United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 8-K

Current Report
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of Earliest Event Reported): January 5, 2024

California Resources Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware
(State or Other Jurisdiction of
Incorporation)

001-36478
(Commission
File Number)

46-5670947
(IRS Employer
Identification No.)

1 World Trade Center
Suite 1500
Long Beach
California
(Address of Principal Executive Offices)

90831
(Zip Code)

Registrant’s Telephone Number, Including Area Code: (888) 848-4754

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:
☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class
Common Stock
Trading Symbol(s)
CRC
Name of Each Exchange on Which Registered
New York Stock Exchange

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR §230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).
Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐
Item 7.01 Regulation FD.

On January 5, 2024, California Resources Corporation (the "Company") posted an updated investor presentation on its website at www.crc.com. The presentation is furnished as Exhibit 99.1 to this report on Form 8-K and is incorporated herein by reference.

The information contained in this report and the exhibit hereto shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and shall not be incorporated by reference into any filings made by the Company under the Securities Act of 1933, as amended, or the Exchange Act, except as may be expressly set forth by specific reference in such filing.

Statements contained in the exhibit to this report that state the Company’s or its management’s expectations or predictions of the future are forward-looking statements intended to be covered by the safe harbor provisions of the Securities Act and the Exchange Act. It is important to note that the Company’s actual results could differ materially from those projected in such forward-looking statements. Factors that could affect these results include those mentioned in the documents that the Company has filed with the Securities and Exchange Commission (the “SEC”).

The Company undertakes no duty or obligation to publicly update or revise the information contained in this report, although the Company may do so from time to time as management believes is warranted. Any such updating may be made through the filing of other reports or documents with the SEC, through press releases or through other public disclosure including disclosure in the Investor Relations portion of the Company’s website.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

<table>
<thead>
<tr>
<th>Exhibit No.</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>99.1</td>
<td>Investor Presentation dated January 5, 2024</td>
</tr>
<tr>
<td>104</td>
<td>Cover Page Interactive Data File (embedded within the Inline XBRL document).</td>
</tr>
</tbody>
</table>
Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

California Resources Corporation

/s/ Michael L. Preston
Name: Michael L. Preston
Title: Executive Vice President, Chief Strategy Officer and General Counsel

DATED: January 5, 2024
Table of Contents

ON PACE FOR STRONG YEAR END 2023 RESULTS

CARBON MANAGEMENT BUSINESS
- CENTRAL CALIFORNIA
- NORTHERN CALIFORNIA
- DAC HUB

APPENDIX
Expecting Strong Quarterly Results

4Q23E Total Production
82 – 84MMBOE/D
~60% Oil

4Q23E Total Capital
$65 – $75MM

4Q23E FCF1
$40 – $60MM

CRC is still preparing its reserve report for 2023, but does not currently expect to write down any reserves as a result of state regulatory or Kern County permitting matters.

ADVANCING CALIFORNIA'S LEADING CARBON MANAGEMENT BUSINESS
EPA Released California's First
Class VI Draft Permit
For 26R reservoir (part of CTV 1 storage vault)

38MMT of permitted injection capacity with an injection rate of up to ~1.5MMTPA1, both above type curve

Started 90-day public comment period

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1. 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. Free cash flow is equal to net cash provided (used) by operating activities less capital investments. Reconciliation of 4Q23E non-GAAP measure to its nearest GAAP equivalent can be found on slide 52 of this deck. (2) See CRC’s 3Q23 earnings presentation for a FY23 and 4Q23 guidance. (3) See slide 12 for more information on CTV 1 (26R) reservoir.
Preliminary 2024 E&P Business Outlook

LINE OF SIGHT TO WELL
PERMITTING PROGRESSION IN 2024
EXPECTED INVENTORY OF SIDETRACKS, WORKOVERS, NATURAL GAS TO INCREASE ACTIVITY IN 2H24

CONTRACTED CAPACITY REVENUE1 FROM EHPP TO INCREASE BY ~$45MM IN 2024 VS 2023E

ON PATH TO ACHIEVE $55MM + IN TARGETED YE2023 RUN RATE REDUCTIONS2 IMPLIES ~$2/BOE REDUCTION TO CRC’S OPERATING COST3

EST. ELK HILLS PLANTS TURNAROUND IMPACT IN 1Q24
20 MCFG/D | $34MM CAPITAL

(1) Capacity revenue is a part of electricity revenue on CRC’s income statement. (2) Includes YE2023 reduction in non energy operating costs and Adj. E&P corporate and other G&A. (3) Internal estimates.
Why California Resources Corporation?

LEADING CARBON MANAGEMENT BUSINESS

PREMIER BALANCE SHEET WITH STRONG FREE CASH FLOW GENERATION

STRONG SHAREHOLDER RETURNS STRATEGY

DISCIPLINED CAPITAL ALLOCATION
Carbon TerraVault – California’s Leading Carbon Management Platform

**CALIFORNIA LEADING CARBON MANAGEMENT PLATFORM**

- Identified up to 18MT\(^1\) CO\(_2\) storage in California
- Technological expertise, large scale project management, and financial capability
- Largest number of Class VI CO\(_2\) sequestration permits submitted to the EPA (191 MMT submitted)\(^2\)

**TRUSTED AND RESPONSIBLE PARTNER**

- Direct path to sustainably and meaningfully advance California’s climate goals
- In discussions with >20 MTTPA of potential emissions and 6 CDMs signed
- In partnership with Brookfield Renewable

**DESIGNED FOR LONG TERM SUCCESS**

- Scalable business model that drives value creation
- Total potential addressable California CCS market of 150 – 210 MTTPA\(^1\)
- Evaluating a potential standalone Carbon TerraVault entity

Note: please see slide 50 for details on the footnotes on this slide.
California Has the Largest Amount of Domestic Potential Incentives for CCS Growth

### Potential Economic Incentives

**FEDERAL 45Q TAX CREDIT**
- $45 (2026) Value for Carbon Storage (per MT of CO₂)

**CALIFORNIA LOW CARBON FUEL STANDARD (LCFS)**
- $169 - $66 Trading Range for 2022 -2023 YTD (per MT of CO₂)

**CALIFORNIA CAP & TRADE PROGRAM POTENTIAL**
- Average trading price YTD is ~$30 (per MT of CO₂)

**VOLUNTARY CARBON MARKET POTENTIAL**
- Engineered Carbon Dioxide Removal (CDR) credits market development in the most attractive market in the US with premium pricing for locational and quality differentiation.

### Supportive Domestic Regulatory Policies

- 200+ Policies or Incentives
- 101-200 Policies or Incentives
- 50-100 Policies or Incentives
- 50 or Less Policies or Incentives

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1. 45Q assumes wage and apprenticeship requirements are met.
2. Source: LCFS 2022 and 2023 YTD average prices per MT of CO₂ - The California Air Resources Board – average Type 1 transfer pricing as of August 24, 2023. 45Q assumes wage and apprenticeship requirements are met.
3. Source: CARB; California’s Cap and Trade program currently doesn’t cover CCS and requires regulatory changes to be implemented that may not materialize. Represents average auction prices for 2022 as of July 15, 2022. 4. There are currently no point source CCS projects generating CDR credits. Offsets new CCS industry verification protocols to be available in 2024. 5. Source: Database of State Incentives for Renewables & Efficiency (DSIRE) from the N.C. Clean Energy Technology Center, 2022.
# Application Requirements Capture ▪ In proximity to emitters eligible for LCFS and 45Q/V credits; and are also attracting greenfield projects focused on emerging energy technologies ▪ Strong historical relationships with major petrochemical complexes in CA ▪ Access to capital markets and innovation hubs ▪ Understanding of the commercial and engineering CO₂ capture market from CalCapture and DOE FEED study evaluation ———

**Transportation** ▪ Proximity to CO₂ sources ▪ Ability to leverage key infrastructure in place ▪ Access to supply chain distribution network ▪ Midstream experience ▪ Legal & regulatory structure is being developed by the state of CA ———

**Storage** ▪ Experienced subsurface, reservoir and injection management capabilities ▪ Fully developed static and dynamic reservoir models ▪ Largest fee position in the state ▪ Experience with municipal, county, state & federal permitting agencies ▪ Identified up to 1BMT of potential storage capacity ———

**Use** ▪ Proximity to CO₂ sources and petrochemical complexes ▪ Presence in the large consumption market ▪ Access to vast transportation & aerospace network

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**California’s economy could see rapid near-term emission reduction benefits from CCS**

- Immediate emissions reductions
- Clean, safe and affordable energy
- Low carbon baseload power
- Global technological leadership

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Note: (1) Source: Internal estimates, (2) CARB 2020.
California's Brownfield Emitters

- Brownfield emitters provide a decarbonized product by capturing the CO₂ molecules used in the creation of their products and transporting CO₂ for permanent storage.
- This lowers the carbon intensity of their product and the brownfield takes the decarbonized product to market.
- Decarbonization enabled by emissions which are transported by physical pipeline.

Conventional Brownfield CCS

- Greenfield projects provide product with an inherently lower carbon intensity than gray products.
- Greenfield decarbonized product acts as a substitute for gray product and captures market share.
- Decarbonization occurs via products which displace higher CI products thus creating a "Virtual Pipeline" that takes lower CI products to market rather than taking the CO₂ from gray products.

California Marketplace Demand

New California Greenfield Emitters

- California Marketplace Demand

Increasing Market Share

- Fully Decarbonized product reaches the market.
- Emissions injected into CO₂ Storage.

CRC can either help decarbonization efforts by taking CO₂ emissions from gray products or by enabling newer green products to displace gray emissions by taking market share.

California's Brownfield Emitters

- Gray Emissions are displaced with Greenfield products through substitution.
- "Virtual Pipeline" of CO₂ created via reduced demand for gray product.
Solidifying CTV Class VI Permitting Leadership

CTV Leads CA/Region 9 with EPA Class VI Permit Submissions

~10% of Currently Submitted EPA Class VI Permits are From CTV

EPA released Class VI Draft Permit for 26R (CTV I) reservoir at Elk Hills. 26R (CTV I) final permit approval would be first in California and first permit for storage into a depleted oil and gas reservoir. Proactively engaging with the local communities to share information about the positive benefits of these projects in the local communities.

EPA Projected Permit Timeline

1. Subject to issuance of EPA class VI permits. (2) Source: EPA Tracker, https://www.epa.gov/air/current-class-vi-projects-under-review.epm. One other project in Region 9 is under Completeness Review and another is projected to receive Final Permit in October 2025. (3) Projected to complete preparation of Final permit decision at the end of June '25.
EPA released Class VI Draft Permit for 26R (CTV I) reservoir
Targeting first CO₂ injection at CTV I by the end of 2025

<table>
<thead>
<tr>
<th>Vault</th>
<th>CTV I</th>
<th>CTV II</th>
<th>CTV III</th>
<th>CTV IV</th>
<th>CTV V</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA Permit Application Administratively Complete</td>
<td>Yes (26R)</td>
<td>Yes (A1-A2)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Targeting Class VI Draft EPA Permit Receipt</td>
<td>Released</td>
<td>~2024</td>
<td>~2024</td>
<td>~2024</td>
<td>~2025</td>
</tr>
<tr>
<td>California’s Basin</td>
<td>SJ Basin</td>
<td>Sacramento Basin</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Regional CO₂ Emissions³ (MMTPA)</td>
<td>~50</td>
<td>~60</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Est. Average Annual Injection Capacity⁴ (MMTPA)</td>
<td>~1.5³</td>
<td>0.2</td>
<td>~0.6</td>
<td>~1.8</td>
<td>~0.9</td>
</tr>
<tr>
<td>Potential Total Storage Capacity (MMTPA)</td>
<td>38</td>
<td>8</td>
<td>23</td>
<td>71</td>
<td>34</td>
</tr>
<tr>
<td>Remaining and Available CO₂ Injection Capacity (%)⁵</td>
<td>45%</td>
<td>100%</td>
<td>100%</td>
<td>~77%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Numbers might not add up due to rounding. Note: please see slide 50 for details on the footnotes on this slide.
CENTRAL CALIFORNIA
NORTHERN CALIFORNIA
DAC HUB

THE FOREFRONT OF CARBON MANAGEMENT
Leveraging CRC’s Flagship Elk Hills Asset with a CTV Clean Energy Park

Elk Hills provides ideal conditions to attract greenfield projects, given

- Large 47,000 acres land position at Elk Hills for potential infrastructure development
- Proximity to ~46MMT under Class VI permit application; most advanced EPA permit applications in the queue in California (filed in 2022)
- Additional Elk Hills reservoirs are currently being evaluated for new EPA Class VI permit applications

“We established ambitious and necessary goals to reduce carbon emission ... We provided the tools industry needs to capture and store carbon before it hits the atmosphere ... creating jobs that will support families across the state.”
- G. Newsom, Governor of California, November 16, 2022

Highlights CRC’s strong energy transition commitment through the economic repurposing of legacy assets and employment creation

- Provides incremental pore space to support the CTV Clean Energy Park
- Converts decommissioning liability from depleted reservoirs into revenue generating assets
- Access to land and amenities incentivizes low carbon investments
- Access to skilled energy transition workforce for operations and construction

Note: The exact project location within CTV Clean Energy Park at Elk Hills is TBD.
On Path To First Injection at CTV I (26R) in 2025

CTV I’S 26R RESERVOIR – THE FIRST SEQUESTRATION TARGET

<table>
<thead>
<tr>
<th>Est. CTV JV EBITDA2 ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRC</td>
</tr>
<tr>
<td>$90</td>
</tr>
</tbody>
</table>

~$80MM

Est. 26R reservoir’s EBITDA once fully subscribed

ESTIMATED CTV JV EBITDA2 ($MM) 2025 – 2030

U.S. EPA Released Draft Class VI Permit to CRC’s Carbon TerraVault 26R for CO2 Injection and Storage in California

STORAGE ONLY BUSINESS MODEL UNDER CDMa,2 TOTAL 26R

<table>
<thead>
<tr>
<th>Est. CO2 Injection Rate per Year (KTMPA)</th>
<th>~6551</th>
<th>Up to 1,4601</th>
</tr>
</thead>
<tbody>
<tr>
<td>Est. CTV JV EBITDA2 ($MM)</td>
<td>~$40</td>
<td>~$80</td>
</tr>
</tbody>
</table>

STORAGE ONLY PROJECTS AT 26R VAULT
(VARIETY OF CO2 STREAM CONCENTRATIONS)

- CTV JV is the off-taker of CO2 from the Clean Energy Park at the 26R storage site
- Expected capital requirements on lower end of type curve for storage projects only
- Co-location of projects at Clean Energy Park at Elk Hills will provide CTV JV oversight of the entire development while offering opportunities for synergies and organic growth
- Potential LOFS, Cap and Trade and/or Voluntary Carbon Credit Market expansion could provide further EBITDA potential
- CRC anticipates the majority of the 26R CCS development capital (net to CRC) to be covered by Brookfield Payments for their 49% working interest in the project

1. Actual results could differ materially. Presents estimated future EBITDA from the sequestration of CO2 related to (a) CRC’s decarbonization CCS project at Elk Hills gas plant where CRC intends to pay CTV JV a storage fee for its services, (b) projects subject to signed CDMa and (c) other projects that are not yet identified. Amounts shown are based on an estimated $55 of EBITDA per MT of CO2 storage for CRC’s decarbonization CCS project (assuming 100% MT of injected CO2) and the minimum volume commitments under existing CDMa. Our CDMa frame the anticipated contractual terms between parties and provide a path to reaching definitive agreements. The timing of yet to be identified CDMa and other CO2 injection projects is uncertain. The 26R reservoir is owned by the CTV JV and CRC’s share is 51% of associated EBITDA. 2. EBITDA is a non-GAAP measure, and estimates include tax credits which may change based on further guidance from IRS and other factors and assumes that all wage and apprenticeship requirements are met. (1) Includes CRC’s decarbonization CCS project at Elk Hills gas plant. (2) Total 26R injection capacity as per the draft EPA permit is 380MMT. Assuming the maximum expected injection rate of 1.46 MTMPA, the reservoir would reach capacity in 26 years. (3) See slide 43 for further details.
Announcing CRC’s First Capture to Storage Project at Elk Hills Gas Plant

PROJECT DETAILS FOR CAPTURE TO STORAGE PROJECT AT ELK HILLS

- CTV to construct a pre-combustion project at the CTV Clean Energy Park at Elk Hills to remove CO₂ from inlet gas, increasing operational efficiency of the cryogenic gas processing plant, improving propane recovery, and reducing the carbon intensity of the electricity generated from the Elk Hills Power Plant.

- Expected to capture 100 KMTPA of CO₂ and to be stored at CTV I storage vault.

- The capture project is targeting 450 credit generation as well as the potential for LCFS qualification and Cap & Trade (C&T) avoidance, and anticipates paying CTV JV an injection fee for CO₂ sequestration services.

- Project provides the ability to control the full CCS value chain.

- CTV JV storage only economics are in line with previously disclosed type curve².

- Capture + storage economics net to CRC are in line with previously disclosed IRR range² of 10% to 30%.

- Project FID targeted in 1H24; commercial operations targeted in 2H25.

Note: Due to CTV’s 51% ownership of the storage entity, CTV JV, the metrics above are shown on a storage-only basis for comparison purposes to previously announced projects.
Lone Cypress Energy Services, LLC, (Lone Cypress) has executed projects on behalf of some of the majors and largest E&P/Midstream companies in the energy sector with a variety of well-established strategic partners and industry leaders.

Lone Cypress’ specialized projects span large midstream systems, RNG facilities, carbon capture and storage systems, hydrogen production and generation, waste to energy plant solutions and traditional oil and gas midstream facilities.

Headquartered in Tulsa, OK, Lone Cypress offers a full suite of technology-enabled solutions.

CDMA DETAILS FOR LONE CYPRUS HYDROGEN FACILITY

- Lone Cypress to construct a 450 tons per day (TPD) clean hydrogen facility at the CTV Clean Energy Park at Elk Hills using its proprietary technology.
- CTV JV will provide permanent sequestration for 205 KMTPA using CTV I 2GR storage vault, including the lease of land for the clean hydrogen facility.
- Project FID targeted in 2024; commercial operations targeted in 2026.
- Combination of CTV I first storage project and Lone Cypress hydrogen facility could be eligible for 45Q or 45V tax credits as well as LCFS credits.
- CTV JV and Lone Cypress are also discussing CRC’s potential financial participation in the clean hydrogen facility, including potentially a significant equity stake.

Note: The exact Clean Hydrogen 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) This project would qualify for LCFS credits to the extent it sells clean hydrogen to the mobility market (e.g., hydrogen-powered vehicles). (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) Assumes 25-year project life. See slide 15 of this deck for the details on the CTV project economic type curve for the 2MR reservoir.
InEnTec Renewable Dimethyl Ether Facility

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.

CDMA DETAILS FOR INENTEC DIMETHYL ETHER (DME) FACILITY

- InEnTec to construct a facility that will use proprietary gasification technology to produce 90 to 100 tons per day (TPD) renewable dimethyl ether (DME) from biomass and other waste feedstock at the CTV Clean Energy Park.

- CTV will provide permanent sequestration initially for 300KMTPA of CO2 using CTV I storage vault, including the lease of land for the DME facility.

- Project PIP targeted in 2024; commercial operations targeted in 2026.

- CTV and InEnTec are also discussing CRC’s potential financial participation in the rDME facility, including potentially a significant equity stake.

Note: The exact DME facility’s location within CTV’s TCR is TBD. (1) Our CDMA frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements. (2) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 40% tax credits which may change based on further guidance from IRS and other factors. (3) Assumes a 25-year project life. See slide 15 of this deck for the details on the CTV project economic analysis for the 296h reservoir. (4) Superior Plus Energy Services Inc. (Superior) is a U.S. operating subsidiary of Superior Plus Corp. (TSX: SPU).
NLC Energy LLC, (NLCE) designs, builds, owns, and operates RNG facilities that convert organic waste into useful commodities like clean Renewable Natural Gas (RNG).

- Low-carbon RNG replaces higher-carbon fossil fuels across the transportation, utilities, and manufacturing sectors.
- The company is headquartered in Nashua, NH and has an operational RNG plant in Denmark, WI.

CDMA DETAILS FOR NLCE GREENFIELD RNG FACILITY:

- NLCE to construct a greenfield production facility at the CTV Clean Energy Park at Elk Hills that is expected to generate up to 7,000 MMBtu per day of RNG.
- CTV JV will provide permanent sequestration for 150 KMTPA of CO2 initially using CTV I storage vault, including the lease of land for the RNG facility.
- Project PID targeted for late 2024; commercial operations targeted in 2027.
- CTV JV and NLCE are also discussing CRC’s potential financial participation in the RNG facility.

CO2 INJECTION RATE (KMTPA):

- Project Est. Capital Requirements: $5 to $15 of capital per Mt of CO2 for a storage-only solution.
- Low-Carbon RNG replaces higher-carbon fossil fuels across the transportation, utilities, and manufacturing sectors.

PROJECT EST. EBITDA:

- Offtake Interest: Within our previously disclosed project curve of $5 to $75 of EBITDA per Mt of CO2 for a storage-only solution.

(1) CRC’s CDMA frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements. (2) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 415 tax credits which may change based on further guidance from IRS and other factors. (3) Assumes a 25-year project life. See slide 15 of this deck for the details on the CTV project economic type curve for the 25-year reserve.
Verde Renewable Gasoline Facility

About Verde

- Verde Clean Fuels, Inc. (Verde) focuses on supplying gasoline and other fuels derived from renewable feedstocks or natural gas.
- Verde utilizes its proprietary process to convert synthesis gas derived from biomass feedstocks, such as yard waste, agricultural waste, and sorted municipal solid waste, as well as stranded or flared natural gas (including renewable natural gas) into commodity-grade gasoline.
- Verde, headquartered in Houston, TX, has a fully operational demonstration plant in Hillsborough, NJ. Verde is listed on NASDAQ, trading under ticker symbol VGAS.

CDMA Details for Verde Renewable Gasoline Facility

- Verde to construct a facility at the CTV Clean Energy Park at Elk Hills that will use proprietary gasification technology targeted to produce ~7.5 million gallons per year (GPy) of renewable gasoline from biomass and other agricultural waste feedstock.
- CTV JV will provide permanent sequestration initially for 100 KMTPA of CO2 using CTV I storage vault, including the lease of land for the RG facility.
- Project FID targeted in 2025; commercial operations targeted in 2027.
- CTV JV and Verde are also discussing CRC’s potential financial participation in the renewable gasoline facility, including potentially a significant equity stake.

Note: The exact RG facility’s location within Elk Hills is TBD. (1) CRC’s CDMA focuses on anticipated contractual terms between parties and provides a path to reaching final definitive agreements. (2) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include AQZ tax credits which may change based on further guidance from IRS and other factors. (3) Assumes a 20-year project life. See slide 13 of the deck for the project economic type curve for the 20-year revenue.
CTV Storage Vaults in Northern California

- Approximately 145 MMT of CO₂ storage capacity vaults, or 3.7 MTPA expected injection rate, submitted by CRC to EPA for Class VI permits in Northern California.
- Northern California has ~34% of California’s existing emissions with most of them from hard-to-abate industrial sectors.
- Oakland is home to the ninth busiest container port in the United States where San Francisco Bay ranks among the four largest Pacific Coast ports for container cargo.
- Agribusiness & Food Manufacturing represents a ~$3B industry in the Sacramento region with ~$1B of annual industrial dollar volume surrounding Sacramento.
- Port of Stockton carries ~4MM tons of cargo every year and sits in the heart of the agricultural center of California.

CTV’s CO₂ storage assets are located in close proximity to the majority of existing emission sources in Northern California as well as potential to serve an emerging new energy economy.

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1. Includes CTV II, III, IV and V. 2. Source: CARB 2020, represents legacy emissions within 100 miles of CTV III CO₂ storage vault. 3. Source: Oakland Sea Port. 4. Source: City of Sacramento. 5. Source: CalFia. 6. Source: Port of Stockton.
Grannus Clean Ammonia Facility

370 KMTPA STORAGE ONLY PROJECT

CDMA DETAILS FOR GRANNUS CLEAN AMMONIA FACILITY

- Grannus to construct a 370KMTPA clean ammonia & 10KMTPA hydrogen facility near the CTV III location using its patented process design with commercial operations targeted by the end of 2027.
- CTV will provide permanent storage for 370KMTPA using its CTV III storage vault, including the CO₂ pipeline and the lease of land for the clean ammonia and hydrogen facility.
- Combination of CTV III’s storage project and Grannus’ clean ammonia and hydrogen facility will be eligible for 45Q or 45V tax credits as well as LCFS credits.
- CTV will have the right to take a minority stake in the total outstanding equity of the project company that holds the Grannus Clean Ammonia and Hydrogen Project.
- CTV will have an option to purchase equity in Grannus as well as a right of first refusal (ROFR) to provide storage services for subsequent Grannus ammonia and hydrogen projects in California.

ABOUT GRANNUS

- Grannus is an independent clean-tech company that is building a portfolio of clean ammonia and hydrogen production facilities to supply the agriculture, mobility and marine fuel markets.
- Grannus is using patented technologies that produce effectively no emissions and exceed the conversion efficiencies of today’s best in class clean ammonia and hydrogen production facilities’ designs.
- Headquartered in Tucson, AZ, Grannus offers a full suite of technology-enabled project development, project management and engineering solutions in the U.S. and North America.

Note: The exact Grannus Clean Ammonia and Hydrogen Project location within CTV III is TBD. Clean ammonia is produced with near zero, or minimal carbon emissions. (1) Our CDMA feeds the anticipated contractual terms between parties and provides a path to reaching FID definitive agreements. (2) This project would qualify for LCFS credits to the extent it sells the clean ammonia/hydrogen to the mobility market (e.g., hydrogen powered vehicles). (3) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits. (4) See exhibits 44 and 45 of this deck for the latest details on the CTV project economic type curve. (5) A binding off-take agreement with respect to the Grannus Clean Ammonia and Hydrogen Project related to CTV III is subject to evaluation and approval by Grannus and CALAMCO.
Clean Ammonia Will Help Accelerate The Decarbonization of CA’s Agricultural Sector

CLEAN AMMONIA – ENERGY TRANSITION MIX IN CALIFORNIA

- The U.S. is the world’s third largest producer of ammonia, consuming ~19.5MMTPA of ammonia which is mainly used in the agricultural sector (~88% of U.S. ammonia consumption was for fertilizer use)?
- CALAMCO represents the majority of agricultural ammonia demand in California where most of it is imported into Stockton, Sacramento and other entry points from other U.S. states and countries such as Trinidad and Tobago.
  - CALAMCO’s terminal at the Port of Stockton, the only ammonia marine import terminal in California, currently hosts 40,000 tons of ammonia storage tanks.
- California produced low carbon clean ammonia can replace imported grey ammonia to create local employment, lower the carbon intensity of fertilizers used in the agricultural sector (~9% of CA’s 2020 total GHG emissions) and further drive the technological evolution of the energy transition in California.

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.

1. Our CDMA frame the anticipated contractual terms between parties and provide a path to reaching final definition agreements. 2. This project would qualify for LCFS credits to the extent it sells the hydrogen to the mobility market (e.g., hydrogen-powered vehicles). 3. Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 450 tax credits which may change based on further guidance from IRS and other factors. 4. See slides 44 and 45 of this deck for the latest details on the CTV project economic type curve.

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 2026.

CTV will provide truck offloading facility and permanent sequestration for the initial 40 KMTPA 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.

Combination of CTV’s storage project and Yosemite’s hydrogen facility will be eligible for 45Q or 45V tax credits as well as LCFS credits.

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 180 KMTPA 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.

CO₂ INJECTION RATE

PROJECT EST. CAPITAL REQUIREMENTS ($/MT)

PROJECT EST. EBITDA ($/MT)

OFFTAKER INTEREST

CDMA DETAILS FOR YOSEMITE’S RENEWABLE FUELS PROJECT

WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE2 OF $5 TO $15 OF CAPITAL PER MT OF CO₂ FOR A STORAGE-ONLY SOLUTION

WITHIN OUR PREVIOUSLY DISCLOSED TYPE CURVE2 OF $50 TO $75 OF EBITDA2 PER MT OF CO₂ FOR A STORAGE-ONLY SOLUTION

Yosemite has entered into a letter of intent for a master hydrogen off-take agreement with GLUNVOR USA.
Accelerating Climate Leadership and Energy Transition Through Direct Air Capture (DAC)

Carbon TerraVault has formed a DAC Hub consortium to accelerate a Direct Air Capture and storage solution (DAC+S) for California through its wholly owned subsidiary CTV Direct.

WHAT IS DAC+S?
Direct Air Capture plus Storage (DAC+S) is a technological solution that can remove and then permanently store decades-old atmospheric carbon in underground reservoirs using low carbon emission energy. DAC+S reduces overall levels of CO₂ in the atmosphere and therefore is carbon negative.

WHAT IS A CALIFORNIA DAC HUB?
A newly formed consortium, led by CTV Direct, EPRI, and Kern Community College District (Kern CCD), seeks to bring together like-minded energy transition industry, technology, academic, non-profit, community, government, and labor participants with the main goal to create and accelerate the development of the State’s first full scale DAC+S hub.

WHY FORM A DAC CONSORTIUM IN CALIFORNIA?
California has ample access to sustainable Carbon Dioxide Removal (CDR) credits, advanced technologies, world-leading research institutions, and supportive government-driven financial incentives. CarbonTerraVault leads in EPA Class VI permit applications for CO₂ non-EOR storage reservoirs in California that are supplemented by extensive existing infrastructure that can be repurposed to further advance DAC+S across California. California has ambitious climate targets that require CDR for success.

WHY IS IT IMPORTANT?
Acceleration of DAC+S in California can provide positive economic impacts, create high-paying jobs, successfully and sustainably reduce CO₂ emissions, and help the state lead in the energy transition with long-lasting benefits for Californians and our communities.

1 CTV Direct is a wholly owned subsidiary of Carbon TerraVault focused on DAC. (2) Source: “Big tech’s carbon removal scheme announces its first purchasers”. Protocol. June 2022. (3) Source: EPA. (4) California’s leading goal for Carbon Direct Removal is 1.0 Mt CO₂, of which ~66 MMT CO₂ is projected to be from DAC per CARB Scoping Plan. Source: CARB.
Development Vision

HOW WILL IT BE DEVELOPED?

The first DAC Hub is targeted for Kern County and is expected to store CO₂ at the CTV I reservoir. The hub is expected to expand to other locations across the state to store CO₂ in non-EDR reservoirs while providing high-paying energy transition driven jobs and training programs for reskilling workers, and helping California reach its carbon removal goals.

HOW WILL THIS BE FUNDED?

In August of 2023, DAC Hub has been selected to receive ~$22MM in funding from the U.S. DOE under its Regional DAC Hubs Initiative related to the proposed development of California’s first full-scale DAC plus storage (DAC+X) network of regional hubs. With successful selection for the DOE funding, the DAC Hub could also qualify for additional funding from the OEC in the amount of $3MM.

The full cost to perform FEED studies, community benefits and engagement in 2024/25 on the proposed DAC facilities in Kern County is expected to be ~$24MM where the remainder of this amount will be split between the California DAC Consortium members.

In 2025, California DAC Hub is expecting to submit a subsequent funding request to the DOE under its Regional DAC Hubs Initiative for a potential total amount of $500MM which will include a planned development and construction plan.

California Direct Air Capture Hub

Potential total funding amount of ~$500MM²

Under the U.S. Department of Energy (DOE) Regional DAC Hubs Initiative

$180 Value (per MT of CO₂) for Carbon Storage³

LCFS Credits

Voluntary CDR Credits Market

Note: DOE = Department of Energy; (1) DOE has applied for EPA Class VI permits and the environmental review has begun for two initial permanent carbon capture and storage (CCS) units at the Da Vinci Field, which are collectively referred to as Carbon Terrestrial I; (2) CO₂ is establishing a program under which the Department of Energy will provide funding (total funding amount of $3.6 billion) for eligible projects that contribute to the development of new regional direct air capture hubs. Potential total funding amount for California DAC Hub was estimated per the latest funding opportunity announcement to potential domestic hubs. Total funding amount may vary based on DOE goals. Source: DOE (https://www.energy.gov/power/regional-direct-air-capture-hubs); (3) CO₂, (4) Source: LCFS PEG03053 weighted average price of $65 per MT of CO₂, (5) The California Air Resources Board.
Together We Can Achieve Bigger and “DAC” Things

Lead DOE Applicant Represents a Public-Private Partnership of Leading CA Community, Academic, DAC, and Carbon Storage Organizations
“California is pioneering new solutions to fight climate change. It’s not enough to cut emissions – we have to go further by actively removing carbon pollution from the atmosphere. This project will be the first of its kind in our state and will help us meet our world-leading climate goals.”

- G. Newsom, Governor of California, August 2023
Huntington Beach – Asset Optimization & Value Unlock

- 1 ACRE PARCEL – FT APACHE
  - 1810 Pacific Coast Highway, Huntington Beach, CA
  - Completed the abandonment of six wells
  - In the process of completing surface abandonment
  - Targeting call for offers for ~1 acre parcel of land (Fort Apache) in 1Q24
  - Planning to provide additional details with 4Q23/YE23 results

- Over 1 mile of direct access to Pacific Coast Highway

- ~90 ACRES PARCEL – HUNTINGTON BEACH
  - Continuing the re-zoning, re-entitlements and due diligence processes
  - Multi year process
  - Developing strategy to optimize production and ARO schedule
    - Huntington Beach field 2022 gross production¹ was ~3,000 BOPD
    - The field is connected to a producing offshore platform Emmy
    - Free cash flow² generating asset
    - Plugged and abandoned 20 wells year to date
    - Targeting to P&A an additional 40 wells in 2024

Source: Newmark

¹ Represents a non-GAAP measure. For all historical non-GAAP financial measures, please see the Investor Relations page at www.ocr.com for a reconciliation to the nearest GAAP equivalent and other additional information. Free cash flow is equal to operating cash flow less total capital requirements.
Transforming the Way We Operate for a Long-Term Outlook

- Transforming the way we operate to improve margins and drive higher cash flows
- Utilizing Alvarez & Marsal’s industry experience and proprietary PeerView E&P benchmarking and analytics

**Focus Areas:**
- Non Energy Operating Costs
- Adj. E&P Corp. & Other G&A

$55MM +
Targeted YE2023 run rate² reduction

**Opportunity Identification**
- Identified major cost saving opportunities
- Evaluating additional operational efficiencies

**Deployment & Integration**
- Implement identified cost saving opportunities
- Integrate process improvements into operating model

**Long-Term Vision**
- Lock-in operational efficiencies and cost reductions
- Organizational alignment

---
(1) Represents a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.cnco.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) Current 2023 guidance doesn’t include targeted cost reduction initiatives. Excludes CTV from the scope of this initiative.
Sustainability Is In Our Business Model

2022 Sustainability Update

Targets
- Reduce or Offset Scope 1, 2 & 3 Emissions
  100% by 2045
- Reduce Methane Emissions
  30% from 2020 levels by 2030

Progress
- Reduced Scope 1 & 2 Emissions
  9.5% from 2020 to 2022
- Reduced Methane Emissions
  15.5% from 2020 to 2022

ESG Milestones

CO₂ Removal
Announced a California DAC Hub with a purpose to permanently store atmospheric CO₂ using low carbon emission energy and provide economic benefits to surrounding communities

Carbon Management
Submitted 191MMT of CO₂ Reservoirs to EPA for Class VI permits in five carbon vaults with many more in development; leading the nation in Class VI permit applications

Governance
Investor-favored changes including the removal of Supermajority votes. Board exhibited diversity with 33% being gender diverse and 44% consisting of members from underrepresented communities.

Community
Pledged $2.5MM to fund several Kern County initiatives to advance the energy transition
Differentiated and Diversified Asset Base Across California

LA BASIN

THUMS Islands

SACRAMENTO BASIN

Largest Natural Gas Producer in California

SAN JOAQUIN BASIN

San Joaquin Valley

Huntington Beach

Midstream Infrastructure at Elk Hills

NG Processing Plant & 550MW Power Plant at Elk Hills

CRC Holds ~1.9MM Net Mineral and ~ 100K Surface Acres

Note: The above pictures were taken by CRC and represent its current properties and assets.
Long Durability, Low Decline & Low Carbon Intensity O&G Assets

~13 years of low carbon intensity multi year production runway

LONG DURABILITY 1P ASSETS

<table>
<thead>
<tr>
<th>Basin</th>
<th>MMBoe</th>
<th>% Oil</th>
<th>Est. Annual Decline</th>
<th>1H23 Average Net Production</th>
<th>R/P</th>
<th>NRI (s/h)</th>
<th>CO2 (Scope 1+2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sacramento Basin</td>
<td>100%</td>
<td>9</td>
<td>-13%</td>
<td>3</td>
<td>-9</td>
<td>-82%</td>
<td>9.3</td>
</tr>
<tr>
<td>San Joaquin Basin</td>
<td>87%</td>
<td>-62%</td>
<td>-12%</td>
<td>66</td>
<td>-12</td>
<td>-92%</td>
<td>7.5</td>
</tr>
<tr>
<td>Los Angeles Basin</td>
<td>85%</td>
<td>-99%</td>
<td>-7%</td>
<td>19</td>
<td>-15</td>
<td>-71%</td>
<td>5.6</td>
</tr>
</tbody>
</table>

We See a Long-Term Need in California for CRC's Low Carbon Intensity Barrel & Carbon Management Strategy

Note: please see slide 50 for details on the footnotes on this slide.
California Needs Low Carbon Intensity Domestic Natural Gas

**POWER AND INDUSTRY CONSUME ~70% OF THE STATE’S NATURAL GAS**

California’s Natural Gas Demand (Bcf/d)

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Electric Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>1.7</td>
<td>2.1</td>
<td>0.7</td>
<td>1.2</td>
</tr>
<tr>
<td>2019</td>
<td>1.6</td>
<td>2.1</td>
<td>0.7</td>
<td>1.3</td>
</tr>
<tr>
<td>2020</td>
<td>1.7</td>
<td>1.9</td>
<td>0.6</td>
<td>1.3</td>
</tr>
<tr>
<td>2021</td>
<td>1.7</td>
<td>1.9</td>
<td>0.7</td>
<td>1.2</td>
</tr>
<tr>
<td>2022</td>
<td>1.8</td>
<td>1.6</td>
<td>0.7</td>
<td>1.1</td>
</tr>
</tbody>
</table>

**EVEN IN 2045, NATURAL GAS POWER PLANTS PLAN TO CONTRIBUTE 12%**

Total Capacity (Giga-watts)

- California continues to need a consistent and reliable supply of electricity from natural gas power plants through 2045.
- California imports ~4.6 Bcf/d or ~90% of its demand from regions that frac for natural gas.
- CRC expects natural gas to play a key role in supporting energy transition.
- CA imports 90% of its gas needs. Lack of flexibility with the legacy natural gas infrastructure will continue to drive elevated prices and volatility in periods of high demand.
- CRC expects relatively strong natural gas prices with the premium to Henry Hub to continue.

---

(1) EIA excludes Vehicle Fuel which was less than 0.029 mcf/d from 2016 to 2022
(2) CARB Scoping Plan 2022
(3) Other includes pumped storage, tidal, DR, geothermal, nuclear, biomas, O&P and coal
(4) CARB's internal estimates
CRC’s Natural Gas Inventory Depth – 1Tcf\(^1\) Opportunity

CRC’s Opportunity Set\(^1\) by Basin

- **Sacramento Basin** Opportunity Set\(^1\)
  - ~110 Bcf of actionable inventory
  - Resource:
    - >250 Bcf of dry gas
    - ~300 locations

- **San Joaquin Basin** Opportunity Set\(^1\)
  - ~700 Bcf of actionable inventory
  - Resource:
    - >800 Bcf of associated gas
    - ~1,100 locations

CALIFORNIA’S NATURAL GAS FORWARD CURVES\(^2\)

<table>
<thead>
<tr>
<th>Year</th>
<th>NYMEX HH</th>
<th>PG&amp;E City-gate</th>
<th>SoCal Border</th>
<th>SoCal City-gate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2023 YTD</td>
<td>$3.85</td>
<td>$5.42</td>
<td>$4.93</td>
<td>$5.98</td>
</tr>
<tr>
<td>2024</td>
<td>$4.00</td>
<td>$5.50</td>
<td>$5.00</td>
<td>$6.00</td>
</tr>
<tr>
<td>2025</td>
<td>$4.20</td>
<td>$5.60</td>
<td>$5.20</td>
<td>$6.20</td>
</tr>
<tr>
<td>2026</td>
<td>$4.40</td>
<td>$5.70</td>
<td>$5.40</td>
<td>$6.40</td>
</tr>
<tr>
<td>2027</td>
<td>$4.60</td>
<td>$5.80</td>
<td>$5.60</td>
<td>$6.60</td>
</tr>
<tr>
<td>2028</td>
<td>$4.80</td>
<td>$5.90</td>
<td>$5.80</td>
<td>$6.80</td>
</tr>
<tr>
<td>2029</td>
<td>$5.00</td>
<td>$6.00</td>
<td>$6.00</td>
<td>$7.00</td>
</tr>
<tr>
<td>2030</td>
<td>$5.20</td>
<td>$6.10</td>
<td>$6.20</td>
<td>$7.20</td>
</tr>
<tr>
<td>2031</td>
<td>$5.40</td>
<td>$6.20</td>
<td>$6.40</td>
<td>$7.40</td>
</tr>
<tr>
<td>2032</td>
<td>$5.60</td>
<td>$6.30</td>
<td>$6.60</td>
<td>$7.60</td>
</tr>
</tbody>
</table>

Note: please see slide 50 for details on the footnotes on this slide.
Partnered with ICE Thermal Harvesting ("ICE"), who was awarded a ~$2MM "Wells of Opportunity" grant from the DOE.

- Provides an avenue for CRC to pilot a new zero-carbon energy technology.
- Potential commercial benefits: field electrical cost reductions, decreased emissions, postponement of asset retirement obligations, increased reliability of power and improved economics.
- Project kicked off in October 2022 and is expected to last 3 to 4 years with a potential for free zero-emissions electricity capable to power 6 wells.
- Initial planned location at Elk Hills with prospects to expand this technology to other fields or to other applications.
- Areas of Elk Hills, Buena Vista, Yowlumne, Kern Front, and Kettleman are associated with geothermal opportunities.
Solar Developments on Track

SELF SUPPLY | BEHIND THE METER UPDATE:
Progressing our solar developments:

- **38 MW**
  - of BTM projects in development

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mount Poso</td>
<td>12</td>
<td>2H24</td>
<td>15% - 25%</td>
</tr>
<tr>
<td>Kern Front</td>
<td>22</td>
<td>1H25</td>
<td>15% - 25%</td>
</tr>
<tr>
<td>Other</td>
<td>4</td>
<td>TBD</td>
<td>TBD</td>
</tr>
</tbody>
</table>

- **Mt. Poso & Kern Front:**
  - Projects are in the Net Energy Metering (NEM) 2.0 program
  - Front-end engineering and design packages completed
  - Kern Front grading permit submitted and construction start expected after permit issuance
    - Received grading permit for Mount Poso; targeting construction in Q1 2024
  - Continue to advance additional 4MW of BTM projects across CRC’s operations

GRID SUPPLY | FRONT OF THE METER UPDATE:
- CRC has identified over 5,000 acres of surface potentially suitable for utility scale solar development that could present future value for CRC and investors
  - Potential for 300 to 1,000 MW with 3 core projects preliminarily identified
  - Evaluating further FTM opportunities in future Interconnection Cluster Studies
  - Potential to further reduce CO₂ emissions while adding further commercial opportunity

(1) Other includes sites across CRC’s asset base. (2) www.cpuc.ca.gov
Decarbonizing California and Building a CTV Driven Energy Transition Ecosystem

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.)

<table>
<thead>
<tr>
<th>Project Type</th>
<th>DAC</th>
<th>Renewable Diesel/Gas</th>
<th>Ammonia</th>
<th>Hydrogen</th>
<th>Ethanol</th>
<th>Existing Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Emitter</td>
<td>Tech</td>
<td>Greenfield</td>
<td></td>
<td></td>
<td></td>
<td>Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CCUS)</td>
</tr>
<tr>
<td>Cost of Capture ($/TCO₂)</td>
<td>Very High</td>
<td>Medium</td>
<td>Low</td>
<td>Medium</td>
<td>Low</td>
<td>Medium to High</td>
</tr>
<tr>
<td>Concentration of CO₂</td>
<td>Very Low</td>
<td>Medium</td>
<td>High</td>
<td>Medium</td>
<td>High</td>
<td>Low to Medium</td>
</tr>
<tr>
<td>LOS Eligible?</td>
<td>Yes, plus Incremental Incentives</td>
<td>Depends on Use</td>
<td>Depends on Use</td>
<td>Yes</td>
<td>Depends on Use</td>
<td></td>
</tr>
</tbody>
</table>

Source: Internal estimates

[Map of California with various locations and project types]
Strategic Partnership – A Structural Capital Advantage

Illustrative 2027 CO₂ Storage/Injection Goal Capital Funding Needs¹

<table>
<thead>
<tr>
<th>Est. Capital Required</th>
<th>Est. Pore Space Contribution</th>
<th>200MMT of CO₂ Pore Space</th>
</tr>
</thead>
<tbody>
<tr>
<td>~50% Equity ~$1.25B</td>
<td>~50% Debt ~$1.26B</td>
<td>$10/MT of CO₂ Storage Space</td>
</tr>
</tbody>
</table>

Ownership

| 51% | 49% |
|CRC  | Brookfield |

---

2022 GOAL

CRC Capital Contribution

~$637MM of Capital

Brookfield's Capital Contribution

~$613MM of Capital

Project Excess Capital Available for Early Stage CMB Expenses and Capital²

~$980MM Est. Brookfield Pore Space Contribution

~$637MM Est. CRC’s Capital Contribution

~$343MM Available to fund CRC early stage CMB expenses and capital (represents approximately 5 years of spending and CMB 2023E Guidance of ~$70MM)

---

¹ Assumes the average capital needs for 5MTPA of projects that are fully approved through the CTV JV, Brookfield’s initial commitment of $500 million to invest in CO₂ projects that are fully approved through the CTV JV, and the partnership is targeting 5MTPA of CO₂ injection by YE 2023.
² Results subject to effects of tax credit, timing, pace of project development and Brookfield’s further approval to fund capital.

---

Improves & Increases Flexibility of CRC’s Capital Allocation Framework

- Capitalizes first 5MTPA of projects and provides potential funding for CRC’s development of 200MMT of CO₂ storage by 2027
- CRC’s equity commitments for the first 5MTPA 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 CO₂ E&P business expansion

---

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CTV JV – Vault Dropping Mechanism

CTV presented subsequent reservoirs to CTV JV with a combined capacity of 163MMT

If Accepted:
- Brookfield to Pay Initial Payment ($10/Ton x Permitted Pore Space x 49% / 3)
- Brookfield to Pay Milestone Payment at Permit Public Comment Expiration ($10/Ton x Permitted Pore Space x 49% / 3)
- Brookfield to Pay Milestone Payment at FID ($10/Ton x Permitted Pore Space x 49% / 3)

Brookfield Retains the Right to Defeat the Approval Decision Through FID
If Deferred, Projects to be Re-presented to Brookfield at FID
- If Approved, Brookfield to Pay Lump Sum for Full Buy-in ($10/Ton x Permitted Pore Space x 49%) + 10% Carry2 to CRC
- If Rejected, CRC is Free to Develop the Reservoir / Project Outside of the CTV JV

Note: CTV JV terms simplified for illustrative purposes. Sources: Internal notes and/or Brookfield. (1) As it pertains to a previously committed reservoir, if this coal reservoir is not interested in jointly pursuing a specific opportunity, CRC reserves the right to sell back up to 20% of the permitted pore space to a new entity or an equivalent opportunity or as its own accord. (2) Brookfield pays 10% Carry to CRC corresponding to their 49% interest in the CTV JV reservoir in excess of 100% of FID. The condensed nature of this presentation enables the reader to identify the relationship of the 10% carry to the 49% equity. (3) Scope to re-present project as per terms outlined in the draft EOA parcel of SMNT. (4) Calculated from data of initial ROFL presentation at carbon milestone, (5) Brookfield fully participates in CCS projects up to JV target of 8MMT of injection and 25MMT of CO2 storage.
Illustrative CTV JV Type Curve Demonstrates Potential Valuation Upside

Example Strategic Partnership Economics
CTV project could generate an 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>Unit</th>
<th>Low</th>
<th>High</th>
<th>Notes/Incorporated Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Incentive Potential (LOFS + 40Q)</td>
<td>$/MT</td>
<td>$170</td>
<td>$205</td>
<td>40Q ($/MT); $85, LOFS ($/MT); $85 - $120, 100% LOFS eligibility</td>
</tr>
<tr>
<td>Opex</td>
<td>$/MT</td>
<td>$10</td>
<td>$75</td>
<td>Range reflects costs associated with full range of business model possibilities and includes G&amp;A of dedicated staff.</td>
</tr>
<tr>
<td>Capex</td>
<td>Avg</td>
<td>$5</td>
<td>$20</td>
<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 -25% in Year 2 and -25% to -40% in Year 3. Depending on project structure and location, capex could be lower or higher than range represented.</td>
</tr>
</tbody>
</table>

Note: See Slide 51 for important information regarding the assumptions used in the preparation of the information shown on this slide. CTV JV economics are shared 51% to CRC and 49% to Brookfield. EBITDA is a non-GAAP measure.
Large Opportunity Set With a Variety of Potential Emitters

**ILLUSTRATIVE EBITDA VS CAPEX REQUIREMENTS FOR VARIOUS CO₂ PROJECTS**

**STORAGE ONLY PROJECTS**
- CTV JV is the off-taker of CO₂ at storage site through Storage Co.
- Lower expected capital requirements for project development, including injection and monitoring wells, facilities and compression

**MID - HIGH CO₂ CONCENTRATION PROJECTS**
(≥15% CO₂ 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 CO₂ concentration of stream
- Project financing more likely vs. storage only and provides opportunity to increase levered returns
- Potential LCF expansion could provide further EBITDA potential

**LOW CO₂ CONCENTRATION PROJECTS**
(<15% CO₂ 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 is an advantaged low CO₂ concentration project given its proximity to storage (insignificant transport capital)

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 R&D 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 Ex-Kills Power Plant.
Wilmington Production Sharing Contracts (PSC) At Higher Commodity Prices

For every $1/BBL increase/decrease in Brent price, we expect a ~90 BOD decrease/increase in our net oil production related to PSCs.

Approximately 30% of CRC’s oil production is subject to PSCs Mechanics:
- As operator, CRC pays our partners’ share of the Operating and Capital Cost
- CRC recovers our partners’ share of operating and capital costs through production sharing, where CRC’s cost recovery is reported as revenue
- CRC receives 45-49% of the gross production as “Profit Barrels” after cost recovery
- CRC’s net share of production includes cost recovery and profit barrels

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

CRC sees a difference of ~5.3 MBOD in net oil production between $65/BBL and $115/BBL.

**EFFECT OF OIL PRICE ON NET PRODUCTION**

<table>
<thead>
<tr>
<th>Brent Price ($/BBL)</th>
<th>Net Production GBD</th>
<th>Net Production Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>$60</td>
<td>-180 BOD</td>
<td>-3.4 MBOD increase in net production</td>
</tr>
<tr>
<td>$65</td>
<td>0 BOD</td>
<td></td>
</tr>
<tr>
<td>$70</td>
<td>90 BOD</td>
<td>~1.9 MBOD decrease in net production</td>
</tr>
<tr>
<td>$75</td>
<td>0 BOD</td>
<td></td>
</tr>
<tr>
<td>$80</td>
<td>90 BOD</td>
<td></td>
</tr>
<tr>
<td>$85</td>
<td>180 BOD</td>
<td></td>
</tr>
<tr>
<td>$90</td>
<td>0 BOD</td>
<td></td>
</tr>
<tr>
<td>$95</td>
<td>90 BOD</td>
<td></td>
</tr>
<tr>
<td>$100</td>
<td>180 BOD</td>
<td></td>
</tr>
<tr>
<td>$105</td>
<td>0 BOD</td>
<td></td>
</tr>
<tr>
<td>$110</td>
<td>90 BOD</td>
<td></td>
</tr>
<tr>
<td>$115</td>
<td>180 BOD</td>
<td></td>
</tr>
<tr>
<td>$120</td>
<td>0 BOD</td>
<td></td>
</tr>
</tbody>
</table>

(1) Based on Brent price of $90 per barrel of oil. (2) Net Production from Wilmington field only. Includes the effects of a development program in LA Basin.
**Strong Price Realizations in CA’s Unique Market Dynamics**

- **Crude:** California crude prices continued to move in tandem with the broader market with realizations for 3Q23 firming slightly from 2Q23. For the balance of the year, local (permits, refining margins & outages) and geopolitical dynamics (OPEC+ central bank policies, Middle East tensions) remain key determinants as to where prices will trend in California.

- **NGLs:** 3Q23 NGL prices across North America continued to weaken driven by seasonal trend and general oversupply. As reflected within 2023 realizations - and as projected for the balance of the year - California has been and should remain a premium-priced NGL marketplace.

- **Natural Gas:** California 3Q23 natural gas prices increased relative to 2Q23 as storage inventories were replenished. A material increase in Aliso Canyon natural gas storage capacity stands to support prices this Fall while - along with an abundance of hydro generation capacity - limiting the potential for gas price run-ups this Winter.

- **Power:** As measured on year/year basis, 3Q power prices retreated on the back of record snowpack & hydro output, incremental on-peak solar output, and uncharacteristically mild weather.

---

### Oil w/ Hedges ($/BBL)

<table>
<thead>
<tr>
<th></th>
<th>4Q22</th>
<th>1Q23</th>
<th>2Q23</th>
<th>3Q23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Benchmark Prices $1</td>
<td>$61.33</td>
<td>$63.04</td>
<td>$63.66</td>
<td>$66.12</td>
</tr>
<tr>
<td>% of Benchmark $2</td>
<td>96%</td>
<td>96%</td>
<td>97%</td>
<td>99%</td>
</tr>
<tr>
<td>Hedge Settlements $2</td>
<td>$(-7.02)</td>
<td>$(-7.01)</td>
<td>$(-13.11)</td>
<td>$(-19.24)</td>
</tr>
<tr>
<td>Average Realized Prices $2</td>
<td>$61.33</td>
<td>$63.04</td>
<td>$63.66</td>
<td>$66.12</td>
</tr>
</tbody>
</table>

### NGLs ($/BBL)

<table>
<thead>
<tr>
<th></th>
<th>4Q22</th>
<th>1Q23</th>
<th>2Q23</th>
<th>3Q23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Benchmark Prices $1</td>
<td>$56.96</td>
<td>$58.88</td>
<td>$42.48</td>
<td>$45.06</td>
</tr>
<tr>
<td>% of Benchmark $2</td>
<td>94%</td>
<td>64%</td>
<td>72%</td>
<td>54%</td>
</tr>
<tr>
<td>Hedge Settlements $2</td>
<td>$(-6.7)</td>
<td>$(-7)</td>
<td>$(-5.1)</td>
<td>$(-5.2)</td>
</tr>
<tr>
<td>Average Realized Prices $2</td>
<td>$56.96</td>
<td>$58.88</td>
<td>$42.48</td>
<td>$45.06</td>
</tr>
</tbody>
</table>

### Natural Gas ($/MCF)

<table>
<thead>
<tr>
<th></th>
<th>4Q22</th>
<th>1Q23</th>
<th>2Q23</th>
<th>3Q23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Benchmark Prices $1</td>
<td>$8.73</td>
<td>$12.68</td>
<td>$3.46</td>
<td>$4.83</td>
</tr>
<tr>
<td>% of Benchmark $2</td>
<td>113%</td>
<td>65%</td>
<td>165%</td>
<td>189%</td>
</tr>
<tr>
<td>Hedge Settlements $2</td>
<td>$(-0.22)</td>
<td>$(-0.24)</td>
<td>$(-0.24)</td>
<td>$(-0.24)</td>
</tr>
<tr>
<td>Average Realized Prices $2</td>
<td>$8.51</td>
<td>$12.15</td>
<td>$3.46</td>
<td>$4.83</td>
</tr>
</tbody>
</table>

---

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.

---

**CALIFORNIA IS AN OIL ISLAND AND THE LARGEST U.S. GDP CONTRIBUTOR**

(amounts shown as % of U.S. domestic GDP)

Note: All largest contribution to domestic GDP. Source: BEA, Data from: 02/2023 EIA.
Hedging Program

Strategy
CRC’s hedging strategy is designed to meet our business objectives should market prices decline and participate should market prices increase.

2024 Crude Revenue Net Hedge Settlement Sensitivity to Brent Price

<table>
<thead>
<tr>
<th>Est. 2024 Brent Price (~$80/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$40</td>
</tr>
<tr>
<td>CRC Realized Price ($/bbl)</td>
</tr>
<tr>
<td>$500</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2024 CRUDE REVENUE</th>
<th>($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Revenue</td>
<td>$500</td>
</tr>
<tr>
<td>Net Hedge</td>
<td>$700</td>
</tr>
</tbody>
</table>

Oil Hedges
As of September 30, 2023

<table>
<thead>
<tr>
<th>4Q23</th>
<th>1Q24</th>
<th>2Q24</th>
<th>3Q24</th>
<th>4Q24</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bbls per Day</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5,747</td>
<td>23,650</td>
<td>30,000</td>
<td>30,000</td>
<td>26,000</td>
<td>16,748</td>
</tr>
<tr>
<td>Weighted Average Price per Barrel</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>$57.06</td>
<td>$90.00</td>
<td>$90.07</td>
<td>$90.07</td>
<td>$90.07</td>
<td>$85.83</td>
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</tbody>
</table>

Swaps

<table>
<thead>
<tr>
<th>4Q23</th>
<th>1Q24</th>
<th>2Q24</th>
<th>3Q24</th>
<th>4Q24</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bbls per Day</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>21,044</td>
<td>9,000</td>
<td>7,760</td>
<td>7,760</td>
<td>5,800</td>
<td>3,374</td>
</tr>
<tr>
<td>Weighted Average Price per Barrel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$70.73</td>
<td>$79.37</td>
<td>$79.65</td>
<td>$79.64</td>
<td>$77.45</td>
<td>$72.66</td>
</tr>
</tbody>
</table>

Net Purchased Puts

<table>
<thead>
<tr>
<th>4Q23</th>
<th>1Q24</th>
<th>2Q24</th>
<th>3Q24</th>
<th>4Q24</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bbls per Day</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5,747</td>
<td>30,084</td>
<td>30,000</td>
<td>30,000</td>
<td>29,000</td>
<td>16,748</td>
</tr>
<tr>
<td>Weighted Average Price per Barrel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$76.25</td>
<td>$67.27</td>
<td>$65.17</td>
<td>$65.17</td>
<td>$65.17</td>
<td>$60.00</td>
</tr>
</tbody>
</table>

Hedge Contract Settlements Expected to Significantly Decrease in 4Q23 and Beyond

Actual & Estimated Hedge Contract Settlements ($MM)

<table>
<thead>
<tr>
<th>2021</th>
<th>2022</th>
<th>1Q23</th>
<th>2Q23</th>
<th>3Q23</th>
<th>4Q23</th>
<th>2023E</th>
<th>2024E</th>
<th>2025E</th>
</tr>
</thead>
<tbody>
<tr>
<td>($319)</td>
<td>($798)</td>
<td>($105)</td>
<td>($95)</td>
<td>($75)</td>
<td>($100)</td>
<td>($95)</td>
<td>($35)</td>
<td>($20)</td>
</tr>
</tbody>
</table>

1. Hedge position as of September 30, 2023, includes deferred option premium payment. For the purposes of this example, assume CRC physical sales realize 100% of Brent price. (2) Hedges are based on weighted-average Brent price per barrel. (3) Purchased and sold puts with the same strike price have been netted together. (4) Assumes forward commodity prices as of September 30, 2023 and assumes a 2023 Brent price of $84.10 per barrel of oil, NGL, and gas. (5) Includes commodity derivative contract settlements for derivative contracts as of 9/30/2023, except 2Q23, 1Q23, 3Q23, and 4Q23 which are actuals for the year ended December 31, 2022, the year ended December 31, 2021, the year ended December 31, 2020, and the year ended September 30, 2023 respectively. Historical settlements include natural gas derivatives on production volumes.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bcf</td>
<td>Billion Cubic Feet</td>
</tr>
<tr>
<td>BMT</td>
<td>Billion Metric Tons</td>
</tr>
<tr>
<td>CARB</td>
<td>California Air Resources Board</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
</tr>
<tr>
<td>CCS+</td>
<td>Carbon Capture and Storage + EOR</td>
</tr>
<tr>
<td>CDMA</td>
<td>Carbon Dioxide Management Agreement</td>
</tr>
<tr>
<td>CEQA</td>
<td>California Environmental Quality Act</td>
</tr>
<tr>
<td>CGP</td>
<td>Cryogenic Gas Plant</td>
</tr>
<tr>
<td>CI</td>
<td>Carbon Intensity</td>
</tr>
<tr>
<td>CMRB</td>
<td>Carbon Management Business</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CTV</td>
<td>Carbon Tons/Vault (a subsidiary of CRC)</td>
</tr>
<tr>
<td>DAC</td>
<td>Direct Air Capture</td>
</tr>
<tr>
<td>D&amp;C</td>
<td>Drilling and Completions</td>
</tr>
<tr>
<td>E&amp;P</td>
<td>Exploration and Production</td>
</tr>
<tr>
<td>EHPP</td>
<td>Elk Hills Power Plant</td>
</tr>
<tr>
<td>EIR</td>
<td>Environmental Impact Report</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>ESG</td>
<td>Environmental, Social and Governance</td>
</tr>
<tr>
<td>FCF</td>
<td>Free Cash Flow</td>
</tr>
<tr>
<td>FEED</td>
<td>Front End Engineering and Design</td>
</tr>
<tr>
<td>FID</td>
<td>Final Investment Decision</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>KMTPA</td>
<td>Thousand Metric Tons Per Annum</td>
</tr>
<tr>
<td>LCFS</td>
<td>Low Carbon Fuel Standard</td>
</tr>
<tr>
<td>MMT</td>
<td>Million Metric Tons</td>
</tr>
<tr>
<td>MMTPA</td>
<td>Million Metric Tons Per Annum</td>
</tr>
<tr>
<td>MRV</td>
<td>Monitoring, Reporting and Verification Plan</td>
</tr>
<tr>
<td>MT</td>
<td>Metric Tons</td>
</tr>
<tr>
<td>MTPA</td>
<td>Metric Tons Per Annum</td>
</tr>
<tr>
<td>OCF</td>
<td>Operating Cash Flow</td>
</tr>
<tr>
<td>PD</td>
<td>Proved Developed</td>
</tr>
<tr>
<td>PUD</td>
<td>Proved Undeveloped</td>
</tr>
<tr>
<td>RSG</td>
<td>Responsibly Sourced Gas</td>
</tr>
<tr>
<td>RFL</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>
</tr>
<tr>
<td>SFDR</td>
<td>Sustainable Finance Disclosure Regulation</td>
</tr>
<tr>
<td>SRP</td>
<td>Share Repurchase Program</td>
</tr>
<tr>
<td>SJV</td>
<td>San Joaquin Valley</td>
</tr>
<tr>
<td>TBA</td>
<td>To Be Announced</td>
</tr>
<tr>
<td>Tcf</td>
<td>Trillion Cubic Feet</td>
</tr>
<tr>
<td>WI</td>
<td>Working Interest</td>
</tr>
</tbody>
</table>
Assumptions & Relevant Footnotes:

Slide 7:
- (1) Source: Internal estimates.
- (2) EPA, source: www.epa.gov/ucic/advanced-permitting-epa
- (3) The CTV JV partnership is targeting 5MMTPA of CO2 injection by YE 2027 which implies 200MMT of CO2 pore space under Class VI EPA permits. CTV JV is under 49% Brookfield ownership.
- (4) See slide 45 for details on the CTV project economic type curve assumptions. Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure. EBITDA estimates include 45Q tax credits. Results subject to effects of taxes, timing, pace of project development and Brookfield further approvals to fund capital.

Slide 12:
- Source: Internal estimates. Numbers may not add up due to rounding. SJ Basin implies San Joaquin basin.
- (1) Our CDMs frame the anticipated contractual terms between parties and provide a path to reaching final definitive agreements.
- (2) Source: CARB 2020.
- (3) Includes CRC’s decarbonization CCS project at Elk Hills gas plant planned to sequester 1.09MMTPA of CO2, which is not under CDM. Assumes minimum voluntary commitment injection rate for each announced CTV I project.
- (4) Injection rates are average rates based on max permit volumes times injection rate. Actual volumes and the injection period will vary over time.
- (5) 26R injection capacity as per the draft EPA permit is 38MMT. Assuming the maximum expected injection rate of 1.46 MMTPA, the reservoir would reach capacity in 28 years. Each CTV reservoir will have a unique set of operating, injection and site parameters that will vary and will be reflected in the submitted permit. See slide 15 of this deck for the details on the CTV project economic type curve for the 26R reservoir.
- (6) Internal estimates as of October 2023. Represents remaining capacity after taking into account pore space attributable to signed CDMs and CRC’s projects.

Slide 15:
- (1) Internal estimates.
- (2) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure.
- (3) Assumes a 12-year project life. See slide 15 of this deck for the details on the CTV project economic type curve and cash flow details for the 26R reservoir.
- (4) 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. Of $185 per metric ton of sequestered CO2, assumes $120 LCFS price for approximately 20% of sequestered CO2, anticipates 90% of the CO2 volume sequestered avoids cap and trade (C&T) costs assumed at $35 per metric ton.

Slide 30:
- (1) Reserves estimated as of December 31, 2022 using $80.00 per barrel for oil, $54.17 per barrel of NGLs and $4.97 per Mcf for natural gas. PV-10 is the non-GAAP measure. GAAP does not prescribe a standardized measure of reserves on a basis other than SEC Prices. As such, a GAAP reconciliation for reserves estimated using $80.00 per barrel for oil, $54.17 per barrel of NGLs and $4.97 per Mcf for natural gas has not been provided.
- (2) Calculated using reserves estimated as of December 31, 2022 using $80.00 per barrel for oil described in footnote one and divided by annualized average (U.S) production.
- (3) Calculated using internal estimates of 2022 Scope 1 and Scope 2 emissions from oil and gas operations divided by gross production. Excludes emissions from Elk Hills power plant related to power not used in our operations.

Slide 36:
- (1) Internal estimates. The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas reserves other than “reserves” as that term is defined by the SEC. This presentation includes estimates of quantities of oil and gas using certain terms, such as “opportunity set” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC’s definitions of proved, probable and possible reserves, and which the SEC’s guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered. Readers are urged to consider closely the reserves and other disclosures in our periodic filings with the SEC.
- (2) CRC is pursuing a RSQ certification for its natural gas assets. This certification depends on many factors which may or may not be achievable.
- (3) Source: ICE forward market prices as of October 18, 2023.
- (4) Subject to availability of drilling permits and additional surface infrastructure which may be needed.
Slide 44: The information on slide 44 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:

- 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 24MMT injected per year for 40-year project life unless specified otherwise.
- Assumes Brookfield fully participates in CO2 projects up to JV target of 5MMTPA 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 15MM and 55MM to represent 3MMTTPA of projects and 5MMTTPA 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 that incentive potential can be monetized through tax equity breaks and LOPS monetized in the LOPS 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 23 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.
Free Cash Flow

Management uses the non-GAAP measure of free cash flow, which is defined by us as net cash provided by operating activities less our capital investment, as a measure of liquidity. The table below presents a reconciliation of net cash provided by operating activities to free cash flow.

<table>
<thead>
<tr>
<th></th>
<th>2003E Low</th>
<th>2003E High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Est. Net Cash Provided by Operating Activities</td>
<td>$115</td>
<td>$125</td>
</tr>
<tr>
<td>Est. Capital Investment</td>
<td>(75)</td>
<td>(65)</td>
</tr>
<tr>
<td>Est. Free Cash Flow</td>
<td>$40</td>
<td>$60</td>
</tr>
</tbody>
</table>

Note: Free Cash Flow is 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.
Forward Looking / Cautionary Statements – Certain Terms

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," "let," "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 uncertainties that could cause our actual 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 US producers in future periods;
- government policy, war and political conditions and events, including the war in Ukraine and other and 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 in our carbon management business; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions; (3) our 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 in 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 contract effects on production and operating costs;
- the use of natural hedges and the ability to profit from such hedges; and
- 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, state, local and international environmental laws and regulations including remediation activities;
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCO projects, partnerships and other parties;
- reorganization or restructuring of our operations;
- our ability to meet 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 Transvanty JV, and our ability to convert our CDM credits to definitive agreements and enter into other CDM agreements;
- our ability to monetize 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 contemporaneous terms;
- uncertainties 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 capital in commercial banking and capital markets, including our ability to finance 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;
- the effects of hedging transactions;
- the effect of any security price on costs and capital costs associated with incentive compensation;
- liability to enter into derivative transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any anticipated synergies;
- disruptions due to earthquakes, fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cyber-attacks or breaches or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19;
- 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.