capital EmployedŦ **climbs to**
10-15% over the 5 year plan

~25% Cash FlowŦ **CAGR**
2017F – 2022F

~$1.5 Billion Free Cash FlowŦ
2018F – 2022F

Assumes flat $50/bbl WTI oil price, flat $3/MMBtu NYMEX natural gas price.
Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

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, 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. Free Cash Flow is Non-GAAP Cash Flow in excess of capital expenditures. Corporate Margin is Non-GAAP 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 may be used, along with other measures, in the calculation of certain performance targets for the company's management and employees.
- **Net Debt, Adjusted EBITDA and Net Debt to Adjusted EBITDA** – 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. Adjusted EBITDA is defined as trailing 12-month net earnings (loss) before income taxes, DD&A, impairments, accretion of asset retirement obligation, interest, unrealized gains/losses on risk management, foreign exchange gains/losses, gains/losses on divestitures and other gains/losses. Net Debt to Adjusted EBITDA is monitored by management as an indicator of the company's overall financial strength and as a measure considered comparable to peers in the industry.
- **Operating Margin/Operating Cash Flow/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 Cash Flow/Operating Netback is defined as indicated divided by average barrels of oil equivalent sales volumes. Operating Margin/Operating Cash Flow/Operating Netback is used by management as an internal measure of the profitability of a play(s).
- **Return on Capital Employed (ROCE)** – Adjusted Operating Earnings divided by Capital Employed. Adjusted Operating Earnings is defined as Non-GAAP Operating Earnings (Loss) plus after-tax interest expense. Capital Employed is defined as average net debt plus average shareholders' equity.
- **Non-GAAP 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 items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

FUTURE ORIENTED INFORMATION

This presentation contains certain forward-looking statements or information (collectively, “FLS”) within the meaning of applicable securities legislation, including the U.S. Private Securities Litigation Reform Act of 1995. FLS include:

- expectation of meeting or exceeding the targets in Encana’s corporate guidance and five-year plan
- anticipated capital program, including focus of development, amount and allocation thereof, number of wells on stream, level of capital productivity, expected return and source of funding
- well performance, completions intensity, location of acreage and costs relative to peers and within assets
- anticipated production, including growth from core assets, cash flow, capital coverage, payout, profit, net present value, rates of return, recovery, return on capital employed, production efficiency, execution efficiency, operating, income and corporate margins, including expected timeframes, impact of prices and commodity mix
- number of potential drilling locations (including premium return inventory and ability to add to or consume such inventory), well spacing, number of wells per pad, decline rate, rig count, rig release metrics, focus and timing of drilling, anticipated vertical and horizontal drilling, cycle times, commodity composition, gas-oil ratios and operating performance compared to type curves
- running room and scale of assets, including its competitiveness and pace of growth against peers
- pacesetting operational metrics being indicative of future well performance and costs, and sustainability thereof
- timing, success and benefits from innovation, cube development approach, advanced completions design, technology advancements and asset quality, including efficiency, capital productivity and transferability of ideas
- expected transportation and processing capacity, commitments, curtailments and restrictions, including flexibility of commercial arrangements and costs and timing of certain infrastructure being operational
- anticipated reserves and resources, including product types and stacked resource potential
- anticipated third-party incremental and joint venture carry capital
- ability to manage costs and maintain or enhance efficiencies, including drilling and completion, operating, corporate, transportation and processing, associated staffing levels, services secured and sustainability thereof
- expected net debt and debt ratios
- growth in long-term shareholder value and timing thereof
- commodity price outlook
- anticipated hedging and outcomes of risk management program, including exposure to commodity prices and foreign exchange, amount of hedged production, market access and physical sales locations
- management of balance sheet and credit rating, including access to sources of liquidity
- expected growth, returns and free cash flow in Encana’s five-year plan, including projections based on commodity prices and use of cash therefrom
- environmental, health and safety performance
- advantages of Encana’s multi-basin portfolio
- execution of strategy and future outlook, including funding within cash flow, production, growth and leverage, and momentum into 2018

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 results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; ability to access its credit facilities and shelf prospectuses; assumptions contained in Encana’s corporate guidance, five-year plan and in this presentation; data contained in key modeling statistics; enforceability of risk management program; results from innovations; expectation that counterparties 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; 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, benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: ability to generate sufficient cash flow to meet obligations; commodity price volatility; ability to secure adequate transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors to declare and pay dividends, if any; timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties, including impact of weather; counterparty and credit risk; impact of a downgrade in credit rating and its impact on access to sources of liquidity; fluctuations in currency and interest rates; risks inherent in Encana's corporate guidance; failure to achieve cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; changes in or interpretation of laws or regulations; risks associated with existing and potential lawsuits and regulatory actions made against Encana; impact of disputes arising with partners, including suspension of certain obligations and 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 sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future acquisitions 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 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 asset 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 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. Drilling and completions costs have been normalized as specified in this presentation based on certain lateral lengths for a particular asset. Premium well locations are 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 OIL & GAS INFORMATION

All proved and probable reserve and economic contingent resource estimates in this presentation are effective as of December 31, 2016, prepared by internal 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 is contained in Encana’s Form 51-101F1 for the year-ended December 31, 2016 (“Form 51-101F1”) and detailed U.S. protocol disclosure is 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 has filed with applicable securities regulatory authorities on February 27, 2017. Additional detail regarding Encana’s economic contingent resources disclosure is 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 is 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 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”), 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 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 its assets which are “analogous information” as defined in NI 51-101, including estimates of PIIP, NGIP, COIP, EUR 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, but are not necessarily indicative of ultimate recovery. 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. Estimates of drilling locations and premium return well inventory include proved, probable, contingent and unbooked locations. These estimates are prepared internally based on Encana's prospective acreage and are based on an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Approximately 36 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 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.