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# Barclays CEO Energy – Power Conference

September 2017

50 YEARS OF EXPLORATION DISCOVERIES

# Forward-Looking Information

**Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995**

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this presentation other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, are forward-looking statements. When used in this presentation, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial, market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas exploration, drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other revenue-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2016, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this presentation occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this presentation, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

# 2017 Guidance Improved
# More Growth for Less Capital & Cost

**Production Raised**

- Exit-rate: +24%-31% over 4Q'16 (260-275 MBoepd)
- Full-year: +6%-11% YoY (230 to 240 MBoepd)

**CAPEX Revised to Lower Range**

- $1.75 billion to $1.95 billion
- Cash neutral at annual average of $45-$51 WTI

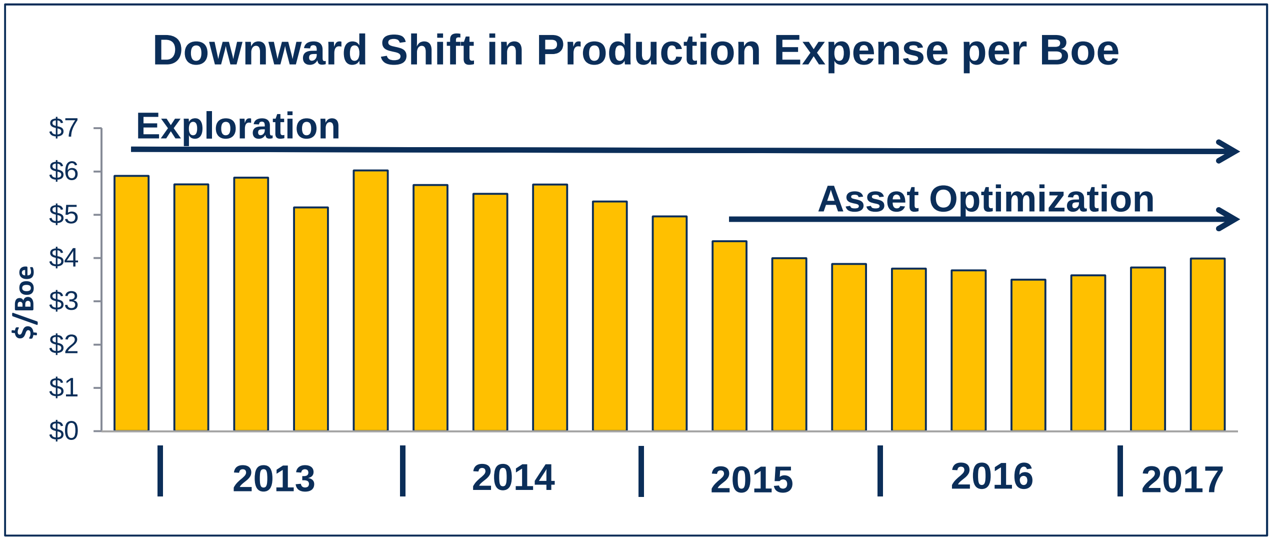
**Operating Costs Lowered**

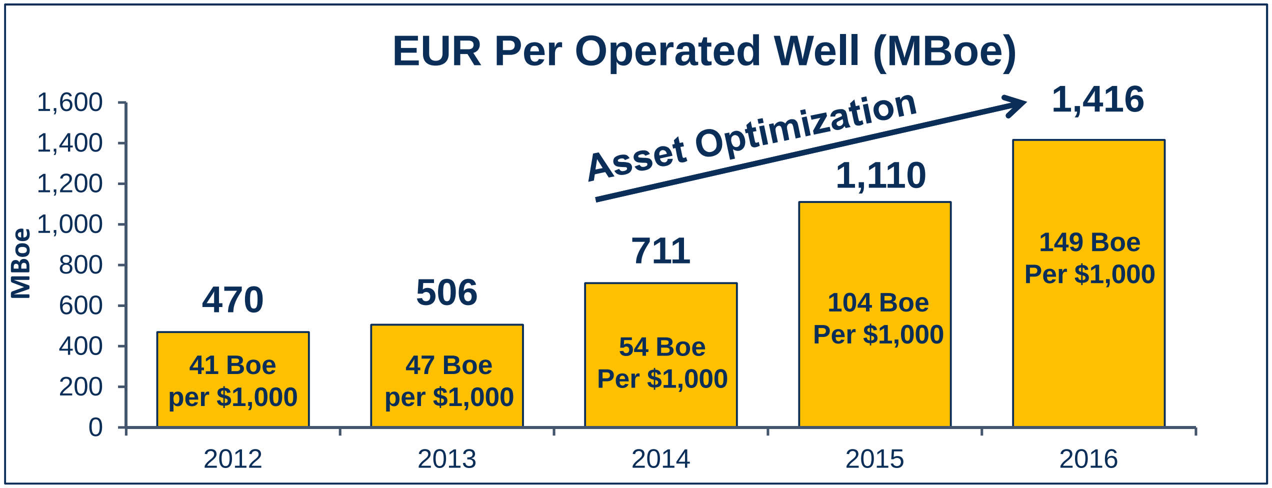
- Production Expense, G&A, DD&A and oil differential all lowered

**Non-Strategic Asset Sales of $147.5MM**

- $72.5 MM non-core STACK leasehold
- $68.0 MM non-core Arkoma Woodford leasehold
- $7.0 MM for sale of oil-loading facilities
- Expected to close in 2H 2017

# Building Value Through Asset Optimization




**3Q'15 through 2Q'17**

Production expense down 30% or $2/Boe

$3.50 to $3.90/Boe full-year 2017 guidance

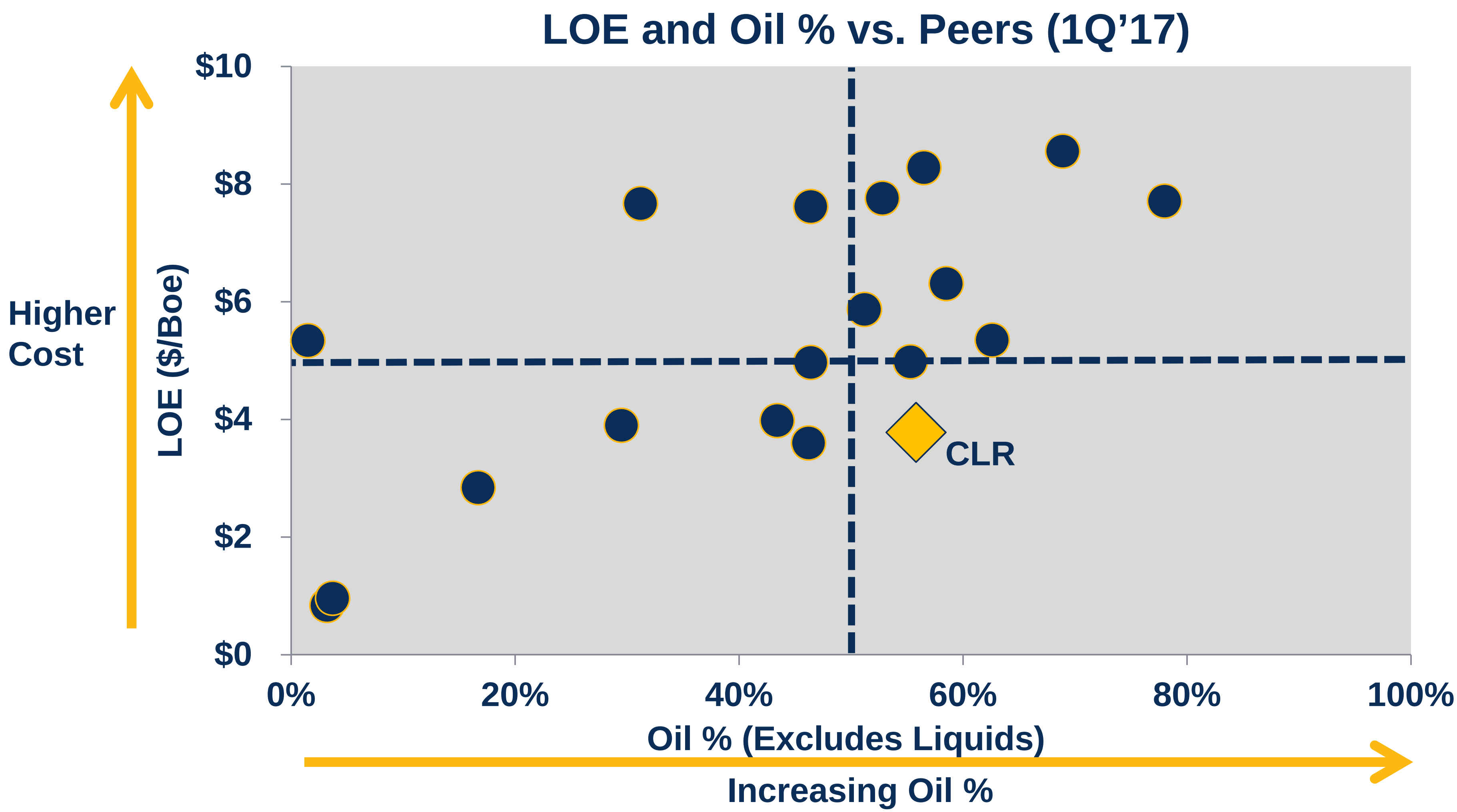
**2014 to 2016**

EUR per well up ~100%

Capital efficiency[1] up ~175% (Boe/$ invested)

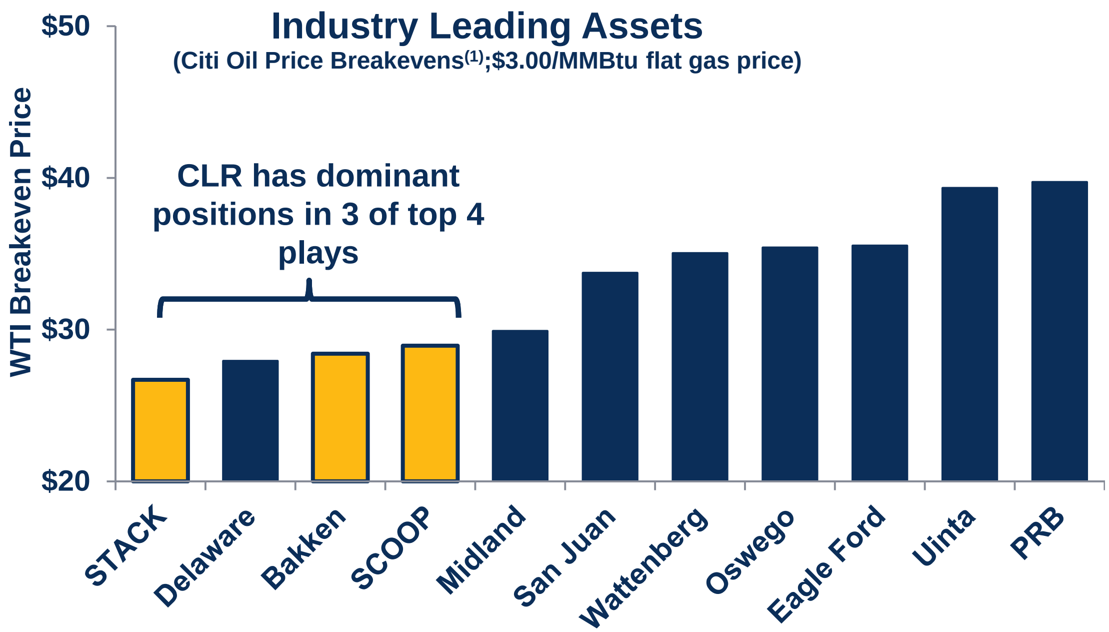
1. Capital efficiency is based on estimated ultimate recoveries added per dollar invested for wells spud during the indicated periods. An assumed net revenue interest of 82% and cost estimates are used in determining capital efficiency for non-producing properties.

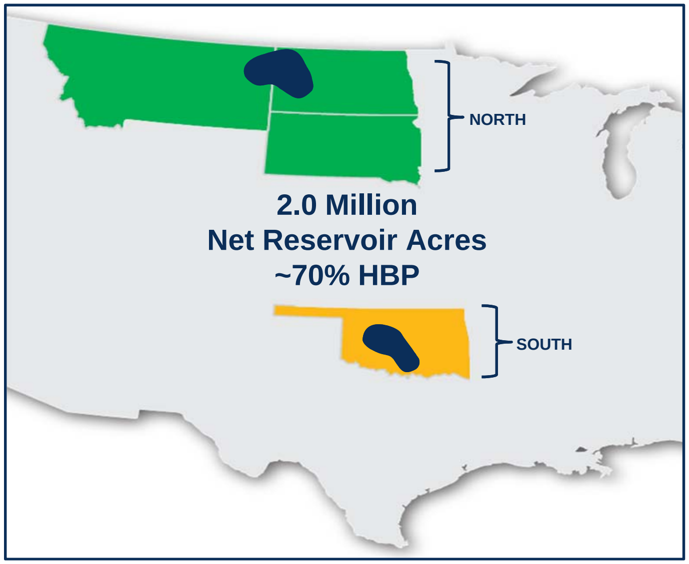
# CLR = Low Cost + Oil-Weighted Producer




Peers include: APA, APC, CHK, COG, CXO, DVN, EOG, MRO, MUR, NBL, NFX, OAS, PXD, RRC, SWN, WLL, WPX, XEC
Source: Company public filings

# CLR: Superior Oil-Weighted Assets




**Oil-weighted assets**

| Play | % Oil | Est. Total % Liquids |
|---|---|---|
| Bakken Drilling + DUCs | 80% | 90% |
| STACK Meramec Oil | 60% | 70% |
| Springer | 80% | 85% |
| SCOOP Woodford Oil | 60% | 85% |
| SCOOP Woodford Condensate | 25% | 55% |

| Play | Net Reservoir Acres[2] |
|---|---|
| Bakken | 806,000 |
| STACK Meramec | 207,000 |
| STACK Woodford | 193,000 |
| SCOOP Springer | 188,000 |
| SCOOP Sycamore | 314,000 |
| SCOOP Woodford | 314,000 |
| Total | 2,022,000 |

1. June 2017 Citi Research report; based on current D&C costs
2. Acreage numbers are approximate

Continental RESOURCES

50 YEARS

# Bakken Value Growing Through Technology

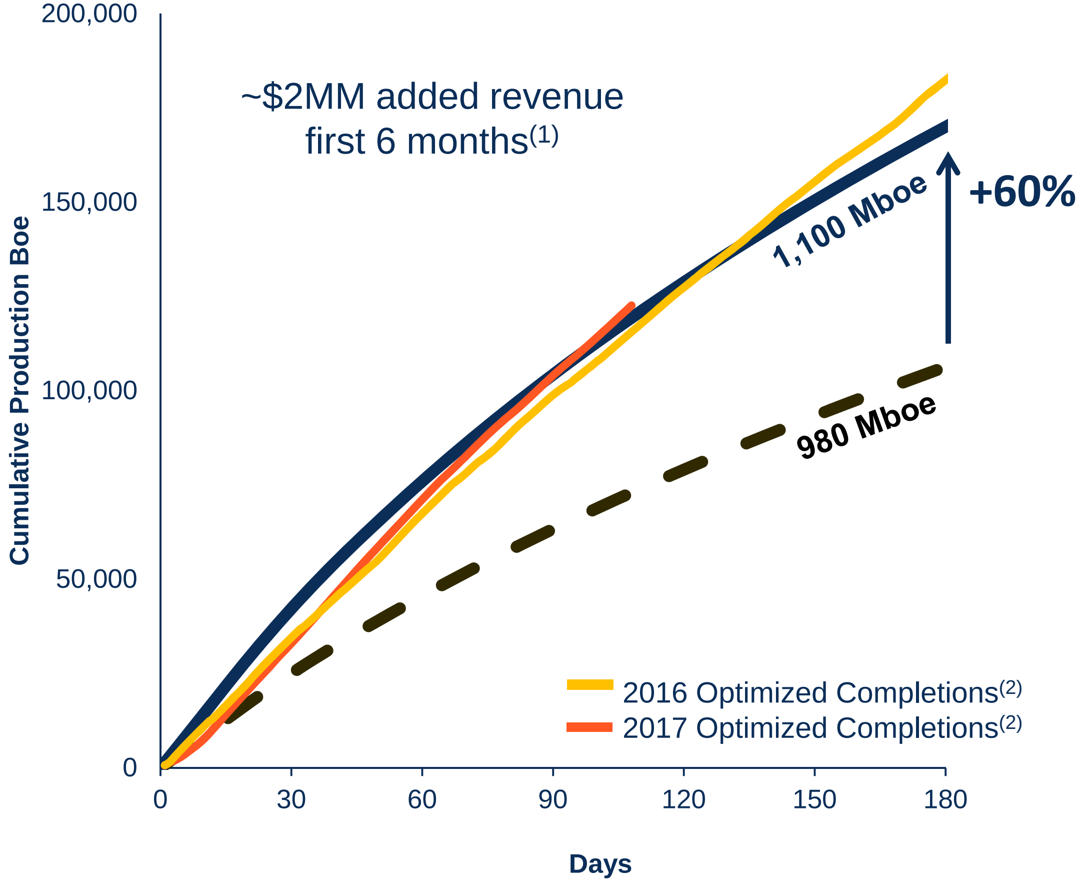
**Optimized completions delivering record results**

- ROR[1] doubled to 82%
- Payouts decreased 50% to 15 months[1]
- NPV up 70% per well[1]
- Type curve EUR increased to 1,100 MBoe per well (~80% oil)

**2Q'17**

- 19 completions
- 1,606 Boepd avg. 24 hour IP
- (82% oil)

**New Optimized Type Curve**



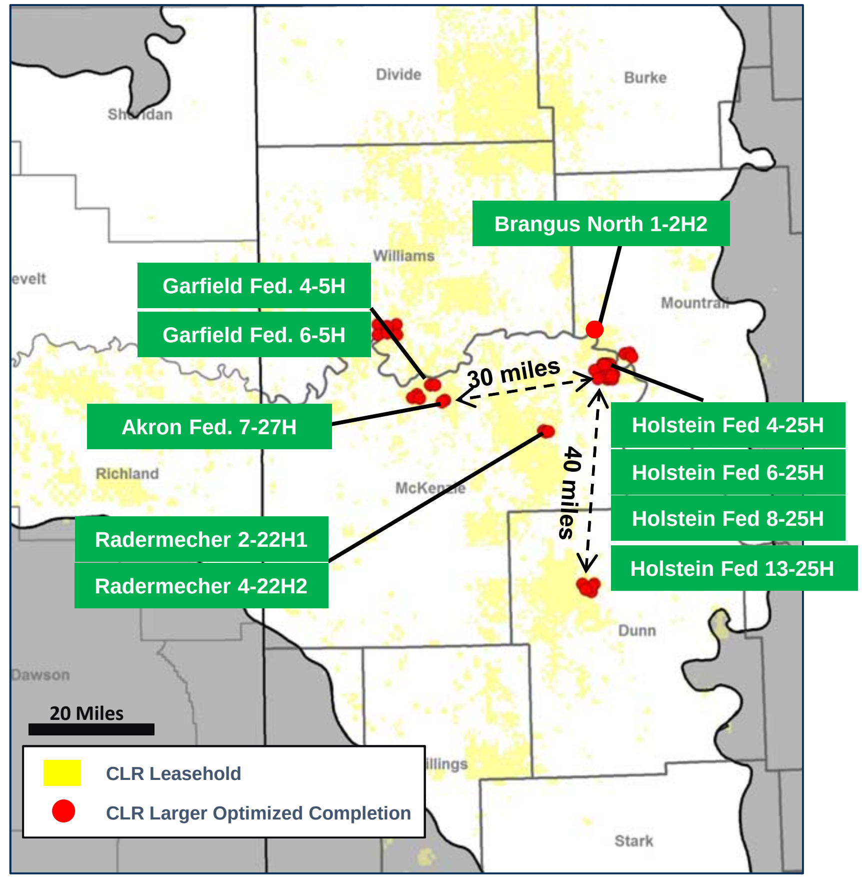

1. ROR, NPV & payout are based on $50 WTI and $3.25 gas, see ROR footnote on slide 18
2. Optimized completions for MB, TF1 and TF2 HBP or grassroots density wells

# Bakken Optimized Completions
# Delivering Widespread Record 30-Day Rates

### CLR top ten 30-day record rate wells

| 30-Day Avg, Boepd | % Oil | Formation | Quarter |
|---|---|---|---|
| 2,015 | 83% | MB | ***2Q17*** |
| 1,853 | 79% | MB | 1Q17 |
| 1,837 | 79% | MB | ***2Q17*** |
| 1,833 | 79% | TF1 | 1Q17 |
| 1,782 | 85% | TF2 | 3Q16 |
| 1,750 | 83% | MB | ***2Q17*** |
| 1,750 | 77% | MB | ***2Q17*** |
| 1,729 | 82% | MB | 4Q16 |
| 1,634 | 80% | MB | ***2Q17*** |
| 1,618 | 78% | TF2 | 1Q17 |

### CLR Record well locations

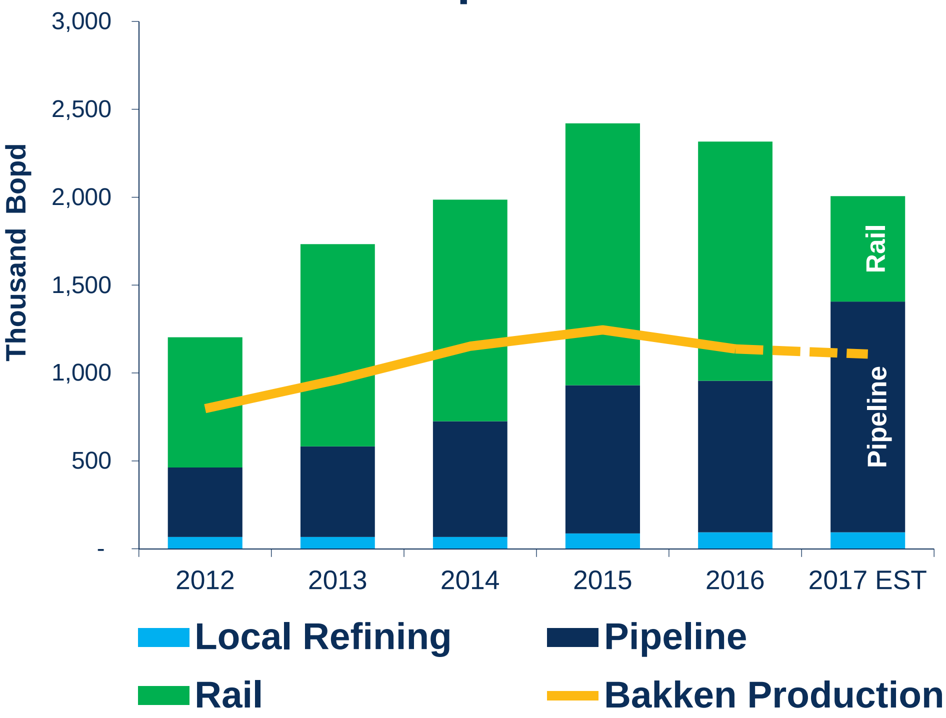


# Bakken Value
# Also Growing from Improved Differentials

## Added capacity from DAPL improving differential

- $1.00 reduction on full-year corporate differential guidance
    - Up to $2.00 improvement expected in 2H 2017 in Bakken
- Further improvement in 2018

## Pipeline takeaway exceeds current production



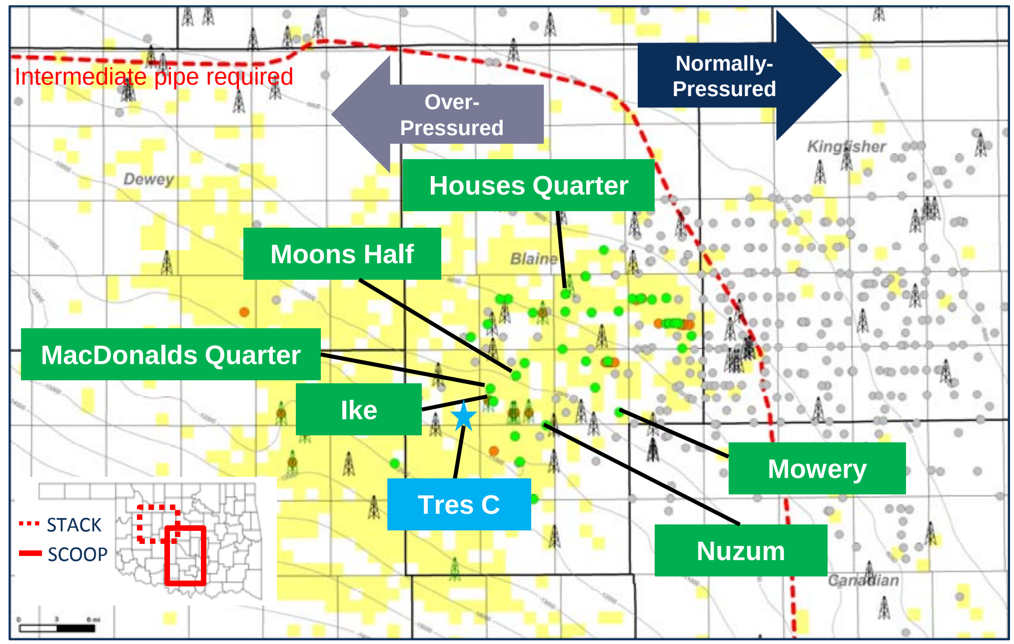
# STACK Meramec
# Successful Expansion and De-Risking Continues

| 2Q 2017 Highlight Completions | 24-Hour IP, Boe | % Oil | FCP, psi | Lateral Length (ft) |
|---|---|---|---|---|
| Nuzum 1-12-1XH | 3,011 | 10% | 4,327 | 10,061 |
| Ike 1-20-17XH | 2,170 | 43% | 5,717 | 10,200 |
| Mowery 1-36H | 2,104 | 51% | 3,100 | 4,800 |
| Moons Half 1-16H | 1,765 | 52% | 4,600 | 3,835 |
| MacDonalds Quarter 1-18H | 1,441 | 40% | 4,175 | 4,871 |
| Houses Quarter 10-7-6XH | 1,000 | 72% | 2,825 | 7,385 |

## Record STACK completion:

- Tres C FIU 1-35-2XH
- 24-hour IP: 1,021 Bo and 29,590 Mcf (5,953 Boe)
- 7,442 Boe[1] (40% liquids) on estimated 3 stream basis
- FCP: 6,500 psi

## Completions / Ongoing Activity



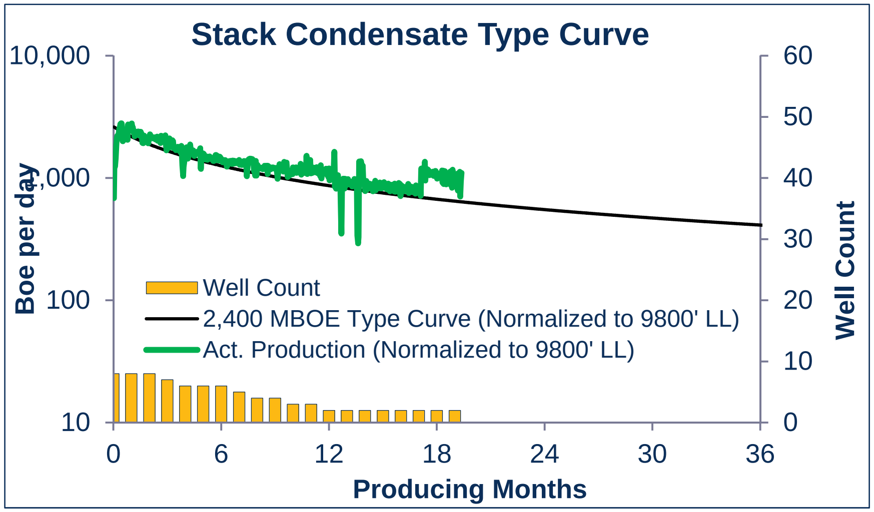

CLR Meramec producing wells · CLR Meramec wells drilling / completing · Industry Meramec well · Industry Rigs · CLR Rigs · CLR Leasehold

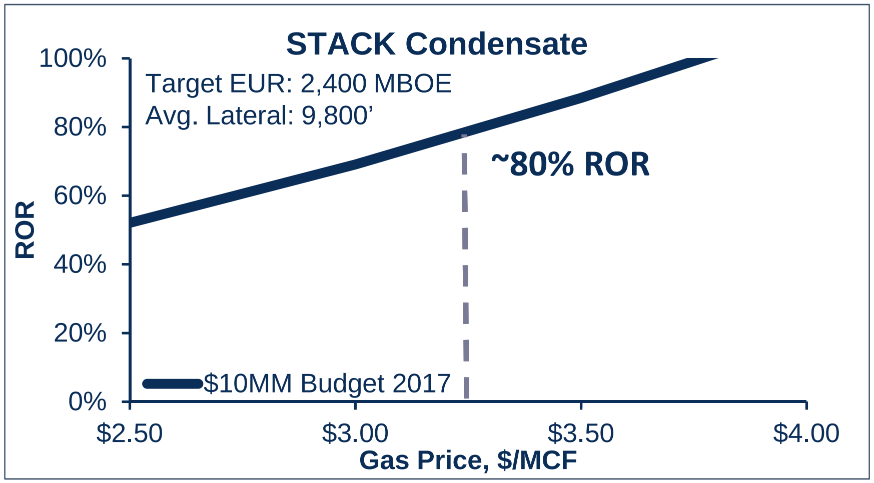
1. This is calculated by adding an additional 1,978 barrels of anticipated natural gas liquids post-processing

# STACK Condensate Type Curve Announced

**Condensate type curve: 2,400 MBoe EUR (14% oil)**

- ~80% ROR[(1)]
- Average 24-hour IP: 2,625 Boe
- $10 million CWC
- 9,800 foot lateral
- 8 well dataset



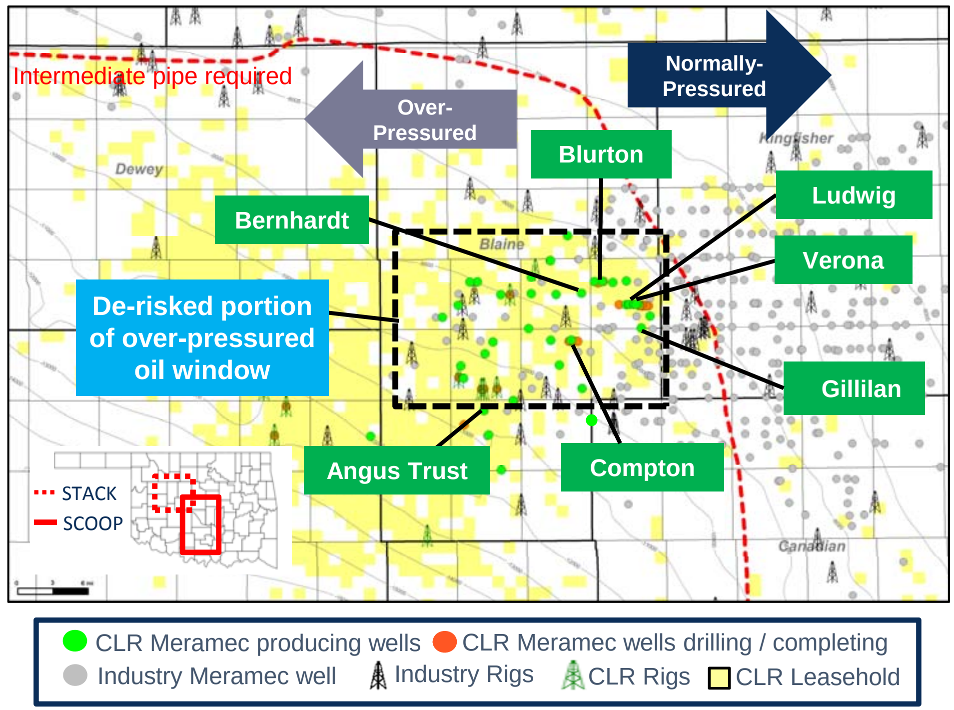




1. ROR is based on $50 WTI and $3.25 gas, see ROR footnote on slide 18

# CLR STACK Density Tests Ongoing

| Density Tests | Status | Meramec zones tested | # of wells per zone | Avg Lateral Length (ft) |
|---|---|---|---|---|
| Ludwig | Producing | Upper / Middle | 4 | 9,700 |
| Bernhardt | Producing | Lower | 5 | 4,860 |
| Blurton | Flowing back | Upper / Lower | 3 – 5 | 10,000 |
| Compton | Completing | Upper / Lower | 5 | 9,800[1] |
| Gillilan | Completing | Upper / Lower | 5 | 9,800[1] |
| Verona | Completing | Upper / Lower | 4 | 9,800[1] |
| Angus Trust | Drilling | Upper / Lower | 6 | 9,800[1] |

## ~47,000 net acres under development (~55 op units)




## Blurton Results (announced August 8, 2017)

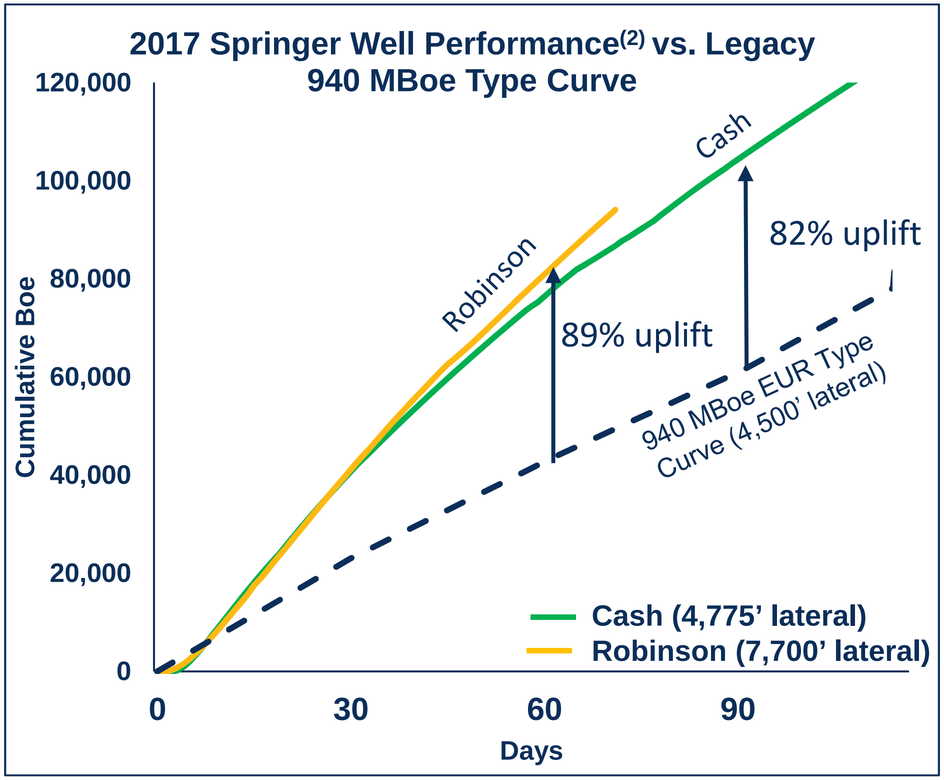
- In early stages of flow back and not reached peak IP rates
- To date, 8 wells have a combined 24-hour IP rate of 10,514 Boe (78% oil)
- At day 22, the 7 density wells are producing at average rates ~80% of the parent well

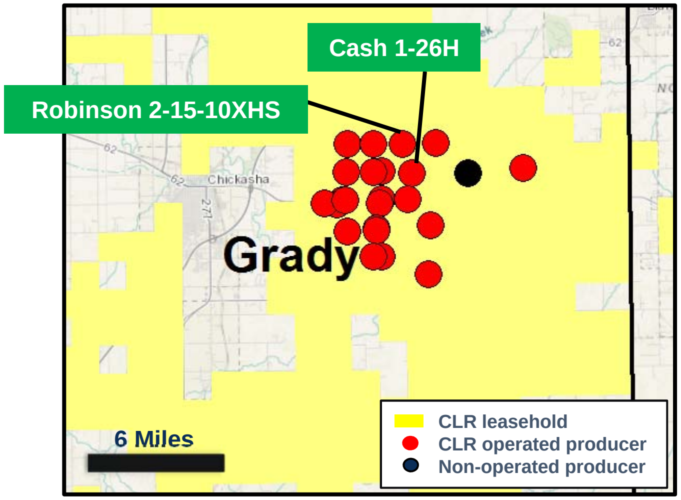
1. Planned lateral lengths

# SCOOP Springer: New Wells Outperforming Legacy Type Curve by Over 80%

**2Q'17 Completion: Robinson 2-15-10XHS**
- 1,636 Boepd 24 hour IP (82% oil)
- 89% uplift to legacy 940 MBoe at 60 days

**1Q'17 Completion update: Cash 1-26H**
- 1,691 Boepd 24 hour IP (84% oil)
- 82% uplift to legacy 940Mboe at 90 days
- 100% ROR[1]
- $7.6 million CWC
- 1,160 MBoe EUR



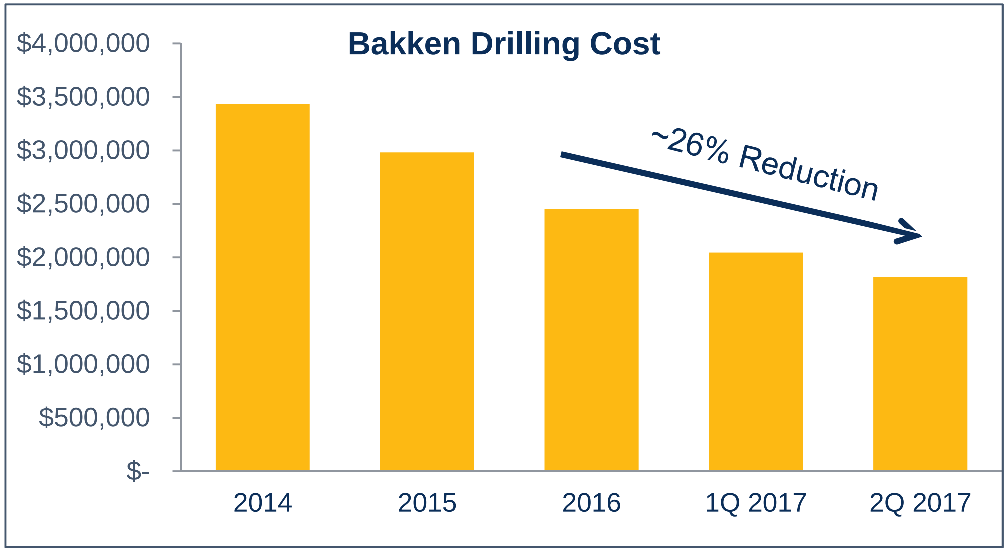



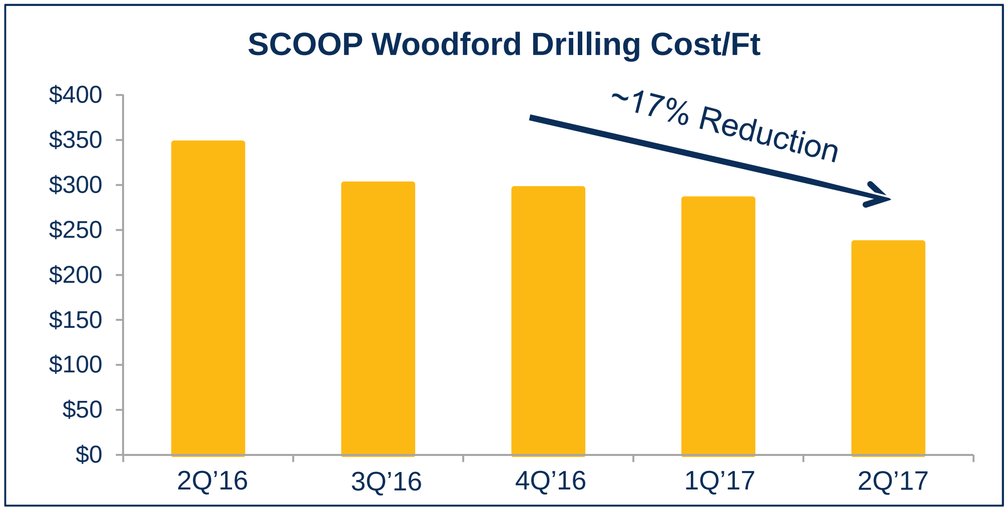

**Activity to continue in 2017**
- 6 well-density pilot underway (Celesta Unit)
- Targeting Q4 2017 completion

1. ROR is based on $50 WTI and $3.25 gas, see ROR footnote on slide 18
2. Actual production without normalization to a 4,500' lateral

# Operational Efficiencies Continue to Drive Drilling Costs Down

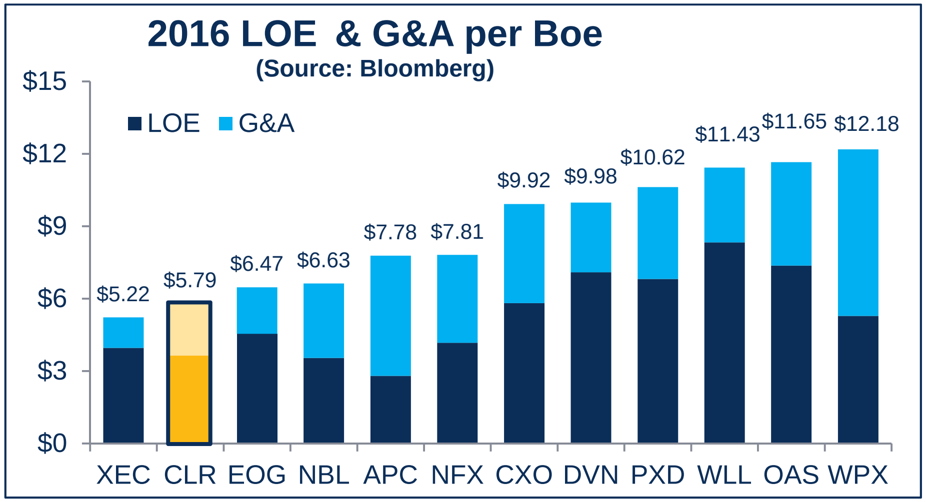
- Bakken: down 26% from 2016 average
- STACK condensate: down 13% from 2016 average
- SCOOP Woodford : down 17% from 4Q'16 ($/foot)
- SCOOP Springer: down 33% from 2015 average (Cash 1-26H)

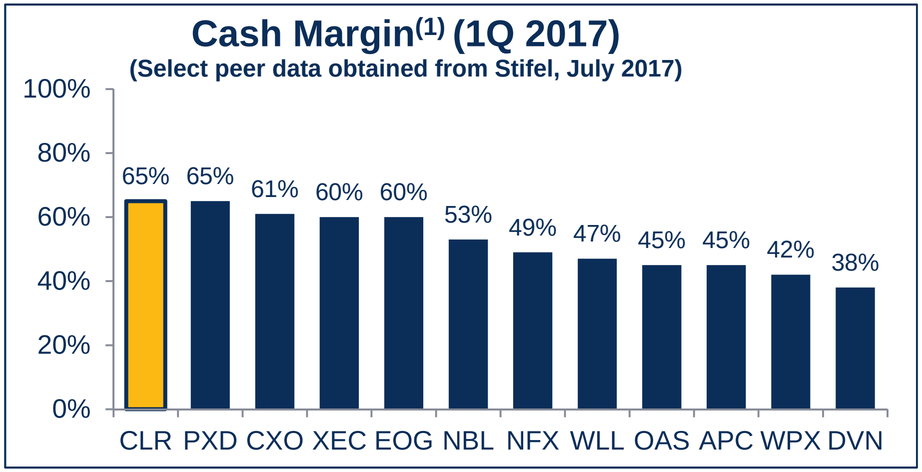


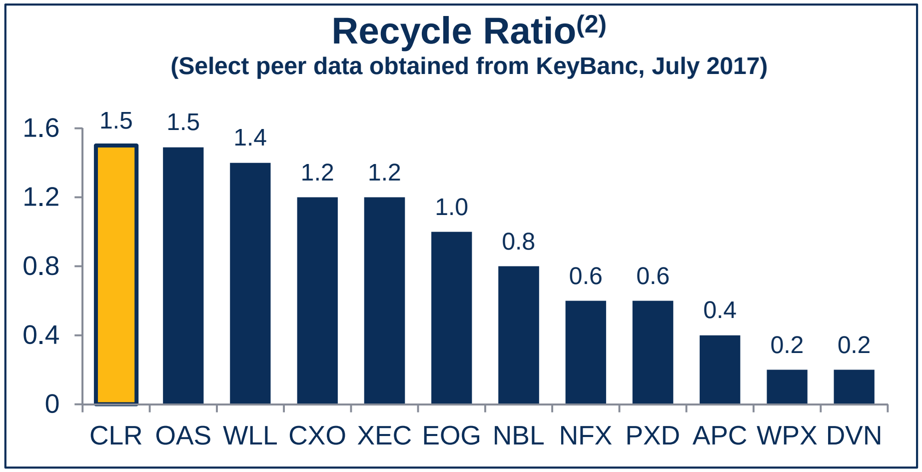



# CLR Superior Assets and Operating Efficiencies Translating to Bottom Line

## Peer-leading cost metrics driven by continued technical innovation




1. See "Continuing to Deliver Strong Margins" on slide 19 for details on CLR's method for calculating margin. Peer company margin data was obtained from Stifel and may not be determined in a comparable manner to CLR's margin calculation.
2. Recycle ratio = ((Sum of 3-year unhedged oil and gas revenues less production costs and G&A)/(3 year production))/ 3 year F&D per unit

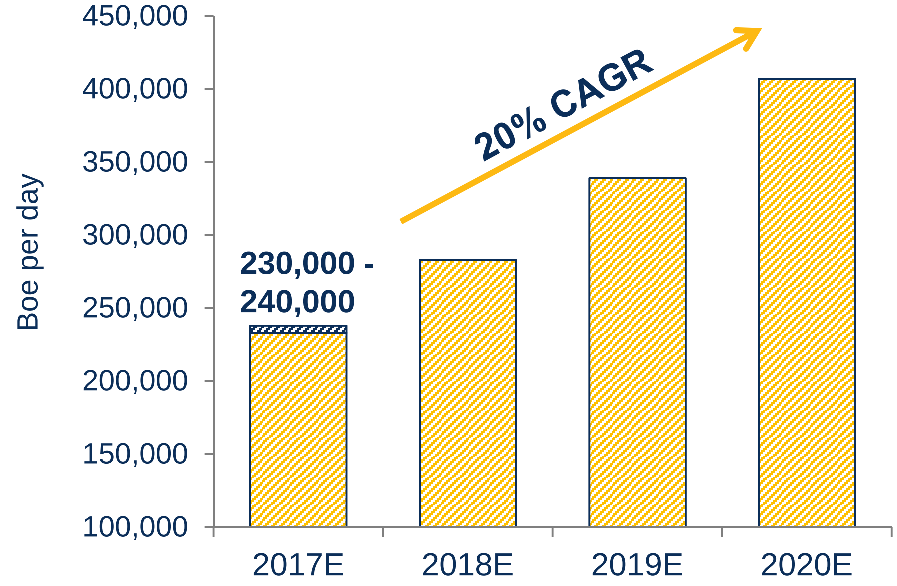
# CLR Strategy Going Forward

**Disciplined growth within cash flow**

**Reduce debt (LT target: $5 billion)**

**Continue optimizing performance of all assets**

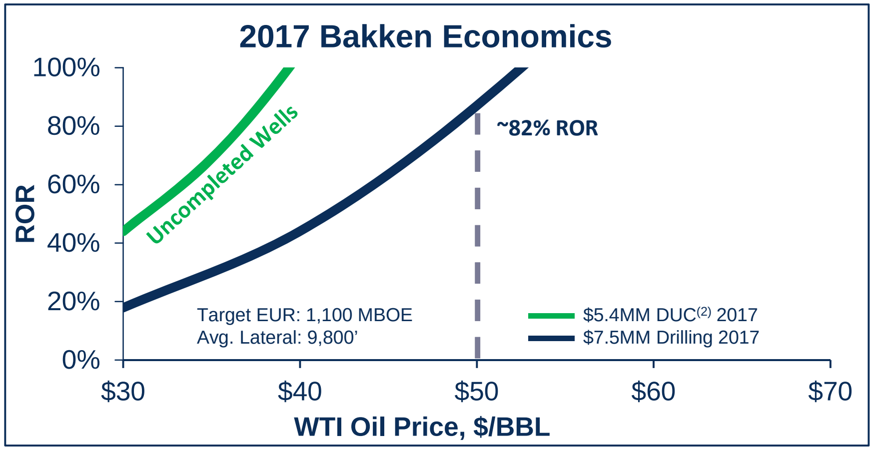
**Capable to deliver 20% growth**
**(Cash neutral at $50-$55 WTI)**

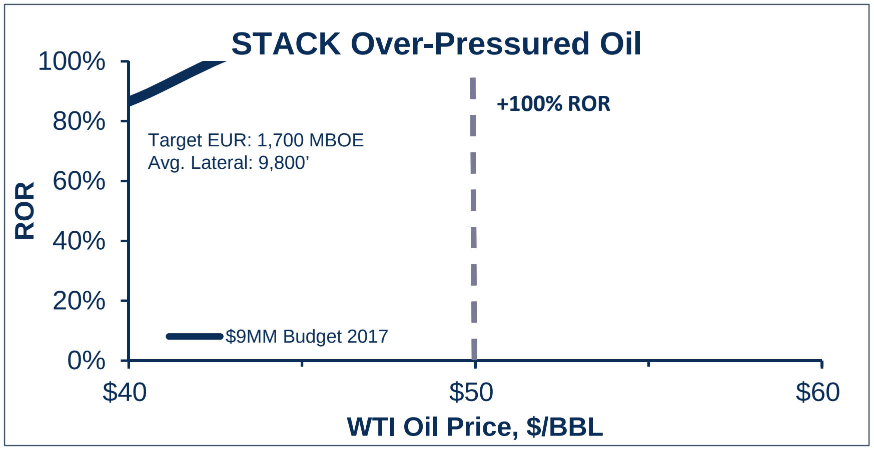


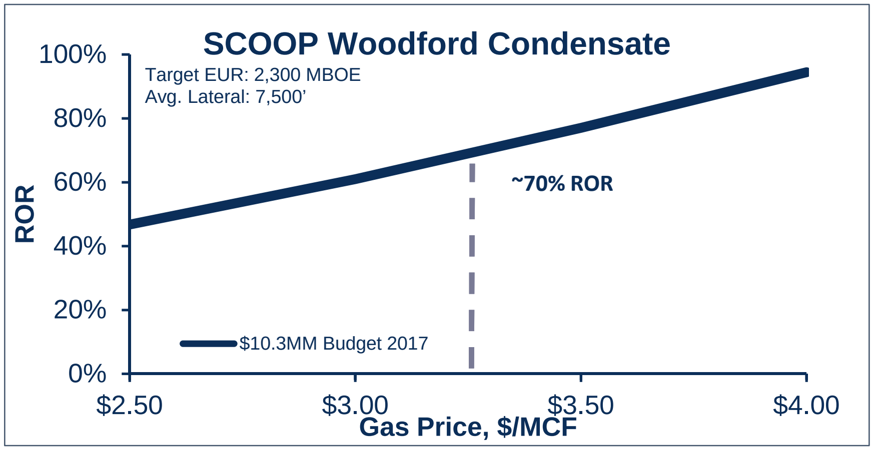

**Debt targets: $6 billion $5 billion**

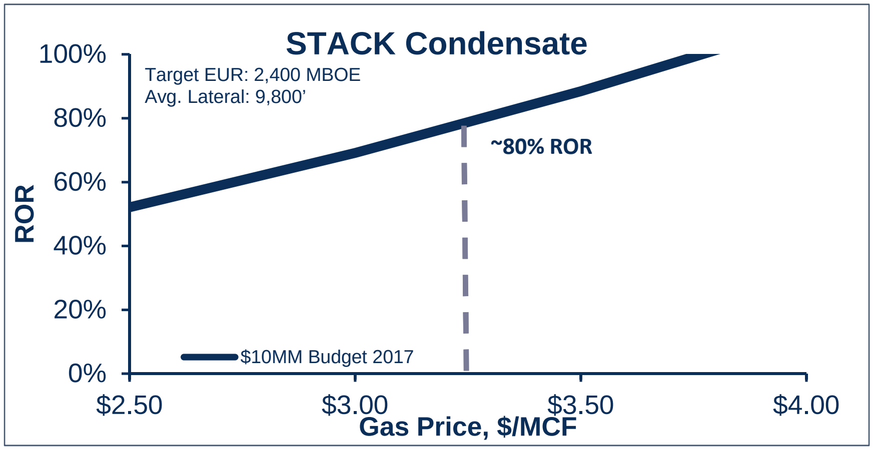
# APPENDIX

# CLR Assets Deliver Excellent Rates of Return[1]




1. Pre-tax rate of return (ROR) is based on projected cash flow and time value of money; costs include completed well cost, production expense, severance tax and variable operating costs. $3.25 gas is the wellhead price and used for oil price sensitivities and $50 WTI is used for gas price sensitivities. The description of the ROR calculation applies to any ROR reference appearing in this presentation.
2. $5.4 MM gross cost forward incremental completion cost

# Continuing to Deliver Strong Margins[(1)]

| | 2012 | 2013 | 2014 | 2015 | 2016 | 1Q 2017 | 2Q 2017 |
|---|---|---|---|---|---|---|---|
| Realized oil price ($/Bbl) | $84.59 | $89.93 | $81.26 | $40.50 | $35.51 | $44.69 | $41.91 |
| Realized natural gas price ($/Mcf) | $3.73 | $4.87 | $5.40 | $2.31 | $1.87 | $3.00 | $2.63 |
| Oil production (Bopd) | 68,497 | 95,859 | 121,999 | 146,622 | 128,005 | 119,201 | 125,381 |
| Natural gas production (Mcfpd) | 174,521 | 240,355 | 313,137 | 450,558 | 533,442 | 567,328 | 604,991 |
| Total production (Boepd) | 97,583 | 135,919 | 174,189 | 221,715 | 216,912 | 213,755 | 226,213 |
| EBITDAX ($000's)[(2)] | $1,963,123 | $2,839,510 | $3,776,051 | $1,978,896 | $1,881,889 | $482,472 | $479,490 |
| **Key Operational Statistics (per Boe)[(3)]** | | | | | | | |
| Average oil equivalent price (excludes derivatives) | $65.99 | $72.04 | $66.53 | $31.48 | $25.55 | $32.90 | $30.31 |
| Production expense | $5.49 | $5.69 | $5.58 | $4.30 | $3.65 | $3.78 | $3.99 |
| Production tax and other | $5.58 | $6.02 | $5.54 | $2.47 | $1.79 | $2.14 | $2.03 |
| Cash G&A[(4)] | $2.38 | $2.07 | $2.06 | $1.70 | $1.53 | $1.86 | $1.45 |
| Interest | $3.95 | $4.74 | $4.49 | $3.86 | $4.04 | $3.69 | $3.52 |
| **Total of selected costs** | **$17.40** | **$18.52** | **$17.67** | **$12.33** | **$11.01** | **$11.47** | **$10.99** |
| **Margin[(1)]** | **$48.59** | **$53.52** | **$48.86** | **$19.15** | **$14.54** | **$21.43** | **$19.32** |
| **Margin %** | **74%** | **74%** | **73%** | **61%** | **57%** | **65%** | **64%** |

1. Margin represents the Company's average sales price for a period expressed in barrels of oil equivalent (Boe) less production expenses, production taxes, G&A expenses (exclusive of non-cash equity compensation expenses), and interest expense, all expressed on a per-Boe basis. Margin does not reflect all activities of the Company that give rise to cash inflows and outflows and specifically excludes income and costs associated with derivative settlements, service operations, exploration activities, asset dispositions, and various non-operating activities. These items are excluded from the computation of Margin because they can vary significantly from period to period in a manner that does not correlate with changes in the Company's production and sales volumes. Therefore, these items are not typically utilized by management on a per-Boe basis in assessing the performance of the Company's E&P operations from period to period.
2. See "EBITDAX reconciliation to GAAP" on slide 21 for a reconciliation of GAAP net income and net cash provided by operating activities to EBITDAX, which is a non-GAAP measure.
3. Average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.
4. See "Cash G&A Reconciliation to GAAP" on slide 23 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure.

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# EBITDAX Reconciliation to GAAP

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings (net income (loss)) before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income (loss) or net cash provided by operating activities as determined by GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income (loss) and net cash provided by operating activities in arriving at EBITDAX because those amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

See the following page for reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the applicable periods.

# EBITDAX Reconciliation to GAAP

**The following tables provide reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the periods presented:**

| *In thousands* | 2012 | 2013 | 2014 | 2015 | 2016 | 2Q 2017 |
|---|---|---|---|---|---|---|
| Net income (loss) | $ 739,385 | $ 764,219 | $ 977,341 | $ (353,668) | $ (399,679) | $ (63,557) |
| Interest expense | 140,708 | 235,275 | 283,928 | 313,079 | 320,562 | 72,744 |
| Provision (benefit) for income taxes | 415,811 | 448,830 | 584,697 | (181,417) | (232,775) | (37,855) |
| Depreciation, depletion, amortization and accretion | 692,118 | 965,645 | 1,358,669 | 1,749,056 | 1,708,744 | 395,770 |
| Property impairments | 122,274 | 220,508 | 616,888 | 402,131 | 237,292 | 123,316 |
| Exploration expenses | 23,507 | 34,947 | 50,067 | 19,413 | 16,972 | 3,204 |
| Impact from derivative instruments: | | | | | | |
| Total (gain) loss on derivatives, net | (154,016) | 191,751 | (559,759) | (91,085) | 67,099 | (27,109) |
| Total cash received (paid), net | (45,721) | (61,555) | 385,350 | 69,553 | 89,522 | 3,844 |
| Non-cash (gain) loss on derivatives, net | (199,737) | 130,196 | (174,409) | (21,532) | 156,621 | (23,265) |
| Non-cash equity compensation | 29,057 | 39,890 | 54,353 | 51,834 | 48,097 | 9,133 |
| Loss on extinguishment of debt | -- | -- | 24,517 | -- | 26,055 | -- |
| EBITDAX (non-GAAP) | $ 1,963,123 | $ 2,839,510 | $ 3,776,051 | $ 1,978,896 | $ 1,881,889 | $ 479,490 |

| *In thousands* | 2012 | 2013 | 2014 | 2015 | 2016 | 2Q 2017 |
|---|---|---|---|---|---|---|
| Net cash provided by operating activities | $ 1,632,065 | $ 2,563,295 | $ 3,355,715 | $ 1,857,101 | $ 1,125,919 | $ 446,371 |
| Current income tax provision (benefit) | 10,517 | 6,209 | 20 | 24 | (22,939) | - |
| Interest expense | 140,708 | 235,275 | 283,928 | 313,079 | 320,562 | 72,744 |
| Exploration expenses, excluding dry hole costs | 22,740 | 25,597 | 26,388 | 11,032 | 12,106 | 3,204 |
| Gain on sale of assets, net | 136,047 | 88 | 600 | 23,149 | 304,489 | 780 |
| Tax benefit (deficiency) from stock-based compensation | 15,618 | -- | -- | 13,177 | (9,828) | -- |
| Other, net | (7,587) | (1,829) | (17,279) | (10,044) | (10,636) | 353 |
| Changes in assets and liabilities | 13,015 | 10,875 | 126,679 | (228,622) | 162,216 | (43,962) |
| EBITDAX (non-GAAP) | $ 1,963,123 | $ 2,839,510 | $ 3,776,051 | $ 1,978,896 | $ 1,881,889 | $ 479,490 |

# ADJUSTED Earnings Reconciliation to GAAP

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments, gains and losses on asset sales, and losses on extinguishment of debt. Management believes these measures provide useful information to analysts and investors for analysis of our operating results. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following table reconciles earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

| | 2Q 2017 | | 2Q 2016 | | 1H 2017 | | 1H 2016 | |
|---|---|---|---|---|---|---|---|---|
| *In thousands, except per share data* | $ | Diluted EPS | $ | Diluted EPS | $ | Diluted EPS | $ | Diluted EPS |
| Net income (loss) (GAAP)[1] | $ (63,557) | $ (0.17) | $ (119,402) | $ (0.32) | $ (63,088) | $ (0.17) | $ (317,727) | $ (0.86) |
| Adjustments: | | | | | | | | |
| Non-cash (gain) loss on derivatives | (23,265) | | 116,835 | | (68,420) | | 114,972 | |
| Property impairments | 123,316 | | 66,112 | | 174,689 | | 145,039 | |
| (Gain) Loss on sale of assets | (780) | | (96,907) | | 2,859 | | (97,016) | |
| Total tax effect of adjustments | (37,515) | | (32,548) | | (41,061) | | (61,646) | |
| Total adjustments, net of tax | 61,756 | 0.17 | 53,492 | 0.14 | 68,067 | 0.18 | 101,349 | 0.28 |
| Adjusted net income (loss) (Non-GAAP) | $ (1,801) | $ - | $ (65,910) | $ (0.18) | $ 4,979 | $ 0.01 | $ (216,378) | $ (0.58) |
| Weighted average diluted shares outstanding | 371,111 | | 370,435 | | 373,518 | | 370,248 | |
| Adjusted diluted net income (loss) per share (Non-GAAP) | $ - | | $ (0.18) | | $ 0.01 | | $ (0.58) | |

1. In 1Q 2017 we adopted ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which requires, among other things, that companies recognize excess tax benefits and deficiencies from stock-based compensation as income tax benefit or expense in the income statement rather than through additional paid-in capital. This change resulted in a $3.8 million ($0.01 per diluted share) increase in net loss for YTD 2017 with no comparable impact in the prior period.

# Cash G&A Reconciliation to GAAP

Our presentation of cash general and administrative ("G&A") expenses per Boe is a non-GAAP measure. We define cash G&A per Boe as total G&A determined in accordance with U.S. GAAP less non-cash equity compensation expenses and corporate relocation expenses, expressed on a per-Boe basis. We report and provide guidance on cash G&A per Boe because we believe this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes cash G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Cash G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

The following table reconciles total G&A per Boe as determined under U.S. GAAP to cash G&A per Boe for the periods presented.

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2Q 2017 | 2017 Guidance |
|---|---|---|---|---|---|---|---|
| Total G&A per Boe (GAAP) | $3.42 | $2.91 | $2.92 | $2.34 | $2.14 | $1.89 | $1.85 - $2.35 |
| Less: Non-cash equity compensation per Boe | ($0.82) | ($0.80) | ($0.86) | ($0.64) | ($0.61) | ($0.44) | ($0.50) – ($0.60) |
| Less: Relocation expenses per Boe | ($0.22) | ($0.04) | - | - | - | - | - |
| Cash G&A per Boe (non-GAAP) | $2.38 | $2.07 | $2.06 | $1.70 | $1.53 | $1.45 | $1.35 - $1.75 |