"A Different Kind of Energy Company"

Fourth Quarter & Year End 2022 Results

Strategic Realignment to Maximize Cash Flow Per Share

February 24, 2023

Presenters

- Mac McFarland — *President & Chief Executive Officer*
- Francisco Leon — *EVP & Chief Financial Officer*

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," "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 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 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;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms; and
- 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 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.

Glossary

Term	Definition
BMT	Billion Metric Tons
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CCS+	Carbon Capture and Storage + EOR
CDMA	Carbon Dioxide Management Agreement
CEQA	California Environmental Quality Act
CGP	Cryogenic Gas Plant
CI	Carbon Intensity
CMB	Carbon Management Business
CO_2	Carbon Dioxide
CTV	Carbon TerraVault (a subsidiary of CRC)
DAC	Direct Air Capture
D&C	Drilling and Completions
E&P	Exploration and Production
EHPP	Elk Hills Power Plant
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESG	Environmental, Social and Governance
FCF	Free Cash Flow

Term	Definition
FEED	Front End Engineering and Design
FID	Final Investment Decision
GHG	Greenhouse Gas
LCFS	Low Carbon Fuel Standard
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
OCF	Operating Cash Flow
PD	Proved Developed
PUD	Proved Undeveloped
ROFL	Right of First Look
R/P	Reserves to Production Ratio
RTC	Round-the-Clock
SFDR	Sustainable Finance Disclosure Regulation
SRP	Share Repurchase Program
SJV	San Joaquin Valley
WI	Working Interest

Key Highlights

Delivered on Our 2022 Priorities – Returned 120% of FCF[1] through SRP and Dividends

91 MBOE/D
2022 NET PRODUCTION

Oil	NGLs	Gas
61%	12%	27%

4
ACTIVE DRILING RIGS[2]

LA Basin	San Joaquin Basin
~1.5	~2.5

California's Largest and Domestically Lowest Carbon Intensity Producer[3]

- Low Carbon Intensity Production
- Midstream Infrastructure
- Carbon Capture & Storage
- BTM Solar Opportunities
- FTM/Grid Power Production
- Geothermal Opportunities

$9.2B
PV-10 OF 2022 PROVED RESERVES[4]

PUD	PD	
13%	87%	417 MMBOE

200MMT
YE27 CTV JV STORAGE CAPACITY TARGET

Submited to EPA	TBA
140MMT	60MMT

DELIVERED STRONG RESULTS

Strong Earnings Progress
$852MM
2022 Adj. EBITDAX[4]

Record Cash Flow
$690MM
2022 OCF

Shareholder Returns
$372MM
2022 SRP & Dividends

Ample Liquidity[5]
$765MM
YE22

Robust FCF[1] Generation
$311MM
2022 FCF

Repurchased
~14%
Of The Company's Common Stock[6] From The Inception Of The Program

Maintained
~57 MBO/D
Entry to Exit Oil Production[7]

Invested
$242MM
Of 2022 E&P D&C Capital

EXPANDED THE CARBON MANAGEMENT BUSINESS

Formed An Industry Leading
CTV JV
With Brookfield Renewable

Announced 2 CDMAS For
470,000MTPA
Of Greenfield Projects

Submitted to EPA
140MMT
Of CO_2 Reservoirs for Class VI Permits

Formed
California DAC Hub
Consortium

(1) Represents a non-GAAP measure. For all historical non-GAAP financial measures for CRC 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 operating cash flow less total capital requirements. 2022 free cash flow includes the acceleration of incentive compensation and pension contributions of ~$30MM. (2) Average rig count over 2022. (3) Source: Enverus; CARB; CATF. (4) PV-10 is a non-GAAP measure. Please see the Investor Relations page at www.crc.com for a reconciliation of PV-10 using SEC Prices to the nearest GAAP equivalent and other additional information. PV-10 of reserves estimated as of December 31, 2022 using SEC Prices (after factoring in price realizations) of $97.50 per barrel for oil, $67.83 per barrel for NGLs and $7.84 per Mcf for natural gas. (5) Calculated as $307MM of available cash and cash equivalents plus $602MM of capacity on CRC's Revolving Credit Facility less $144MM in outstanding letters of credit. (6) As of December 31, 2022. (7) Net oil production at January 2022 entry has been reduced by 2.3 MBO/D due to divested assets in Ventura and Lost Hills.

Strategic Realignment to Enhance Value and Positioning to Return 100% of FCF in 2023

REPOSITIONING STRUCTURE AND LEADERSHIP TO SUPPORT ACCELERATION OF CARBON MANAGEMENT

- Laying the groundwork for potential separation of E&P and Carbon Management Businesses
- Francisco Leon to succeed Mac McFarland as President and Chief Executive Officer of CRC
- Mac McFarland to continue as a Non-Executive Director and Chair the Board of Carbon TerraVault

CARBON TERRAVAULT

ADJUSTING E&P DEVELOPMENT PLAN AND FOCUSING ON PORTFOLIO OPTIMIZATIONS

- Reducing rig count to 1.5 rigs in 2023 to minimize permitting uncertainty
- Focusing on cost reduction initiatives (non-energy operating costs & Adj. G&A[1] on a $/BOE basis aligned with activity) and cash flow generation
- Pursuing monetization of Huntington Beach surface acreage

2023E FCF FROM E&P CORP & OTHER

~$455MM

At MID-POINT OF GUIDANCE[2]

2023E TOTAL FCF OF $385MM AT MIDPOINT OF GUIDANCE[2]

TARGETING GREATER FINANCIAL FLEXIBILITY TO BOOST SHAREHOLDER RETURNS

- Intending to refinance senior notes to increase pace of share repurchases and flexibility to support future business separation
- Increasing share repurchase plan authorization by $250MM in the interim pending the refinancing

~$640MM

AVAILABLE FOR FURTHER SRP PURCHASES

Through June 30, 2024[3]

(1) Represents Adj. E&P Corp & Other G&A which is a non-GAAP measure. See slide 12 for additional details. For all historical non-GAAP financial measures for CRC please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. (2) 2023E guidance assumes a 2023 Brent price of $79.12 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.27 per mcf. Free Cash Flow is a non-GAAP measure. For all historical non-GAAP financial measures for CRC 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 operating cash flow less total capital requirements. See slide 35 for reconciliation. (3) As of December 31, 2022 and after the increase of $250MM.

Revised Corporate Structure – Focus on E&P FCF Maximization and Eye Toward Separation of CMB

2045

Board of Directors
Chaired by
Tiffany (TJ) Thom Cepak

Francisco J. Leon
President and CEO

Low Carbon Intensity E&P Business

Carbon Management Business

CARBON TERRAVAULT
Positioned to Be California's Premier Carbon Management Provider

Carbon TerraVault Board
Chaired by
Mac McFarland

Brent priced, low capital intensity, low decline & low carbon intensity integrated[1] energy business

Special Finance Committee of the Board focused on right-sizing the cost structure with the projected level of activity

Pursuing monetization of Huntington Beach surface acreage

Mac McFarland to Chair newly formed Board of Carbon TerraVault

Andrew Bremner and James Chapman will sit on the CTV Board to bring their expertise in corporate and financial structuring and knowledge of emerging California CCS market

Structure shows ongoing support for overall business and provides more specific oversight for the fast-growing CTV business

Francisco J. Leon
to succeed **Mac McFarland** as President and Chief Executive Officer of California Resources Corporation

- More than 20 years of experience in the oil and gas industry, and 11 years focused on California
- Expertise in Operational Management, Corporate Finance, Economic Evaluation, Domestic and International M&A Transactions and Strategic Planning
- Intimately involved in Carbon TerraVault partnerships and agreements; sits on the management committee of Carbon TerraVault Joint Venture with Brookfield

A DIFFERENT KIND OF ENERGY COMPANY

(1) Includes upstream, midstream and power integrated assets. CRC doesn't have downstream capabilities or assets.

Building on our Momentum to Accelerate The Carbon Management Business

Carbon TerraVault Is Born

Up to 1BMT CO_2 Storage Opportunity

Initial 200MMT of CO_2 in Focus

Submitted CTV Class VI Permit for CTV I (26R)

2022

Submitted CTV Class VI Permit for CTV I (A1/A2)

Defined a path to reduce CRC's Scope 1,2 and 3 emissions

2045 Net Zero Goals

Early-Stage Development Goals

200MMT of Class VI permits submitted by YE25

Begin 1MMTPA Injection by YE25

Begin 5MMTPA injection by YE27

Submitted CTV Class VI Permit for CTV II and III

Announced NextDecade CalCapture Feed Study

Defined CRC's ESG Goals

Introduced CTV to Northern California

CTV JV With Brookfield Renewable

Initial commitment of $500MM from BGTF[1]

Kern County Energy Transition Investment

Expanded CCS total market opportunity to include New Energy Economy emissions

Inflation Reduction Act: 45Q tax Incentive rose to $85/MT for Carbon Storage[3]

Expanded California's CCS Market Opportunity By 2.4x[4]

2023

California's First CCS Storage Project

100,000MTPA Blue Hydrogen Facility storage-only project at CTV I

Capital Costs and EBITDA within previously disclosed Type Curve[2]

Announced Net Zero Industrial Park at Elk Hills

370,000MTPA Blue Ammonia and Hydrogen Facility at CTV III

Capital Costs and EBITDA within previously disclosed Type Curve[2]

Decarbonizing California's Agricultural Sector

Blue NH_3 and H_2 Facility CO_2 Storage Project

California DAC Hub Consortium

Accelerating DAC+S in California through its wholly owned subsidiary CTV Direct

The first DAC Hub is targeted for Kern County and is expected to store CO_2 at the CTV I reservoir

2023 Outlook…

Introducing Carbon TerraVault Board of Directors

Targeting First Class VI EPA Draft Permit by YE2023[5]

Submission of additional reservoirs for EPA Class VI permitting

Advancing New CDMAs

2024

Completion of NextDecade Feed Study

Targeting to FID CalCapture in 1H24

Targeting to FID Lone Cypress Project in YE23[5]

Advancing CalCapture & Lone Cypress Project to The Next Stage of Development

CARBON TERRAVAULT

Positioned to Be California's Premier Carbon Management Provider

Source: CRC unless otherwise stated. (1) Brookfield Global Transition Fund. Initial commitment applies to CCS projects that are jointly approved through the CTV JV. (2) EBITDA 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. Note CTV JV EBITDA estimates include 45Q tax credits. See slides 27, 28 and 38 of CRC's 3Q22 Earnings slides for detailed information on the previously disclosed Type Curve. (3) Source: Inflation Reduction Act. (4) Source: Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020; EPA; NATCARB; CARB; Internal estimates; Includes Brownfield and Greenfield opportunities; CARB Scoping Plan: AB32 Source Emissions Final Modeling Results, October 28, 2022; Department of Energy Hydrogen Program Plan, U.S. Department of Energy, November 2020. Converted from CARB's estimated 13% of U.S. hydrogen demand of 21 – 44MMTPA. (5) Draft permit expected by YE23, but is subject to EPA approvals and public review. FID subject to permit approvals.

2023 Development Plan Based on Permits in Hand Significantly Reduces Uncertainty

2023 MAIN OPERATIONAL GOALS

- Mitigate CRC's decline in oil production from entry to exit in light of Kern County EIR litigation
- Maintain non-energy operating costs per BOE across O&G operations despite an inflationary environment and additional OPEX in downhole maintenance
- Optimize cash flow generation in the current regulatory environment
- Pursuing new or updated CEQA review to reduce reliance on Kern County EIR
    - Targeting field level CEQA coverage on our PUD inventory
- Review proved undeveloped inventory outside of Kern County

CRC's drilling plan focused on developing highest-returning projects with permits in hand and on well servicing to reduce base production declines

CRC 2023E ADJ. CAPITAL PROGRAM[1]	2023E Low	2023E High
E&P Capital | D&C and Workovers ($MM)	$110	$130
E&P Capital | Facilities ($MM)	$44	$54
Adj. E&P Capital[1] ($MM)	$154	$184
Corporate & Other ($MM):	$31	$36
Adj. CMB Capital[1] ($MM)	$15	$25
CRC 2023E Adj. Capital Program[1] ($MM)	**$200**	**$245**

CRC's Normalized 1.5 Rigs Capital Program ($MM) *excludes one-time items, Corporate & Other capital and CMB capital (which is anticipated to be funded by projected CTV JV contributions[2] over time)*	~$155 MM

D&C & Workovers capital includes:

- 1.5 drilling rig program
- Increased focus on maintenance rigs throughout the year
- Operations in Wilmington field and outside of Kern County
    - Program consists of 32 Higher IP horizontals and lower decline vertical wells
    - Utilizing existing workover inventory

Facilities capital includes:

- ~$15MM one-time purchase of specialized equipment item for EHPP due to lead times and contractual obligations, regular annual facilities capital rate of ~$30 - $40MM

Corporate & Other capital includes the following one-time items for a total of ~$21MM:

- ~$6MM for ESG initiatives (ex. freshwater reduction, methane reduction, pneumatic valve replacements etc)
- ~$6MM for CEQA permitting
- ~$3MM for Solar BTM projects
- ~$6MM for major IT overhaul of technical systems

Carbon Management Business capital includes:

- Capital for new regulatory permitting (Class VI, state, county needs and environment)
- Preparation of new reservoirs for CO_2 sequestration and technical equipment procurement

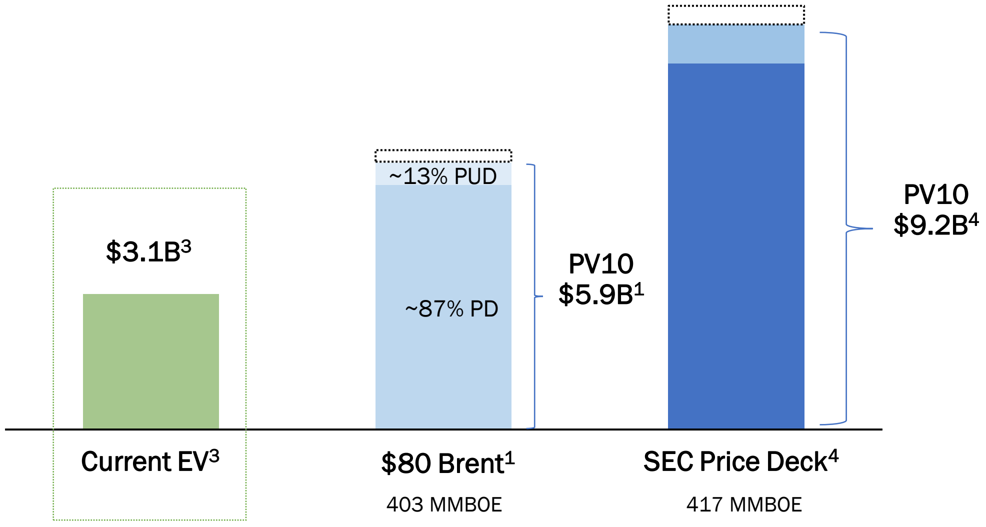
Note: E&P Capital is comprised of D&C, workovers and facilities capital. (1). Adjusted E&P Capital and Adjusted CMB Capital are Non-GAAP measures. These measures reflect the reclassification of ~$11 million from E&P, Corporate & Other Capital to Adjusted CMB Capital related to the expected 2023 investment in facilities to advance carbon sequestration activities beginning in 2Q23. (2) See slide 17 for additional details on projected CTV JV contributions.

Revised Capital Allocation - Buyback Shares at a Discount to PV10 or Deploy Capital Through the Drillbit

LONG DURABILITY 1P ASSETS	PD / PUD	MMBoe ($80 Brent)[1]	% Oil	Est. Annual Decline	Est. Annual Production[2] (MBOE/D)	R/P
San Joaquin Basin	87% / 13%	287	~62%	~12%	69	~11
Los Angeles Basin	85% / 15%	107	~99%	~7%	19	~15
Sacramento Basin	100%	9	0%	~13%	3	~9
				Multi-year Runway		~12 Years[2]

PD PUD

~12 years of expected production from Reserves[2]



Potential upside if locations within 3,200" of sensitive receptors added back

RESERVES DETERMINATION INCLUDES:

- 1.5 rig program in 2023 with an expected 3 rigs program beginning in 2H24 *(Assumes CRC obtains new drill permits through Kern County EIR or stand-alone CEQA starting by 2Q24)*
- Well locations without drilling permits potentially impacted by SB 1137 were removed from the reserves report; however, could represent additional upside depending on 2024 vote

Note: please see slide 37 for detailed information on the footnotes on this slide.

Focusing on Reducing Costs & Unlocking Value From Real Estate Assets

Special Finance Committee of the Board in conjunction with CRC's management team are focused on:

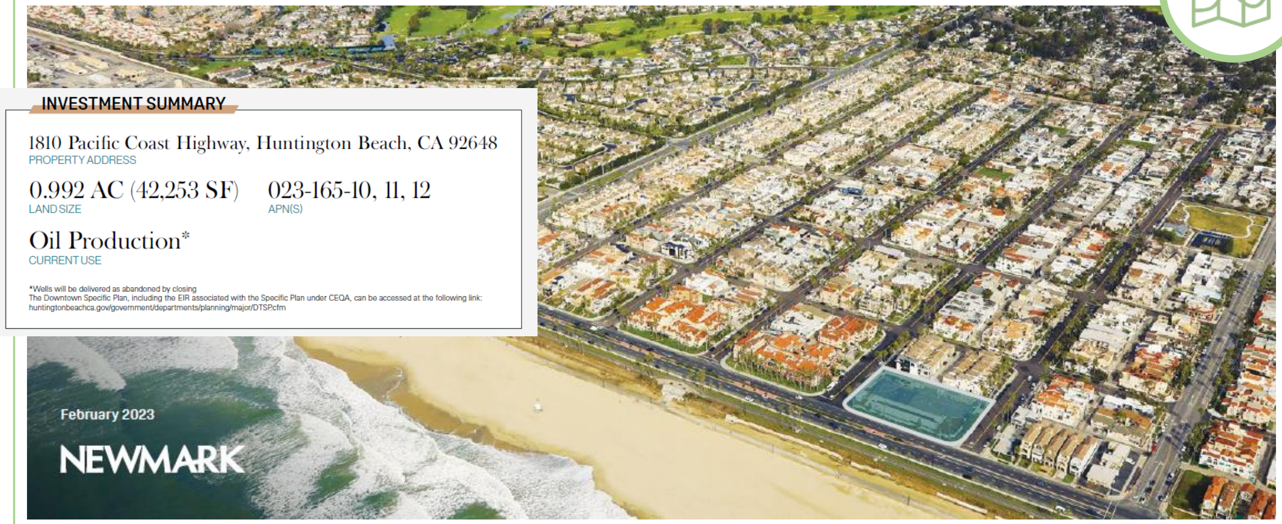
- Aligning non-energy operating costs and our Adj. E&P Corp & Other G&A[1] on a combined basis to our drilling activity and downhole maintenance to maintain margins and drive higher cash flows
- Targeting a year end run rate reduction of 5% - 10% for all other non- energy operating costs and Adj. E&P Corp & Other G&A[1]

REDUCING COSTS TO ALIGN WITH ACTIVITY	2022A	2023E	
	-	Low	High
All other Non-Energy Operating Costs *(looking to offset significant inflationary pressures)*	$310	$305	$320
Downhole Maintenance Costs (Increased activity from 32 to 38 rigs for quick payback, high return projects and ~2% improvement in est. annual average decline rate)	$152	$165	$180
Non-Energy Operating Costs ($MM):	$462	$470	$500
Adj. E&P Corp & Other G&A[1] ($MM) *(looking to offset inflation and reduced activity)*	$189	$185	$210

If the rig count is sustained at lower levels, we will continue further cost reductions to align with activity levels

PURSUING THE MONETIZATION OF HUNTINGTON BEACH

- Began ARO activities: removed Ensign 550 in December of 2022
- Began P&A of ~30 existing wells and started elements of the forward plan for longer-term remediation of the ~90 acres property
  - Began re-zoning, re-entitlements and due diligence processes
- Targeting a close on the sale of ~1 acre parcel of land (Fort Apache) at HB in 2H23



(1) Represents a non-GAAP measure. For all historical non-GAAP financial measures for CRC please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. See slide 35 for reconciliation.

Financial Flexibility to Increase Shareholder Returns

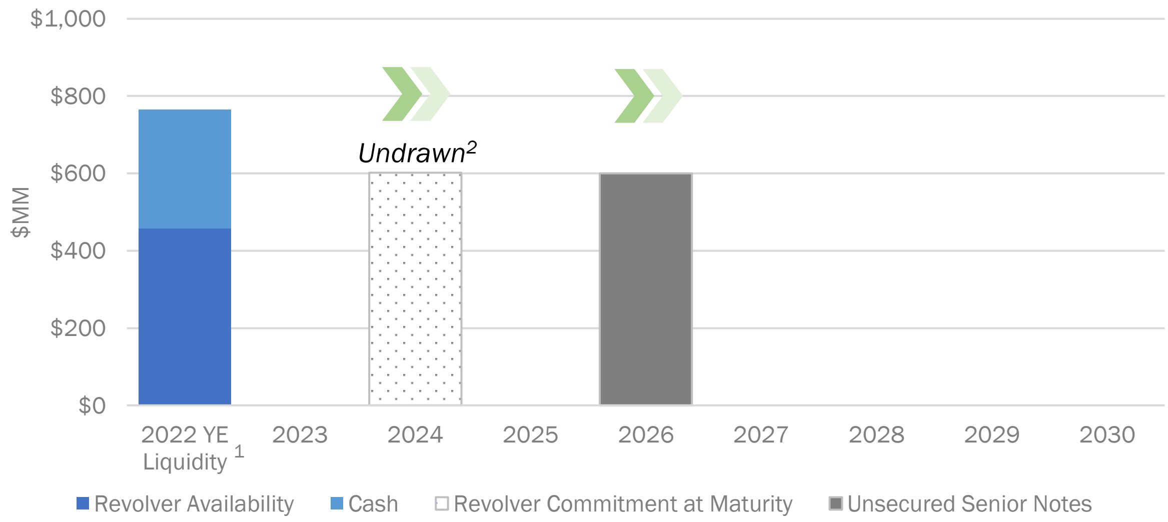
EVALUATING FURTHER FINANCIAL FLEXIBILITY

Intend to:

- Amend and extend or replace the RBL credit facility in 2023
- Refinance $600MM senior unsecured notes

In order to:

- Lengthen maturity
- Provide flexibility to increase shareholder returns
- Contemplate potential separation of Carbon Management Business



Boost In SRP

Right-size Cost Structure

Financial Flexibility

ENHANCED SHAREHOLDER RETURNS

(1) Liquidity at 12/31/22 calculated as unrestricted cash and cash equivalents of $307MM and $602MM capacity on CRC's Revolving Credit Facility less $144MM in outstanding letters of credit. (2) Undrawn revolver as of December 31, 2022.

REPEATABLE PLAN

CALIFORNIA RESOURCES CORPORATION

- Reduces Costs to Align with Activity
- Pursues E&P Development that Reduces Uncertainty
- Creates Financial Flexibility to Accelerate Pace & Increase Shareholder Returns
- Maximizes Cash Flow Per Share via Buyback & Dividends

2023 Corporate Guidance

CRC's 2023E Corporate Guidance

CRC 2023E GUIDANCE[1]:	2023E E&P, Corp. & Other	2023E CMB	2023E FY23E	1Q23E E&P, Corp. & Other	1Q23E CMB	1Q23E FY23E
Net Total Production[1] (MBOE/D)	**91 – 85**	—	91 – 85	**91 – 89**	—	91 – 89
Net Oil Production[1] (MBO/D)	**55 – 51**	—	55 – 51	**54 – 53**	—	54 – 53
Operating Costs ($MM)	**$845 – $895**	—	$845 – $895	**$260 – $270**	—	$260 – $270
CMB Expenses[2] ($MM)	—	$25 - $35	$25 - $35	—	$5 - $10	$5 - $10
Adj. G&A[3] ($MM)	**$185 – $210**	$10 - $15	$195 – $225	**$47 – $53**	$3 - $5	$50 – $58
Adj. Total Capital[4] ($MM)	**$185– $220**	$15 - $25	$200 - $245	**$55 – $65**	$2 - $4	$57 - $69
FCF[3] ($MM)	**$410 - $500**	($60) – ($80)	$330 - $440	**$175 - $195**	($15) – ($24)	$151 - $180

Annual Adj. CMB capital[4] and expenses[2] for JV projects anticipated to be funded by CTV JV contributions

(See slide 17)

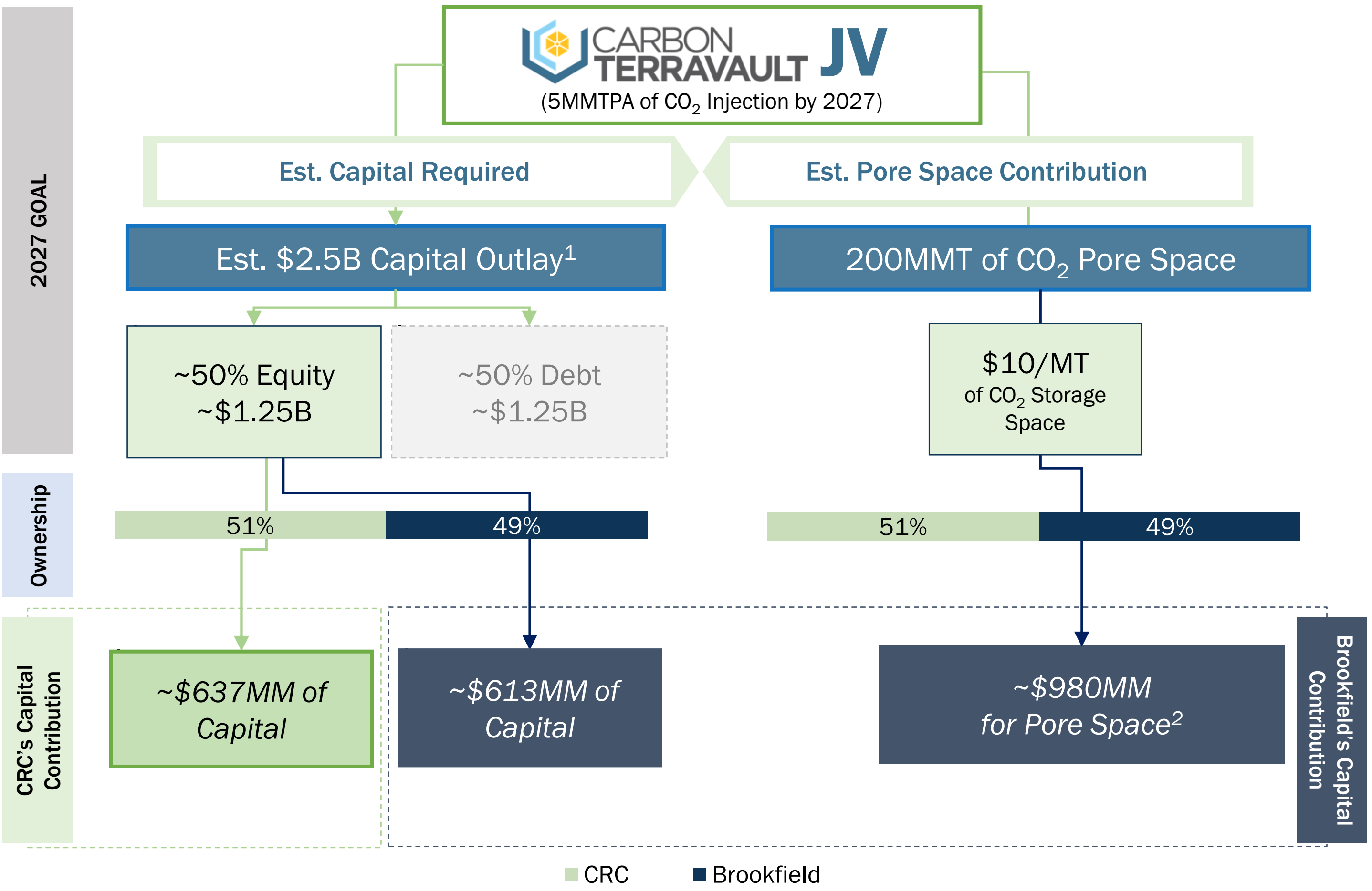
Other Guidance Items:	2023E Low	2023E High	1Q23E Low	1Q23E High	
Natural gas Trading, Net ($MM)	$60	$70	$35	$45	
Net Electricity ($MM)	$80	$120	$25	$35	
Transportation Expense ($MM)	$50	$70	$14	$16	
ARO Settlement Payments ($MM)	$55	$60			*~ 25% of estimated annual amount is paid every quarter*
Taxes Other Than on Income ($MM)	$175	$185			*~ 30% of estimated annual amount is paid in 1Q and 4Q, respectively*
Interest and Debt Expense ($MM)	$55	$60			*~46% of estimated annual amount is paid in cash in 1Q and 3Q, respectively*
Cash Income Taxes ($MM)	$80	$100			*Cash taxes aren't paid evenly throughout 2023*
Commodity Realizations:					
Oil - % of Brent:	97%	99%	97%	99%	
NGL - % of Brent:	58%	64%	63%	65%	
Natural Gas - % of NYMEX:	150%	250%	400%	500%	

Note: please see Slide 37 for detailed information on the footnotes on this slide. January and February natural gas average realized prices were ~$47.50 and ~$10.00 per Mcf, respectively.

Strategic Partnership – A Structural Capital Advantage

Illustrative 2027 CO_2 Storage/Injection Goal Capital Funding Needs[1]

assumes Brookfield fully participates in 5MMTPA of CTV JV projects



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 CO_2 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

Projected Excess Capital Available for Early Stage CMB Expenses and Capital[3]

	~$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 5MMTPA of Carbon Sequestration from the CTV JV economic "Type Curve". See slides 27, 28 and 38 of CRC's 3Q22 Earnings slides 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 CO_2 injection by YE 2027, aligned with CRC's 2027 goals, thereby requiring an estimated ~$2.5B of capital. (2) ~$980MM assumes 200MMT of CO_2 pore space for $10/MT of CO_2 storage space and 49% Brookfield ownership which assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO_2 storage. (3) Results subject to effects of taxes, timing, pace of project development and Brookfield further approval to fund capital.

Why California Resources Corporation?

A DIFFERENT KIND OF ENERGY COMPANY

Strong Balance Sheet with Attractive Free Cash Flow Generation

Enhanced Shareholder Returns Strategy

Leading Carbon Management Business

Low Carbon Intensity E&P Business

Strong 2022 Asset Performance Despite Challenging Regulatory Hurdles

KEY ACHIVEMENTS:

- Optimized asset portfolio to offset challenges from Kern County EIR litigation and SB1137
- Performed a successful and safe CGP1 maintenance turnaround in a quicker period than initially forecasted with all impacted production successfully back online
- Maintained net oil production with a smaller D&C budget (ex. asset divestitures)
- Implemented several operational measures such as technical redesign, surface maintenance and facilities repositioning to offset inflation and other cost increases

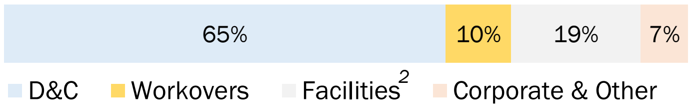
San Joaquin Basin	
Rigs	~2.5
Wells Drilled & Online	108
TMD (ft.)	5,021

+

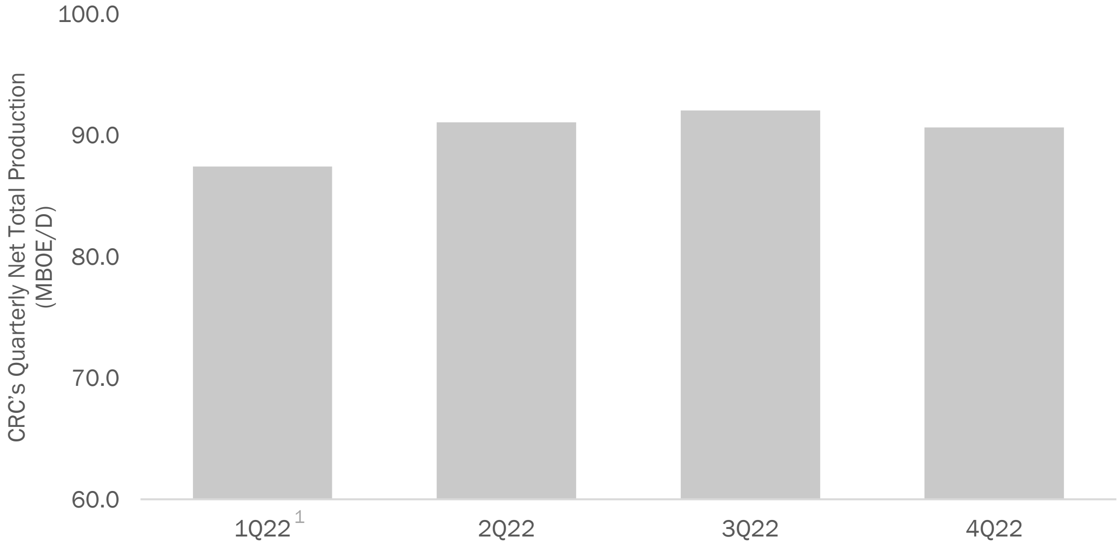
Long Beach	
Rigs	~1.5
Wells Drilled & Online	37
TMD (ft.)	5,622

$375MM

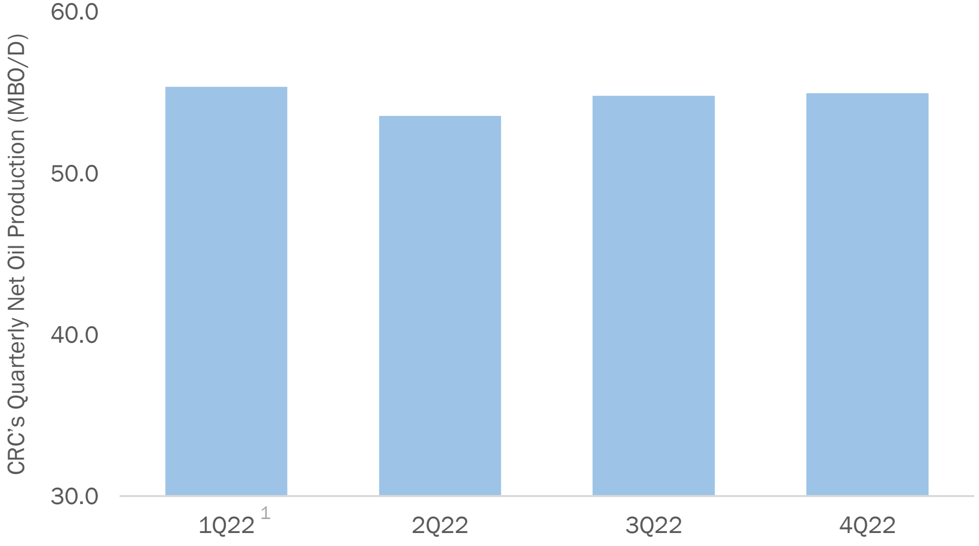
2022A E&P CORP. & OTHER CAPEX



THROUGH 2022, CRC MODESTLY GREW NET PRODUCTION …



… AND MAINTAINED TOTAL NET OIL PRODUCTION

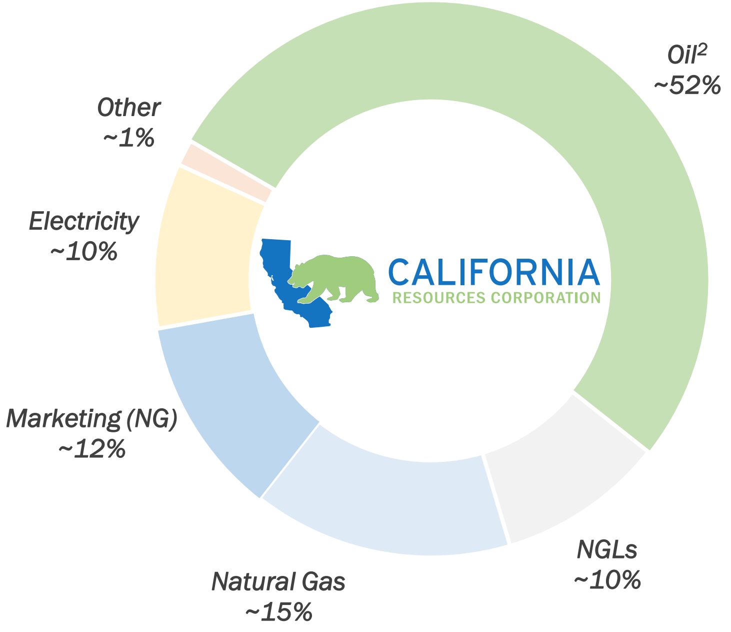


Note: TMD represents total measured depth. (1) January's net oil production has been reduced by 2.3 MBO/D due to divested assets in Ventura and Lost Hills. (2). Facilities capital for oil and gas operations included $12 million to build replacement water injection facilities which will allow us to divert produced water away from a depleted oil and natural gas reservoir held by the Carbon TerraVault JV.

Integrated Assets[1] Across a Unique Western Energy Island

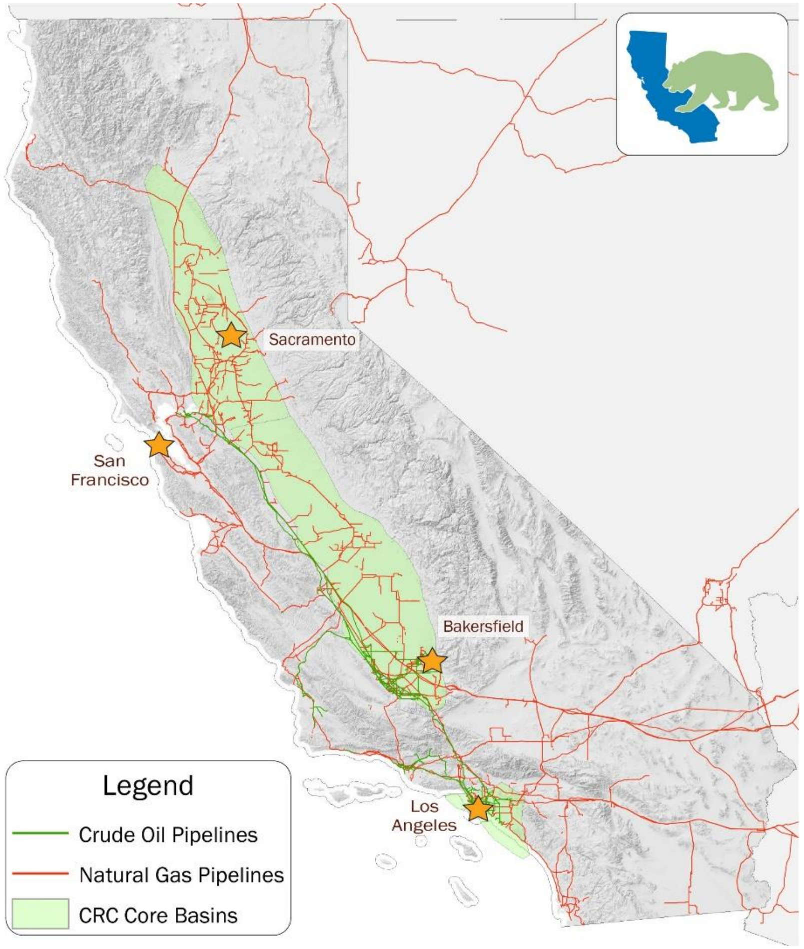
Diversified Revenue Stream

CRC has some of the lowest carbon intensity production in the U.S. and in California[2]
(% of Total 2022A Revenue[3])



CRC's commodity realizations continued to trend **above domestic WTI averages**

CALIFORNIA IS AN ENERGY ISLAND



2022 Commodity Realizations

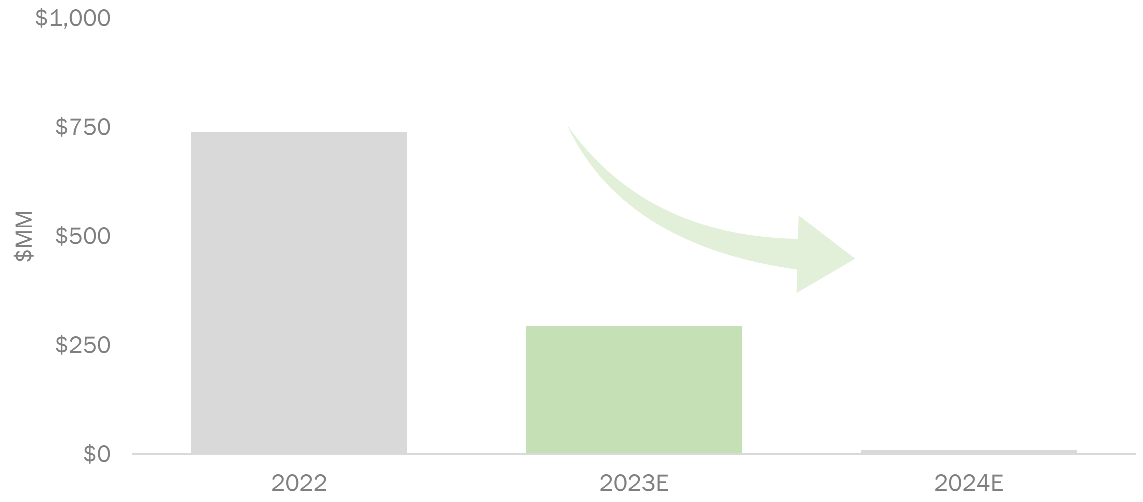
Oil Realizations	NGL Realizations	NG Realizations
99%	65%	121%
Of Brent	Of Brent	Of NYMEX

(1) Includes upstream, midstream and power integrated assets. CRC doesn't have downstream capabilities or assets. (2) Source: CARB; CATF. (3) Includes the effect of commodity derivatives.

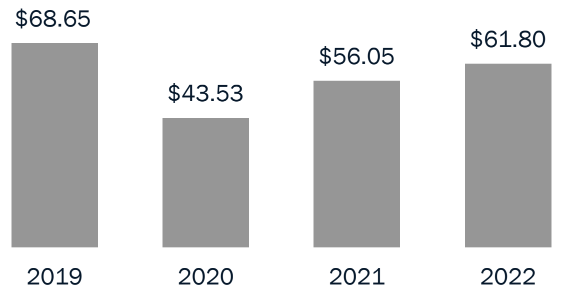
Strong Price Realizations in CA's Unique Market Dynamics

- **Crude**: Crude realizations were solid for 2022 as refining margins across California continued to be supportive to local physical crude postings. For 2023, we expect California crude prices to continue to be heavily influenced by global Brent prices with realizations softening slightly relative to 2022 levels.
- **NGLs:** As compared to other North American locations, California NGLs remained relatively well supported. For 2023, we anticipate logistical constraints that contributed to elevated CA prices in late 2022 will be relieved, prompting relative realizations to normalize.
- **NG:** Unlike most of the US, California natural gas prices exhibited strength going into the latter part of 2022 on the back of ambient and generation demand. Following a historic start to prices for 2023, CA prices are expected to work their way towards more normalized levels relative to the broader North American market for the balance of the year.
- **Power:** Reduced out-of-state imports and increased reliance upon intermittent resources prompted marginal power prices – when combined with natural gas price strength – to be very strong for 2022. Imports and intermittency will contribute to outcomes for 2023.

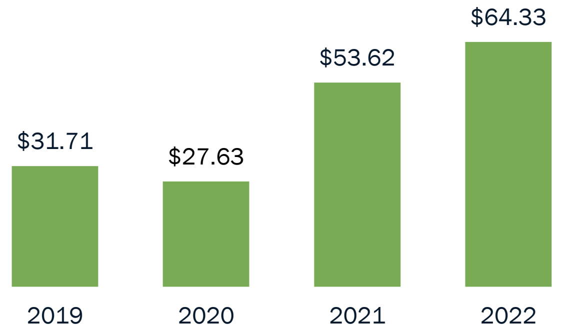
EST. HEDGE SETTLEMENTS SIGNIFICANTLY LOWER IN 2023[1]



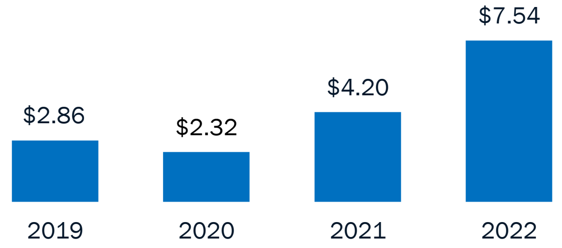
Oil w/ Hedges ($/BBL)



NGLs ($/BBL)



Natural Gas ($/MCF)



Oil w/ Hedges ($/BBL)	2019	2020	2021	2022
Average Benchmark Prices[2]	$64.18	$43.21	$70.79	$98.89
% of Benchmark[2]	101%	97%	99%	99%
Hedge Settlements	$3.82	$1.64	($14.38)	($36.46)
Average Realized Prices[3]	$68.65	$43.53	$56.05	$61.80

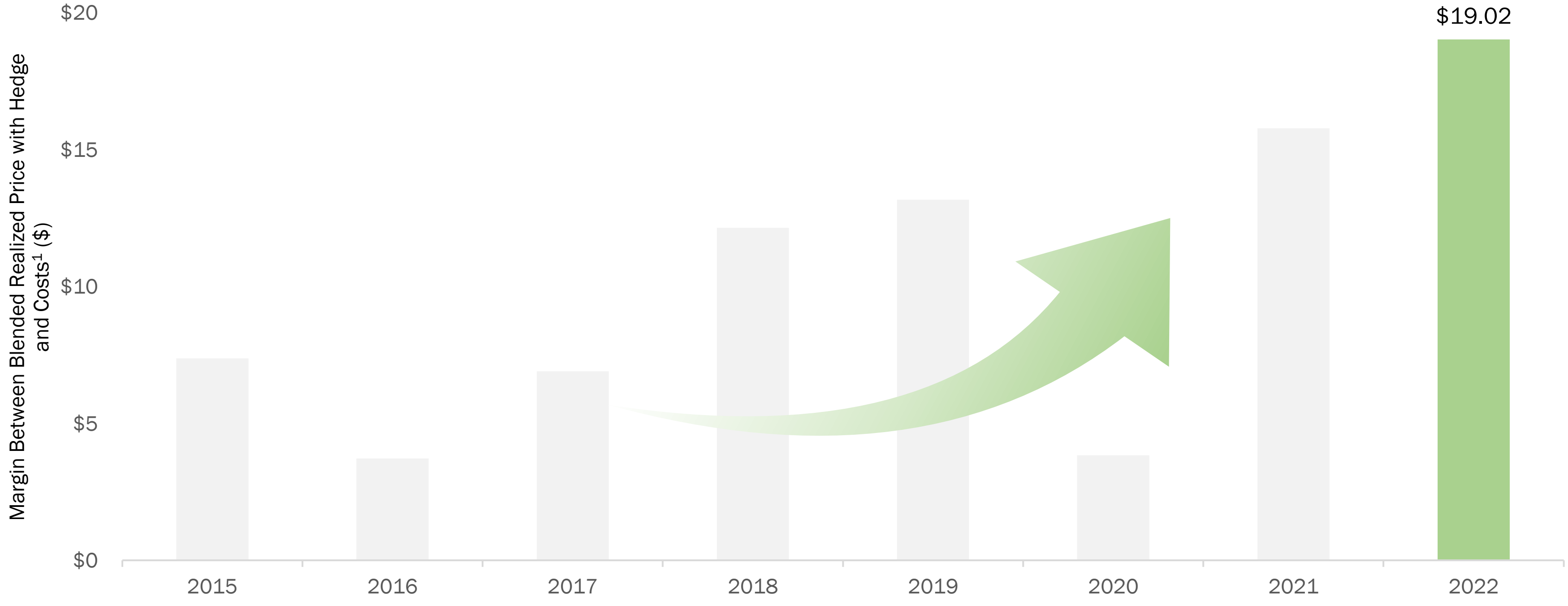
NGLs ($/BBL)	2019	2020	2021	2022
Average Benchmark Prices[2]	$64.18	$43.21	$70.79	$98.89
% of Benchmark[2]	49%	64%	76%	65%
Hedge Settlements	–	–	–	–
Average Realized Prices[3]	$31.71	$27.63	$53.62	$64.33

Natural Gas ($/MCF)	2019	2020	2021	2022
Average Benchmark Prices[2]	$2.67	$2.10	$3.61	$6.36
% of Benchmark[2]	107%	109%	117%	121%
Hedge Settlements	($0.01)	$0.04	($0.02)	($0.14)
Average Realized Prices[3]	$2.86	$2.32	$4.20	$7.54

(1) Assumes commodity pricing remains at the similar levels as of December 31, 2022. Represents estimated net cash settlement payments for derivative contracts as of 12/31/2022, except 2022, which is actuals for the year ended on December 31, 2022 (2) Benchmark prices are based on Brent for oil and NGLs, and NYMEX average daily price for natural gas. (3) Average realized prices include hedges on oil and natural gas.

Focus on Expanding Margin to Offset Rising Energy Costs and Inflation

HIGHEST MARGIN[1] SINCE CRC'S INCEPTION[2]



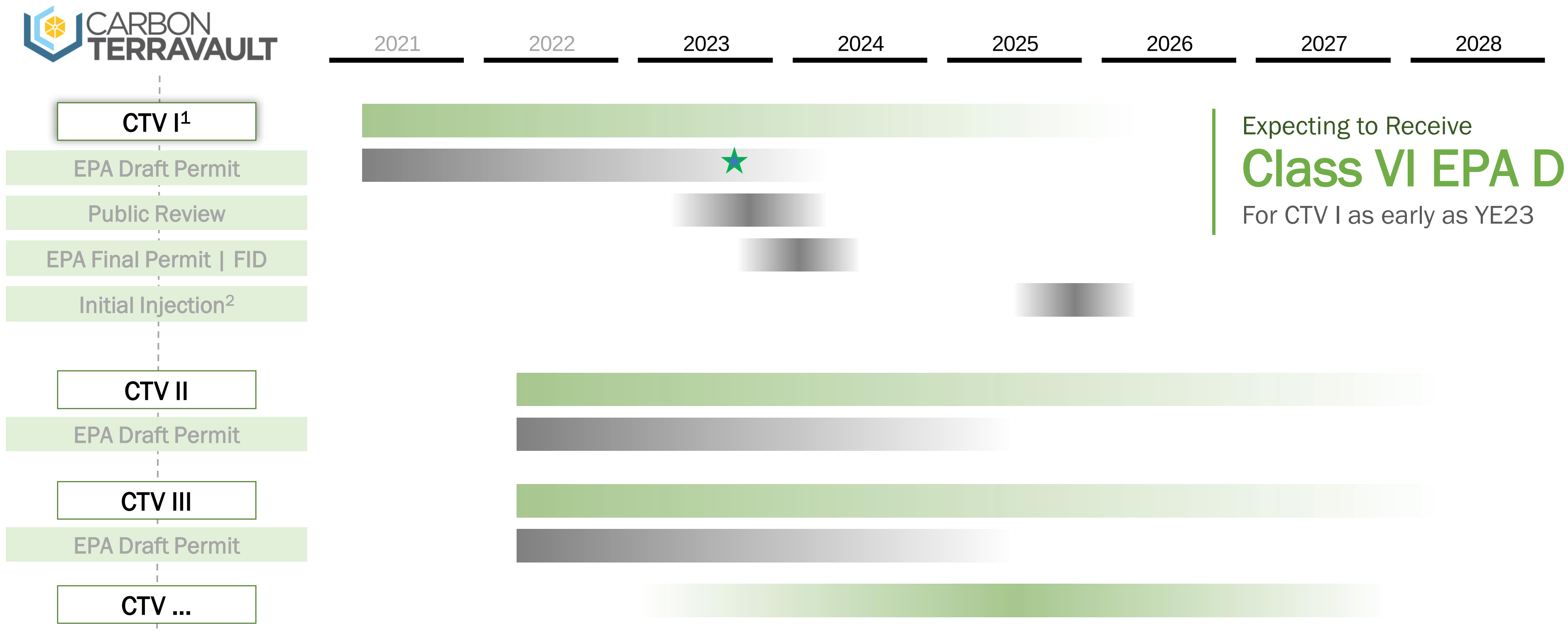
	2015	2016	2017	2018	2019	2020	2021	2022
Margin[1] ($/BOE)	$7.38	$3.72	$6.91	$12.15	$13.18	$3.84	$15.78	$19.02
Margin[1] (%)	19%	11%	17%	25%	26%	11%	33%	33%

Largest Margin[1] Since CRC's Spin-off

(1) Margin is calculated as Oil, natural gas and NGL sales plus proceeds/less payments from settled derivatives less operating costs, transportation costs, taxes other than on income, general and administrative expenses and interest expense. Please see crc.com for historical per BOE data. (2) 2015 to 2019 Predecessor, 2020 combined and 2021 to 2022 Successor as described in Part I, Item 7 – Basis of Presentation in CRC's Form 10-K.

Carbon Management Business

Carbon TerraVault EPA Class VI Permits



Expecting to Receive

Class VI EPA Draft Permit

For CTV I as early as YE23

Scalable Business Model that Lowers Carbon Emissions & Drives Value

140MMT | > 60MMT

CTV I | CTV II | CTV III | CTV ...

Targeting Additional CO_2 Reservoir for EPA Class VI Permits

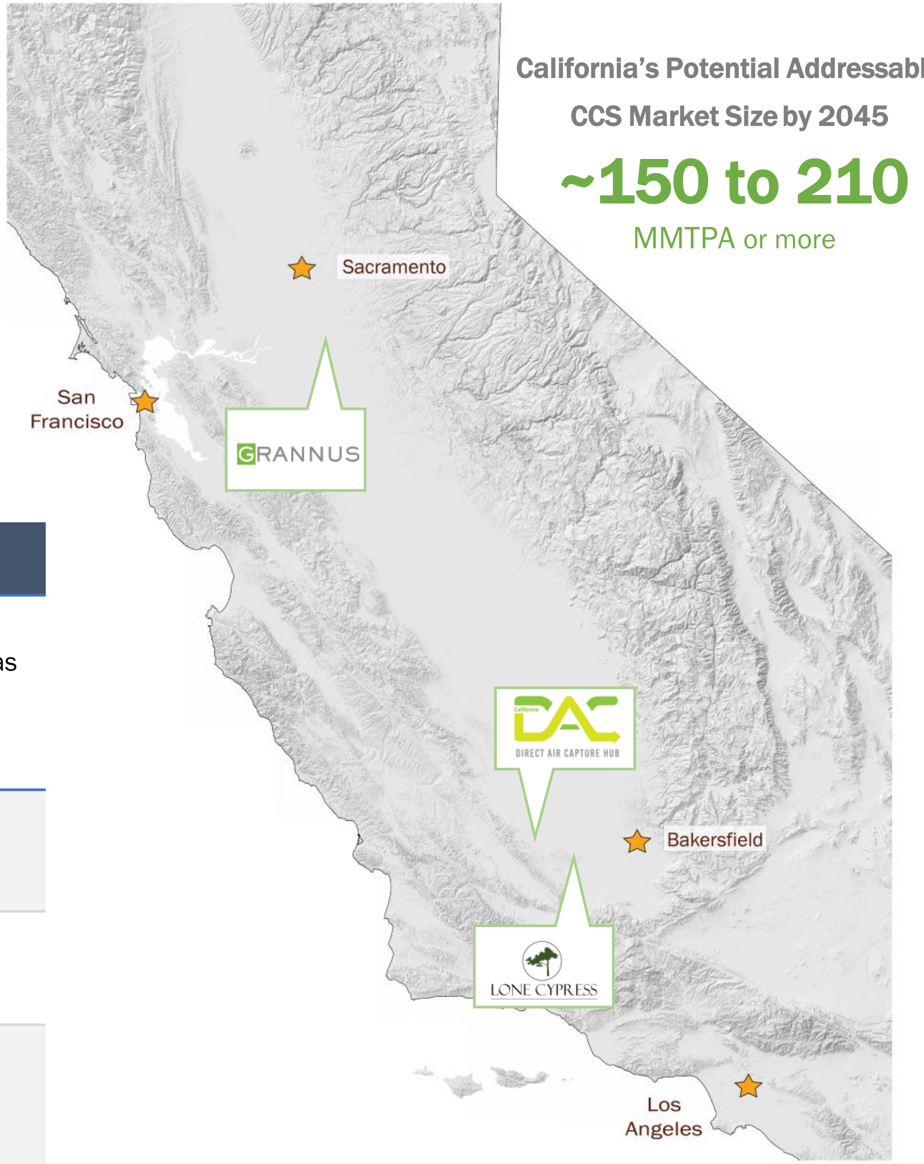
Source: Internal estimates. (1) CTV I consists of both the 26R and A1/A2 reservoirs. (2) First injection date dependent on permitting and capture facility type.

Decarbonizing California and Building a Diversified Portfolio of CO_2 Emissions

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[1]	Tech	Greenfield				Existing Sources
Type of Emitter	DAC	Renewable Diesel	Ammonia	Hydrogen	Ethanol	Refiners, Cement, Steam Generators and Natural Gas Power Plants (incl. CalCapture)
Cost of Capture ($/$TCO_2$)	Very High	Medium	Low	Medium	Low	Medium to High
Concentration of CO_2	Very Low	Medium	High	Medium	High	Low to Medium
LCFS Eligible?	Yes, plus Incremental Incentives	Yes	Depends on Use	Depends on Use	Yes	Depends on Use



California's Potential Addressable CCS Market Size by 2045

~150 to 210

MMTPA or more

Source: Internal estimates.

Supplemental Materials

Sustainability Is In Our DNA

Sustainable Commitment

- Submitted 140MMT of CO_2 Reservoirs to EPA for Class VI permits with many more in development
- Pledged $2.5MM to fund several Kern County initiatives to advance the energy transition
- Announced a California DAC Hub with a purpose to permanently store atmospheric CO_2 using low carbon emission energy and provide economic benefits to surrounding communities

ESG Driven Market Recognition

- Largest global energy transition fund by Brookfield Renewable[1] invested in CRC's Carbon TerraVault business
- CRC is part of several SFDR Article 8 "Light Green" funds in Europe
- Continuing to be a part of leading sustainability events in the world such as Agora CERAWeek[2], GS Carbonomics[3] and many more

2021 Sustainability Report Highlights

CRC's 2021 Sustainability Report references Sustainability Accounting Standards Board (SASB), Global Reporting Initiative (GRI) and International Petroleum Industry Environmental Conservation Association (IPIECA) standards

- Adopted a 2045 Full-Scope Net Zero Goal and updated and expanded ESG goals on methane emissions, freshwater usage, community giving, diversity in leadership and linked ESG performance to executive pay
- Hired CRC's first Chief Sustainability Officer
- Continued to be a net supplier of both fresh water and electricity in California
- Full Scope 1,2,and 3 Scope emissions decreased by 6% year over year
- CRC's Board of Directors is 33% gender diverse, 33% ethnically diverse and is comprised of 9 members, 8 of whom are independent[4]

ESG Milestones

2021 Sustainability Report

CDP DISCLOSURE INSIGHT ACTION 2022

full SCOPE net ZERO 2045 CALIFORNIA

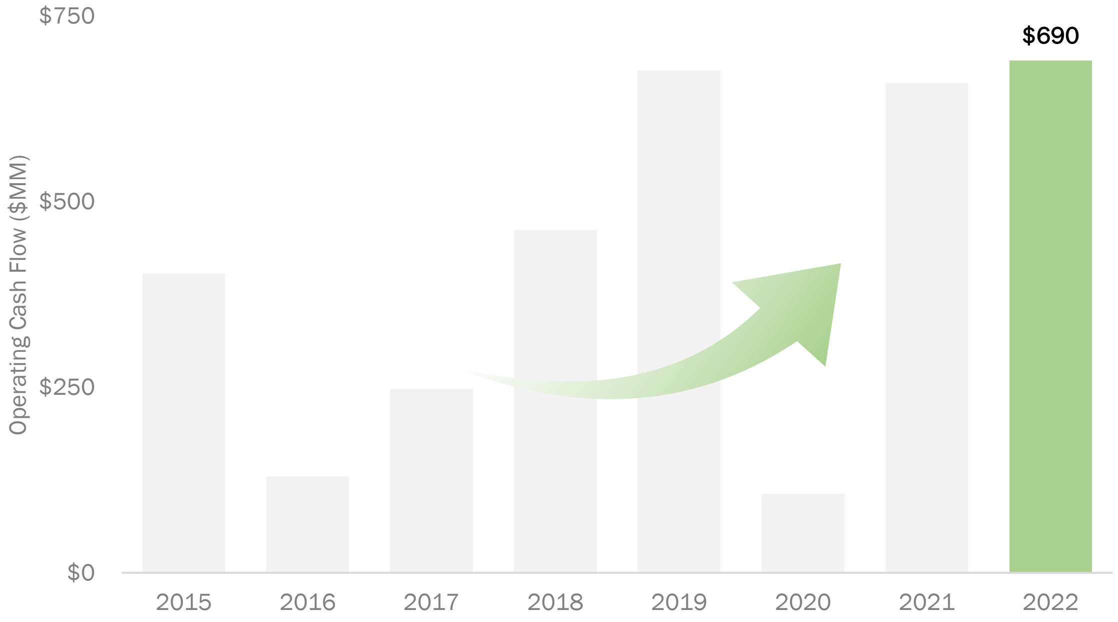
AMERICA'S MOST RESPONSIBLE COMPANIES 2022 & 2023 Newsweek statista

(1) Brookfield Renewable. See CRC's slide 18 from 2Q22 earnings release. (2) CERAWeek (3) Goldman Sachs (4) Within the meaning of NYSE listing standards.

2022 – Delivered on Our Guidance

CRC GUIDANCE	Final Guidance FY22E[1]	Final Results FY22A
Total Production[2] (MBOE/D)	94 – 91	91
Oil Production[2] (MBO/D)	58 – 53	55
Operating Costs ($MM)	$760 – $790	$785
Carbon Management Expenses[4] ($MM)	$10 - $20	$14
Adj. G&A[5] ($MM)	$195 – $210	$201
Adj. EBITDAX[5] ($MM)	$835 – $890	$852
Capital ($MM)	$380 – $400	$379
Free Cash Flow[5] ($MM)	$325 – $370	$311

RECORD 2022 CASH FLOW FROM OPERATIONS[3]



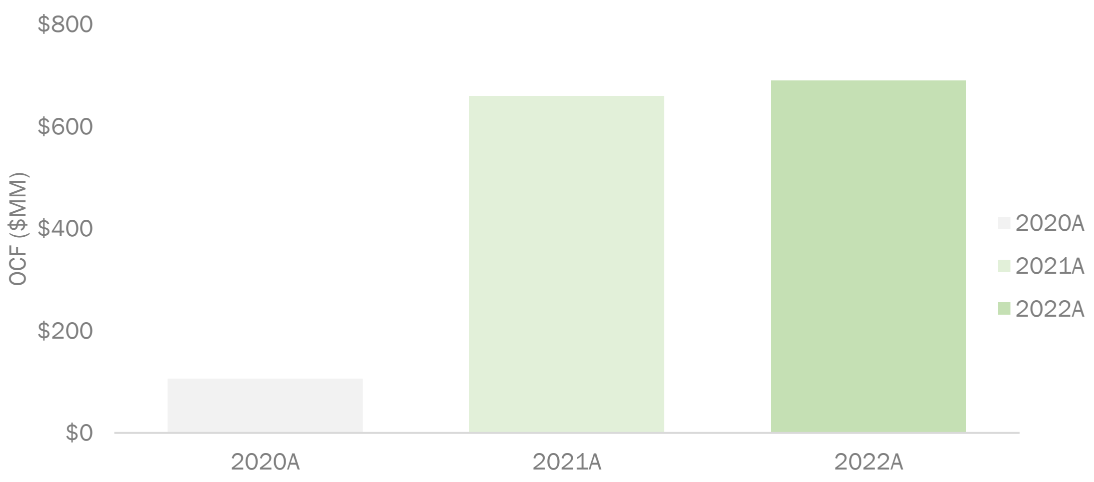
2022 Results in Line With Guidance
excluding FCF which was affected by one-time discretionary cash outlays of ~$30MM for acceleration of incentive compensation and pension contributions

Highest Annual Cash Flow
From Operations Since CRC's Inception

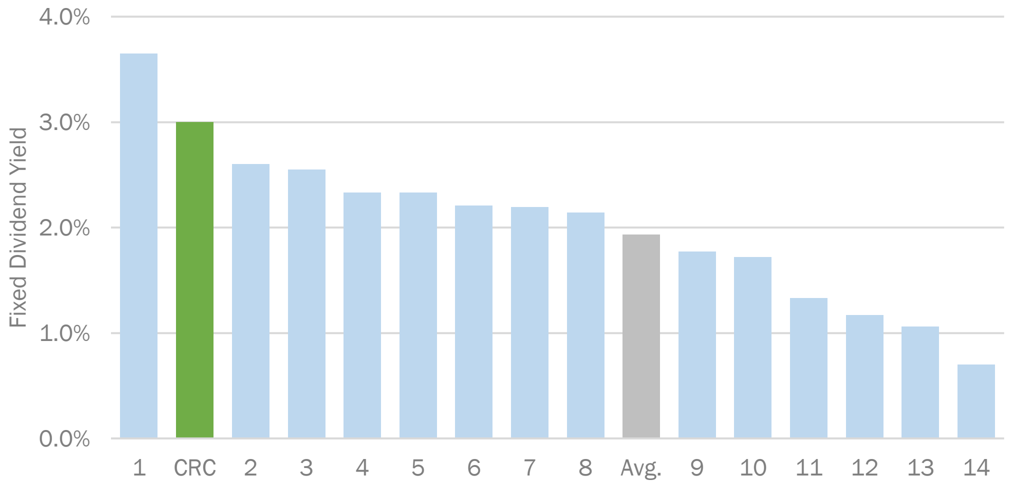
(1) FY22E guidance assumed a 2022 Brent price of $99.75 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $6.47 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. (2) 2022E production ranges subject to PSC effects and account for the Ventura and Lost Hills divestitures as well as CGP1 scheduled maintenance. (3) 2015 to 2019 Predecessor, 2020 combined and 2021 to 2022 Successor as described in Part I, Item 7 – Basis of Presentation in CRC's Form 10-K. (4) CMB Expenses includes lease cost for sequestration easements, advocacy, and other startup related costs. (5) 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 operating cash flow less total capital requirements.

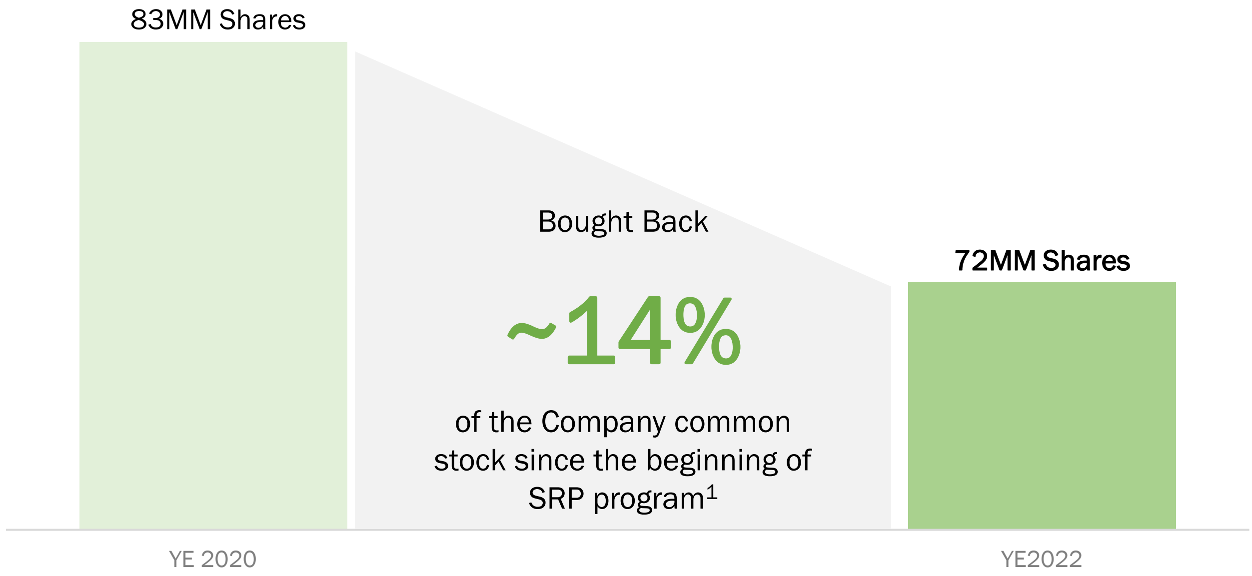
Robust Shareholder Returns Platform Supported by Cash Flow Generating Assets

SIGNIFICANT OPERATING CASH FLOW SUPPORTS SHAREHOLDER RETURNS

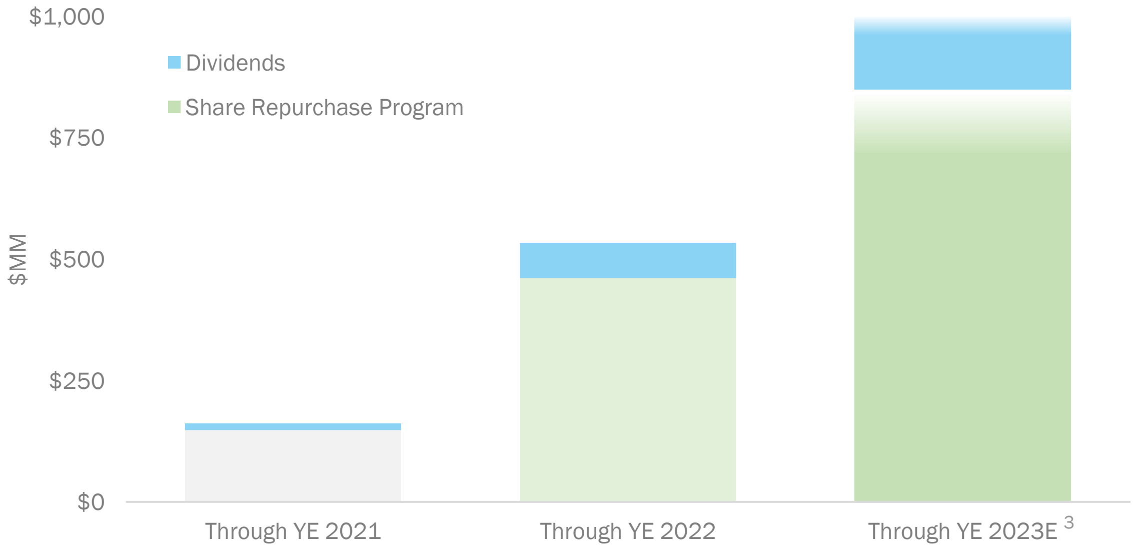


CRC'S FIXED DIVIDEND IS AMONGST THE TOP OF ITS PEERS





EST. CUMULATIVE SHAREHOLDER RETURN BY YE23[2]



Note: Peers include: APA, BRY, CHK, CHRD, DVN, EOG, EQT, FANG, HES, MRO, MTDR, MUR, PDCE and PXD. Dividend Yield as of February 8, 2023. (1) As of December 31, 2022. (2) Share repurchases and dividends are subject to Board approval. (3) Assumes our intentions for the prior $850MM SRP program to be completed throughout the year.

Solar Developments on Track

SELF SUPPLY | BEHIND THE METER UPDATE :

Progressing our solar developments:

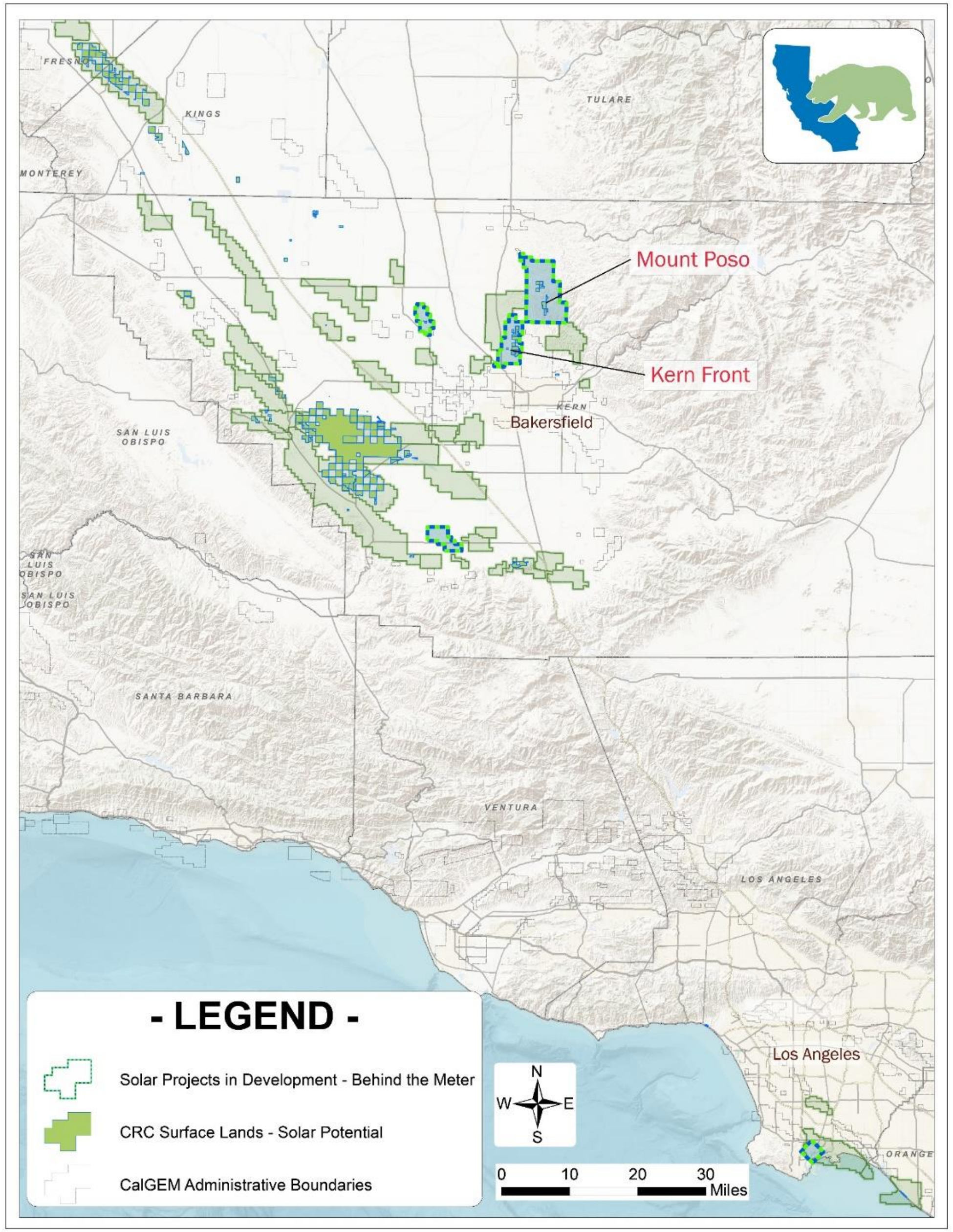
~ 39 MW
of BTM projects in development

BTM Development Field	Capacity (MW)	Est. Commercial Operation
Mount Poso	12	4Q23
Kern Front	22	1H24
Other[1]	5	2H24

- **Mt. Poso & Kern Front Notices to Proceed (NTP) issued in 4Q22**
  - Construction expected to begin in 2Q23
  - Allocating $3MM in 2023E capital program towards BTM solar development
- Continue to advance additional 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**
- **Interconnection request applications in Cluster 14 have been withdrawn** primarily due to high interconnection upgrade costs
- Evaluating further FTM opportunities for Cluster 15 Interconnection Request study process for additional statewide opportunities
- Potential to further reduce CO_2 emissions while adding further commercial opportunity



(1) Other includes sites across CRC's asset base.

Wilmington Production Sharing Contracts (PSC) At Higher Commodity Prices

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

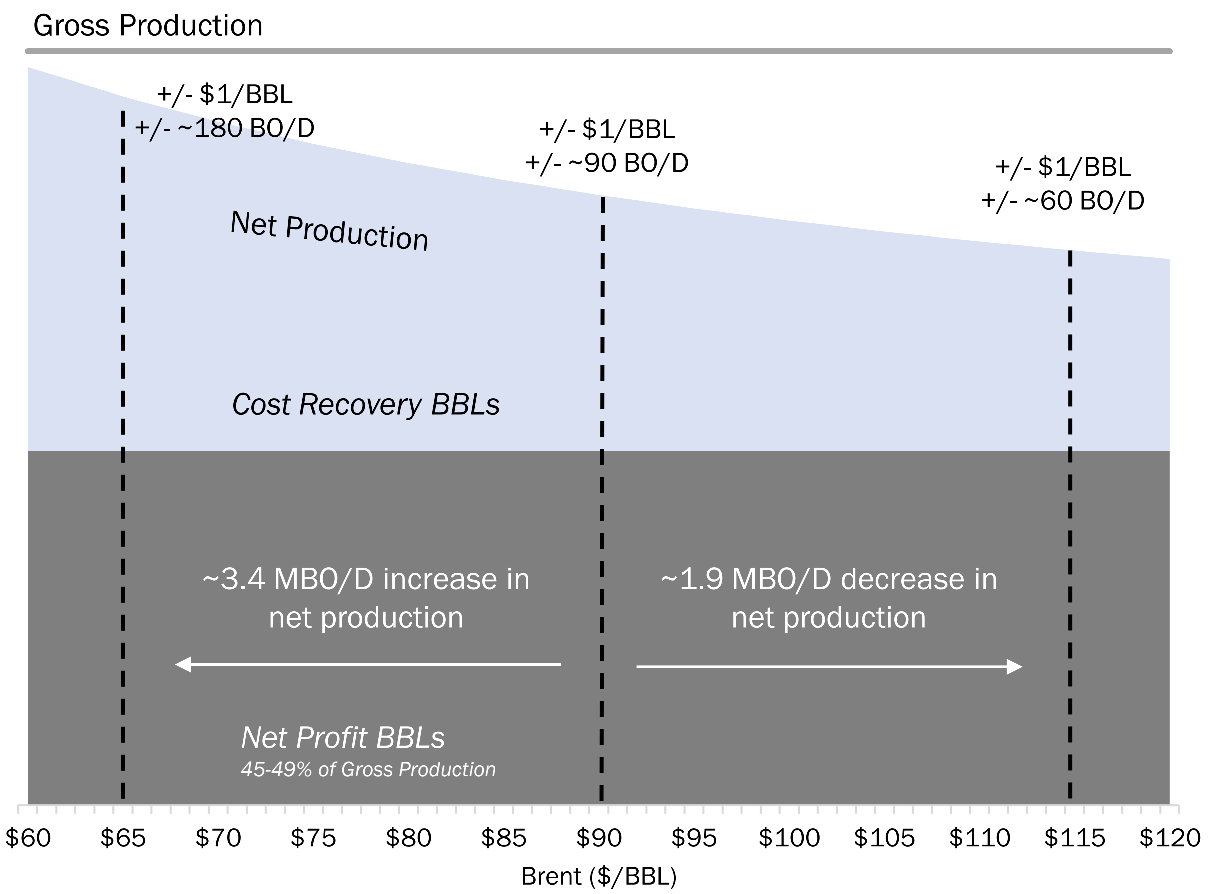
Approximatively 30% of CRC's oil production is subject to PSCs Mechanics:

- 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 MBO/D in net oil production between $65/BBL and $115/BBL

EFFECT OF OIL PRICE ON NET PRODUCTION[2]



(1) Based on Brent price of $90 per barrel of oil (2) Net Production from Wilmington field only. Includes the effect of the additional rig at Tidelands.

Hedging Program

STRATEGY

CRC's hedging strategy is focused on supporting capital to maintain oil production, interest payments on debt, shareholder returns, and our CMB operations

HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 2023[3]

	2021	4Q22	2022	1Q23E	2Q23E	3Q23E	4Q23E	2023E	2024E
Hedge Contract Settlements[4] ($MM)	($319)	($134)	($738)	($88)	($81)	($80)	($45)	($294)	($9)

OIL HEDGES[1]

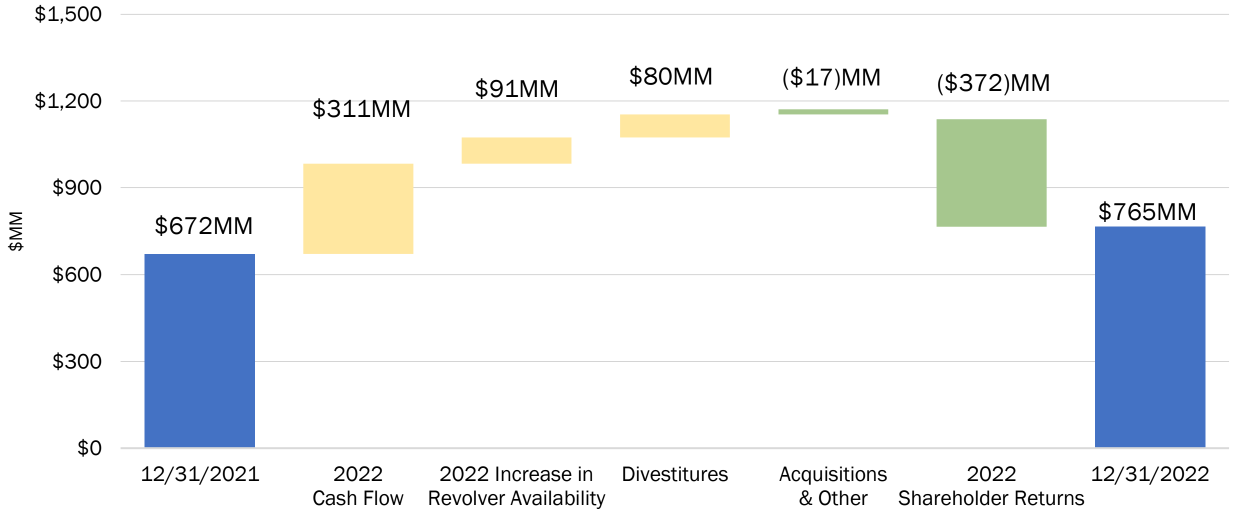
Date as of December 31, 2022

		1Q23	2Q23	3Q23	4Q23	2024
SOLD CALLS	Barrels per Day	18,322	17,837	17,363	5,747	—
	Weighted-Average Price per Barrel	$57.28	$60.00	$57.06	$57.06	—
SWAPS	Barrels per Day	16,620	16,475	16,697	26,094	1,492
	Weighted-Average Price per Barrel	$69.46	$68.53	$68.33	$70.18	$79.06
NET PURCHASED PUTS[2]	Barrels per Day	18,322	17,837	17,363	5,747	1,724
	Weighted-Average Price per Barrel	$76.25	$76.25	$76.25	$76.25	$75.00

1) Hedges are based on weighted-average Brent prices per barrel. CRC also entered NG 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 December 31, 2022. (4) Represents estimated net cash settlement payments for derivative contracts as of 12/31/2022, except 2021, 4Q22 and 2022 which are actuals for the year ended on December 31, 2021, the three months ended December 31, 2022, and the year ended December 31, 2022, respectively.

Maintaining Balance Sheet Strength, Liquidity, and Financial Flexibility

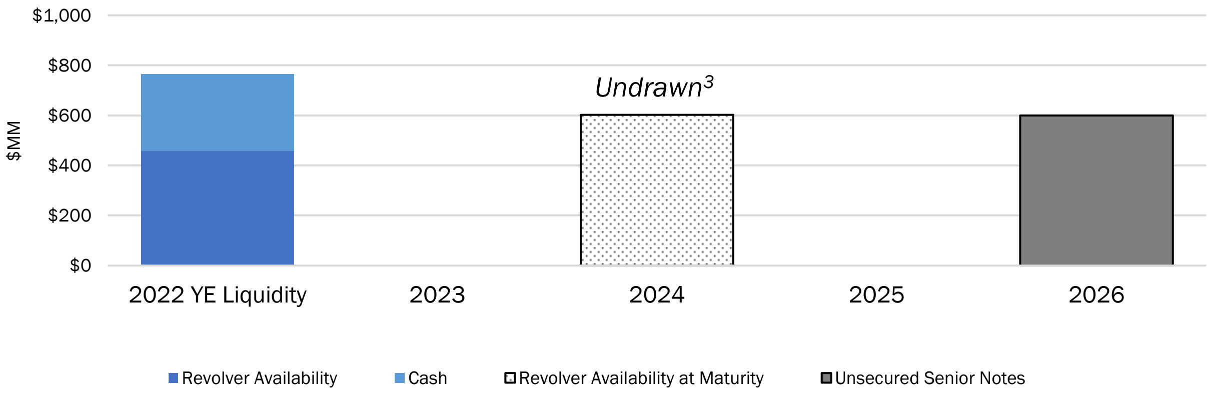
ESTIMATED LIQUIDITY ROLL FORWARD[1]



12/31/22 NET DEBT SNAPSHOT

($MM)		
Revolving Credit Facility (RCF)[1]	$	0
7.125% Senior Notes		600
Face Value of Debt	**$**	**600**
Less Available Cash & Cash Equivalents		(307)
Net Debt[2]	**$**	**293**

NO SIGNIFICANT MATURITIES UNTIL 2026



MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)		
RCF Borrowing Base	$	1,200
2022 Free Cash Flow[2]		$311
YE 2022 Net Debt[1,2] / 2022 Adjusted EBITDAX[2]		0.3x
2022 Adjusted EBITDAX[2] / 2022 Interest & Debt Expense, net		16.1x

(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. (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 December 31, 2022.

Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations (Cont.)

Free Cash Flow

Management uses free cash flow, which is defined by us as net cash provided by operating activities after our internal capital investment, as a measure of liquidity. The table below presents a reconciliation of net cash provided by operating activities to free cash flow. CRC has supplemented its non-GAAP measures of consolidated free cash flow with free cash flow from our exploration and production and corporate items (free cash flow from E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines free cash flow from E&P, Corporate & Other as consolidated free cash flow less results attributable to CMB.

	2023E		CMB 2023E		E&P, Corp. & Other 2023E	
($MM)	Low	High	Low	High	Low	High
Net Cash Provided (Used) by Operating Activities	$575	$640	($55)	($45)	$630	$685
Adjusted Capital Investments[1]	(245)	(200)	(25)	(15)	(220)	(185)
Estimated Free Cash Flow	**$330**	**$440**	($80)	($60)	$410	$500

Adjusted General & Administrative Expenses

Management uses a measure called adjusted general and administrative (G&A) expenses to provide useful information to investors interested in comparing our costs between periods and performance to our peers. We supplemented our non-GAAP measure of adjusted general and administrative expenses with adjusted general and administrative expenses of our exploration and production and corporate items (Adjusted General & Administrative Expenses for E&P, Corporate & Other) which we believe is a useful measure for investors to understand the results or our core oil and gas business. We define Adjusted General & Administrative Expenses for E&P, Corporate & Other as consolidated adjusted general and administrative expenses less results attributable to our carbon management business.

	2023E		CMB 2023E		E&P, Corp. & Other 2023E	
($MM)	Low	High	Low	High	Low	High
General & Administrative Expenses	$235	$250	$10	$15	$225	$235
Equity-settled Stock-based Compensation	(25)	(15)	-	-	(25)	(15)
Other	(15)	(10)	-	-	(15)	(10)
Estimated Adjusted General & Administrative Expenses	**$195**	**$225**	$10	$15	$185	$210

Note: Free Cash Flow and Adjusted G&A 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. (1) Adjusted E&P Capital and Adjusted CMB Capital are Non-GAAP measures. These measures reflect the reclassification of ~$11 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 2Q23.

Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations (Cont.)

Free Cash Flow

Management uses free cash flow, which is defined by us as net cash provided by operating activities after our internal capital investment, as a measure of liquidity. The table below presents a reconciliation of net cash provided by operating activities to free cash flow. CRC has supplemented its non-GAAP measures of consolidated free cash flow with free cash flow from our exploration and production and corporate items (free cash flow from E&P, Corporate & Other) which CRC believes is a useful measure for investors to understand the results of its core oil and gas business. CRC defines free cash flow from E&P, Corporate & Other as consolidated free cash flow less results attributable to CMB.

	1Q23E		CMB 1Q23E		E&P, Corp. & Other 1Q23E	
($MM)	**Low**	**High**	Low	High	Low	High
Net Cash Provided (Used) by Operating Activities	$220	$237	($20)	($13)	$240	$250
Adjusted Capital Investments[1]	(69)	(57)	(4)	(2)	(65)	(55)
Estimated Free Cash Flow	**$151**	**$180**	($24)	($15)	$175	$195

Adjusted General & Administrative Expenses

Management uses a measure called adjusted general and administrative (G&A) expenses to provide useful information to investors interested in comparing our costs between periods and performance to our peers. We supplemented our non-GAAP measure of adjusted general and administrative expenses with adjusted general and administrative expenses of our exploration and production and corporate items (Adjusted General & Administrative Expenses for E&P, Corporate & Other) which we believe is a useful measure for investors to understand the results or our core oil and gas business. We define Adjusted General & Administrative Expenses for E&P, Corporate & Other as consolidated adjusted general and administrative expenses less results attributable to our carbon management business.

	1Q23E		CMB 1Q23E		E&P, Corp. & Other 1Q23E	
($MM)	**Low**	**High**	Low	High	Low	High
General & Administrative Expenses	$62	$66	$3	$5	$59	$61
Equity-settled Stock-based Compensation	(7)	(5)	-	-	(7)	(5)
Other	(5)	(3)	-	-	(5)	(3)
Estimated Adjusted General & Administrative Expenses	**$50**	**$58**	$3	$5	$47	$53

Note: Free Cash Flow and Adjusted G&A 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. (1) Adjusted E&P Capital and Adjusted CMB Capital are Non-GAAP measures. These measures reflect the reclassification of ~$11 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 2Q23.

Assumptions & Relevant Footnotes:

Slide 11:

- (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 a 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 annualized 4Q22 production.
- (3) Enterprise value calculated using net debt of $293MM (as of December 31, 2022) plus market capitalization (as of Feb 22, 2023) using 71.9MM shares outstanding.
- (4) PV-10 of reserves estimated as of December 31, 2022 using SEC Prices (after factoring in price realizations) of $97.50 per barrel for oil, $67.83 per barrel for NGLs and $7.84 per Mcf for natural gas. PV-10 is a non-GAAP measure.

Slide 16:

- (1) 2023E guidance assumes a 2023 Brent price of $79.12 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.27 per mcf. 1Q23E guidance assumes a 1Q23 Brent price of $79.81 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.46 per mcf CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline.
- (2) CMB Expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.
- (3) Represents 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. Reconciliations of 2023E non–GAAP measures to their nearest GAAP equivalent can be found on slides 35 to 36.
- (4) Adjusted E&P Capital and Adjusted CMB Capital are Non-GAAP measures. These measures reflect the reclassification of ~$11 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 2Q23.

Joanna Park (Investor Relations)

818-661-3731

Joanna.Park@crc.com

Richard Venn (Media)

818-661-6014

Richard.Venn@crc.com