First Quarter 2023 Results

May 01, 2023
This document contains statements that we believe to be "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 other than historical facts are forward-looking statements, and include statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives of management for the future. Words such as "expect," "could," "may," "anticipate," "intend," "plan," "ability," "believe," "seek," "see," "will," "would," "estimate," "forecast," "target," "guidance," "outlook," "opportunity" or "strategy" or similar expressions are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular results to be materially different than those expressed in our forward-looking statements include:

- fluctuations in commodity prices, including supply and demand considerations for our products and services;
- decisions as to production levels and/or pricing by OPEC or U.S. producers in future periods;
- government policy, war and political conditions and events, including the war in Ukraine and oil sanctions on Russia, Iran and others;
- regulatory actions and changes that affect the oil and gas industry generally and us in particular, including (1) the availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development activities or our carbon management business; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions; (3) the protection of health, safety and the environment; or (4) the transportation, marketing and sale of our products;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and our capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to our estimates of reserves and related future cash flows, including changes arising from our inability to develop such reserves in a timely manner, and any inability to replace such reserves;
- the recoverability of resources and unexpected geologic conditions;
- general economic conditions and trends, including conditions in the worldwide financial, trade and credit markets;
- production-sharing contracts/ effects on production and operating costs;
- the lack of available equipment, service or labor price inflation;
- limitations on transportation or storage capacity and the need to shut-in wells;
- any failure of risk management;
- results from operations and competition in the industries in which we operate;
- our ability to realize the anticipated benefits from prior or future efforts to reduce costs;
- environmental risks and liability under federal, regional, state, provincial, tribal, local and international environmental laws and regulations (including remedial actions);
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of our operations;
- our ability to claim and utilize tax credits or other incentives in connection with our CCS projects;
- our ability to realize the benefits contemplated by our energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and our ability to convert our CDMAs to definitive agreements and enter into other offset agreements;
- our ability to maximize the value of our carbon management business and operate it on a stand-alone basis;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms;
- uncertainty around the accounting of emissions and our ability to successfully gather and verify emissions data and other environmental impacts;
- changes to our dividend policy and share repurchase program, and our ability to declare future dividends or repurchase shares under our debt agreements;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- our access to and the terms of credit in commercial banking and capital markets, including our ability to refinance our debt or obtain separate financing for our carbon management business;
- changes in state, federal or international tax rates, including our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- effects of hedging transactions;
- the effect of our stock price on costs associated with incentive compensation;
- inability to enter into desirable transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; and
- other factors discussed in Part I, Item 1A – Risk Factors.

We caution you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and we undertake no obligation to update this information. This document may also contain information from third party sources. This data may involve a number of assumptions and limitations, and we have not independently verified them and do not warrant the accuracy or completeness of such third-party information.
Presenters

Francisco Leon  President & Chief Executive Officer
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
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</thead>
<tbody>
<tr>
<td>BMT</td>
<td>Billion Metric Tons</td>
</tr>
<tr>
<td>CARB</td>
<td>California Air Resources Board</td>
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<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
</tr>
<tr>
<td>CCS+</td>
<td>Carbon Capture and Storage + EOR</td>
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<td>CDMA</td>
<td>Carbon Dioxide Management Agreement</td>
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<td>CEQA</td>
<td>California Environmental Quality Act</td>
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<td>CDP</td>
<td>Cryogenic Gas Plant</td>
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<td>Cl</td>
<td>Carbon Intensity</td>
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<td>CMB</td>
<td>Carbon Management Business</td>
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<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
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<tr>
<td>CTV</td>
<td>Carbon TerraVault (a subsidiary of CRC)</td>
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<tr>
<td>DAC</td>
<td>Direct Air Capture</td>
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<tr>
<td>D&amp;C</td>
<td>Drilling and Completions</td>
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<tr>
<td>E&amp;P</td>
<td>Exploration and Production</td>
</tr>
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<td>EHPP</td>
<td>Elk Hills Power Plant</td>
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<tr>
<td>EIR</td>
<td>Environmental Impact Report</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
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<td>EPA</td>
<td>Environmental Protection Agency</td>
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<td>ESG</td>
<td>Environmental, Social and Governance</td>
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<tr>
<td>FCF</td>
<td>Free Cash Flow</td>
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<table>
<thead>
<tr>
<th>Term</th>
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<tbody>
<tr>
<td>FEED</td>
<td>Front End Engineering and Design</td>
</tr>
<tr>
<td>FID</td>
<td>Final Investment Decision</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>LCFS</td>
<td>Low Carbon Fuel Standard</td>
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<td>MMT</td>
<td>Million Metric Tons</td>
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<tr>
<td>MMTPA</td>
<td>Million Metric Tons Per Annum</td>
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<tr>
<td>MRV</td>
<td>Monitoring, Reporting and Verification Plan</td>
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<tr>
<td>MT</td>
<td>Metric Tons</td>
</tr>
<tr>
<td>MTPA</td>
<td>Metric Tons Per Annum</td>
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<tr>
<td>OCF</td>
<td>Operating Cash Flow</td>
</tr>
<tr>
<td>PD</td>
<td>Proved Developed</td>
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<tr>
<td>PUD</td>
<td>Proved Undeveloped</td>
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<tr>
<td>ROFL</td>
<td>Right of First Look</td>
</tr>
<tr>
<td>R/P</td>
<td>Reserves to Production Ratio</td>
</tr>
<tr>
<td>RTC</td>
<td>Round-the-Clock</td>
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<tr>
<td>SDRF</td>
<td>Sustainable Finance Disclosure Regulation</td>
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<tr>
<td>SRP</td>
<td>Share Repurchase Program</td>
</tr>
<tr>
<td>SJV</td>
<td>San Joaquin Valley</td>
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<tr>
<td>WI</td>
<td>Working Interest</td>
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1Q23 Business Highlights - Strong Start to the Year

RECORD QUARTERLY FINANCIAL PERFORMANCE
- Maintained oil production on lower quarterly capital
- Leading gas position\(^1\) supported by strong commodity realizations drove record quarterly profits
- Returned $79MM to shareholders ($59MM through SRP and $20MM in dividends)

REPOSITIONING BUSINESS TO UNLOCK SHAREHOLDER VALUE
- Manuela (Nelly) Molina named as CRC’s new Executive Vice President (EVP) and Chief Financial Officer (CFO)
- Initiated cost saving initiative targeting 5% - 10% or $25 - $50MM by YE23\(^2\); engaged Alvarez & Marsal (A&M) to assist with the execution of cost savings initiative to increase cash flow generation
- Increased flexibility by successfully amending the RBL agreement

EXECUTING CALIFORNIA-LEADING CARBON MANAGEMENT STRATEGY
- Announced 2 new storage-only CDMAs for a combined ~140,000 MTPA of CO\(_2\); ~610,000 MTPA of CDMAs signed to date\(^4\)
- Submitted a Class VI permit to the EPA for 34 MMT for CTV IV CO\(_2\) reservoir, increasing CTV’s total potential storage capacity to 174MMT
- Targeting receipt of first Class VI draft permit from EPA by YE23

Source: Internal estimates. (1) CRC is California’s largest natural gas producer and is net long in natural gas. (2) Represents a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (3) Current 2023 guidance doesn’t include targeted cost reduction initiatives. Excludes CTV from the scope of this initiative. (4) Our CDMAs frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements.

Strong Performance
$263MM of FCF\(^2\) in 1Q23 Raising FY23 FCF\(^2\) Guide by 8%

Cost Reduction and Business Transformation Initiative Targeting
$25 - $50MM in annualized savings
YE23 sustainable run rate reduction for non-energy operating costs and Adj. E&P Corp & Other G&A\(^2\)

Signed 4 CDMAs To Date
610,000 MTPA
CTV’s Est. Combined CO\(_2\) Injection Rate
Key Operational Results:

- Drilled 9 wells and 2 sidetracks in 1Q23
- Continuing to build a sidetrack inventory in San Joaquin and Sacramento basins
- Exited the quarter with 1 drilling rig in LA basin and 39 maintenance rigs across CRC’s asset base

Drilling Permits:

- CRC has secured all the necessary drilling permits to execute its 2023 capital program
- Submitted CEQA permit applications for three core fields in the San Joaquin Basin

Natural Gas Strategy:

- Forming team to evaluate and develop projects for CRC’s natural gas inventory

THROUGHOUT 1Q23, SUCCESSFULLY MAINTAINED NET OIL PRODUCTION ON LOWER CAPITAL

$31MM
1Q23 E&P D&C + Workover Capital

(1) Includes the effect of commodity derivatives. (2) Source: CARB, Enverus. (3) Source: EIA.
Delivered on 1Q23 Guidance With Record Quarterly Financial Performance

1Q23 Results Exceeded CRC’s Guidance

Due to high natural gas realizations, better performance of natural gas marketing activities, and lower-than-expected operating costs and deployed capital, CRC’s 1Q23 financial results were above guidance.

<table>
<thead>
<tr>
<th>CRC GUIDANCE</th>
<th>Final Guidance 1Q23E³</th>
<th>Final Results 1Q23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Production (MBOE/D)</td>
<td>91 - 89</td>
<td>89</td>
</tr>
<tr>
<td>Oil Production (MBO/D)</td>
<td>54 - 53</td>
<td>55</td>
</tr>
<tr>
<td>Operating Costs ($MM)</td>
<td>$260 – $270</td>
<td>$254</td>
</tr>
<tr>
<td>Carbon Management Expenses ($MM)</td>
<td>$5 - $10</td>
<td>$4</td>
</tr>
<tr>
<td>Adj. G&amp;A ($MM)</td>
<td>$50 – $58</td>
<td>$55</td>
</tr>
<tr>
<td>Capital ($MM)</td>
<td>$57 – $69</td>
<td>$47</td>
</tr>
<tr>
<td>Free Cash Flow ($MM)</td>
<td>$151 – $180</td>
<td>$263</td>
</tr>
</tbody>
</table>

Other Guidance Items

| Marketing & Trading, Net ($MM)                   | $35 – $45             | $60                  |
| Net Electricity ($MM)                            | $25 – $35             | $19                  |
| Transportation Expense ($MM)                     | $14 – $16             | $17                  |

Note: please see slide 24 for details on the footnotes on this slide.
Committed To Peer Leading Returns Of Capital To Shareholders

Fixed Dividend Yield

Current implied annualized yield of 2.87%; Paid $20MM in dividends in 1Q23

~22% TOTAL RETURN

Since the Inception of the Shareholder Return Strategy

Bought back 15% of the outstanding stock of the company since the beginning of the SRP program through 1Q23; Bought back $59MM of shares in 1Q23

Share Repurchase Program

Note: please see slide 24 for details on the footnotes on this slide.
Progressing Business Repositioning to Unlock Shareholder Value

CRC’s management in conjunction with finance committee of the Board launched cost reduction initiative

▪ Commenced internal review of organization
▪ Engaged A&M to assist with the execution of cost savings initiative

YE23 Sustainable Run Rate Cost Reductions Target

$25 - $50MM

For non-energy operating costs and Adj. E&P Corp & Other G&A

Increased Financial Flexibility

Successfully amended the RBL facility

$1.2B

Borrowing base for CRC’s Revolving Credit Facility Reaffirmed

▪ $590MM in commitments
▪ Extended the maturity date to July 31, 2027
▪ Increased ability to pay dividends and make share repurchases, improved flexibility to make investments in carbon management business, released liens on certain assets (including the Elk Hills power plant) and enabled us to designate certain entities (including Elk Hills Power, LLC) as unrestricted subsidiaries subject to certain conditions

Path to Potential Business Separation

Preparation for potential separation – working on CTV Holdings organization design

Important milestones for potential business separation include:

▪ EPA Class VI Permit > Project FID > Line of Sight to First CO₂ Injection & Cash Flow

Executive Leadership Appointment

Manuela (Nelly) Molina appointed as CRC’s new EVP & CFO

▪ Previously served as VP of Audit Services since April 2022 and prior to that as a VP of Investor Relations for Sempra (NYSE:SRE) since September 2020
▪ Over 25 years of energy experience in both financial and operational appointments

(1) Current 2023 guidance doesn’t include targeted cost reduction initiatives. (2) Represents a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (3) Subject to a springing maturity to August 4, 2025 if any of our Senior Notes are outstanding on that date.
Strengthening The Expansion of Carbon Management Business

Signed 2 additional storage only CDMAs for a combined injection rate of 140,000 MTPA with Yosemite Clean Energy and InEnTec

Submitted a Class VI permit application to the EPA for CTV IV with 34 MMT of CO₂ storage capacity as we continue to build out the leading CO₂ storage asset class in California with additional Vaults in various stages of development

Direct access to existing, greenfield and new tech CO₂ emissions opportunities to further support growth in California’s decarbonization plans and energy transition employment opportunities

<table>
<thead>
<tr>
<th>Vault</th>
<th>CTV I</th>
<th>CTV II</th>
<th>CTV III</th>
<th>CTV IV</th>
</tr>
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<tbody>
<tr>
<td>EPA Permit Application</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>In progress</td>
</tr>
<tr>
<td>Administratively Complete</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Targeting Class VI Draft EPA Permit Receipt</td>
<td>~YE23</td>
<td>~2024</td>
<td>~2024</td>
<td>~2025</td>
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<tr>
<td>California’s Basin</td>
<td>SJ Basin</td>
<td>Sacramento Basin</td>
<td></td>
<td></td>
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<tr>
<td>Annual Regional CO₂ Emissions² (MMTPA)</td>
<td>~30</td>
<td>~60</td>
<td></td>
<td></td>
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<tr>
<td>Est. Average Annual Injection Capacity³ (MMTPA)</td>
<td>~1.2</td>
<td>~0.6</td>
<td>~1.8</td>
<td>~0.9</td>
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<tr>
<td>Potential Total Storage Capacity (MMT)</td>
<td>46</td>
<td>23</td>
<td>71</td>
<td>34</td>
</tr>
<tr>
<td>Targeting First CO₂ Injection⁴</td>
<td>~2025</td>
<td>~2026</td>
<td>~2026</td>
<td>~2027</td>
</tr>
<tr>
<td>Remaining and Available CO₂ Injection Capacity (%)⁵</td>
<td>~79%</td>
<td>100%</td>
<td>~70%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Source: Internal estimates. SJ Basin implies San Joaquin basin. (1) Our CDMAs frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements. (2) CARB 2020. (3) Injection rates are average rates based on max permit volumes over life of project using a 40-year basis, and that actual volumes and the injection period will vary over time. (4) Internal estimates as of April 2023 as exact times might vary. (5) Represents remaining capacity after taking into account pore space attributable to signed CDMAs.
Why California Resources Corporation?

- Premier Balance Sheet with Strong Free Cash Flow Generation
- Superior Shareholder Returns Strategy
- Leading Carbon Management Business
Updated 2023E Corporate Guidance (as of May 2nd, 2023)

CRC 2023E GUIDANCE:

<table>
<thead>
<tr>
<th>E&amp;P, Corp. &amp; Other</th>
<th>CMB</th>
<th>FY23E Combined</th>
<th>2Q23E Combined</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Total Production(^1) (MBOE/D)</td>
<td>91 – 85</td>
<td>91 – 85</td>
<td>88 – 86</td>
</tr>
<tr>
<td>Net Oil Production(^1) (MBO/D)</td>
<td>55 – 51</td>
<td>55 – 51</td>
<td></td>
</tr>
<tr>
<td>Operating Costs ($MM)</td>
<td>$815 – $865</td>
<td>$815 – $865</td>
<td>$175 – $195</td>
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<tr>
<td>CMB Expenses(^2) ($MM)</td>
<td>–</td>
<td>$25 – $35</td>
<td>–</td>
</tr>
<tr>
<td>Adj. G&amp;A(^3) ($MM)</td>
<td>$185 – $210</td>
<td>$195 – $225</td>
<td>$50 – $55</td>
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<tr>
<td>Adj. Total Capital(^4) ($MM)</td>
<td>$185 – $220</td>
<td>$200 – $245</td>
<td>$45 – $60</td>
</tr>
<tr>
<td>FCF(^3) ($MM)</td>
<td>$440 – $530</td>
<td>$360 – $470</td>
<td>($60) – ($80)</td>
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</tbody>
</table>

Other Guidance Items:

- **Marketing & Trading, Net ($MM)**
  - Low: $80
  - High: $110

- **Net Electricity ($MM)**
  - Low: $70
  - High: $110

- **Transportation Expense ($MM)**
  - Low: $50
  - High: $70

- **ARO Settlement Payments ($MM)**
  - Low: $55
  - High: $60

- **Taxes Other Than on Income ($MM)**
  - Low: $175
  - High: $185

- **Interest and Debt Expense ($MM)**
  - Low: $55
  - High: $60

- **Cash Income Taxes ($MM)**
  - Low: $100
  - High: $120

Commodity Realizations:

- **Oil - % of Brent:**
  - FY2023E: 97% - 99%
  - FY2023E: 94% - 98%

- **NGL - % of Brent:**
  - FY2023E: 58% - 64%
  - FY2023E: 55% - 60%

- **Natural Gas - % of NYMEX:**
  - FY2023E: 150% - 250%
  - FY2023E: 150% - 160%

Annual Adj. CMB capital\(^4\) and expenses\(^2\) for JV projects anticipated to be funded by CTV JV contributions (See slide 18)

Note: please see slide 24 for details on the footnotes on this slide. Current 2023 guidance doesn't include targeted cost reduction initiatives.
Yosemite to build and operate a 24 tons per day (TPD) hydrogen facility in the city of Oroville, California, using dual bed gasification technology with commercial operations targeted in late 2025.

CTV will provide truck offloading facility and permanent sequestration for the initial 40,000 MTPA of CO₂ emissions from this facility using CTV storage vaults.

Yosemite plans to deliver CO₂ to CTV location via a fleet of low emissions trucks.

CTV will receive an injection fee to be paid on a per ton basis that fits within our previously disclosed economic type curve for storage only projects that do not require capture capital or significant transportation costs.

CTV has the right to participate in project for up to a majority equity stake.

Yosemite has plans for two additional green hydrogen facilities in California with up to an additional 160,000 MTPA of CO₂ emissions under consideration; CTV has the right of first negotiation to provide CO₂ sequestration services to any hydrogen production facility constructed in California.

Further Expanding CTV’s Northern California Storage Opportunity Set

CDMA DETAILS FOR YOSEMITE’S RENEWABLE FUELS PROJECT

- Yosemite to build and operate a 24 tons per day (TPD) hydrogen facility in the city of Oroville, California, using dual bed gasification technology with commercial operations targeted in late 2025.
- CTV will provide truck offloading facility and permanent sequestration for the initial 40,000 MTPA of CO₂ emissions from this facility using CTV storage vaults.
- Yosemite plans to deliver CO₂ to CTV location via a fleet of low emissions trucks.
- CTV will receive an injection fee to be paid on a per ton basis that fits within our previously disclosed economic type curve for storage only projects that do not require capture capital or significant transportation costs.
- CTV has the right to participate in project for up to a majority equity stake.
- Yosemite has plans for two additional green hydrogen facilities in California with up to an additional 160,000 MTPA of CO₂ emissions under consideration; CTV has the right of first negotiation to provide CO₂ sequestration services to any hydrogen production facility constructed in California.

ABOUT YOSEMITE CLEAN ENERGY

Yosemite Clean Energy LLC (“Yosemite”) is a bioenergy development company that specializes in transforming farm and forest wood waste into carbon-negative hydrogen, providing renewable solutions to California’s transportation and broader energy sectors.

Headquartered in Fresno, CA, Yosemite and its development partners have experience in forestry, agriculture, banking, law, energy, engineering, and marketing.

EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors.
Elk Hills Net Zero Industrial Park Expands With Its Second Storage Only Project

CDMA DETAILS FOR INENTEC DIMETHYL ETHER (DME) FACILITY

- InEnTec to construct a facility that will use proprietary gasification technology to produce \( 80 \) to \( 100 \) tons per day (TPD) renewable dimethyl ether (rDME) from biomass and other waste feedstock at the Elk Hills Net Zero Industrial Park.
- CTV will provide permanent sequestration initially for \( 100,000 \) MTPA of CO\(_2\) using CTV I storage vault, including the lease of land for the rDME facility.
- Project FID targeted in 2024; commercial operations targeted in the first half of 2026.
- CTV will receive an injection fee to be paid on a per ton basis that fits within our previously disclosed economic type curve for storage only projects that do not require capture capital or significant transportation costs.
- CTV and InEnTec are also discussing CRC’s potential financial participation in the rDME facility, including potentially a significant equity stake.

ABOUT INENTEC

Today’s Waste, Tomorrow’s Clean Energy

- InEnTec Inc. (InEnTec) is an industry leader in proprietary gasification systems that economically and responsibly turn the world’s waste into valuable green products, fuels, and energy.
- Headquartered in Richland, WA, InEnTec has a strong team of highly-skilled engineers and experts in project development and management.

Note: The exact DME facility’s location within Elk Hills is TBD. (1) Our CDMA frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements. (2) See slides 19 and 20 of CRC’s 1Q23 earnings presentation for the latest details on the CTV project economic type curve. (3) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors. (4) Additional infrastructure development requires conditional use and other permits from Kern County. (5) Superior Plus Energy Services Inc. (Superior) is a U.S. operating subsidiary of Superior Plus Corp. (TSX: SPB).
### Expecting to Further Diversify CTV’s Portfolio of Emitters Across The Energy Spectrum in California

### Continuing to attract new emissions sources due to ideal conditions for greenfield and existing sources projects (Subsurface knowledge, technical expertise, assets’ location, access to capital, permitting process & etc.)

#### Project Type

<table>
<thead>
<tr>
<th>Type of Emitter</th>
<th>Tech</th>
<th>Greenfield</th>
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<tbody>
<tr>
<td>DAC</td>
<td>Renewable Diesel</td>
<td>Ammonia</td>
</tr>
<tr>
<td>Renewable Diesel</td>
<td>Medium</td>
<td>Low</td>
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<tr>
<td>Ammonia</td>
<td>Medium</td>
<td>High</td>
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<tr>
<td>Hydrogen</td>
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<td>High</td>
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<tr>
<td>Ethanol</td>
<td>Medium to High</td>
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#### Cost of Capture ($/TCO₂)

<table>
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<th>Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CalCapture)</th>
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</thead>
<tbody>
<tr>
<td>Very High</td>
</tr>
<tr>
<td>Medium to High</td>
</tr>
</tbody>
</table>

#### Concentration of CO₂

<table>
<thead>
<tr>
<th>Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CalCapture)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very Low</td>
</tr>
<tr>
<td>Low to Medium</td>
</tr>
</tbody>
</table>

#### LCFS Eligible?

<table>
<thead>
<tr>
<th>Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CalCapture)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes, plus Incremental Incentives</td>
</tr>
<tr>
<td>Depends on Use</td>
</tr>
</tbody>
</table>

Source: Internal estimates.
Strategic Partnership – A Structural Capital Advantage

Illustrative 2027 CO₂ Storage/Injection Goal Capital Funding Needs
assumes Brookfield fully participates in 5MMTPA of CTV JV projects

Est. Capital Required

- ~$2.5B Capital Outlay \(^1\)
- ~50% Equity  
  ~$1.25B
- ~50% Debt  
  ~$1.25B

Est. Pore Space Contribution

- 200MMT of CO₂ Pore Space
- $10/MT of CO₂ Storage Space

Ownership

CRC: 51%  
Brookfield: 49%

CRC’s Capital Contribution

- ~$613MM of Capital
- ~$980MM for Pore Space \(^2\)

Brookfield’s Capital Contribution

- ~$637MM of Capital
- ~$980MM for Pore Space

Projected Excess Capital Available for Early Stage CMB Expenses and Capital \(^3\)

- ~$980MM Est. Brookfield Pore Space Contribution
- ~$343MM Est. CRC’s Capital Contribution
- ~$637MM Available to fund CRC early stage CMB expenses and capital (represents approximately 5 years of spending and CMB 2023E Guidance of ~$70MM)

Improves & Increases Flexibility of CRC’s Capital Allocation Framework

- Capitalizes first 5MMTPA of projects and provides potential funding for CRC’s development of 200MMT of CO₂ storage by 2027
- CRC’s equity commitments for the first 5MMTPA are more than 2x covered by Brookfield’s initial commitment for projects jointly approved through the CTV JV
- Allows CRC to increase flexibility for shareholder returns strategy and explore strategic alternatives for low CI E&P business expansion

\(^1\) Assumes the average capital needs for 5MMTPA of Carbon Sequestration from the CTV JV economic “Type Curve”. See slides 19, 20 and 24 for detailed information on the previously disclosed Type Curve. Brookfield made an initial commitment of $500 million to invest in CCS projects that are jointly approved through the Carbon Terravault JV. The partnership is targeting 5MMTPA of CO₂ injection by YE 2027, aligned with CRC’s 2027 goals, thereby requiring an estimated ~$2.5B of capital. \(^2\) ~$980MM assumes 200MMT of CO₂ pore space for $10/MT of CO₂ storage. \(^3\) Results subject to effects of taxes, timing, pace of project development and Brookfield further approval to fund capital.
Illustrative CTV JV Type Curve Demonstrates Potential Valuation Upside

<table>
<thead>
<tr>
<th>First Full Year of Est. Impact</th>
<th>2026E</th>
<th>2028E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Est. CO2 Injection Rate per Year</td>
<td>1MMTPA</td>
<td>5MMTPA</td>
</tr>
<tr>
<td>Est. CTV JV EBITDA ($MM)</td>
<td>$50 - $135</td>
<td>$250 - $675</td>
</tr>
</tbody>
</table>

Example Strategic Partnership Economics

An average CTV project could generate on average $50 to $135 of EBITDA per metric ton injected per annum depending on project structure.

<table>
<thead>
<tr>
<th>Example CTV JV Project Economics – “TYPE CURVE”</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(PER MT OF INJECTED CO2)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Notes/Incorporated Assumptions</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Incentive Potential (LCFS + 45Q)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$/MT</td>
<td>$170</td>
<td>$205</td>
</tr>
<tr>
<td>45Q ($/MT): $85, LCFS ($/MT): $85 - $120, 100% LCFS eligibility</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Opex</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$/MT</td>
<td>$25</td>
<td>$75</td>
</tr>
<tr>
<td>Range reflects costs associated with full range of business model possibilities and includes G&amp;A of dedicated staff.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capex</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avg $/MT</td>
<td>$5</td>
<td>$20</td>
</tr>
<tr>
<td>Range of capital includes cost of capture facility and pipeline retrofit. Cost of capture facility depends on CO2 concentration at source. Pipeline costs depend on distance from source to sink and size of pipe. Pace of capex deployment is expected to be ~5% to ~10% of Total Project Capex in Year 1, ~10% to ~35% in Year 2 and ~55% to ~85% in Year 3. Depending on project structure and location, capex could be lower or higher than range represented.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note to Slide: Please see Slide 24 for important information regarding the assumptions used in the preparation of the information show on this slide. CTV JV economics are shared 51% to CRC and 49% to Brookfield. EBITDA is a non-GAAP measure.
ILLUSTRATIVE EBITDA\(^1\) VS CAPEX REQUIREMENTS FOR VARIOUS CO\(_2\) PROJECTS

**STORAGE ONLY PROJECTS**
- CTV JV is the off-taker of CO\(_2\) at storage site through Storage Co.
- Lower expected capital requirements for project development, including injection and monitoring wells, facilities and compression

**MID - HIGH CO\(_2\) CONCENTRATION PROJECTS**
(≥15% CO\(_2\) STREAM CONCENTRATION)
- CTV JV controls the entire value chain (capture to storage) and majority of the incentives
- Capital requirements for capture systems, while still significant, are expected to be on the lower end of the capture cost curve due to higher CO\(_2\) concentration of stream
- Project financing more likely vs. storage only and provides opportunity to increase levered returns
- Potential LCFS expansion could provide further EBITDA potential

**LOW CO\(_2\) CONCENTRATION PROJECTS**
(<15% CO\(_2\) STREAM CONCENTRATION)
- CTV JV controls value chain and incentive but lower expected IRR due to higher costs of capture (Ex: Natural Gas Combined Cycle Power Plants)
- Inflation Reduction Act of 2022 expands potential project opportunities
- Advancements in capture technology to play key role in improving project economics
- CARB considering new incentive programs to unlock traditionally hard to decarbonize sectors (e.g. cement)
- CalCapture\(^2\) is an advantaged low CO\(_2\) concentration project given its proximity to storage (insignificant transport capital)

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Note: Depicts illustrative examples of expected and estimated IRR, EBITDA and capital expenditure requirements based on internal estimates. Actual results could differ materially. (1) EBITDA is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors and assumes that 45Q wage and apprenticeship requirements are met. (2) CalCapture refers to CRC’s project at the Elk Hills Power Plant.
**Crude:** California crude prices generally moved in tandem with the broader market with realizations for Q1 2023 experiencing a degree of seasonal softness. For the balance of the year, local (permits), political (SPR) and geopolitical dynamics (OPEC+) appear to be the key determinants as to where prices trend in California.

**NGLs:** Relative to most of North America, NGL realizations in California for Q1 2023 remained well supported. A colder-than-normal weather pattern and logistical constraints impeding the ability of out-of-state product to make its way to California were the drivers. As we move out of Q1, we see realizations falling more in line with other North American markets.

**Natural Gas:** California natural gas prices reached historic levels early in Q1 2023. The remainder of the quarter was also quite strong. Colder-than-normal temperatures and limited quantities of natural gas in storage were the drivers. Prices in California, relative to other parts of North America, should remain well supported until such time as local storage inventories achieve more normalized levels.

**Power:** Declining out-of-state imports and colder-than-normal temperatures drove demand and prices for power in Q1 2023. With Western reservoirs full headed into the spring and summer, it remains to be seen what impact this will have on energy prices. Regardless, the market for capacity remains fierce as CAISO market participants struggle to meet capacity obligations.

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**CRC’s commodity realizations continue to trend above domestic WTI averages**

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**Strong Price Realizations in CA’s Unique Market Dynamics**

- **Oil w/ Hedges ($/BBL):**
  - 2Q22: $63.17
  - 3Q22: $62.45
  - 4Q22: $61.33
  - 1Q23: $63.04

- **Average Benchmark Prices:**
  - 2Q22: $111.79
  - 3Q22: $97.81
  - 4Q22: $88.60
  - 1Q23: $82.22

- **% of Benchmark:**
  - 2Q22: 100%
  - 3Q22: 100%
  - 4Q22: 98%
  - 1Q23: 96%

- **Hedge Settlements:**
  - 2Q22: ($49.15)
  - 3Q22: ($35.51)
  - 4Q22: ($25.82)
  - 1Q23: ($15.64)

- **Average Realized Prices:**
  - 2Q22: $63.17
  - 3Q22: $62.45
  - 4Q22: $61.33
  - 1Q23: $63.04

- **NGLs ($/BBL):**
  - 2Q22: $68.29
  - 3Q22: $57.68
  - 4Q22: $56.55
  - 1Q23: $58.88

- **Natural Gas ($/MCF):**
  - 2Q22: $6.72
  - 3Q22: $8.58
  - 4Q22: $8.73
  - 1Q23: $21.56

---

(1) Benchmark prices are based on Brent for oil and NGLs, and NYMEX average daily price for natural gas. (2) Average realized prices include hedges on oil and natural gas.
CRC's hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our team continues to evaluate CRC's hedging strategy based on prevailing market prices and conditions.

**Hedging Program**

**STRATEGY**

CRC’s hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our team continues to evaluate CRC’s hedging strategy based on prevailing market prices and conditions.

**HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 2023**

<table>
<thead>
<tr>
<th></th>
<th>2021</th>
<th>2022</th>
<th>1Q23</th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>2Q23E</th>
<th>3Q23E</th>
<th>4Q23E</th>
<th>2023E</th>
<th>2024E</th>
</tr>
</thead>
</table>

**OIL HEDGES**

*Date as of March 31, 2023*

**SOLD CALLS**

<table>
<thead>
<tr>
<th></th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>1H 2024</th>
<th>2H 2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barrels per Day</td>
<td>17,837</td>
<td>17,363</td>
<td>5,747</td>
<td>2,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Weighted-Average Price per Barrel</td>
<td>$60.00</td>
<td>$57.06</td>
<td>$57.06</td>
<td>$90.53</td>
<td>$90.53</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>1H 2024</th>
<th>2H 2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barrels per Day</td>
<td>19,475</td>
<td>17,897</td>
<td>27,094</td>
<td>3,500</td>
<td>1,000</td>
</tr>
<tr>
<td>Weighted-Average Price per Barrel</td>
<td>$70.48</td>
<td>$69.27</td>
<td>$70.73</td>
<td>$78.79</td>
<td>$77.20</td>
</tr>
</tbody>
</table>

**SWAPS**

<table>
<thead>
<tr>
<th></th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>1H 2024</th>
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<td>2,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Weighted-Average Price per Barrel</td>
<td>$76.25</td>
<td>$76.25</td>
<td>$76.25</td>
<td>$71.80</td>
<td>$66.25</td>
</tr>
</tbody>
</table>

**NET PURCHASED PUTS**

<table>
<thead>
<tr>
<th></th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>1H 2024</th>
<th>2H 2024</th>
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<td>$76.25</td>
<td>$76.25</td>
<td>$76.25</td>
<td>$71.80</td>
<td>$66.25</td>
</tr>
</tbody>
</table>

1) Hedges are based on weighted-average Brent prices per barrel. CRC also entered natural gas hedges which can be found in its 3Q22 10-Q. (2) Purchased and sold puts with the same strike price have been netted together. (3) Assumes commodity pricing remains at the similar levels as of March 31, 2023 and assumes a 2023 Brent price of $79.54 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.92 per mcf. (4) Represents estimated net cash settlement payments for derivative contracts as of 3/31/2023, except 2021, 2022 and 1Q23 which are actuals for the year ended on December 31, 2021, the year ended December 31, 2022 and the three months ended March 31, 2023, respectively. Historical settlements include natural gas derivatives put in place and can be found in CRC’s 3Q22 10-Q.
Maintaining Balance Sheet Strength, Liquidity, and Financial Flexibility

LIQUIDITY ROLL FORWARD¹

3/31/23 NET DEBT SNAPSHOT

($MM)

Revolving Credit Facility (RCF)¹ $ 0
7.125% Senior Notes 600
Face Value of Debt $ 600
Less Available Cash & Cash Equivalents (477)
Net Debt² $ 123

MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)

RCF Borrowing Base $ 1,200
1Q23 Free Cash Flow² $263
1Q23 Net Debt¹⁻² / LTM Adjusted EBITDAX² 0.1x
LTM Adjusted EBITDAX² / LTM Interest & Debt Expense, net 18.6x

1 Liquidity at 12/31/22 calculated as unrestricted cash of $307MM and $602MM capacity on CRC’s Revolving Credit Facility less $144MM in outstanding letters of credit. Liquidity at 3/31/23 calculated as unrestricted cash of $477MM and $602MM capacity on CRC’s Revolving Credit Facility less $148MM in outstanding letters of credit. (2) Adj. EBITDAX, Net Debt and Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (3) Undrawn revolver as of March 31, 2023. Subject to a springing maturity to August 4, 2025 if any of our Senior Notes are outstanding on that date.
Assumptions & Relevant Footnotes:

Slide 7:
- Margin is calculated as oil, natural gas and NGL sales, plus proceeds and less payments from settled derivatives, and less operating costs, transportation costs, taxes other than on income, general and administrative expenses and interest expense. Please see crc.com for historical percentage data.
- 2015 to 2019 Predecessor, 2020 combined and 2021 to 2022 Successor as described in Part L Item 7 – Basis of Presentation in CRC's 2022 Form 10-K.
- Assumes total incentive potential can be monetized through tax equity brokers and LCFS monetized in the LCFS trading market.
- Assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO2.
- Capex range assumes end-to-end value chain business model and low-end assumes carbon storage business model, both described on slide 19 of CRC’s Carbon Storage Update on October 6, 2021.
- Capex range assumes project capital of between $200MM and $800MM for an end-to-end business model. Project/partnership structures where CRC provides storage only could result in capital ranges below stated ranges.

Slide 8:
- Peers include: APA, BRY, CHK, CHRD, DVN, EOG, EQT, FANG, HES, MRO, MTDR, MUR, PDCE, PXD and SM. Dividend yield calculated on an annualized basis.
- Total return is calculated as the sum of all amounts paid for dividends and share repurchases from May 5, 2021 through March 31, 2023 divided by CRC’s market cap using 70,549,158 shares and an April 20, 2023 share price of $39.40. Total return does not include changes in share price over the applicable period.
- Dividends are subject to Board approval.
- Share repurchases and dividends are subject to Board approval.

Slide 13:
- 2023 guidance assumes a 2023 Brent price of $79.54 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.92 per mcf CRC’s share of production under PSCs decreases when commodity prices rise and increases when prices decline.
- 2023E guidance assumed a 2023 Brent price of $79.69 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.22 per mcf. CRC’s share of production under PSCs decreases when commodity prices rise and increases when prices decline.
- CMB Expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.
- A reconciliation of historical non-GAAP financial measures to the nearest GAAP equivalent and other additional information can be found on the Investor Relations page at www.crc.com. A GAAP reconciliation of forward-looking non-GAAP financial measures can be found in Attachment 7 to the Company's earnings release dated May 2, 2023, also available at www.crc.com.
- Adjusted E&P Capital and Adjusted CMB Capital are non-GAAP measures. These measures reflect the reclassification of $5 to $15 million from E&P, Corporate & Other Capital to Adjusted CMB Capital related to the expected 2023 investment in facilities to advance carbon sequestration activities beginning in 2023.

Slide 19:
- The information on Slide 19 is an example of project economics for the strategic partnership with Brookfield, which are shared 51% to CRC and 49% to Brookfield. The terms and availability of third-party sources of financing, if needed, could also affect returns and outcomes. The following assumptions were used in the preparation of the information present on Slide 19:
  - Assumes that projects are completed and online with no material delays or impediments to the issuance of necessary permits, government approvals, or third party third-party arrangements.
  - Assumes development at the mid-point of the CTV JV economic “Type Curve”.
  - Assumes 1MMT injected per year for 40-year project life.
  - Assumes Brookfield fully participates in CCS projects up to JV target of SMMTPA of injection and 200MMT of CO2 storage.
  - EBITDA amounts that are shown as a range assume the top and bottom ranges of the EBITDA assumptions and are multiplied by 1MM and 5MM to represent 1MMTPA of projects and 5MMTPA of projects, respectively. The EBITDA range presented has been reduced by –20% – 50% to reflect uncertainties related to project structure, financing and ownership.
  - EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors and assumes that 45Q wage and apprenticeship requirements are met. Based on incentives available under current regulatory framework.
  - Assumes total incentive potential can be monetized through tax equity brokers and LCFS monetized in the LCFS trading marketplace and recorded as revenue.
  - For simplicity, a 5-year accelerated straight line depreciation and amortization is assumed. Assumes no bonus depreciation. which may change based on further guidance from IRS and other factors.
  - Assumes that a project is cash flow positive in year 4 with payback period of ~ 4 to 6 years and reflects the midpoint of range estimates. Payback period is defined as total CRC investment / annual cash flow and is specifically for CTV JV project level economics.
  - High end of Opex range assumes end-to-end value chain business model and low-end assumes carbon storage business model, both described on slide 19 of CRC’s Carbon Storage Update on October 6, 2021.
  - Capex range assumes project capital of between $200MM and $800MM for an end-to-end business model. Project/partnership structures where CRC provides storage only could result in capital ranges below stated ranges.