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, 2015, 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.
2Q 2016 Highlights

Updating guidance due to strong outperformance
- Full-year production guidance raised to 210,000 to 220,000 Boe per day
- Exit rate production guidance raised to 195,000 to 205,000 Boe per day
- Production expense lowered to $3.75 to $4.25 per Boe
- Total G&A (cash and non-cash) lowered to $1.85 to $2.45 per Boe
- NYMEX WTI crude oil differential lowered to ($7.00) to ($8.00) per Bo

$613 million in divestitures announced YTD – non-strategic asset sales, with proceeds to be applied to reduce debt

Excellent results extend over-pressured STACK oil window west
- Madeline 1-9-4XH IP: 3,538 Boe per day (71% oil), 9,600’ lateral
- Frankie Jo 1-25-24XH: IP 2,627 Boe per day (56% oil), 9,700’ lateral

Enhanced completions uplift SCOOP Woodford oil EURs by ~30%
- 1.3 MMBoe EUR (62% oil) for 9,800-foot lateral
- 32% ROR at $9.8 million CWC, $45 WTI and $2.50 gas

Operational efficiencies continue to translate to the bottom line
- STACK oil window target CWC down $500,000 to $9.0 million
- Production expense down 13% over 2015 average and down 33% over 2014 average
CLR Capital Efficiency Taken to New Level
Structural Improvement Since 2014

From FY 2014 to 1H 2016:
• Combined Production and Cash G&A$^{(1)}$ costs DOWN 36%

From FY 2014 to FY 2016 target:
• EUR per operated well UP 70%
• Capital efficiency$^{(2)}$ (Boe/$ invested) UP 133%

---

1. See "Cash G&A Reconciliation to GAAP" on slide 37 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure
2. Average net revenue interest of 82% assumed for net capital efficiency
   Note: Capital efficiency based on reserves developed per dollar invested
CLR Lowest Among Select Peers
(As of 2Q 2016)

Peers include: CXO, DVN, EOG, NBL, NFX, OAS, PXD, WLL, WPX and XEC

Note: Production expense for peer group excludes gathering and transportation expense; cash G&A excludes equity based compensation
Source: GMP Securities, August 2016

1. See “Cash G&A Reconciliation to GAAP” on slide 37 for a reconciliation of CLR GAAP Total G&A per Boe to CLR Cash G&A per Boe, which is a non-GAAP measure
CLR Positioned for Industry-Leading Growth

**Key Strengths**

- Top quartile assets in U.S. (1)
- Capital efficiency more than doubled since 2014(2)
- Lowest production expense per Boe among select oil-weighted peers(3)

**Key Catalysts**

<table>
<thead>
<tr>
<th>STACK Meramec</th>
<th>Adds up to 25% to CLR net unrisked resource potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bakken DUCs</td>
<td>~190 gross operated wells at YE 2016, ~850 MBoe average EUR per well</td>
</tr>
<tr>
<td>Bakken core</td>
<td>10+ years of drilling ~775 MBoe average per well (assuming 15 rigs)</td>
</tr>
<tr>
<td>SCOOP Springer</td>
<td>Oil asset ready for full-field development</td>
</tr>
<tr>
<td>Enhanced completions</td>
<td>Improving well performance in all plays</td>
</tr>
<tr>
<td>19 operated rigs</td>
<td>Maintained momentum and grew expertise during the last 18 months</td>
</tr>
<tr>
<td>Strong balance sheet</td>
<td>Ample liquidity</td>
</tr>
</tbody>
</table>

1. See slide 7 for supporting detail
2. See slide 4 for supporting detail
3. See slide 5 for supporting detail
CLR Assets Are in Top Quartile of U.S. Plays
It All Comes Down to the Rocks

Single Well Breakeven For North American Oil Plays(1)

1. To generate a 10% after-tax IRR

Source: Evercore ISI, January 2016

Note: Post announced sales the Company will retain ~384,000 net acres in SCOOP Woodford, ~191,000 net acres in SCOOP Springer and ~905,000 net acres in Bakken
Top-Tier Rates of Return\(^{(1)}\)

**STACK Over-Pressured Oil**
- Target EUR: 1,700 MBoe
- Avg. Lateral: 9,800’
- ~70% ROR at $40 WTI Oil Price, $BBL
- ~100% ROR at $50 WTI Oil Price, $BBL

**SCOOP Woodford Condensate**
- Target Enhanced Completion EUR: 2,000 MBoe
- Historic EUR: 1,725 MBoe
- Avg. Lateral: 7,500’
- ~45% ROR at $2 Gas Price, $/Mcf

**ND Bakken**
- Avg. Lateral: 9,800’
- DUCs: ~70% ROR at $40 WTI Oil Price, $BBL
- 850 MBoe: $3.5MM Completion cost \(^{(2)}\)
- 900 MBoe: $6.0MM Target 2016
- 800 MBoe: $6.8MM YE 2015
- ~40% ROR at $50 WTI Oil Price, $BBL
- ~20% ROR at $30 WTI Oil Price, $BBL

**NW Cana JDA\(^{(3)}\)**
- Target EUR: 2,150 MBoe
- Avg. Lateral: 9,800’
- ~80% ROR at $3 Gas Price, $/Mcf

---

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. $2.50 gas is used for oil price sensitivities and $45 WTI is used for gas price sensitivities. The description of the ROR calculation applies to any ROR reference appearing in this presentation.
2. Estimated ~190 gross operated DUC's at YE 2016, $3.5MM gross incremental completion cost
3. NW Cana economics factor in a ~50% carry from JDA participant
SCOOP & STACK
Leading Acreage Positions in Top-Tier Plays

~970,000 Net Reservoir Acres

STACK Meramec/Osage
~183,000 Net Acres

STACK Woodford
~168,000 Net Acres

SCOOP Woodford
~413,000 Net Acres

SCOOP Springer
~206,000 Net Acres

Note: Post sale the Company will retain ~384,000 net acres in SCOOP Woodford and ~191,000 net acres in SCOOP Springer
STACK 2Q 2016 Results
Expanding Meramec’s Proven Productive Footprint

2 excellent step-out wells extend over-pressured oil window 17 miles west of Verona

2 confirmation wells completed near Verona

1 excellent gas producer completed 18 miles south of Verona

<table>
<thead>
<tr>
<th>Over-pressured oil window</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Well Name</td>
<td>IP (Boepd) / Flowing Pressure</td>
</tr>
<tr>
<td>Madeline 1-9-4XH</td>
<td>3,538 (71% oil) / 4,500 psi</td>
</tr>
<tr>
<td>Frankie Jo 1-25-24XH</td>
<td>2,627 (56% oil) / 4,320 psi</td>
</tr>
<tr>
<td>Gillilan 1-35-24XH</td>
<td>2,439 (70% oil) / 2,030 psi</td>
</tr>
<tr>
<td>Oppel 1-25-24XH</td>
<td>1,308 (76% oil) / 1,670 psi</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Over-pressured gas window</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Yocum 1-35-26XH</td>
<td>2,355 (99% gas) / 4,810 psi</td>
</tr>
</tbody>
</table>
STACK: Exceptional, Repeatable Meramec Results Competes with Best Oil Plays in U.S.

Data as of August 1, 2016

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Prod. Days</th>
<th>Cum. Production (MBoe)</th>
<th>Current Rate (Boepd)</th>
<th>Current Flowing Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boden(1)</td>
<td>241</td>
<td>361 (27% oil)</td>
<td>1236 (26% oil)</td>
<td>4215 psi</td>
</tr>
<tr>
<td>Ludwig(1)(2)</td>
<td>310</td>
<td>279 (74% oil)</td>
<td>767 (70% oil)</td>
<td>1575 psi</td>
</tr>
<tr>
<td>Compton(1)</td>
<td>209</td>
<td>221 (70% oil)</td>
<td>704 (68% oil)</td>
<td>1235 psi</td>
</tr>
<tr>
<td>Yocum</td>
<td>104</td>
<td>179 (99% gas)</td>
<td>1621 (99% gas)</td>
<td>2495 psi</td>
</tr>
<tr>
<td>Blurton(1)</td>
<td>204</td>
<td>176 (76% oil)</td>
<td>636 (74% oil)</td>
<td>1145 psi</td>
</tr>
<tr>
<td>Ladd(1)</td>
<td>284</td>
<td>171 (75% oil)</td>
<td>610 (72% oil)</td>
<td>1095 psi</td>
</tr>
<tr>
<td>Marks</td>
<td>327</td>
<td>144 (58% oil)</td>
<td>162 (52% oil)</td>
<td>710 psi</td>
</tr>
<tr>
<td>Foree</td>
<td>107</td>
<td>110 (60% oil)</td>
<td>713 (48% oil)</td>
<td>840 psi</td>
</tr>
<tr>
<td>Quintle(1)</td>
<td>98</td>
<td>109 (72% oil)</td>
<td>897 (69% oil)</td>
<td>930 psi</td>
</tr>
<tr>
<td>Bernhardt (1-mile)</td>
<td>99</td>
<td>45 (72% oil)</td>
<td>343 (71% oil)</td>
<td>605 psi</td>
</tr>
</tbody>
</table>

1. Wells not produced at maximum capacity
2. Current rates are prior to June 9, 2016 when well was shut in for stimulation for Ludwig density

CLR Completed Wells
With 90 days of production

- Blarton
- Bernhardt
- Foree
- Compton
- Boden
- Yocum
- Marks
- Quintle
- Ladd
- Ludwig

Fault > 300' vertical displacement

Normally-Pressured
Over-Pressured

Meramec

CLR Leasehold

Normally-Pressured

Lateral

CLR Leasehold

Industry Meramec 2 mi. Lateral / 1 mi. Lateral
CLR Meramec 2 mi. Lateral / 1 mi. Lateral

PROPERTY OF CONTINENTAL RESOURCES, INC. REPRODUCTION AND DISTRIBUTION ONLY WITH WRITTEN PERMISSION
STACK
Leasehold Position Increasing – Well Costs Decreasing

183,000 net acres
• +27,000 net acres over YE 2015

~95% of acreage in over-pressured window
• Reservoir 700’ – 1,200’ thick
• ~40% oil, ~40% liquids-rich, ~20% gas
• 60% HBP by YE 2016

Project over 1,200 potential net Meramec and Woodford drilling locations
• Targeting 2 Meramec zones on average, 1 Woodford zone
• 12 wells per 1,280-acre unit

Oil window CWC down 20% from 2015
• Target CWC $9.0 million, down $1 million from initial 2016 target
• Cycle times down 40% from 2015, ~27 days spud-to-TD

Current activity
• 6 rigs drilling Meramec
• 5 rigs drilling Woodford
• 3 density tests underway in oil window
STACK
Density Pilots in Over-Pressured Oil Window Underway

**Ludwig Density Pilot**
- Completion underway
- Drilling cost down 28% from parent well
- Enhanced completions
- Results expected 4Q 2016

**Bernhardt Density Pilot**
- Drilling commenced in 2Q 2016
- Enhanced completions
- Results expected late 2016/early 2017

**Blurton Density Pilot**
- Drilling commenced in late 2Q 2016
- Enhanced completions
- Results expected 2017

---

**Layers:**
- **Upper Meramec**
- **Middle Meramec**
- **Lower Meramec**
- **Osage**
- **Woodford**

**Drilling Symbols:**
- **Red**: New Well
- **Black**: Parent Well
SCOOP Woodford Condensate Growing Through Step-Outs and Enhanced Completions

**Enhanced completions increasing performance**
- Delivering 40% production uplifts
- Increased type curve EUR by 15% to 2,000 MBoe
- > 100% ROR for incremental capital of $400,000(1)
- ~50% more proppant per foot on average

4 rigs drilling

26 wells with > 90 days of production;
14 wells with > 180 days of production

---

1. When compared to offset production at $45 WTI and $2.50 natural gas

---

**Widespread, Repeatable Results**

180 days 40% higher than offsets

~60 miles

12 Miles

CLR Leased
CLR Enhanced Completion
Woodford HZ Producing Well
Gas
Condensate
Oil

PROPERTY OF CONTINENTAL RESOURCES, INC. REPRODUCTION AND DISTRIBUTION ONLY WITH WRITTEN PERMISSION
SCOOP Woodford Oil Enhanced Completions Increase EUR By ~30%

22 enhanced completions outperform legacy offsets

- ~30% increase in 180-day rate
- ~30% increase in EUR to 1.3 MMBoe per well (62% oil) for 9,800-foot lateral
- 32% ROR\(^{(1)}\) for $9.8 million CWC
- At least 50,000 net acres upgraded to new EUR model

1. Assumes $45 WTI and $2.50 natural gas
SCOOP Woodford
Pending Non-Strategic Asset Sale

PSA signed

$281 million sale price

~29,500 net acres
  • Non-strategic acreage

Current production of ~550 net Boepd

Minimal proved reserves (less than 1%)
Bakken
Focusing On the Core at Reduced Costs

Average EUR up 13% from 2015
• 2016 target average EUR: 900 MBoe per well\(^{(1)}\)
• 2015 average EUR: 800 MBoe per well\(^{(1)}\)

Enhanced CWC reduced to $6.2 million
• Down from $600,000\(^{(2)}\) from YE 2015
• Targeting $6.0 million by YE 2016

Valuable DUC\(^{(3)}\) inventory
• Projecting ~190 DUCs\(^{(4)}\) at YE 2016
• 850 MBoe average EUR
• $3.5 million incremental completion cost
• Over 100% ROR for incremental completion cost for DUCs at $45 WTI and $2.50 gas

---

1. Target EUR for 2015 and 2016 spuds, normalized to 9,800’ lateral
2. For two-mile laterals with 30-stages
3. DUCs are a gross operated number
4. Up from 135 DUCs at YE 2015

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Outlines of Productive Bakken and Three Forks Reservoirs

---

CLR Leasehold
2015 Operated Spuds
2016 Operated Spuds
Bakken
Pending Non-Strategic Asset Sale

PSA signed

$222 million sale price

80,000 net acres
  • Non-strategic acreage
  • 68,000 net acres in Williams County, North Dakota
  • 12,000 net acres in Roosevelt County, Montana

Current production of ~2,800 net Boepd

Minimal proved reserves (less than 1%)
Bakken
Capital Efficiency Taken to New Level

1. F&D Cost is computed by taking the CWC divided by Boe
2. CLR-Operated North Dakota MB, TF1 & TF2 wells spud in 2014, 2015 and 2016 Projected
3. Capital efficiency based on reserves developed per dollar invested
4. Average net revenue interest of 82% assumed for net F&D and net capital efficiency

F&D\(^{(1)}\) Costs per Boe Down 63%

Capital Efficiency\(^{(3)}\) Up 167%

19
Bakken Enhanced Completions Continue to Deliver

~25% to ~40% EUR uplift

Production Uplift
~60% Slickwater (54 Wells)
~45% Hybrid (72 Wells)

Average Standard Completion Offsetting Legacy Wells

Note: Enhanced Slickwater and Hybrid 30-stage Well Completions in Williams and McKenzie Counties
CLR Bakken Differentials Decreasing Through Increased Pipeline Capacity

Bakken Takeaway Capacity

~85% of CLR Bakken Barrels on Pipe

Energy Transfer DAPL Expected Online: YE2016 450,000 to 570,000 Bopd

Energy Transfer ETCOP Expected Online: YE2016 450,000 to 570,000 Bopd

North Dakota Pipeline Authority and CLR estimates
Low Costs\(^{(1)}\)
Competitively Positions CLR in Any Environment

1. Cash margin presented on this slide 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. Cash 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 cash 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. See “Continuing to Deliver Strong Margins” on slide 33 for additional details on the method for calculating cash margin.
2. See “Cash G&A Reconciliation to GAAP” on slide 37 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure.
3. Based on average oil equivalent price (excluding derivatives and including natural gas).
**Unsecured Credit Facility**
- **Ample liquidity** with $2.75 billion revolver and ability to upsize to $4.0 billion\(^1\)
- ~$1.93 billion available on revolver as of July 31, 2016
- No borrowing base redetermination
- 2-year extension option beyond 2019\(^1\)

**Financial Strength**
- No near-term debt maturities (Earliest is $500 million in 11/2018)
- 4.3% average interest rate

---

**Financial Metrics\(^2\)**

<table>
<thead>
<tr>
<th>Net Debt(^3)/2Q 2016 Annualized EBITDAX(^4)</th>
<th>3.38x</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Debt(^3)/YE 2015 Proved Reserves</td>
<td>$5.82</td>
</tr>
</tbody>
</table>

---

**Debt Maturities Summary**

- No maturities for ~2+ years

### Debt Maturities Breakdown

- **2016:** Revolver Balance 7/31/16
- **2017:** Callable 10/1/15
- **2018:** Callable 4/1/16
- **2019:** Callable 3/15/17
- **2020:** Callable 5/15/19
- **2021:** Callable 7/15/21
- **2022:** Callable 10/15/22
- **2023:** Callable 1/15/23
- **2024:** Callable 4/15/24
- **2025:** Callable 7/15/25

---

1. With lender consent
2. All ratios are as of 6/30/16, except where noted
3. Net Debt is a non-GAAP measure and represents the total face value of debt of $7.2 billion plus outstanding letters of credit of $0.5 million, less cash and cash equivalents of $16.6 million as determined under GAAP
4. See appendix for reconciliation of GAAP net income and net cash provided by operating activities to EBITDAX, which is a non-GAAP measure
Continental’s Strategy Moving Forward

- Disciplined growth based on sustainable crude oil supply/demand fundamentals and price
- WTI above $37: Strengthen balance sheet first
- Mid-to-upper $40s: Consider working down Bakken DUCs and reduce debt further
- At $60+: Consider adding drilling rigs

Pay Down Debt

DUC Completions

Add Rigs

$37 WTI (cash flow neutral)

$40

$50

$60

$70 WTI
### Updated 2016 Guidance

<table>
<thead>
<tr>
<th>Production &amp; Capital</th>
<th>Updated 2016 Guidance</th>
<th>Previous 2016 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (Boe per day)</td>
<td>210,000 - 220,000</td>
<td>205,000 – 215,000</td>
</tr>
<tr>
<td>Capital expenditures (non-acquisition)</td>
<td>$920 million</td>
<td>$920 million</td>
</tr>
</tbody>
</table>

### Operating Expenses

<table>
<thead>
<tr>
<th></th>
<th>Updated 2016 Guidance</th>
<th>Previous 2016 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production expense ($ per Boe)</td>
<td>$3.75 - $4.25</td>
<td>$4.25 - $4.75</td>
</tr>
<tr>
<td>Production tax (% of oil &amp; gas revenue)</td>
<td>6.75% - 7.25%</td>
<td>6.75% - 7.25%</td>
</tr>
<tr>
<td>Cash G&amp;A expense(1) ($ per Boe)</td>
<td>$1.20 - $1.60</td>
<td>$1.25 - $1.75</td>
</tr>
<tr>
<td>Non-cash equity compensation ($ per Boe)</td>
<td>$0.65 - $0.85</td>
<td>$0.65 - $0.85</td>
</tr>
<tr>
<td>DD&amp;A ($ per Boe)</td>
<td>$20.00 - $22.00</td>
<td>$20.00 - $22.00</td>
</tr>
</tbody>
</table>

### Average Price Differentials

<table>
<thead>
<tr>
<th></th>
<th>Updated 2016 Guidance</th>
<th>Previous 2016 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYMEX WTI crude oil ($ per barrel of oil)</td>
<td>($7.00) - ($8.00)</td>
<td>($7.00) - ($9.00)</td>
</tr>
<tr>
<td>Henry Hub natural gas(2) ($ per Mcf)</td>
<td>$0.00 - ($0.65)</td>
<td>$0.00 - ($0.65)</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Income tax rate</td>
<td>38%</td>
<td>38%</td>
</tr>
<tr>
<td>Deferred taxes</td>
<td>90% - 95%</td>
<td>90% - 95%</td>
</tr>
</tbody>
</table>

Bolded item above in guidance denotes a change from the previous disclosure

1. See “Cash G&A Reconciliation to GAAP” on slide 37 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure
2. Includes natural gas liquids production in differential range
J. Warren Henry  
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**Website:**  
www.CLR.com/Investors
REFERENCE MATERIALS
Historical Organic Growth

Targeting 210,000 to 220,000 Boe per Day Average in 2016

Total Proved Reserves Down 9% YOY with 47% Reduction in WTI Prices

For 2Q 2016:
- Natural Gas: 39%
- Oil: 61%

For YE 2015:
- Natural Gas: 43%
- Oil: 57%
Boden-Yocum Unique Results Defined by Fault

- Yocum designed to test down-thrown side of fault identified from 3D seismic east of Boden
- Up to 525’ of vertical displacement on fault
- Boden on up-thrown side of fault in condensate window
- Yocum on down-thrown side of fault in gas window
- Only fault of this magnitude identified by 3D seismic/well control that could influence production
- Results increase acreage in gas window by 2%
SCOOP Woodford
Condensate Window Density Projects – Strong Repeatable Results

1. Normalized to 7,500’ lateral
SCOOP Springer Oil Asset Waiting for Higher Prices

Historical results in line with 940 MBoe type curve

<table>
<thead>
<tr>
<th>WELL COUNT</th>
<th>TYPE CURVE (NORMALIZED TO 4,500’ LL)</th>
<th>ACT. PRODUCTION (NORMALIZED TO 4,500’)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10,000</td>
<td>1,000</td>
<td>100</td>
</tr>
<tr>
<td>1,000</td>
<td>100</td>
<td>100</td>
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<tr>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>10</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

Boe Per day vs. Producing Months

Springer ROR

Target EUR: 940 MBoe
Avg. Lateral: 4,500’

<table>
<thead>
<tr>
<th>ROR (%)</th>
<th>$30</th>
<th>$40</th>
<th>$50</th>
<th>$60</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>20%</td>
<td>40%</td>
<td>60%</td>
<td>80%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WTI Oil Price, $/BBL</th>
<th>$7.0MM Target 2016</th>
<th>$7.8MM YE 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>20%</td>
<td>40%</td>
</tr>
<tr>
<td>20%</td>
<td>40%</td>
<td>60%</td>
</tr>
<tr>
<td>40%</td>
<td>60%</td>
<td>80%</td>
</tr>
</tbody>
</table>

Untested upside
- Longer laterals – 7,500’ to 10,000’
- Enhanced completions
# Continuing to Deliver Strong Margins\(^{(1)}\)

<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Realized oil price ($/Bbl)</td>
<td>$54.44</td>
<td>$70.69</td>
<td>$88.51</td>
<td>$84.59</td>
<td>$89.93</td>
<td>$81.26</td>
<td>$40.50</td>
<td>$38.38</td>
</tr>
<tr>
<td>Realized natural gas price ($/Mcf)</td>
<td>$2.95</td>
<td>$4.26</td>
<td>$4.87</td>
<td>$3.73</td>
<td>$4.87</td>
<td>$5.40</td>
<td>$2.31</td>
<td>$1.31</td>
</tr>
<tr>
<td>Oil production (Bopd)</td>
<td>27,459</td>
<td>32,385</td>
<td>45,121</td>
<td>68,497</td>
<td>95,859</td>
<td>121,999</td>
<td>146,622</td>
<td>133,044</td>
</tr>
<tr>
<td>Natural gas production (Mcfpd)</td>
<td>59,194</td>
<td>65,598</td>
<td>100,469</td>
<td>174,521</td>
<td>240,355</td>
<td>313,137</td>
<td>450,558</td>
<td>517,677</td>
</tr>
<tr>
<td>Total production (Boepd)</td>
<td>37,324</td>
<td>43,318</td>
<td>61,865</td>
<td>97,583</td>
<td>135,919</td>
<td>174,189</td>
<td>221,715</td>
<td>219,323</td>
</tr>
<tr>
<td>EBITDAX ($000's)(^{(2)})</td>
<td>$450,648</td>
<td>$810,877</td>
<td>$1,303,959</td>
<td>$1,963,123</td>
<td>$2,839,510</td>
<td>$3,776,051</td>
<td>$1,978,896</td>
<td>$528,109</td>
</tr>
</tbody>
</table>

### Key Operational Statistics (per Boe)\(^{(3)}\)

- **Average oil equivalent price (excludes derivatives)**: $44.68, $59.35, $72.45, $65.99, $72.04, $66.53, $31.48, $26.36
- **Production expense**: $6.89, $5.87, $6.13, $5.49, $5.69, $5.58, $4.30, $3.72
- **Production tax and other**: $2.95, $4.47, $5.82, $5.58, $6.02, $5.54, $2.47, $1.96
- **Cash G&A\(^{(4)}\)**: $2.19, $2.35, $2.36, $2.38, $2.07, $2.06, $1.70, $1.22
- **Interest**: $1.72, $3.34, $3.40, $3.95, $4.74, $4.49, $3.86, $4.11
- **Total of selected costs**: $13.75, $16.03, $17.71, $17.40, $18.52, $17.67, $12.33, $11.01
- **Cash margin\(^{(1)}\)**: $30.93, $43.32, $54.74, $48.59, $53.52, $48.86, $19.15, $15.35
- **Cash margin %**: 69%, 73%, 76%, 74%, 74%, 73%, 61%, 58%

1. Cash 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. Cash 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 cash 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 35 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 37 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure.
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 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.
The following tables provide reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the periods presented:

### EBITDAX Reconciliation to GAAP

**In thousands**

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2Q 2016</th>
<th>TTM at 6/30/16</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net income (loss)</strong></td>
<td>$71,338</td>
<td>$168,255</td>
<td>$429,072</td>
<td>$739,385</td>
<td>$764,219</td>
<td>$977,341</td>
<td>$(353,668)</td>
<td>$(119,402)</td>
<td>$(539,827)</td>
</tr>
<tr>
<td><strong>Interest expense</strong></td>
<td>23,232</td>
<td>53,147</td>
<td>76,722</td>
<td>140,708</td>
<td>235,275</td>
<td>283,928</td>
<td>313,079</td>
<td>81,922</td>
<td>322,449</td>
</tr>
<tr>
<td><strong>Provision (benefit) for income taxes</strong></td>
<td>38,670</td>
<td>90,212</td>
<td>258,373</td>
<td>415,811</td>
<td>448,830</td>
<td>584,697</td>
<td>(181,417)</td>
<td>(72,632)</td>
<td>(325,516)</td>
</tr>
<tr>
<td><strong>Depreciation, depletion, amortization and accretion</strong></td>
<td>83,694</td>
<td>64,951</td>
<td>108,458</td>
<td>122,274</td>
<td>220,508</td>
<td>616,888</td>
<td>402,131</td>
<td>66,112</td>
<td>322,737</td>
</tr>
<tr>
<td><strong>Exploration expenses</strong></td>
<td>12,615</td>
<td>12,763</td>
<td>27,920</td>
<td>23,507</td>
<td>34,947</td>
<td>50,067</td>
<td>19,413</td>
<td>1,674</td>
<td>9,703</td>
</tr>
<tr>
<td><strong>Impact from derivative instruments:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total cash received (paid), net</strong></td>
<td>569</td>
<td>35,495</td>
<td>30,049</td>
<td>191,751</td>
<td>385,350</td>
<td>69,553</td>
<td>110,903</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Non-cash (gain) loss on derivatives, net</strong></td>
<td>2,089</td>
<td>166,257</td>
<td>(4,057)</td>
<td>130,196</td>
<td>(174,409)</td>
<td>(21,532)</td>
<td>84,841</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Non-cash equity compensation</strong></td>
<td>11,408</td>
<td>11,691</td>
<td>16,572</td>
<td>39,890</td>
<td>54,353</td>
<td>51,834</td>
<td>11,839</td>
<td>45,452</td>
<td></td>
</tr>
<tr>
<td><strong>Loss on extinguishment of debt</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>EBITDAX (non-GAAP)</strong></td>
<td>$450,648</td>
<td>$372,986</td>
<td>$1,303,959</td>
<td>$1,963,123</td>
<td>$2,839,510</td>
<td>$3,776,051</td>
<td>$1,978,896</td>
<td>$528,109</td>
<td>$1,735,178</td>
</tr>
</tbody>
</table>

### EBITDAX Reconciliation to GAAP

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2Q 2016</th>
<th>TTM at 6/30/16</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net cash provided by operating activities</strong></td>
<td>$372,986</td>
<td>$653,167</td>
<td>$1,067,915</td>
<td>$1,632,065</td>
<td>$2,563,295</td>
<td>$3,355,715</td>
<td>$1,857,101</td>
<td>$218,819</td>
<td>$1,438,010</td>
</tr>
<tr>
<td><strong>Current income tax provision (benefit)</strong></td>
<td>2,551</td>
<td>12,853</td>
<td>13,170</td>
<td>10,517</td>
<td>6,209</td>
<td>20</td>
<td>6</td>
<td>26</td>
<td></td>
</tr>
<tr>
<td><strong>Interest expense</strong></td>
<td>23,232</td>
<td>53,147</td>
<td>76,722</td>
<td>140,708</td>
<td>235,275</td>
<td>283,928</td>
<td>313,079</td>
<td>81,922</td>
<td>322,449</td>
</tr>
<tr>
<td><strong>Depreciation, depletion, amortization and accretion</strong></td>
<td>6,138</td>
<td>9,739</td>
<td>19,971</td>
<td>22,740</td>
<td>25,597</td>
<td>26,388</td>
<td>11,032</td>
<td>1,468</td>
<td>9,119</td>
</tr>
<tr>
<td><strong>Gain on sale of assets, net</strong></td>
<td>709</td>
<td>29,588</td>
<td>20,838</td>
<td>136,047</td>
<td>88</td>
<td>600</td>
<td>23,149</td>
<td>96,907</td>
<td>97,522</td>
</tr>
<tr>
<td><strong>Excess tax benefit from stock-based compensation</strong></td>
<td>2,872</td>
<td>5,230</td>
<td>--</td>
<td>15,618</td>
<td>--</td>
<td>--</td>
<td>13,177</td>
<td>--</td>
<td>13,177</td>
</tr>
<tr>
<td><strong>Other, net</strong></td>
<td>(3,890)</td>
<td>(3,513)</td>
<td>(4,606)</td>
<td>(7,587)</td>
<td>(1,829)</td>
<td>(17,279)</td>
<td>(10,444)</td>
<td>(3,049)</td>
<td>(12,930)</td>
</tr>
<tr>
<td><strong>Changes in assets and liabilities</strong></td>
<td>46,050</td>
<td>50,666</td>
<td>109,949</td>
<td>13,015</td>
<td>10,875</td>
<td>126,679</td>
<td>(228,622)</td>
<td>132,036</td>
<td>(132,195)</td>
</tr>
<tr>
<td><strong>EBITDAX (non-GAAP)</strong></td>
<td>$450,648</td>
<td>$810,877</td>
<td>$1,303,959</td>
<td>$1,963,123</td>
<td>$2,839,510</td>
<td>$3,776,051</td>
<td>$1,978,896</td>
<td>$528,109</td>
<td>$1,735,178</td>
</tr>
</tbody>
</table>
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 and gains and losses on asset sales. 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 tables reconcile 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.

<table>
<thead>
<tr>
<th>in thousands, except per share data</th>
<th>2Q 2016</th>
<th>2Q 2015</th>
<th>1H 2016</th>
<th>1H 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income (loss) (GAAP)</td>
<td>$ (119,402)</td>
<td>$ 403</td>
<td>$(317,727)</td>
<td>$(131,568)</td>
</tr>
<tr>
<td>Adjustments:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-cash loss on derivatives</td>
<td>116,835</td>
<td>17,919</td>
<td>114,972</td>
<td>8,599</td>
</tr>
<tr>
<td>Property impairments</td>
<td>66,112</td>
<td>76,872</td>
<td>145,039</td>
<td>224,432</td>
</tr>
<tr>
<td>Gain on sale of assets</td>
<td>(96,907)</td>
<td>(20,573)</td>
<td>(97,016)</td>
<td>(22,643)</td>
</tr>
<tr>
<td>Total tax effect of adjustments</td>
<td>(32,548)</td>
<td>(26,171)</td>
<td>(61,646)</td>
<td>(64,189)</td>
</tr>
<tr>
<td>Total adjustments, net of tax</td>
<td>53,492</td>
<td>0.14</td>
<td>48,047</td>
<td>0.13</td>
</tr>
<tr>
<td>Adjusted net income (loss) (Non-GAAP)</td>
<td>$ (65,910)</td>
<td>$ 48,450</td>
<td>$ (216,378)</td>
<td>$ 14,631</td>
</tr>
<tr>
<td>Weighted average diluted shares outstanding</td>
<td>370,435</td>
<td>370,873</td>
<td>370,248</td>
<td>369,448</td>
</tr>
<tr>
<td>Adjusted diluted net income (loss) per share (Non-GAAP)</td>
<td>$ (0.18)</td>
<td>$ 0.13</td>
<td>$(0.58)</td>
<td>$0.04</td>
</tr>
</tbody>
</table>
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.

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Total G&amp;A per Boe (GAAP)</td>
<td>$3.03</td>
<td>$3.09</td>
<td>$3.23</td>
<td>$3.42</td>
<td>$2.91</td>
<td>$2.92</td>
<td>$2.34</td>
<td>$1.82</td>
<td>$1.68</td>
</tr>
<tr>
<td>Less: Non-cash equity compensation per Boe</td>
<td>($0.84)</td>
<td>($0.74)</td>
<td>($0.73)</td>
<td>($0.82)</td>
<td>($0.80)</td>
<td>($0.86)</td>
<td>($0.64)</td>
<td>($0.60)</td>
<td>($0.52)</td>
</tr>
<tr>
<td>Less: Relocation expenses per Boe</td>
<td>-</td>
<td>-</td>
<td>($0.14)</td>
<td>($0.22)</td>
<td>($0.04)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cash G&amp;A per Boe (non-GAAP)</td>
<td>$2.19</td>
<td>$2.35</td>
<td>$2.36</td>
<td>$2.38</td>
<td>$2.07</td>
<td>$2.06</td>
<td>$1.70</td>
<td>$1.22</td>
<td>$1.16</td>
</tr>
</tbody>
</table>