Forward Looking / Cautionary Statements – Certain Terms

This presentation contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding our expectations as to our future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- Value Creation Index (VCI) metrics, which are based on certain estimates including future production rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe assumptions or bases underlying our expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate but have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility
- insufficient cash flow to fund planned investments, debt repurchases or changes to our capital plan
- inability to enter desirable transactions, including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- joint ventures and acquisitions and our ability to achieve expected synergies
- the recoverability of resources and unexpected geologic conditions
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves
- changes in business strategy
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events
- factors discussed in “Risk Factors” in our Annual Report on Form 10-K available on our website at crc.com.

Words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" and similar words that reflect the prospective nature of events or outcomes typically identify forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

See the Investor Relations page at www.crc.com for important information about 3P reserves and other hydrocarbon resource quantities, organic finding and development (F&D) costs, organic recycle ratio calculations, original hydrocarbons in place, Value Creation Index (VCI), drilling locations and reconciliations of non-GAAP measures to the closest GAAP equivalent.
Key Highlights

3rd Quarter 2018

- 95 Gross Wells Drilled\(^1\)
  - Includes 59 CRC wells
- 136 Mboe/d
  - 62% Oil
- $196 Million\(^2\)
  - $158 million internally funded
- $308 Million
  - $400 million Core Adjusted EBITDAX\(^3\)

3QYTD 2018

- 252 Gross Wells Drilled\(^1\)
  - Includes 151 CRC wells
- 131 Mboe/d
  - 62% Oil
- $550 Million\(^2\)
  - $467 million internally funded
- $803 Million
  - $1,022 million Core Adjusted EBITDAX\(^3\)

---

1 Includes JV and non-operated wells.
2 Includes JV capital.
3 Core Adjusted EBITDAX excludes the effect of settled hedges of $79 million in the third quarter and $178 million in the first nine months, and cash-settled equity compensation of $13 million in the third quarter and $41 million in the first nine months. See the Investor Relations page at www.crc.com for historical reconciliations to the closest GAAP measure and other important information.
CRC’s Value-Driven Strategic Approach

**Capture Value of Portfolio**
- Pursue value-driven production
- Delineate future growth areas
- Enhance already substantial inventory
- Pursue strategic joint ventures

**Ensure Effective Capital Allocation**
- Utilize VCI-based decision-making
- Optimize core operating area investment
- Enhance targeted growth area investment
- Pursue impactful capital workovers

**Drive Operational Excellence**
- Streamline processes
- Apply technology
- Leverage sizeable infrastructure
- Drive strategic consolidation
- Employ new thinking and approaches

**Strengthen Balance Sheet**
- Reinvest to grow cash flow
- Simplify capital structure
- Enhance credit metrics
- Pursue value-accrative M&A
- Reduce absolute level of debt

Proven and pressure-tested strategic approach preserved value through the downturn and is set to drive significant value creation for years to come.
Development Results Driving Growth

**Drilling Program History**

- **San Joaquin**
  - 1Q17: 30 wells
  - 2Q17: 25 wells
  - 3Q17: 20 wells
  - 4Q17: 15 wells
  - 1Q18: 10 wells
  - 2Q18: 5 wells
  - 3Q18: 5 wells

- **Los Angeles**
  - 1Q17: 20 wells
  - 2Q17: 15 wells
  - 3Q17: 10 wells
  - 4Q17: 5 wells
  - 1Q18: 5 wells
  - 2Q18: 5 wells
  - 3Q18: 5 wells

- **Ventura**
  - 1Q17: 15 wells
  - 2Q17: 10 wells
  - 3Q17: 5 wells
  - 4Q17: 5 wells
  - 1Q18: 5 wells
  - 2Q18: 5 wells
  - 3Q18: 5 wells

- **Sacramento**
  - 1Q17: 20 wells
  - 2Q17: 15 wells
  - 3Q17: 10 wells
  - 4Q17: 5 wells
  - 1Q18: 5 wells
  - 2Q18: 5 wells
  - 3Q18: 5 wells

**YTD 2018 Results of Major Drilling Programs**

- **Huntington Beach**
  - Avg 30 Day IP: 300 BOEPD

- **Long Beach**
  - Avg 30 Day IP: 250 BOEPD

- **BV Hills**
  - Avg 30 Day IP: 200 BOEPD

- **BV Nose**
  - Avg 30 Day IP: 150 BOEPD

- **(Pre-Steam) Kern Front**
  - Avg 30 Day IP: 100 BOEPD

- **Los Angeles Basin**
  - Avg D&C Cost per Well: $3.6 MM

- **San Joaquin Basin**
  - Avg D&C Cost per Well: $1.6 MM

- **Ventura Basin**
  - Avg D&C Cost per Well: $2.3 MM

- **Sacramento Basin**
  - Avg D&C Cost per Well: $2.3 MM

**Q3 2018 Operations Results**

- **Sacramento Basin**
  - 5,000 BOE per Day
  - No Drilling Rigs in Q3

- **San Joaquin Basin**
  - 99,000 BOE per Day
  - 7 Drilling Rigs

- **Ventura Basin**
  - 6,000 BOE per Day
  - No Drilling Rigs in Q3

- **Los Angeles Basin**
  - 26,000 BOE per Day
  - 3 Drilling Rigs

---

1. Includes JV wells.
2. Kern Front wells are steam flood wells which have low IPs and then ramp up over a period of 12-24 months.
3. Year to date drilling costs may not be comparable to prior periods due to variances in project mix, well depth, horizontal length and other aspects.
Unlocking Value with a Deep Inventory of Actionable Projects at $75 Brent

- **Fully burdened**, growth-focused portfolio
- Achieve a VCI of **1.3 or greater** at $75 Brent and $3.00 NYMEX
- Deliver robust cash flow
- Reflects all recovery mechanisms and reserves types
- Leverage existing infrastructure, while opportunistically targeting new infrastructure investment

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1. Full cycle costs = operating costs + development costs + facility costs + field-level G&A + taxes other than on income.
2. See the Investor Relations page at [www.crc.com](http://www.crc.com) for details regarding net resources.
CRC acquired Chevron’s non-operating working interest ranging between 20% to 22% in different producing horizons within the Elk Hills field for total consideration of $460MM in cash and 2.85MM CRC shares of common stock, closed early April using some of the Ares proceeds.

- CRC now owns Elk Hills Unit in fee simple, holding 100% WI, NRI and surface lands.
- Over $15MM in additional capital cost avoidance.
- Acquired ~10,000 surface fee acres.

*Synergies include operational cost savings and revenue enhancement.
Resilient Resource Base

Net Production By Stream (Mboe/d)

*Total Capital reflected in the graph includes the capital investment of internal CRC capital as well as all JV partners which include BSP and MIRA. Please note our consolidated financial statements include BSP’s investment and exclude MIRA’s investment based on the accounting treatment of each venture.

** Q4 2018 Capital guidance includes CRC, BSP and MIRA capital.
Production Delivers Growth with Expanding Adjusted EBITDAX Margins

Field Production

Field Oil Prod (MBOPD) | Field NGL Prod (MBPD) | Field Gas Prod (MBOEPD)

Elk Hills Acquisition

CRC is growing oil production and Adjusted EBITDAX

Adjusted EBITDAX

Adj. EBITDAX Margin
Impact of Accounting Change
Adj. EBITDAX
Core Adj. EBITDAX

$MM

1Q16 2Q16 3Q16 4Q16 1Q17 2Q17 3Q17 4Q17 1Q18 2Q18 3Q18 4Q18E

% of Adjusted Revenues

1 Field Production includes gross production from the Wilmington field, which is subject to PSCs, and net production from all other assets.
2 See attachment 3 of the current Earnings Release for the calculation of Adj. EBITDAX Margin.
3 Results for reporting periods beginning after January 1, 2018 are presented under the new revenue recognition accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the prior period.
4 See the Investor Relations page at www.crc.com for a reconciliation of Core Adjusted EBITDAX and Adjusted EBITDAX to the closest GAAP measure and other important information.
Production Enhancement Plans for 2018

- CRC 2018 capital plan will be directed to oil-weighted projects in our core fields: Elk Hills, Buena Vista, Wilmington, Kern Front, Huntington Beach, and continued delineation of Ventura and southern San Joaquin areas.
- Additional capital will be deployed to Drilling, Workovers and Facilities focused in the Ventura and San Joaquin basins.
- JV capital will be focused in the San Joaquin basin and Huntington Beach.
- We have a dynamic plan that can be scaled up or down depending on the price environment and efficient deployment of joint venture proceeds.

2018E Total Capital Plan Including JVs
Approx. $720 to $750 million

2018E Internally Funded Development Capital By Drive
Approx. $450 million

2018E Internally Funded Development Capital By Basin
Approx. $450 million

At $65 flat Brent and $3 NYMEX, the fully-burdened1 2017 CRC Development Program delivered a 2.0 VCI or 45% IRR2

---

1 Facility and other support capital are apportioned to producing wells in the year they are drilled.
2 IRR estimate for the 2017 development program. VCI is calculated by dividing the net present value of the project’s expected pre-tax cash flow over its life by the net present value of the investments, each using a 10% discount rate.
3 Other includes maintenance and occupational health, safety and environmental projects, seismic and other investments.
Targeting **10-15% discretionary cash flow** for balance sheet strengthening¹

Combined with **mid-cycle commodity prices**, CRC is positioned for growth in:

- Cash flow
- Production
- Reserves

in total and on a **debt-adjusted per share basis**²

### Capital focused on oil projects that provide

- **Increasing Margins**
- **Low Decline Rates**
- **Compounding Cash Flow**

---

¹Subject to limitations on debt repayment in finance agreements.

²See the Investor Relations page at [www.crc.com](http://www.crc.com) for a description of the calculation of the debt-adjusted per share basis and other important information.

³See the Investor Relations page at [www.crc.com](http://www.crc.com) for a reconciliation to the closest GAAP measure and other important information.

Note: Scenarios assume flat pricing from $65 to $85 Brent and $3.00 to $3.10 NYMEX gas, respectively. Assumes varying lease operating costs within historical ranges depending on the commodity prices of the planning scenario outcomes. Ranges of portfolio planning scenario outcomes assume development of a variety of combinations of steamflood, waterflood, conventional and unconventional projects in our inventory and reflect estimates of geologic, development and permitting risk. Targeting 10-15% of discretionary cash flow for balance sheet strengthening, remaining discretionary cash flow to be reinvested in business in 2019 and beyond for each scenario.
**Strategic Development Joint Ventures – BSP & MIRA**

- **$550 Million**
  - Total Potential JV Capital
  - Portfolio Flexibility and Optionality

- **~$240 Million**
  - Invested Through Q3 2018
  - Enable High Margin Production Growth

- **~3.5-4.0 MBoe/d**
  - Gross Peak Production per $100 MM of Development Capital
  - Accelerate Value

- **>12 MMBoe**
  - Potential Targeted Reserves per $100 MM of Development Capital
  - De-Risk Inventory

---

**Reversion Estimates**

- **2018**
  - Estimated Last Date of BSP Capital Investment: $75
  - Estimated Last Date of MIRA Capital Investment: $85

- **2019**
  - Estimated Last Date of BSP Capital Investment: $65
  - Estimated Last Date of MIRA Capital Investment: $85

- **2020**
  - Estimated Last Date of MIRA Capital Investment: $75

- **2021**, **2022**, **2023**
  - Estimated Last Date of MIRA Capital Investment: $65

*Note: Price scenarios assume Brent pricing.*
Continuous Efforts Provide Pathway to Reasonable Leverage

Estimated Leverage Ratios

1 See the Investor Relations page at www.crc.com for a reconciliation to the closest GAAP measure and other important information. Core Adjusted EBITDAX excludes settled hedges and cash settled equity compensation costs.
2 3QYTD annualized.

Note: Targeting 10-15% of discretionary cash flow for balance sheet strengthening, remaining discretionary cash flow to be reinvested in business in 2019 and beyond for each scenario. Scenarios assume Brent pricing.
California Policies Impact Natural Gas Prices

Aliso Canyon Effect on Inventory

Maximum working gas capacity: 136 Bcf
Current post-leak capacity: 74 Bcf

Impact of Solar Generation

“Duck” Curve

California Natural Gas Prices

Limited third-party storage, summer heat and reliance on renewable sources have increased volatility in local natural gas prices

Source: EIA, California ISO, Bloomberg
CRC believes near-term crude oil differentials will remain strong

- California refinery demand for native crude continues to be strong and reduction in heavy waterborne crude has positively influenced differentials.
- Natural gas prices impacted by summer heat and continued limits on 3rd party storage
- NGL prices have been supported by lower inventories and export markets.

*See attachment 6 of the Earnings Release for information regarding the effects of an accounting change on realized natural gas prices.
Strong Cash Flow Growth

<table>
<thead>
<tr>
<th>3QYTD 17</th>
<th>Volume*</th>
<th>Price*</th>
<th>Costs</th>
<th>Interest</th>
<th>Working Capital/Other</th>
<th>3QYTD 18</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>393</td>
<td>0</td>
<td>0</td>
<td>393</td>
</tr>
</tbody>
</table>

*Includes effects of PSCs.
Cash Generation Improvement

<table>
<thead>
<tr>
<th>2Q18</th>
<th>Volumes</th>
<th>Price</th>
<th>Marketing Gas Trading Income</th>
<th>Settled Hedges</th>
<th>Other*</th>
<th>3Q18</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>245</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Other includes changes in operating costs, taxes other than on income, G&A, and electricity sales from Elk Hills Power.
### Quarterly Cost Comparison

<table>
<thead>
<tr>
<th></th>
<th>3Q17</th>
<th>2Q18</th>
<th>3Q18</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production costs</strong></td>
<td>$18.90</td>
<td>$18.93</td>
<td>$18.92</td>
</tr>
<tr>
<td><strong>($/Boe)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Production costs</strong></td>
<td>$17.81</td>
<td>$17.41</td>
<td>$17.55</td>
</tr>
<tr>
<td>excluding PSC effects</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>($/Boe)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Taxes other than on</strong></td>
<td>$39</td>
<td>$37</td>
<td>$45</td>
</tr>
<tr>
<td>income ($MM)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Exploration expense</strong></td>
<td>$5</td>
<td>$6</td>
<td>$4</td>
</tr>
<tr>
<td>($MM)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Interest expense</strong></td>
<td>$85</td>
<td>$94</td>
<td>$95</td>
</tr>
<tr>
<td>($MM)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**3Q18**

Without the increase in compensation due to higher stock price

<table>
<thead>
<tr>
<th>3Q18</th>
</tr>
</thead>
<tbody>
<tr>
<td>$18.77</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>3Q18</th>
</tr>
</thead>
<tbody>
<tr>
<td>$17.40</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>--------------------------------</td>
</tr>
<tr>
<td>Net Income (Loss) Attributable to Common Stock per Share – Diluted</td>
</tr>
<tr>
<td>Adjusted Net Income (Loss) per Share – Diluted*</td>
</tr>
<tr>
<td>Oil Production</td>
</tr>
<tr>
<td>Total Production</td>
</tr>
<tr>
<td>Realized Oil Price w/ Hedge ($/Bbl)</td>
</tr>
<tr>
<td>Realized NGL Price ($/Bbl)</td>
</tr>
<tr>
<td>Realized Natural Gas Price ($/Mcf)</td>
</tr>
<tr>
<td>Net Income (Loss) Attributable to Common Stock</td>
</tr>
<tr>
<td>Adjusted EBITDAX*</td>
</tr>
<tr>
<td>Core Adjusted EBITDAX*</td>
</tr>
<tr>
<td>Internally Funded Capital Investments</td>
</tr>
<tr>
<td>Cash Flow provided by Operations</td>
</tr>
</tbody>
</table>

* See the Investor Relations page at [www.crc.com](http://www.crc.com) for a reconciliation to the closest GAAP measure and other important information.
Recent Transactions - Improving Debt Metrics

Capitalization ($MM)  

<table>
<thead>
<tr>
<th>Description</th>
<th>9/30/2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Lien 2014 Revolving Credit Facility (RCF)</td>
<td>$342</td>
</tr>
<tr>
<td>1st Lien 2017 Term Loan</td>
<td>1,300</td>
</tr>
<tr>
<td>1st Lien 2016 Term Loan</td>
<td>1,000</td>
</tr>
<tr>
<td>2nd Lien Notes</td>
<td>2,122</td>
</tr>
<tr>
<td>Senior Unsecured Notes</td>
<td>344</td>
</tr>
<tr>
<td><strong>Total Debt</strong></td>
<td><strong>5,108</strong></td>
</tr>
<tr>
<td>Less cash(^1)</td>
<td>(18)</td>
</tr>
<tr>
<td><strong>Total Net Debt</strong></td>
<td><strong>5,090</strong></td>
</tr>
<tr>
<td>Mezzanine Equity</td>
<td>745(^2)</td>
</tr>
<tr>
<td>Equity</td>
<td>(605)</td>
</tr>
<tr>
<td><strong>Total Net Capitalization</strong></td>
<td><strong>5,230</strong></td>
</tr>
</tbody>
</table>

- **Total Debt / Total Net Capitalization**: 98%
- **Total Debt / LTM Adjusted EBITDA\(^3\)**: 4.7x
- **LTM Adjusted EBITDA\(^3\) / LTM Interest Expense**: 2.9x
- **PV-10\(^4\) / Total Debt**: 2.0x
- **Total Debt / Proved Reserves\(^4\) ($/Boe)**: $6.99
- **Total Debt / Proved Developed Reserves\(^4\) ($/Boe)**: $9.67
- **Total Debt / 3Q18 Production ($/Boepd)**: $37,559

\(^1\) Excludes $13MM of restricted cash.

\(^2\) Includes $120 million of noncontrolling interest for BSP and Ares.

\(^3\) LTM Adjusted EBITDA includes an estimated adjustment of +$27.5 million for both 4Q17 and 1Q18 as a result of the Elk Hills transaction.

\(^4\) Proved Reserves and PV-10 estimates are based on mid-year reserves at $75 Brent / $3 Nymex. See the Investor Relations page at www.crc.com for details on how PV-10 is calculated.

Highlights
- Received 8th Amendment to the 2014 Credit Agreement to repurchase $300 million in 2nd Lien Notes notes and unsecured notes
- Repurchased face value of $128 MM of 2nd Lien Notes and $49 MM of senior notes YTD for $149 MM in cash
- Purchased LIBOR interest caps which cap a notional $1.3B of floating rate debt at one-month LIBOR of 2.75% through May 2021
- Recent S&P upgrade on 2nd Lien Notes to B- from CCC+

Debt Maturities ($MM)
## 4Q18 Guidance

### Anticipated Realizations Against the Prevailing Index Prices for 4Q18

<table>
<thead>
<tr>
<th>Resource</th>
<th>Realization Range</th>
<th>Relative to Index Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>93% to 98%</td>
<td>98% of Brent</td>
</tr>
<tr>
<td>NGLs</td>
<td>55% to 60%</td>
<td>60% of Brent</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>100% to 110%</td>
<td>110% of NYMEX</td>
</tr>
</tbody>
</table>

### Production, Capital and Income Statement Guidance

<table>
<thead>
<tr>
<th>Category</th>
<th>Range</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production*</td>
<td>136 to 139</td>
<td>Mboe/d</td>
</tr>
<tr>
<td>Capital</td>
<td>$170 to $200</td>
<td>million</td>
</tr>
<tr>
<td>Production Costs*</td>
<td>$17.75 to $19.25</td>
<td>per Boe</td>
</tr>
<tr>
<td>Adjusted G&amp;A*</td>
<td>$6.30 to $6.70</td>
<td>per Boe</td>
</tr>
<tr>
<td>DD&amp;A*</td>
<td>$10.10 to $10.40</td>
<td>per Boe</td>
</tr>
<tr>
<td>Taxes other than on income</td>
<td>$41 to $45</td>
<td>million</td>
</tr>
<tr>
<td>Exploration expense</td>
<td>$10 to $15</td>
<td>million</td>
</tr>
<tr>
<td>Interest expense</td>
<td>$96 to $100</td>
<td>million</td>
</tr>
<tr>
<td>Cash interest</td>
<td>$150 to $155</td>
<td>million</td>
</tr>
<tr>
<td>Income tax expense rate</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>Cash tax rate</td>
<td>0%</td>
<td></td>
</tr>
</tbody>
</table>

* Based on average Q3 2018 Brent price of $75 per barrel.
## Strategy

Protect cash flow, operating margins and capital investment program

<table>
<thead>
<tr>
<th></th>
<th>4Q18</th>
<th>1Q19</th>
<th>2Q19</th>
<th>3Q19</th>
<th>4Q19</th>
<th>1Q20</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sold Calls</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>15,000</td>
<td>15,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Weighted Average</td>
<td>$58.83</td>
<td>$66.15</td>
<td>$68.45</td>
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<tr>
<td>Ceiling Price per Barrel</td>
<td></td>
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<tr>
<td><strong>Purchased Calls</strong></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td></td>
<td>2,000</td>
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<td></td>
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<tr>
<td>Weighted Average</td>
<td></td>
<td>$71.00</td>
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<tr>
<td>Ceiling Price per Barrel</td>
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</tr>
<tr>
<td><strong>Purchased Puts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Weighted Average</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Floor Price per Barrel</td>
<td></td>
<td>$65.66</td>
<td>$69.75</td>
<td>$73.13</td>
<td>$75.71</td>
<td>$75.00</td>
</tr>
<tr>
<td><strong>Sold Puts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>19,000</td>
<td>40,000</td>
<td>35,000</td>
<td>40,000</td>
<td>35,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Weighted Average</td>
<td>$45.00</td>
<td>$51.88</td>
<td>$55.71</td>
<td>$57.50</td>
<td>$60.00</td>
<td>$60.00</td>
</tr>
<tr>
<td>Floor Price per Barrel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Swaps</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barrels per Day</td>
<td>48,000</td>
<td>7,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Weighted Average</td>
<td>$60.35</td>
<td>$67.71</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price per Barrel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Percentage of 3Q 2018 Oil Production Hedged Against Downside</strong></td>
<td>57%</td>
<td>54%</td>
<td>48%</td>
<td>48%</td>
<td>42%</td>
<td>12%</td>
</tr>
</tbody>
</table>

2019 program continues to target hedges on 50% of crude oil production and provides more upside exposure to commodity price movement.

As of October 2018. Assumes counterparty options are not exercised. Certain of our counterparties have options to increase swap volumes by up to 5,000 barrels per day at a weighted average Brent price of $70.00 for the first quarter of 2019. The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. For further information please see attachment 8 of our latest earnings release.
Chose options to maximize deleveraging and minimize recurring cost to the income statement on a per share basis. Continue to seek opportunistic transactions that reduce overall debt.

<table>
<thead>
<tr>
<th></th>
<th>Total Debt ($ MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2Q15</td>
<td>6,765</td>
</tr>
<tr>
<td>Debt Exchange for 2L</td>
<td></td>
</tr>
<tr>
<td>Open Market Purchases</td>
<td></td>
</tr>
<tr>
<td>Equity for Debt Exchange</td>
<td></td>
</tr>
<tr>
<td>Cash Tender for Unsecureds</td>
<td></td>
</tr>
<tr>
<td>Cash &amp; Working Capital</td>
<td></td>
</tr>
<tr>
<td>3Q18</td>
<td>5,108</td>
</tr>
</tbody>
</table>

Includes Debt Repurchases of $177MM in YTD 2018

Total Debt Reduction

- Total Debt Reduction: $535 million
- Total Debt Reduction: $330 million
- Total Debt Reduction: $102 million
- Total Debt Reduction: $625 million
- Total Debt Reduction: $65 million
- Total Debt Reduction: $1,657 million

1 Represents mid-second quarter 2015 peak debt.
# Summary of Mid-Year 2018 Reserves Changes

**96%**  
Half-Year Proven Organic Reserves Replacement  
(excl. price-related revisions – unaudited)

**731 MMBOE**  
Proved Reserves  
Up 18% from YE 2017

**<$10/BOE**  
F&D Cost

**15 Year**  
R/P

---

## CRC Reserves Changes (Net MMBOE)

<table>
<thead>
<tr>
<th>Reserve Category</th>
<th>YE 2017 Balance</th>
<th>Price Related Revision</th>
<th>1H 2018 Production</th>
<th>Changes²</th>
<th>Acq &amp; Div</th>
<th>July 2018 Balance</th>
<th>1P RRR³ (Excl Price)</th>
<th>Proved R/P</th>
<th>YE 17 Gross Well Count</th>
<th>YE 18 Gross Well Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>PD</td>
<td>440</td>
<td>40</td>
<td>(23)</td>
<td>25</td>
<td>46</td>
<td>528</td>
<td></td>
<td></td>
<td>9,695</td>
<td>10,097</td>
</tr>
<tr>
<td>PUD</td>
<td>178</td>
<td>10</td>
<td>0</td>
<td>(2)</td>
<td>18</td>
<td>203</td>
<td></td>
<td></td>
<td>1,691</td>
<td>1,546</td>
</tr>
<tr>
<td><strong>Proved</strong>⁴</td>
<td><strong>618</strong></td>
<td><strong>50</strong></td>
<td><strong>(23)</strong></td>
<td><strong>23</strong></td>
<td><strong>64</strong></td>
<td><strong>731</strong></td>
<td><strong>96%</strong></td>
<td><strong>15</strong></td>
<td><strong>11,386</strong></td>
<td><strong>11,643</strong></td>
</tr>
</tbody>
</table>

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1 Organic F&D including the effect of the Elk Hills acquisition.
2 Includes transfers, revisions, exploration and development and improved recovery. 58 MMBOE “Technical” proven reserves in contingent replacement due to economics and/or 5-year rule limitations.
3 RRR refers to organic reserves replacement ratio.
4 Proved reserves at $75 Brent / $3 Nymex.
Current Enterprise Value Deeply Discounted

1. See endnotes in the Appendix.
2. See the Investor Relations page at www.crc.com for important information about 3P reserves and other hydrocarbon quantities.
Investment Proposition: Delivering Smart Growth and Real Value

**Portfolio of world-class assets investable throughout the commodity cycle**

**Robust inventory of high value growth projects**

**Deep operational knowledge and technical expertise**

**Integrated and complementary infrastructure**

**Disciplined and effective capital allocation**

**Effective capital allocation through cycle for smart growth**

**Value Driven**

Balance capital investment with financial strengthening efforts for best long-term value creation

**Balance Sheet Goals**
- Reduce Debt
- Reduce Fixed Charges
- Simplify Balance Sheet

**High VCI Projects**
- Core Operating Areas
- Growth Prospects
- Investing for the Future

**Production**

**Innovation**

**Deep Inventory**

**Robust inventory**

**Growth Projects**

**Core Operating Areas**

**Simplify Balance Sheet**

**Reduce Debt**

**Reduce Fixed Charges**

**Simplify Balance Sheet**

**Core Operating Areas**

**Growth Prospects**

**Investing for the Future**

**Balance Sheet Goals**

**High VCI Projects**

**Oil Price $/BBL**

**Gas Price $/MCF**

**V**

**A**

**L**

**U**

**E**

**R**

**I**

**M**

**A**

**N**

**E**

**R**

**O**

**S**

**C**

**O**
Appendix
Accelerating Value and Derisking Inventory through JVs

**Highlights:**

- Up to $250MM over ~2 years
  - Three tranches of $50MM
  - Total of $150MM funded
- Investor funds 100% of project capital in exchange for a net profits interest (NPI)
  - Investor NPI interest reverts to CRC after low teens target IRR
  - CRC retains early termination options
- Current focus is in the San Joaquin and Los Angeles Basin
- CRC operates all wells

---

**Highlights:**

- Up to $300MM
  - Current commitment of $140MM
- DrillCo type structure where Investor funds 100% of project capital for 90% WI, with CRC carried on its 10% WI
  - CRC interest reverts to 75% after target IRR is achieved
  - CRC retains early termination options
- Focus on four fields within the San Joaquin Basin
  - Kern Front, Mt. Poso, Pleito Ranch, Wheeler Ridge
- CRC operates all wells
Typical Industry JV Structure

- Based on recent industry JV deals, a typical deal structure is
  - Partner pays 80-100% Capital
  - Receives 80-100% Working Interest
  - Typical hurdle rate:
    - 10% - 20% IRR
  - Partner’s working interest once hurdle rate is achieved:
    - 5% - 25%
## Summary of Deal

<table>
<thead>
<tr>
<th>Partner</th>
<th>Affiliate of Ares Management (Ares)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contributed Assets</td>
<td>Elk Hills power plant, gas processing assets and related non-borrowing base infrastructure owned by CRC</td>
</tr>
<tr>
<td>Midstream JV Capitalization</td>
<td>Class A common interests (voting) owned 50% by Ares and 50% by California Resources Elk Hills (CREH)</td>
</tr>
<tr>
<td></td>
<td>Class B preferred interests (“Preferred”) owned 100% by Ares</td>
</tr>
<tr>
<td></td>
<td>Class C common interests (distributing) owned 95.25% by CREH and 4.75% by Ares</td>
</tr>
<tr>
<td>Distribution to Partners</td>
<td>Preferred interests to receive distributions of 13.5% per annum on the $750 MM contributed amount</td>
</tr>
<tr>
<td></td>
<td>9.5% cash pay and 4.0% PIK to be deferred for the first three years</td>
</tr>
<tr>
<td></td>
<td>Deferred distributions are interest bearing and repaid over two years following the deferral period</td>
</tr>
<tr>
<td></td>
<td>Remaining cash after Preferred distributions to be distributed pro rata to Class C interests</td>
</tr>
<tr>
<td>Exit Provisions</td>
<td>Prior to end of 5 or 7.5 years, CRC may redeem Preferred at variable amounts that include make whole premiums</td>
</tr>
<tr>
<td></td>
<td>At end of 5 years, CRC may elect to either redeem or extend to 7.5 years</td>
</tr>
<tr>
<td></td>
<td>At 7.5 years, if not redeemed by CRC, Preferred can monetize the JV</td>
</tr>
<tr>
<td>Board</td>
<td>Board of Managers consists of three CRC representatives and three representatives from Ares</td>
</tr>
</tbody>
</table>
Wilmington Field – Production Sharing Contracts

- Over 90% of CRC’s Long Beach production is covered under Production Sharing Contracts (PSCs) with the State and the City of Long Beach.

- CRC’s net production decreases when prices rise and increases when prices decline.

- “Base” rate/profit is defined in contracts:
  - State/City receive most of base profit
  - CRC receives remainder

- “Incremental” rate/profit is everything greater than the Base.

- Per the provisions of the contract, the Base of the LBU PSC ended in 4Q 2016.

*Average profit split %.

![LBU PSC Diagram](image)

![Tidelands PSC Diagram](image)
Wilmington Production Sharing Contracts

• Over 25% of CRC’s oil production is subject to Production Sharing Contracts

• PSC Mechanics
  – CRC pays our partners’ share of the Operating and Capital Cost
  – CRC recovers our partners’ portion of the cost in barrels
  – CRC receives 45-49% of the gross production as “Profit Barrels”

• As prices rise, fewer barrels are required to recover our partners’ portion of the cost

Higher oil prices result in higher cash flow, but lower net production
Enhanced Inventory Growth and Expanded 3P Position

First Half 2018 Highlights

- Mid-year reserves audited by Ryder Scott
- Proved reserves today only 5% lower despite 25% decrease in price from the Spin
- Life-of-field studies increased unproven resources
- Recent exploration success not included

2017 Highlights

- Organic F&D costs excluding price related revisions were $6.82 per BOE in 2017 and 3-year average of $4.84 per BOE
- Organic recycle ratio of 2.1x in 2017 and 3-year average of 2.8x
- Comprehensive technical review of 40% of fields
- Over 95% of total proved reserves audited by Ryder Scott in the previous three years

Unproven Reserves\(^1\) Growth

1 See the Investor Relations page at www.crc.com for important information about 3P reserves and other hydrocarbon quantities.
2 Reserve amounts uneconomic at SEC prices for the applicable year.
3 Unproven reserves (probable and possible) utilize similar price assumptions as of 2014 ($101.30 Brent). Proven reserves utilize applicable SEC prices for all year-end periods. 1H18 proven reserves utilize $75 Brent.
End Notes

From Slide 25

1 CRC estimate of reserves value as of December 31, 2017, including reserves acquired in the Elk Hills transaction at the indicated Brent prices. Includes field-level operating expenses, G&A and taxes other than on income. Assumes $3.00/MMBTU NYMEX in all cases.

2 Reflects the value of facilities and midstream assets at 50% of estimated replacement value. This discount is estimated to exceed the burden on reserves that would be incurred if assets were monetized. Excludes the value of the assets monetized in the Ares transaction.

3 Surface & Mineral reflect the estimated value of undeveloped surface and mineral acreage held in fee.

4 Unproved reserves are comprised of risked probable and possible reserves as of December 31, 2017.

5 Calculated using September 30, 2018 debt at par and a market cap as of 10/26/2018. Includes non-controlling interests reported as mezzanine and permanent equity as of September 30, 2018.

See the Investor Relations page at www.crc.com for important information about 3P reserves and other hydrocarbon resource quantities, organic finding and development (F&D) costs, organic recycle ratio calculations, organic reserves replacement ratios, original hydrocarbons in place, Value Creation Index (VCI), drilling locations and reconciliations of non-GAAP measures to the closest GAAP equivalent.