"Low Carbon Intensity Fuel for Today and Net Zero Fuel for The Future"

Fourth Quarter & Year End 2021 Results

Strong Delivery in a Transformative Year

February 24, 2022

CALIFORNIA RESOURCES CORPORATION COMPANY | CARBON TERRAVAULT

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 and the potential for sustained low oil, natural gas and natural gas liquids prices;
- legislative or regulatory changes, including those related to (i) drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, (ii) managing energy, water, land, greenhouse gases (GHGs) or other emissions, (iii) protection of health, safety and the environment, (iv) tax credits or other incentives, or (v) transportation, marketing and sale of our products;
- availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development projects;
- changes in business strategy and our capital plan;
- lower-than-expected production, reserves or resources from development projects or acquisitions, or higher-than-expected decline rates;
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves;
- the recoverability of resources and unexpected geologic conditions;
- our ability to realize the benefits of business strategies and initiatives related to energy transition, including carbon capture and storage projects and other renewable energy efforts;
- our ability to finance and implement our carbon capture and storage projects;
- global geopolitical, socio-demographic and economic trends and technological innovations;
- changes in our dividend policy and our ability to declare future dividends;
- production-sharing contracts' effects on production and operating costs;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund planned investments, interest payments on our debt, stock repurchases or changes to our capital plan;
- insufficient capital or liquidity unavailability of capital markets or inability to attract potential investors;
- limitations on transportation or storage capacity and the need to shut-in wells;
- inability to enter into desirable transactions, including acquisitions, asset sales and joint ventures;
- joint ventures and acquisitions and our ability to achieve expected synergies;
- our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- our ability to successfully gather and verify data regarding emissions, our environmental impacts and other initiatives;
- the compliance of various third parties with our policies and procedures and legal requirements as well as contracts we enter into in connection with our climate-related initiatives;
- the effect of our stock price on costs associated with incentive compensation;
- changes in the intensity of competition in the oil and gas industry;
- effects of hedging transactions;
- equipment, service or labor price inflation or unavailability;
- climate-related conditions and weather events;
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, labor difficulties, cyber-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 in CRC’s Annual Report on Form 10-K and our other SEC filings available at www.crc.com.

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
BOD	Board of Directors
BTM	Behind the Meter
C	Celsius
C&T	Cap and Trade
CARB	California Air Resources Board
CATF	Clean Air Task Force
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CI	Carbon Intensity
CMB	Carbon Management Business
CO_2	Carbon Dioxide
CTV	Carbon TerraVault
CUP	Conditional Use Permit
DAC	Direct Air Capture
DOE	Department of Energy
DCF	Discretionary Cash Flow
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency

Term	Definition
EPCC	Engineering, Procurement, Construction and Commissioning
FCF	Free Cash Flow
FEED	Front End Engineering and Design
FID	Final Investment Decision
FTM	Front of the Meter
GHG	Greenhouse Gas
LCFS	Low Carbon Fuel Standard
LOI	Letter Of Intent
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MPa	Megapascal Pressure Unit
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
MW	Megawatts
NATCARB	National Carbon Sequestration Database and Geographical Information System
NTP	Notice To Proceed
O&G	Oil and Gas
RNG	Renewable Natural Gas
SRP	Share Repurchase Program

Delivered Strong Results in 2021

2021

Low Carbon Intensity E&P Business	▪ Reliable, safe and ESG driven operations with low decline and low capital intensity production ▪ Est. average 2021 wellhead IRRs[1] of >100 % ▪ Exited 2021 with net oil production of 58.5 mbo/d ▪ Robust and consistent cash flow generation with record 2021 FCF[2] of $466 MM
Advancing Carbon Management Business	▪ Submitted permits for A1/A2 and 26R with constructive feedback from the EPA ▪ Developing permits for CTV 2, 3, 4+, developed backlog of more than 20 MMTPA of interested emitters ▪ Team of ~25 dedicated staff
Solid Financial Foundation	▪ Over $420 MM of cash on hand as of Feb 22 and liquidity[3] of over $780 MM ▪ 2021 Net Debt/Adj. EBITDAX of 0.34x[2] ▪ Bolstered by sale of non-operated interest in Lost Hills and Ventura exit
Commitment to Shareholder Returns	▪ $162 MM (~35% of FCF[2]) returned to shareholders in 2021 ▪ Repurchased $148 million worth of shares through the share repurchase program ▪ Established a quarterly dividend strategy, represents a 1.7% annual yield[4]

(1) IRRs were calculated using actual 2021 average realized prices provided on slide 10, and $82.50/bbl Brent for 2022 onward and $4.00 NYMEX. (2) Adj. EBITDAX, Free Cash Flow and Net Debt 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 closest GAAP measure and other additional information. Reconciliations of 2022E Free Cash Flow and Net Debt to their nearest GAAP equivalent can be found in the Supplemental Materials on slides 33 to 35. (3) Calculated as $424 million of cash and $356 million of available borrowing capacity under our Revolving Credit Facility as of February 22, 2022. (4) Based on the stock price as of February 18, 2022. Annualized amount subject to the Board of Directors approval of quarterly dividends and assumes payment of ~$13.4 MM on 78.744 million shares.

Advancing the Strategy in 2022

2022

Low Carbon Intensity E&P Business

- Entered 2022 with 4 drilling rigs
- 2022E Drilling & Completion capital of $215 to $225 MM to maintain oil production
- 2022E Total Capital of $330 to $375 MM including $55 to $65 MM of facilities capital
- CGP1 maintenance in 1Q22, capital requirement of ~$15 MM
- 2022E production of 90 - 93 mboepd[1] after adjusting for asset sales, CGP1 and PSC impacts at higher prices

Advancing Carbon Management Business

- Spending ~$85 MM in 2022 to unlock 200+ MMT of storage potential and advance CTV I pre-injection activities
- Filing permits for a total of 200 MMT in 2022
- Target 1 MMTPA of emitter deal(s) in 2022
- On-going discussions with numerous emitters, capital partners and technology providers

Solid Financial Foundation

- 2022E E&P Adj. EBITDAX[2] range of $800 - $940 MM | 2022E Adj. EBITDAX[2] range $745 - $900 MM
- 2022E E&P FCF[2] range of $350 - $450 MM | 2022E FCF[2] range of $255 - $380 MM
- 2022E Net Debt[2] / Adj. EBITDAX[2] of ~0.25x at midpoint

Commitment to Shareholder Returns

- Increasing SRP by 40% to $350 MM through 4Q22; $162 MM available[3]
- Continuing fixed quarterly dividend strategy of $0.17 per share

(1) Current guidance assumes a 2022 price of $82.50 per barrel of oil, NGL realizations consistent with prior years and NYMEX gas of $4.00 per mcf. CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. 2022E production ranges subject to PSC effects and account for the Ventura and Lost Hills divestitures as well as CGP1 downtime. (2) E&P Adj EBITDAX, Adj. EBITDAX, Free Cash Flow, E&P Free Cash Flow and Net Debt 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 closest GAAP measure and other additional information. Reconciliations of 2022E E&P Adj. EBITDAX, Adj. EBITDAX, E&P Free Cash Flow, Free Cash Flow and Net Debt to their nearest GAAP equivalent can be found in the Supplemental Materials on slides 33 to 35. (3) As of February 18, 2022.

4Q21 & Year over Year Progress

CRC 2021 Overview

100 MBOE/D
2021 NET PRODUCTION

Oil	NGLs	Gas
60%	13%	27%

~970
EMPLOYEES[1]

Women	Men
19%	81%

4
ACTIVE DRILING RIGS[1]

LA Basin	San Joaquin Basin
1	3

$6.2 B
PV-10 OF 2021 PROVED RESERVES[4,5]

480 MMboe

PUD	PD
16%	84%

STRONG FINANCIAL FOUNDATION

$0.17 / Share
INCREASING SHAREHOLDER RETURNS
Dividend Paid in 4Q21

$672 MM
AMPLE LIQUIDITY[3]
YE21, includes cash & borrowing capacity

$860 MM
STRONG EARNINGS PROGRESS
2021 Adj. EBITDAX[4]

RESPONSIBLE CAPITAL STEWARDSHIP

$148 MM
SHARE REPURCHASES
Average Price of $36.08 per Share | ~11% discount to current price[2]

0.34x
LEADING LEVERAGE POSITION
YE21 NET DEBT to 2021 Adj. EBITDAX[4]

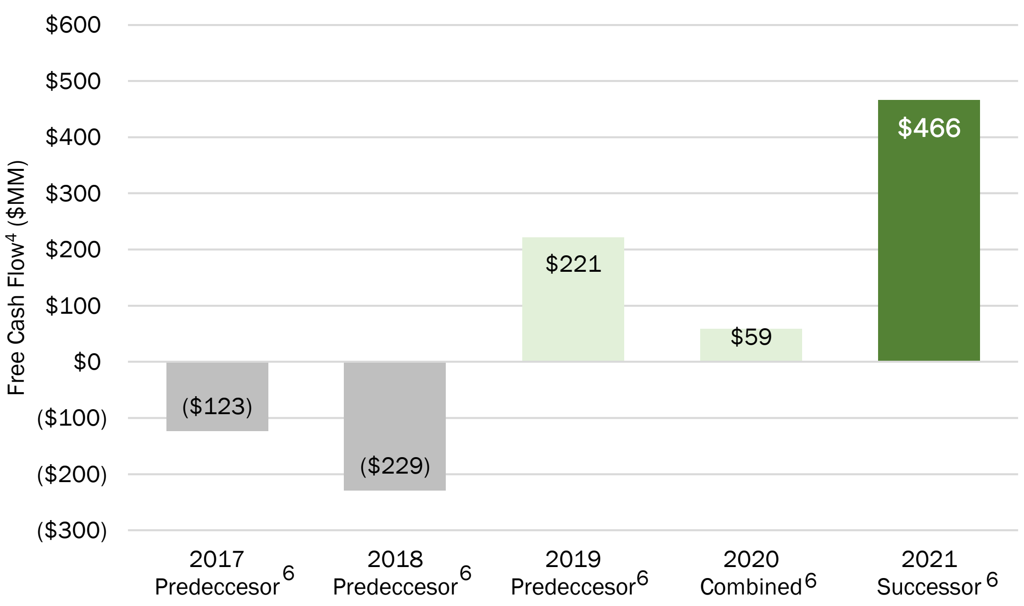
$466 MM
ROBUST FCF GENERATION
2021 FCF[4]

(1) As of year-end 2021. (2) Based on market price on February 18, 2022. (3) Calculated as $305 million of cash and $367 million of available borrowing capacity under our Revolving Credit Facility as of December 31, 2021. (4) Net Debt, Adj. EBITDAX, Free Cash Flow and PV-10 are non-GAAP measures. Please see crc.com for reconciliations to the closest GAAP measures. (5) Represents FY2021 Reserves at SEC prices as of December 31, 2021, and after factoring in price realizations, reflect average realized pricing of $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 per Mcf for natural gas.

Upheld Strong Results on Guidance

	FINAL GUIDANCE FY 2021E[1]	FINAL RESULTS FY 2021
Net Total Production (Mboepd)[2]	99 - 101	100
Net Oil Production (Mbopd)[2]	60 - 62	60
Operating Costs ($MM)	$700 - $720 $18.99 - $19.93 $/boe	$705 $19.39/boe
Capital Spend ($MM)	$180 - $200 $4.88 - $5.53 $/boe	$194 $5.34/boe
G&A ($MM)[3]	$190 - $200 $5.15 - $5.53 $/boe	$200 $5.50/boe
Adjusted EBITDAX[4] ($MM)	$840 - $900 $22.79 – $24.91 $/boe	$860 $23.65/boe
Free Cash Flow[4] ($MM)	$460 - $510	$466
Free Cash Flow Yield[5]	13% - 15%	~13%

RECORD FREE CASH FLOW[4] GENERATION CAPABILITY



Highest Annual Free Cash Flow[4] results since CRC's inception

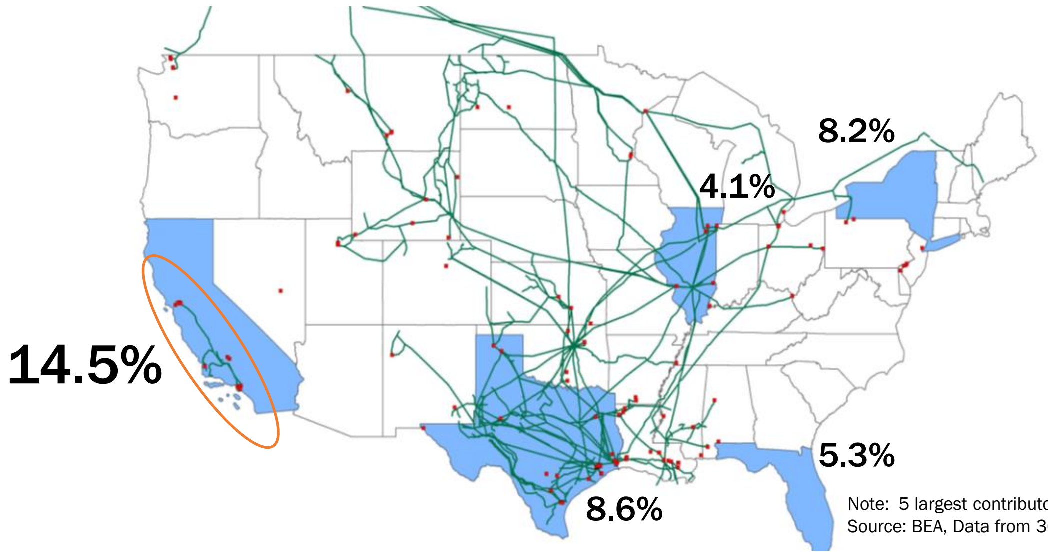
(1) Final FY2021E guidance assumed strip pricing as of September 30, 2021. (2) 2021E production ranges were subject to PSC effects. (3) G&A includes ~$14MM in non-cash stock-based compensation expense. (4) Adj. EBITDAX and Free Cash Flow are non-GAAP measures. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the closest GAAP measure and other additional information. (5) FCF Yield reflects FY 2021E and 2021A Free Cash Flow divided by market capitalization as of October 27, 2021, calculated using 80.775 million shares. Market capitalization used for final results uses the same market capitalization as final guidance for comparison purposes. (6) Periods subsequent to October 31, 2020 (Successor period) and ending on or prior to October 31, 2020 (Predecessor period) are distinct reporting periods as a result of the adoption of fresh start accounting upon emergence from Chapter 11 bankruptcy and as such, amounts prior to October 31, 2020, may not be comparable to prior periods. Combined represents the combined successor and predecessor periods as defined in the 2021 10-K, Part II – Item 7 – Basis of Presentation. For further information, consult the 2021 10-K, Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Fresh Start Accounting.

Strong Price Realizations in CA's Improving Market Dynamics

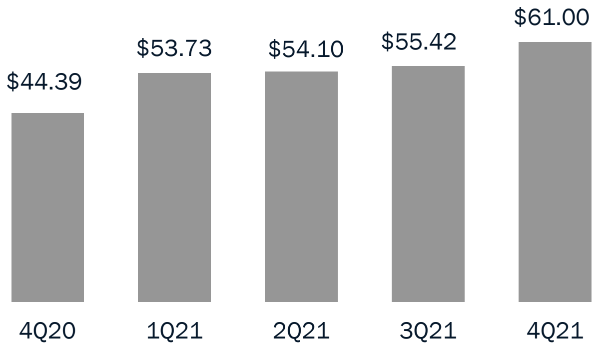
- CRC's 4Q21 crude realizations remained strong, supported largely by moves in global crude pricing, while differentials to Brent came under intermittent pressure due to refinery maintenance in the state and competing waterborne alternatives
- NGL sales price differentials and realizations, led specifically by butane and propane, strengthened across 4Q as a result of increased export and domestic demand
- Natural gas prices were well supported during 4Q due to concerns that low storage levels which, when paired with an anticipated return-to-normal post-Covid, would not be sufficient to meet seasonal domestic and growing export demand

Expecting NGL pricing to remain strong on a relative basis through 1H22

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

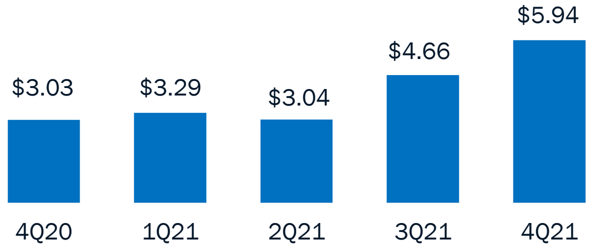


Note: 5 largest contributors to domestic GDP
Source: BEA, Data from 3Q21; EIA



Oil w/ Hedges ($/Bbl)

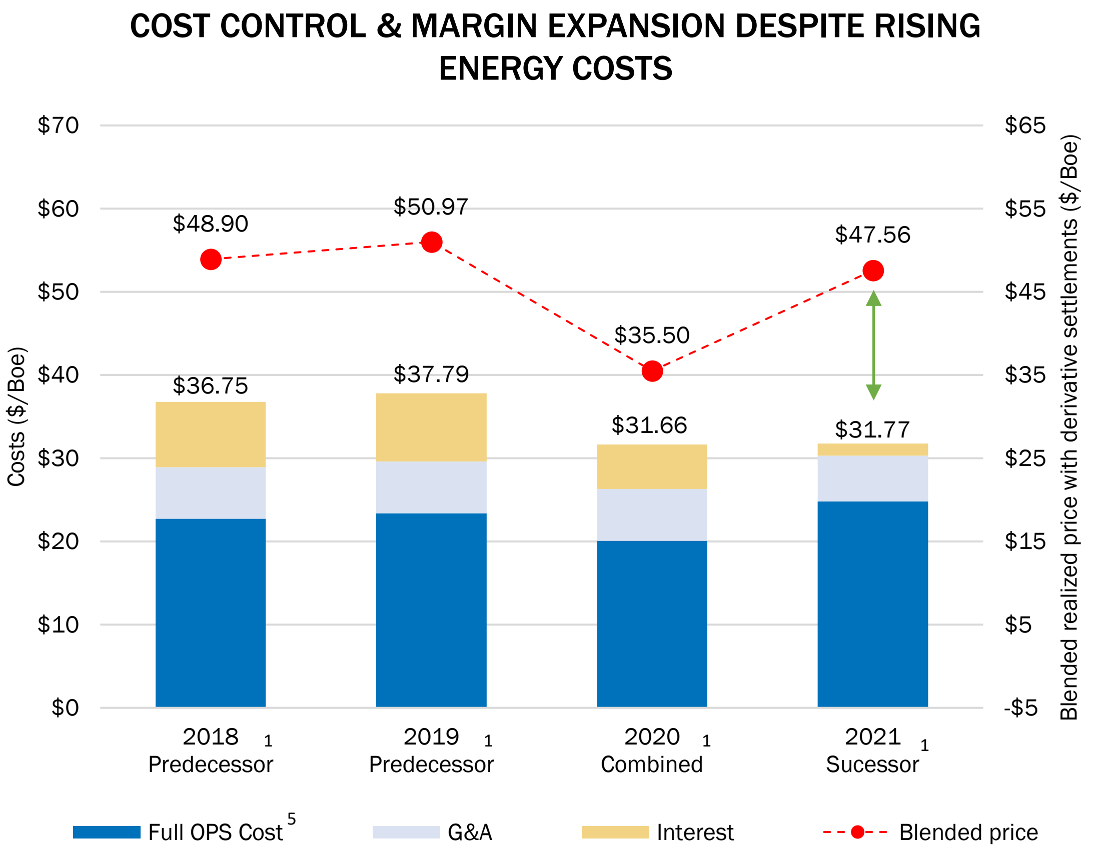
NGLs ($/Bbl)



Natural Gas ($/Mcf)

Average Benchmark Prices	$45.24	$61.10	$69.02	$73.23	$79.80	$45.24	$61.10	$69.02	$73.23	$79.80	$2.66	$2.72	$2.76	$3.71	$5.27
Differential	($1.30)	($0.29)	($0.08)	($0.34)	($0.81)	($9.79)	($12.33)	($24.12)	($19.49)	($12.19)	$0.37	$0.57	$0.28	$0.95	$0.67
Hedge Settlements	$0.45	($7.08)	($14.84)	($17.47)	($17.99)	-	-	-	-	-	-	-	-	-	-
Average Realized Prices	$44.39	$53.73	$54.10	$55.42	$61.00	$35.45	$48.77	$44.90	$53.74	$67.61	$3.03	$3.29	$3.04	$4.66	$5.94

Continued Focus on Cost Management



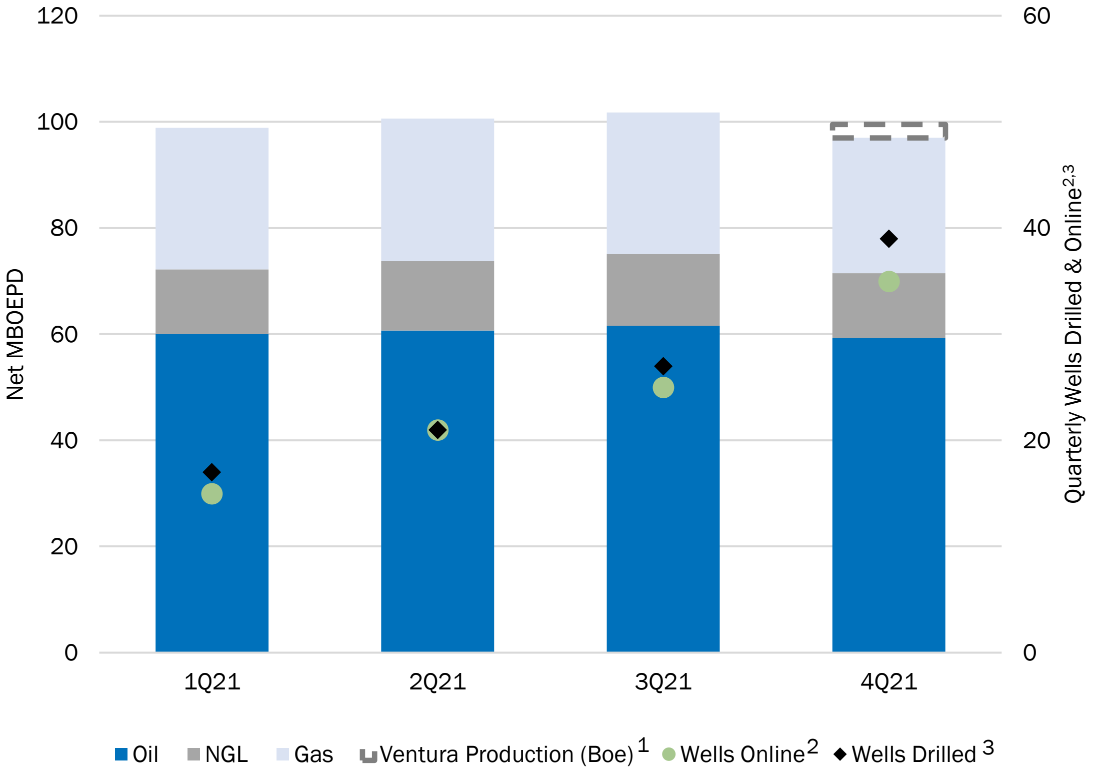
Costs ($/Boe)	2018[1] Predecessor	2019[1] Predecessor	2020[1] Combined	2021[1] Successor
Energy operating costs[2]	$3.62	$3.71	$3.95	$5.09
Gas processing costs	$0.61	$0.63	$0.55	$0.54
Non-energy operating costs[2,3]	$14.65	$14.82	$10.95	$13.76
Operating costs	**$18.88**	**$19.16**	**$15.45**	**$19.39**
Costs attributable to PSCs[4]	($1.41)	($1.46)	($0.89)	($1.83)
Operating costs excluding effects of PSCs[4]	**$17.47**	**$17.70**	**$14.56**	**$17.56**
Transportation + Taxes other than on income	$3.83	$4.22	$4.62	$5.40
G&A	$6.19	$6.21	$6.23	$5.50
Interest and debt expense, net	$7.85	$8.20	$5.36	$1.48

Natural gas markets drove cost increases primarily in our electricity generation and, to a lesser extent, steamflood operations, which are more than offset by increased natural gas revenues

(1) Periods subsequent to October 31, 2020 (Successor period) and ending on or prior to October 31, 2020 (Predecessor period) are distinct reporting periods as a result of the adoption of fresh start accounting upon emergence from Chapter 11 bankruptcy and as such, amounts prior to October 31, 2020, may not be comparable to prior periods. Combined represents the combined successor and predecessor periods as defined in the 2021 10-K, Part II – Item 7 – Basis of Presentation. For further information, consult the 2021 10-K, Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Fresh Start Accounting. (2) Energy operating costs consist of purchases of fuel gas used to generate electricity, purchased electricity and internal costs to produce electricity used in our operations. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs. Purchases of fuel gas to generate steam which is then used in our steamfloods is included in non-energy operating costs. (3) Includes costs of $1.34, $1.24, $0.96 and $1.92 per Boe related to natural gas that is used to heat water for enhanced oil recovery in our steamflood operations for 2018, 2019, 2020 and 2021, respectively. (4) Represent 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 closest GAAP measure and other additional information. (5) Full OPS cost includes operating costs plus transportation costs and taxes other than on income.

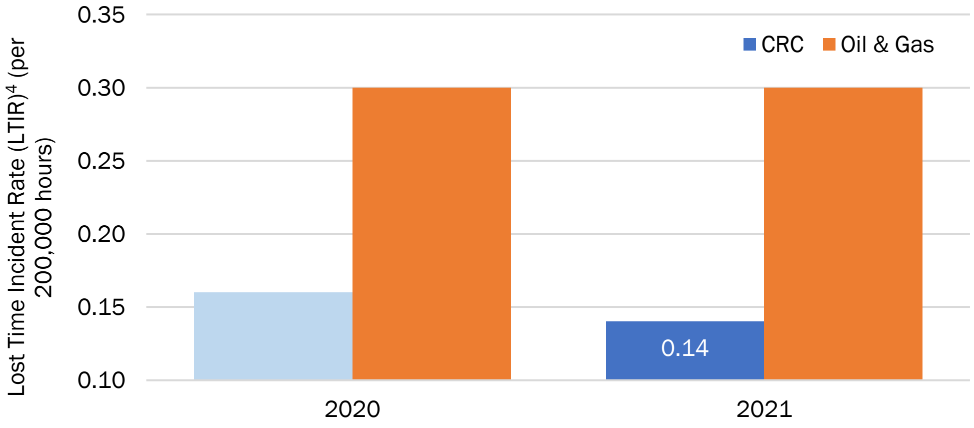
Continued Operational Excellence

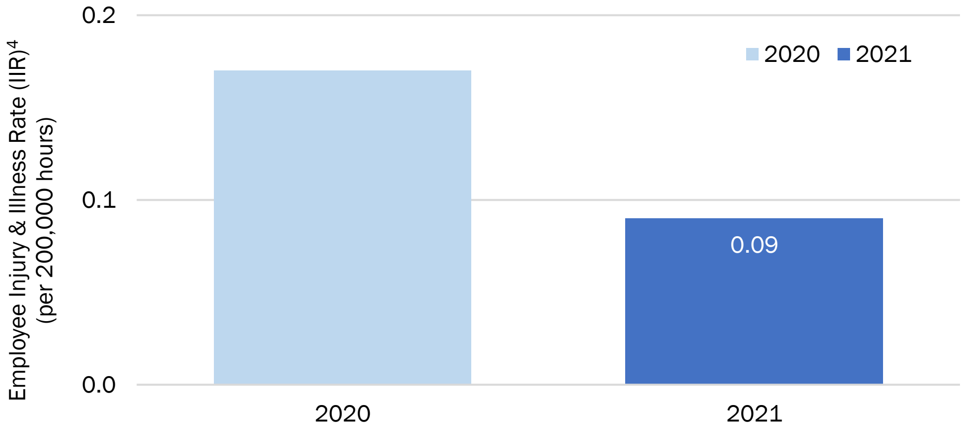
MAINTAINING NET OVERALL AND OIL PRODUCTION WITH LIMITED DRILLING & COMPLETION ACTIVITY



Continued strength in the drilling program driving sustained production levels while outperforming safety goals & standards

CRC'S FOCUS ON SAFETY CONTINUES TO OUTPERFORM THE INDUSTRY AVERAGE





(1) Average production for the three months ended September 30, 2021, less average production for the three months ended December 31, 2021. (2) Wells online reflects gross wells drilled, completed and producing,, excluding outside operated wells. (3) Wells drilled includes steam injectors and drilled but uncompleted wells, which are not included in the SEC definition of wells drilled. Represents gross wells drilled and excludes outside operated wells. (4) Source: Bureau of Labor Statistics; CRC's IIR applies only to CRC employees. CRC's LTIR applies to CRC employees, employees of our joint ventures, suppliers and vendors while working on our operations. 2021 Industry data reflects 2020 actual data. CRC's LTIR is compared to the Bureau of Labor Statistics' Cases with Days Away From Work metric.

Strong Asset Performance Throughout 2021

2021 DEVELOPMENT PERFORMANCE:

- 3 rigs in San Joaquin basin | 1 rig in Long Beach
  - 2021 : 104 Wells Drilled | 96 Wells Online
- ~90% of our drilling efforts were focused on high value, high margin horizontals
- Enhancing our drilling performance by implementing new technologies:
  - Real time data analytics and AI algorithms to improve drilling time
  - Autonomous Inflow Control Device (AICD) completions to improve oil cuts and recoveries from reservoirs
  - Fit for purpose, modular package drilling rigs to enable faster rig moves

SUCCESSFUL 2021 MAINTENANCE OPPORTUNITIES PROGRAM :

- Through rapid technical identification & commercial analysis, well remediation work was prioritized to bring the highest impact wells back online first
- The incremental maintenance program expects IRRs[1] of 200%+ on allocated capital with approximately 620 jobs performed through December 31, 2021
- We expect to continue with an appropriate level of maintenance rigs in the following quarters

As of 4Q21, CRC brought back **~7 MBOEPD** of gross PDP production from incremental $35 MM shift in capital towards the backlog of maintenance opportunities

San Joaquin Basin	
Wells Drilled & Online	88
TMD (ft.)	4,023
Peak IP[2] (boepd)	72
Estimated IRR[1] (%)	106%

Est. **>100% IRR[1]** of 2021 development program demonstrates strong opportunities

Long Beach	
Wells Drilled & Online	8
TMD (ft.)	5,554
Peak IP[2] (boepd)	73
Estimated IRR[1] (%)	113%

Note: TMD represents total measured depth (1) IRRs were calculated using actual 2021 average realized prices , $82.50/bbl Brent for 2022 onward and $4.00 NYMEX. (2) Peak IP rate defined as highest production achieved during first 90 days of production.

Accelerated Shareholder Returns

~35% of FCF[1,2]
Returned to Shareholders in 2021

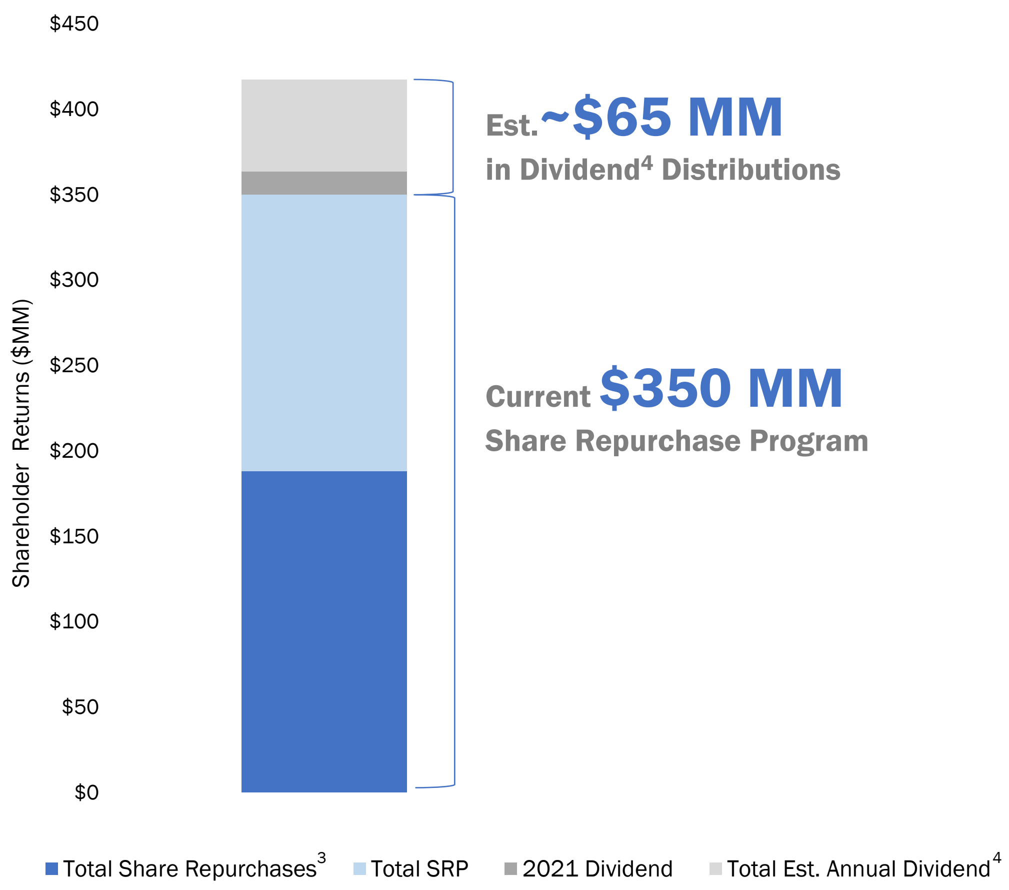
Share Repurchase Program
- Repurchased ~$148 million in 2021
- Repurchased an additional ~$40 million YTD[3]
- $350 MM Share Repurchase Program in place through December 31, 2022

Dividends
- First dividend of $0.17 paid in 4Q21
- Announced a dividend of $0.17 per share for shareholders as of March 7, 2022, and payable on March 16, 2022
- Funded by Free Cash Flow[1]

Additional Shareholder Initiatives

Closely evaluating alternative shareholder friendly initiatives including:
- Variable dividends
- Additional share repurchases

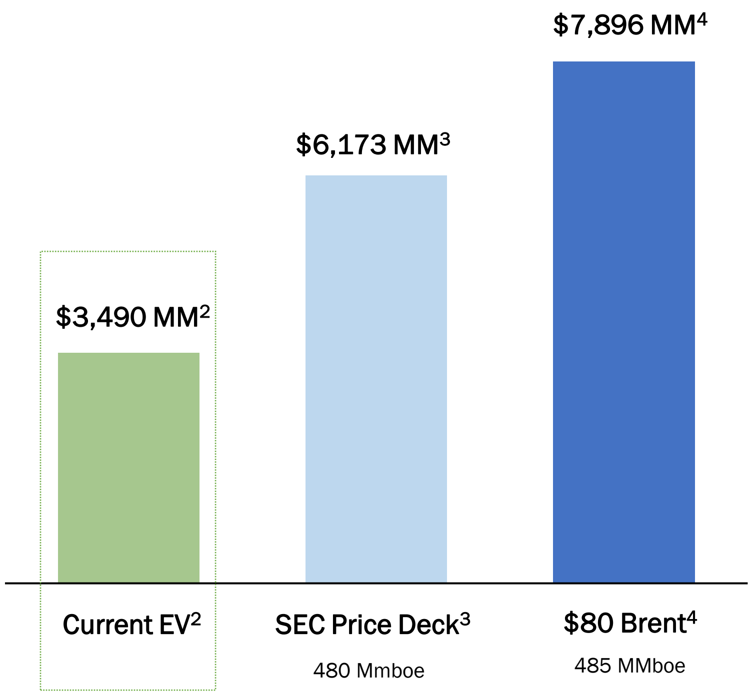
ANNOUNCED OVER $400 MM IN EXPECTED SHAREHOLDER RETURNS



(1) 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 closest GAAP measure and other additional information. (2) Calculated as $148 MM of share repurchases in 2021 and a ~$14 MM dividend payment on December 16, 2021, over 2021 free cash flow of $466 MM. (3) As of February 18, 2022. (4) Annualized amount subject to the Board of Directors approval of quarterly dividends and assumes payment of ~$13.4 MM on 78.744 million shares.

CRC's Reserves Value at Current Prices Demonstrates Equity Upside

PV-10 RESERVES VALUE[1] AND METRICS AT SEC PRICE DECK AND $80 BRENT PRICES

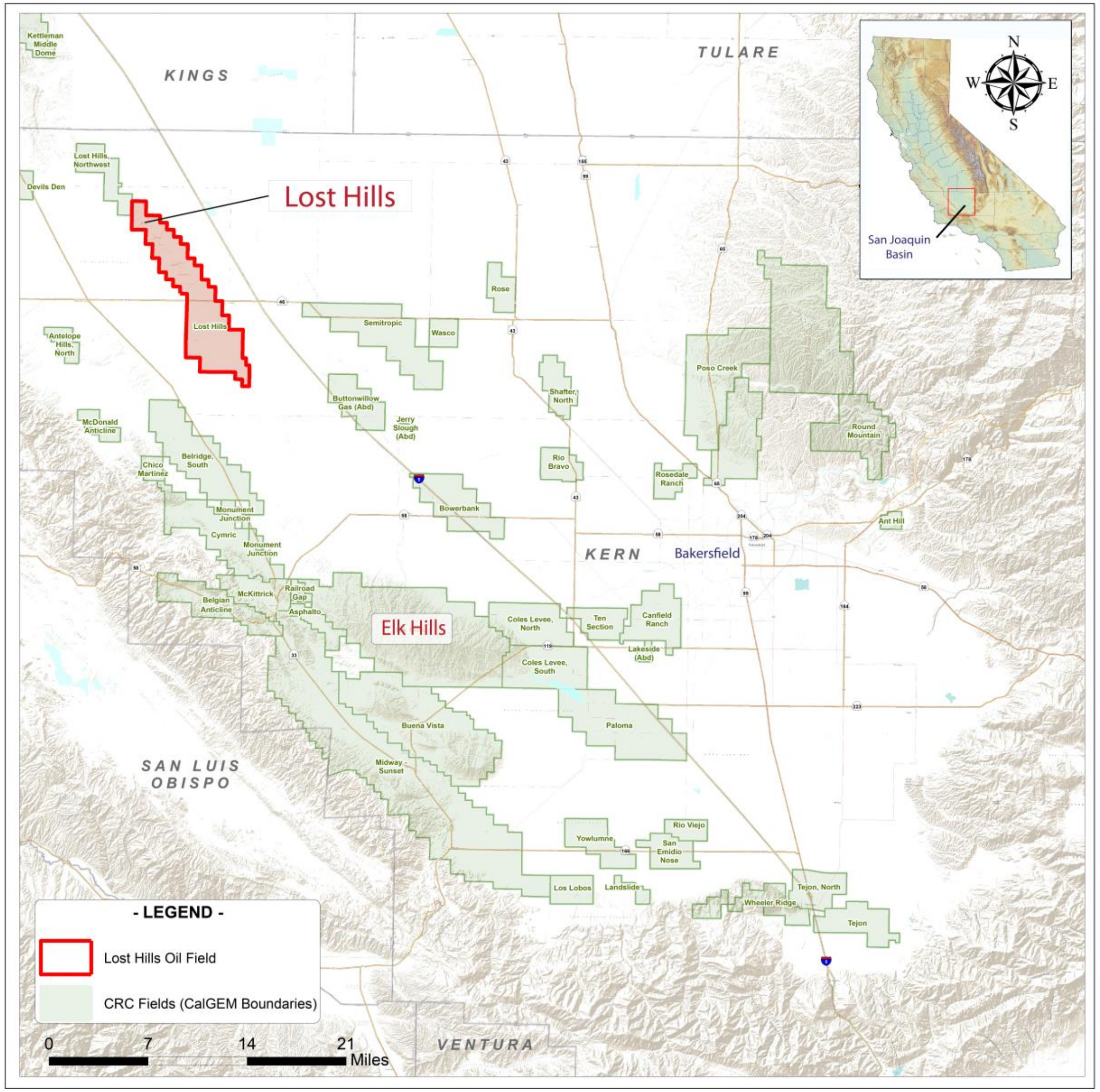


	SEC Price Deck[3]	$80 Brent[4]
Total Proved Reserves / 2021 Exit Production[5]	13.8 years	14.0 years
PV-10[1] ($MM)	$6,173	$7,896
PV-10[1] / Net Debt[1] ($)	20.9x	26.8x
Net Debt[1] / Total Proved Reserves ($/boe)	$0.61	$0.61
EV[2]/Total Proved Reserves ($/boe)	$7.27	$7.20
PV-10[1] /Total Proved Reserves ($/boe)	$12.86	$16.28
EV[2] / PV-10[1] ($)	0.6x	0.4x

(1) PV-10 is as of December 31, 2021. Net Debt is as of December 31, 2021. PV-10 and Net Debt 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 closest GAAP measure and other additional information. (2) Enterprise value calculated using Net Debt as of December 31, 2021, of $295 MM plus market capitalization as of Feb 18, 2022, using 78.744 MM shares outstanding. (3) Represents FY2021 Reserves at SEC prices as of December 31, 2021, and after factoring in price realizations reflect average realized pricing of $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 per Mcf for natural gas. (4) Average realized prices used to estimate our reserves were ~$80 per barrel for oil, ~$60.85 per barrel of NGLs and ~$4.40 per Mcf for natural gas. GAAP does not prescribe a standardized measure of reserves on a basis other than SEC pricing. As such, no standardized measure of proved reserves using ~$80 per barrel for oil, ~$60.85 per barrel of NGLs and ~$4.40 per Mcf for natural gas has been provided. (5) Calculated using annualized December 2021 production.

2022 Outlook

Strategic Divestiture - Lowering Costs & Reducing Carbon Intensity



FULLY DIVESTING THE NON-CORE / NON-OPERATED INTEREST IN LOST HILLS ASSET

- ~1.9 net mboepd in 2021; 100% oil
- Heavy crude (EOR – steamflood) with 2021 operating expense of ~$27 million
- Sold on February 1, 2022, for $55 million

REDUCING CARBON INTENSITY (CI) WHILE KEEPING AN OPTION FOR FURTHER CCS DEVELOPMENT

- Accretive to CRC's CI (Lost Hill's CI is ~21% above CRC's portfolio average)
- CRC retains the option to capture, transport and store 100% of CO_2 from Lost Hills steam generators
- CRC retains 100% of deep rights and seismic data

CONTINUING TO SIMPLIFY CRC'S BUSINESS MODEL

- Committed to our core assets in Elk Hills and Long Beach
- Focused on lower cost and lower CI oil production
- Asset portfolio comprised of only fully operated positions

E&P Operational Outlook

MAIN GOALS

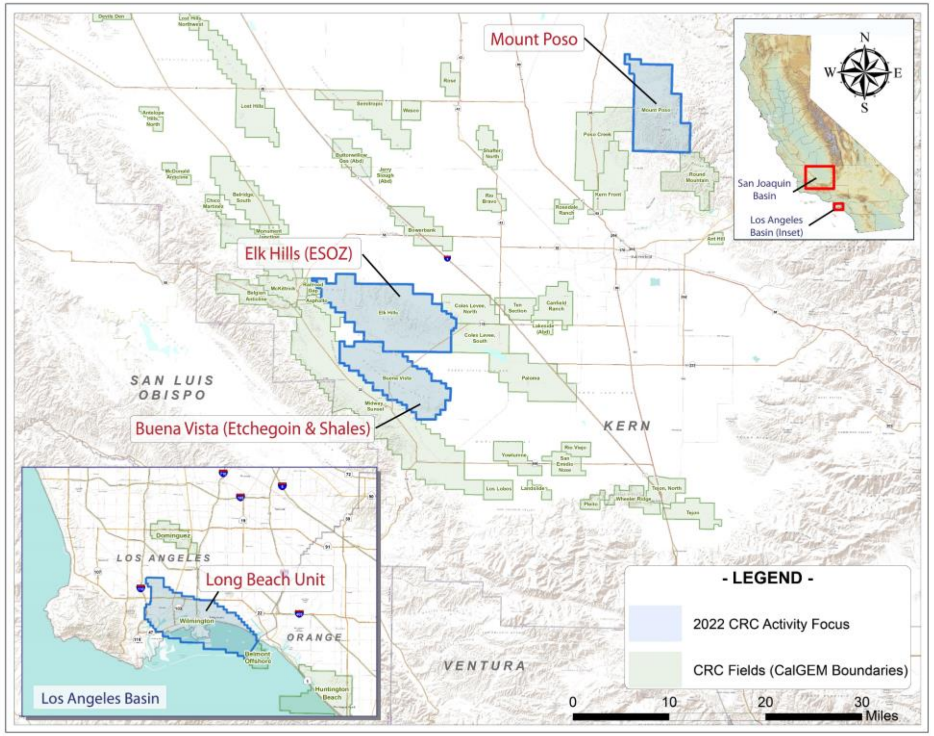
- Maintain flat oil production from exit to exit (*December 2021 net oil production at 58.5 mbo/d*) despite asset sales and PSC effects
- Reduce **non-energy operating costs per BOE[1] by 5% YOY** excluding purchases of fuel gas to generate steam
- Build off successful 2021 horizontal drilling program into 2022

SUBSURFACE OPERATIONAL FOCUS

- Planning to run **4 drilling rigs**
- Expecting to run 5 capital workover rigs
- Focused on Mount Poso, Elk Hills, Buena Vista and Long Beach fields

CRYOGENIC GAS PLANT (CGP1 - 200 MMCFPD) UNDER MAINTENANCE IN 1Q22

- CGP1 approaching a 10-year inspection milestone. Elected to pursue the plant turnaround in 1Q22 to benefit from lower costs of materials and to optimize yields in the summer of 2022
- **Expect a full return to pre-turnaround production levels of Natural Gas and NGLs in 2Q22**
- 1Q22E production impact of ~6 mboepd (56% NGLs) | FY22E production impact of ~2 mboepd



(1) Non-energy operating costs excluding purchases of fuel gas to generate steam are equal to non-energy operating costs, which represent total operating costs less energy operating costs and gas processing costs, excluding purchases of fuel gas to generate steam which is then used in our steamfloods. See slide 11 for CRC's historical performance on operating costs.

Carbon Management Business in Development

2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027

Submitted 2 Class VI EPA Permits | Monitoring, Reporting and Verification Plan (MRV) & LCFS application on track | Kern County CUP & additional permitting in progress

In Concurrent Process

Concurrently exploring options

TBA

CTV I

- Permitting — **EPA Review** | **Public Review** → *Targeting to permit the project in 2023*[1]
- Project Development → *Targeting FID*[2]
- FID | Financing → *Targeting Initial Injection in 2025*[2]
- EPCC

CARBON TERRAVAULT

2022 Goals

- Announce Carbon TerraVault Emissions Source(s)
- Filing for a total of 200 MMT of CO_2 permits by YE2022

CTV II

CTV III

CTV - …

In Evaluation

CalCapture

Permitting[1] | Project Development

Scalable business model that **Lowers Carbon Emissions** & **Drives Value**

Early-Stage Development Goals:

- 1st Injection by YE2025
- 200+ MMT of permits received by YE2025
- 5 MMTPA injection by YE2027

Working on commercial agreements with emitters for > 20 MMTPA

Source: Internal estimates. (1) EPA review estimated to take approximately 18 months followed by a public review estimated to take 3 to 6 months. (2) Source dependent for capture system. First injection date dependent on permitting, capture facility type and the structure, financing and ownership of the project which have not yet been negotiated.

Solar Developments on Track

SELF SUPPLY | BEHIND THE METER UPDATE :

Progressing our solar developments:

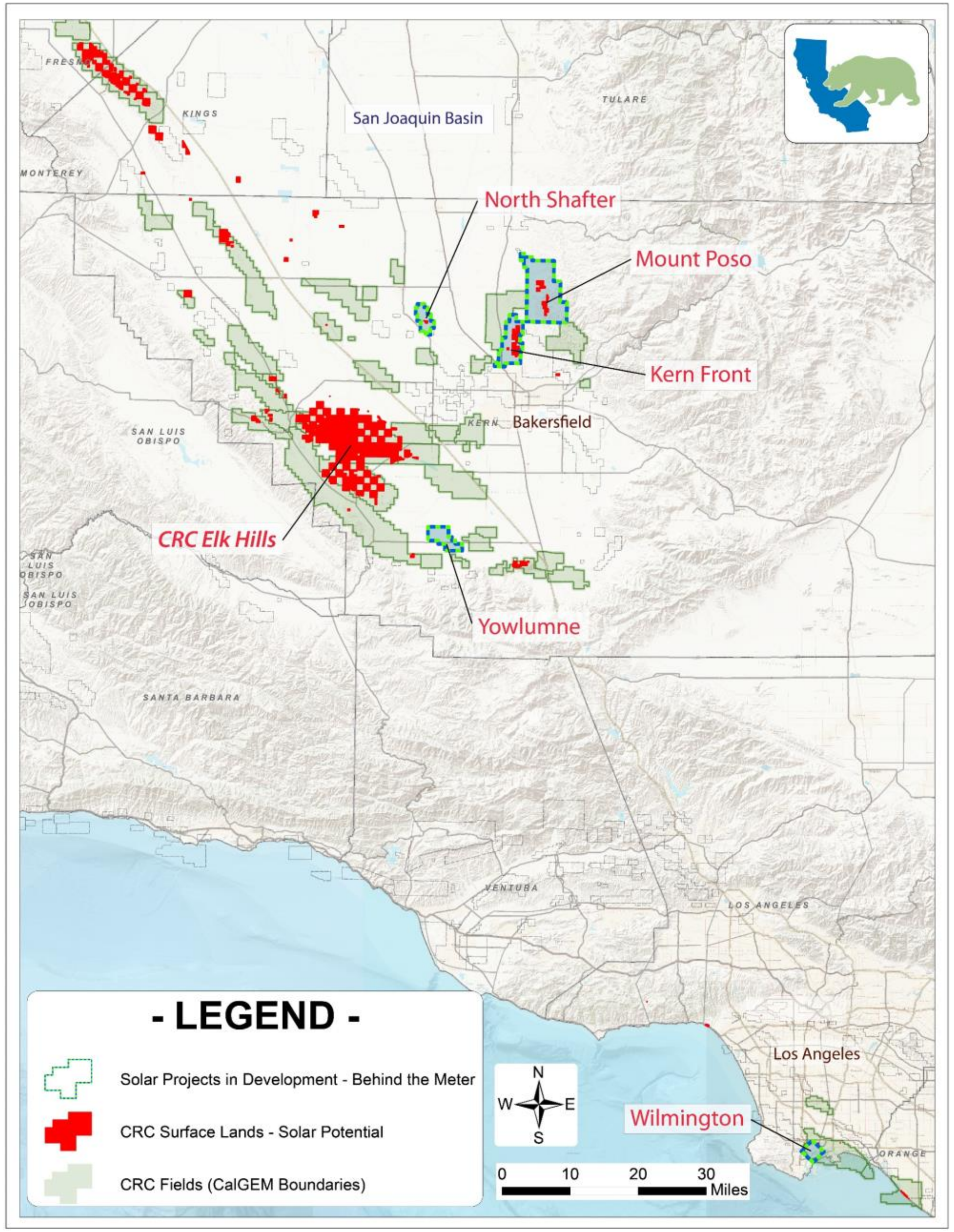
~ 39 MW
of BTM projects in development

BTM Development Field	Capacity (MW)	Est. Commercial Operation
Mount Poso	12	1H23
Kern Front	23	2H23
Other[1]	4	2H23

- Mt. Poso financing agreement executed by project investor; Notice to Proceed (NTP) target early Q2 2022
- Kern Front Letter of Intent (LOI) executed by potential investor, project due diligence process started
- Continue to advance additional BTM projects across CRC's land position

GRID SUPPLY | FRONT OF THE METER UPDATE:

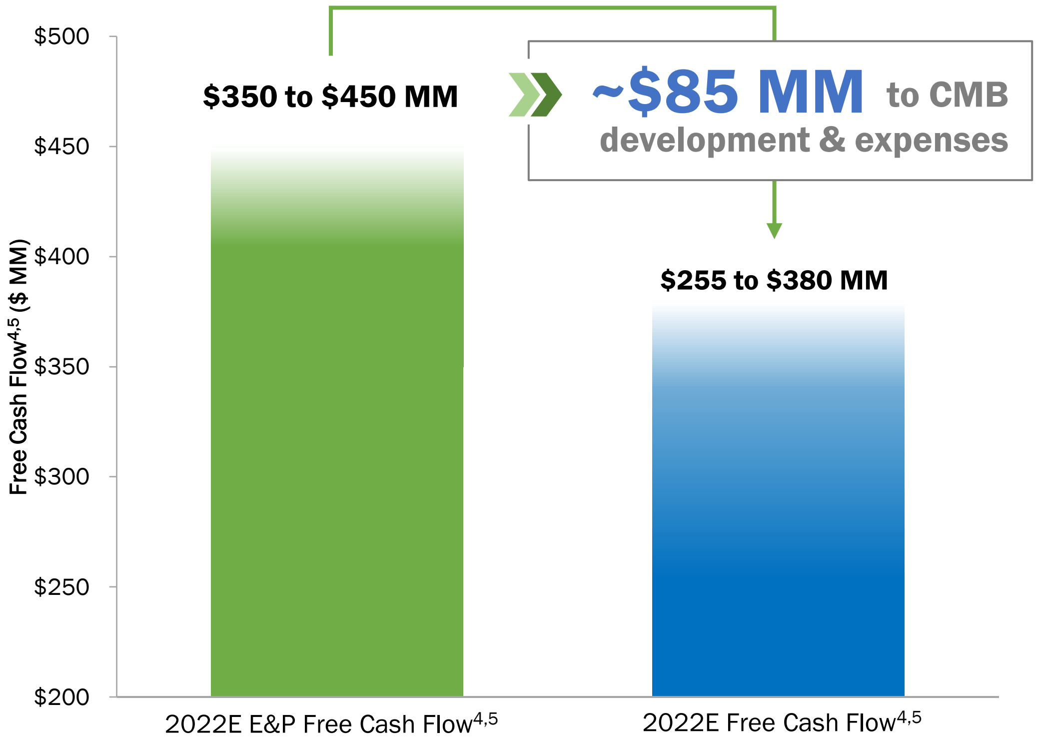
- CRC has identified over 5,000 acres suitable for utility scale development presents future value for CRC and investors
  - Potential for **300 to 1,000 MW with core 3 projects identified**
- **Interconnection request applications for up to 650 MW Solar plus Battery Energy Storage Systems verified and validated by CAISO and included in Cluster 14 phase 1[2]** study which is expected to utilize up to 2,500 acres of CRC-owned lands
- Potential to further reduce CO_2 emissions while adding further commercial opportunity



(1) Other includes the North Shafter, Yowlumne and Wilmington Fields. (2) CAISO Cluster 14 Phase 1 study report expected Q3, 2022.

Corporate Guidance

CRC GUIDANCE[1]	E&P	CMB	FY22E
Total Production[2] (mboe/d)	93 to 90	–	93 to 90
Oil Production[2] (mbo/d)	60 to 56	–	60 to 56
Operating Costs ($ MM)	$640 to $670	–	$640 to $670
Carbon Management Expenses[3] ($ MM)	–	$30 to $40	$30 to $40
Adj. G&A[4] ($ MM)	$155 to $175	$10 to $15	$165 to $190
Adj. EBITDAX[4] ($ MM)	$800 to $940	($40) to ($55)	**$745 to $900**
Capital ($ MM)	$300 to $335	$30 to $40	$330 to $375
Free Cash Flow[4,5] ($ MM)	$350 to $450	($70) to ($95)	**$255 to $380**
Cash Tax as % Pre-Tax Income (%)	–	–	10% to 18%



Production Driven by Operational Performance

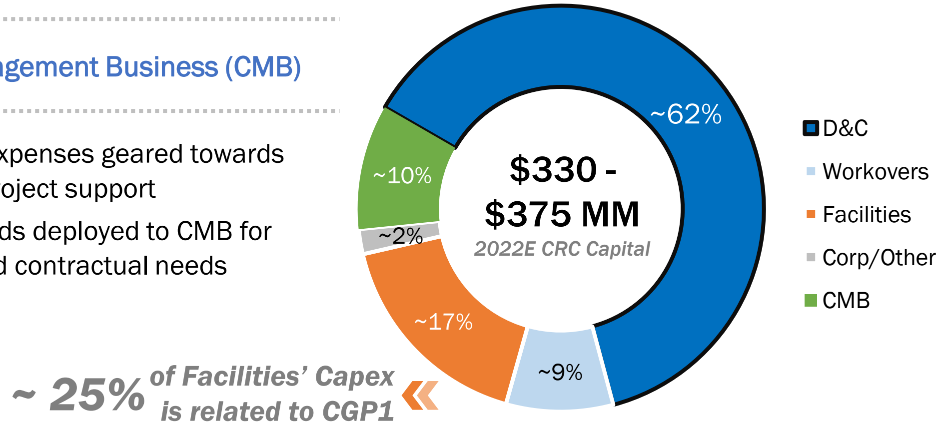
- Continued strong operational performance (horizontal drilling program and workover opportunities)
- Expecting to exit 2022[1,2] at or above 2021 exit oil production rate of ~58.5 mbopd

Efficient OPEX & Capital Allocation

- Expecting to reduce non-energy operating costs per BOE[6] excluding purchases of fuel gas to generate steam by further 5% YoY
- Maintaining average oil production despite lower D&C capital

Introducing Carbon Management Business (CMB)

- Initial CMB operating expenses geared towards personnel and initial project support
- Preliminary capital needs deployed to CMB for asset improvement and contractual needs



(1) Current guidance assumes a 2022 price of $82.50 per barrel of oil, NGL realizations consistent with prior years and NYMEX gas of $4.00 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 downtime. (3) CMB expenses include start-up expenditures. (4) E&P Adj. EBITDAX, Adj. EBITDAX, Adj. G&A, E&P Free Cash Flow 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 closest GAAP measure and other additional information. Reconciliations of 2022E E&P Adj. EBITDAX, Adj. EBITDAX, Adj. G&A, E&P Free Cash Flow and Free Cash Flow to their nearest GAAP equivalent can be found on slides 33 to 35. (5) 2022E E&P Free Cash Flow includes settled ARO liabilities in the range of $60 MM - $64 MM. (6) Non-energy operating costs excluding purchases of fuel gas to generate steam are equal to non-energy operating costs, which represent total operating costs less energy operating costs and gas processing costs, excluding purchases of fuel gas to generate steam which is then used in our steamfloods. See slide 11 for CRC's historical performance on operating costs.

Why California Resources Corporation?

Cyclical Investment

Core Low Carbon Intensity Energy Operations

Low Carbon Intensity Fuel for Today and Net Zero Fuel for The Future

Energy Transition Thesis

Unique Carbon Management Business Supporting CA's Climate Ambitions & Future Growth

Solid Financial Fundamentals

Strong Balance Sheet with a Sustainable Shareholder Returns Strategy

ESG Milestones

SUSTAINABILITY UPDATE 2020

Complete, Diverse & Experienced Board of Directors

CDP DISCLOSURE INSIGHT ACTION 2021

full SCOPE net ZERO 2045

AMERICA'S MOST RESPONSIBLE COMPANIES 2022 Newsweek statista

Supplemental Materials

Wilmington Production Sharing Contracts (PSC)

For every $1/bbl increase/decrease in Brent price, we expect a **~100 bopd** decrease/increase in our net oil production related to PSCs

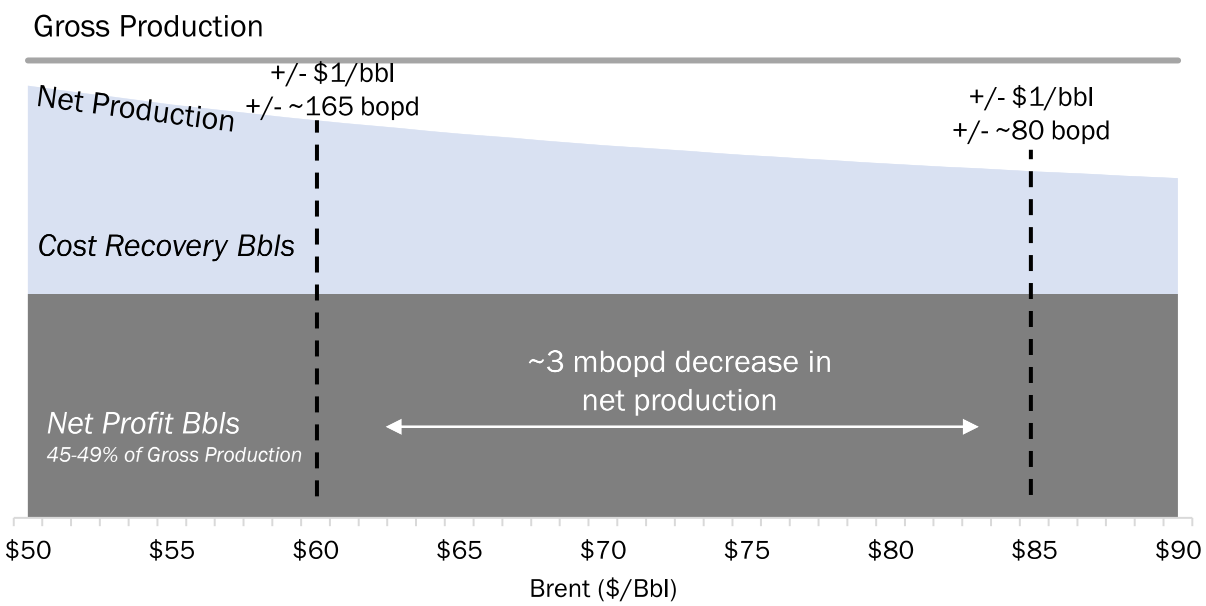
Approximatively 30% of CRC's oil production[2] is subject to PSCs
PSC Mechanics:

- 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 saw a decrease of **~3 mbopd** in net oil production as the commodity prices have moved up from $60/bbl to $85/bbl

EFFECT OF OIL PRICE ON NET PRODUCTION[1]

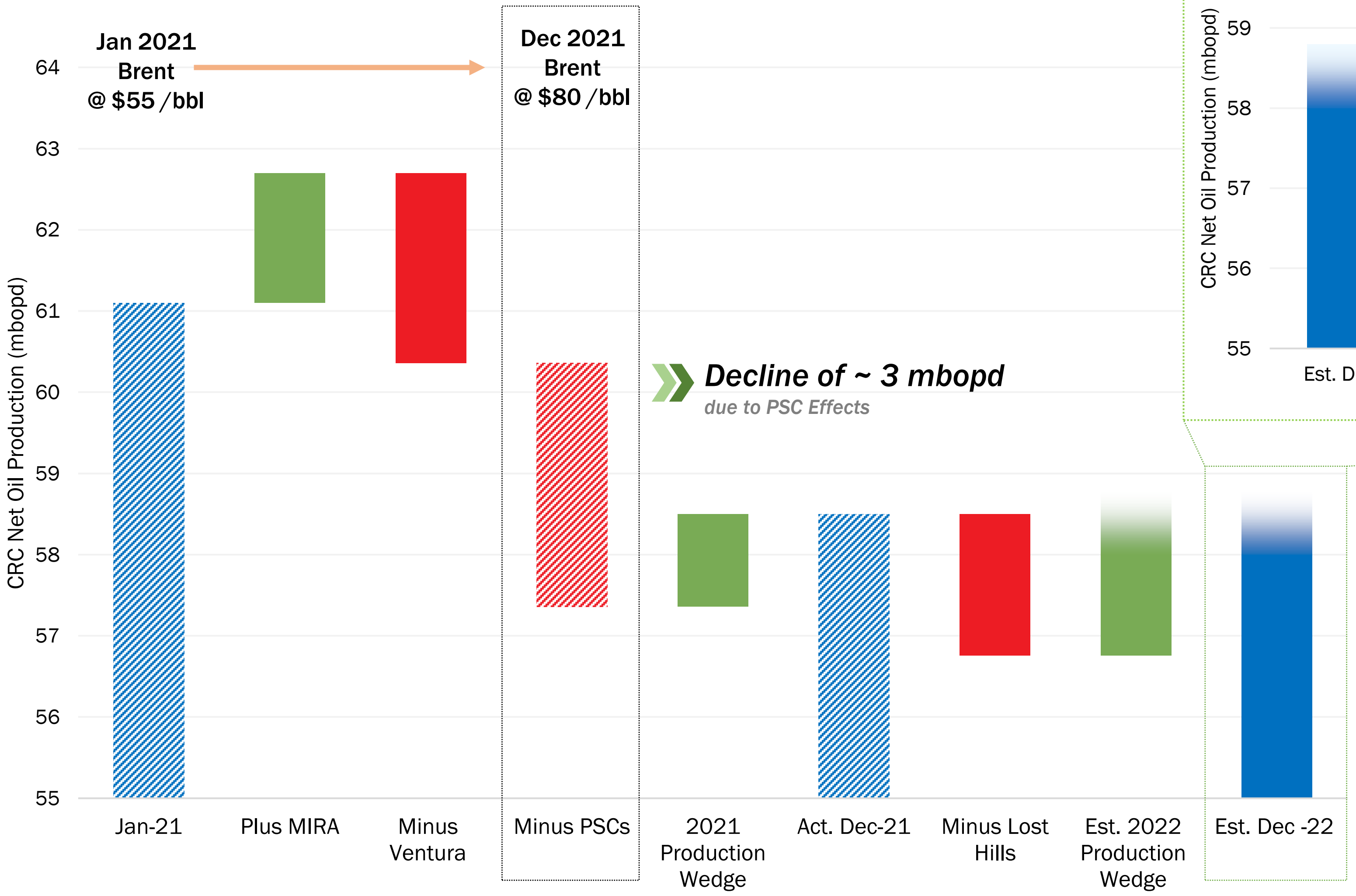


PSC Related Cash Flow Sensitivity to Brent Pricing[3] ($ MM)	+/- $5/bbl Δ in Brent pricing (~500 bopd)	+/-$10/bbl Δ in Brent pricing (~1,000 bopd)
Cash Flow Increase/Decrease Due to Oil Price Change	+/- $34	+/- $67
Cash Flow Decrease/Increase Due to Lost/Gained Barrels	-/+ $11	-/+ $20
Net Change in Cash Flow	**+/- $23**	**+/- $47**

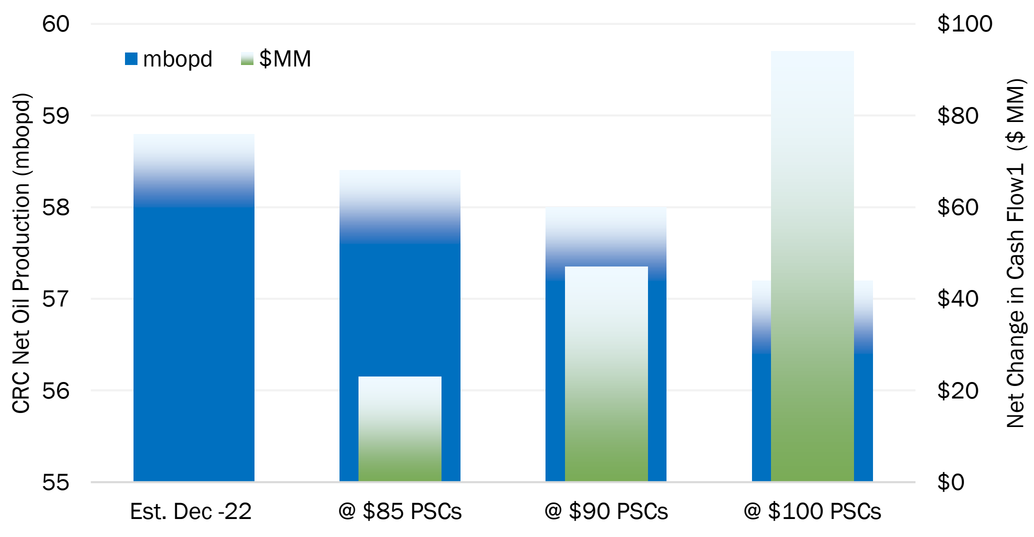
(1) Net Production from Wilmington field only. (2) Approximatively ~ 15% of CRC's total production was subject to PSCs for the year ended December 31, 2021. (3) Sensitivity is prior to hedges and is based on the current 2022 budget outlined on slide 21. Sensitivity applies only to the cash flow related to the oil production under PSC-type contracts and is not a total company sensitivity.

Rise in the Commodity Outlook Outweighs the Decline of Net Barrels Due to PSC Effects

- Est. annual decline rate of ~ 10% - 15%
- 2022 capital program of $215 to $225 million for drilling and completions
- Assuming no forward change to PSC effects at $80/bbl Brent in 2022 baseline budget



IMPACT TO NET PRODUCTION GUIDANCE & NET CASH FLOW[1] DUE TO PSC EFFECTS AS A RESULT OF POTENTIAL RISE IN COMMODITY PRICING



Net Cash Flow impact[1] will positively outweigh the rise in the apparent decline of the net barrels due to PSC effects

(1) Sensitivity is prior to hedges is based on the current 2022 budget outlined on slide 21. Sensitivity applies only to the cash flow related to the oil production under PSC-type contracts and is not a total company sensitivity.

Carbon TerraVault Example Economic “Type Curve”

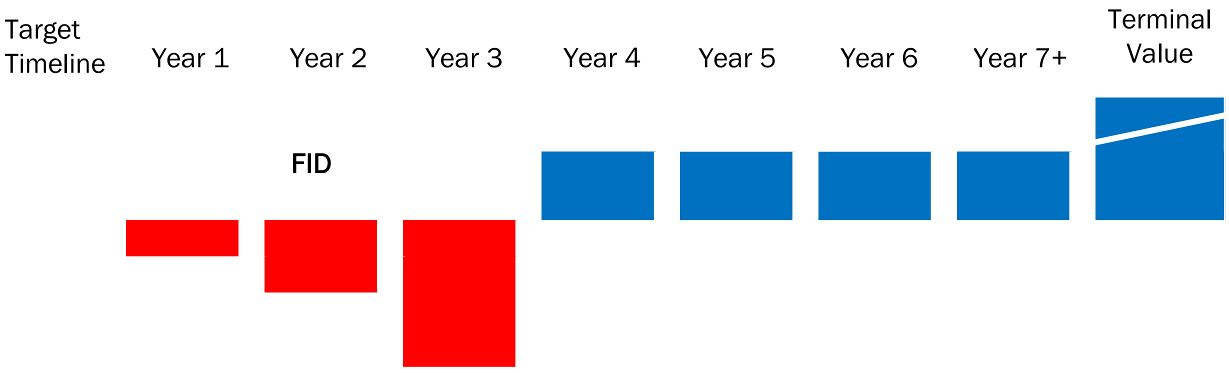
EXAMPLE PROJECT ECONOMICS

(PER MT OF INJECTED CO_2)

	Unit	Low	High	Notes/Incorporated Assumptions
Total Incentive Potential (LCFS + 45Q)	$/MT	$170	$200	45Q ($/MT): $50, LCFS ($/MT): $120 to $150, net of 10% buffer account assumption, 100% LCFS eligibility
Opex	$/MT	$25	$75	Range reflects costs associated with full range of business model possibilities and includes G&A of dedicated staff.
Capex	Avg $/MT	$5	$20	Range of capital includes cost of capture facility and pipeline retrofit. Cost of capture facility depends on CO_2 concentration at source. Pipeline costs depend on distance from source to sink and size of pipe. Pace of capex deployment is expected to be ~5% to ~10% of Total Project Capex in Year 1, ~10% to ~35% in Year 2 and ~55% to ~85% in Year 3. Depending on project structure and location, capex could be lower or higher than range represented.

EXAMPLE PROJECT CASH FLOW PROFILE
EST. CASH FLOW POSITIVE IN YEAR 4 WITH PAYBACK IN ~ 4 YEARS

(REFLECTS MIDPOINT OF RANGE ESTIMATES)



Example **Carbon TerraVault Economics**

A CTV project could generate on average **$50 to $100 of EBITDA[1] per metric ton injected per annum** depending on project structure. The structure, financing and ownership of these projects has yet to be negotiated.

EXAMPLE PROJECT ASSUMPTIONS

Please see slide 32 for a description of assumptions used above. This information is an example of project economics for a CTV project. The structure financing and ownership of a CTV project could take many forms and has not yet been negotiated. The terms and availability of third-party sources of financing could also affect returns and outcomes.

(1) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure.

Variety of Go-to-Market Business Models at Hand

Business Models:	Emission	Capture	Conditioning[1]	Transport	Storage
End-to-end value chain	CRC owns and operates emission assets	CRC manages & operates capture & conditioning Manufacturing / tech development[2], EPC, & installation & facility start-up are outsourced		*Transportation may or may not be necessary as some assets co-located*	CARBON TERRAVAULT
CCS Service	3rd party (e.g., Ethanol producer) owns and operates emission assets	CRC manages & operates capture, conditioning, & transportation Manufacturing / tech development[2], EPC, & installation & facility startup are outsourced			CARBON TERRAVAULT
Joint Venture	3rd party owns and operates emission assets	CRC establishes JV with emissions producer and / or engineering firm to develop, manage, & operate capture, conditioning, & transportation processes			CARBON TERRAVAULT
Carbon storage	3rd party owns and operates emission assets, capture, conditioning, and transportation				CARBON TERRAVAULT

More CRC Capital Integrated Solution

Less CRC Capital Storage Solution

Source: Internal estimates. (1) Liquefaction, compression and purification. (2) Includes partnerships, white label partnerships and licensing of equipment/parts.

Diverse & Experienced Board of Directors

Tiffany (TJ) Thom Cepak
Chair of the Board
Member of the Audit Committee
Member of the Compensation Committee

Andrew B. Bremner
Member of the Sustainability Committee

Douglas E. Brooks
Member of the Nominating and Governance Committee

James N. Chapman
Chair of the Compensation Committee
Member of the Nominating and Governance Committee

Mark A. (Mac) McFarland
President and CEO

Nicole Neeman Brady
Member of the Sustainability Committee
Member of the Compensation Committee

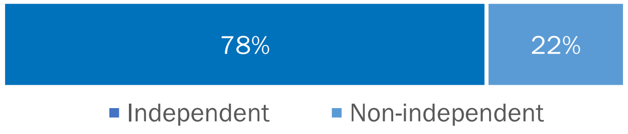
Julio M. Quintana
Chair of the Nominating and Governance Committee
Member of the Audit Committee

William B. Roby
Chair of the Sustainability Committee
Member of the Audit Committee
Member of the Compensation Committee

Alejandra (Ale) Veltmann
Chair of the Audit Committee

Diverse Board Committed to Safely and Responsibly Producing Low Carbon Intensity Fuel for Today and Net Zero Fuel for the Future

INDEPENDENCE



GENDER

Hedging Program Protects Cash Flow

STRATEGY

CRC hedging strategy typically utilizes a mixture of Puts, Collars and Swaps to protect cash flow and to ensure CRC's ability to live within cash flow, and is also aligned with CRC's RBL requirements

HEDGE CONTRACT SETTLEMENTS EXPECTED TO SIGNIFICANTLY DECREASE IN 2022 & 2023[3]

	2021	1Q22E	2Q22E	3Q22E	4Q22E	2022E	1H23E	2H23E	2023E
Hedge Contract Settlements[4] ($MM)	($319)	($80)	($70)	($62)	($57)	($269)	($71)	($50)	($121)

* 2022 and 2023 estimated losses associated with legacy hedges that were required by our RBL lenders in October 2020.

OIL HEDGE PROTECTION[1] *as of December 31, 2021*

		1Q22	2Q22	3Q22	4Q22	FY23
SOLD CALLS	Barrels per Day	35,347	35,343	34,380	25,167	14,790
	Weighted-Average Price per Barrel	$60.37	$60.63	$60.76	$57.82	$58.01
SWAPS	Barrels per Day	12,369	10,669	10,476	17,263	12,937
	Weighted-Average Price per Barrel	$54.38	$54.12	$53.97	$58.79	$59.08
NET PURCHASED PUTS[2]	Barrels per Day	35,347	35,343	34,380	25,167	14,790
	Weighted-Average Price per Barrel	$53.32	$54.69	$55.95	$57.22	$40.00
SOLD PUTS	Barrels per Day	6,869	—	4,000	1,348	—
	Weighted-Average Price per Barrel	$32.00	—	$32.00	$32.00	—

(1) Hedges are based on weighted-average Brent prices per barrel. (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, 2021. (4) Represents estimated net cash settlement payments for derivative contracts as of 12/31/2021, except 2021 which are actuals for the twelve months ended December 31, 2021.

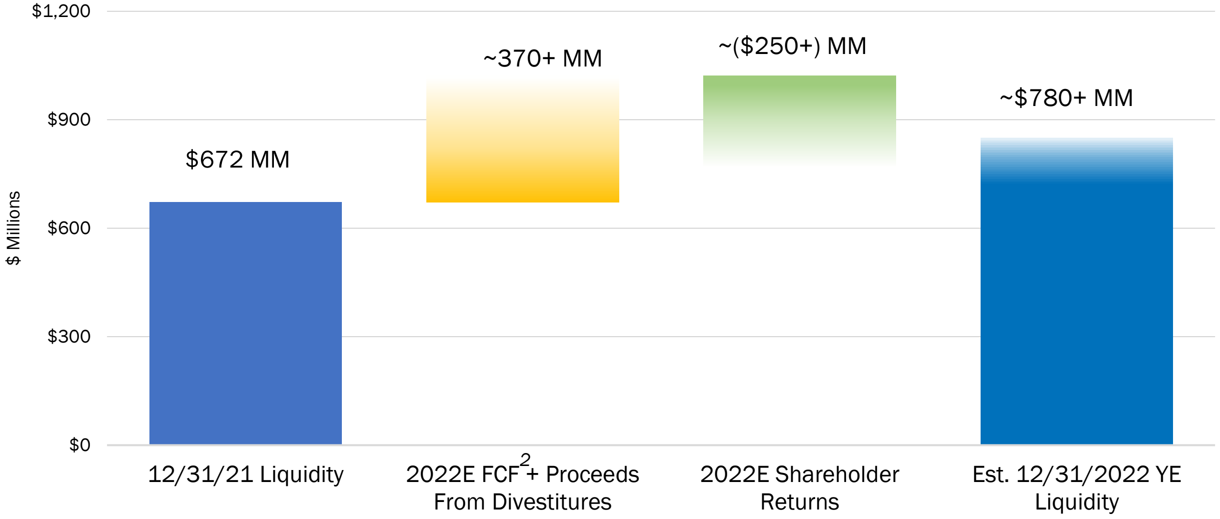
Hedging Program Changes Since September 30, 2021

		Downside Protection (Swaps)
1Q 2023	Barrels per Day	2,000
	Weighted Avg. Price per Barrel	$73.72
2Q 2023	Barrels per Day	2,000
	Weighted Avg. Price per Barrel	$72.34
3Q 2023	Barrels per Day	2,000
	Weighted Avg. Price per Barrel	$71.10
4Q 2023	Barrels per Day	5,315
	Weighted Avg. Price per Barrel	$69.81
FY 2023	Barrels per Day	2,836
	Weighted Avg. Price per Barrel	$71.17

Note: as of December 31, 2021

Maintaining Balance Sheet Strength, Liquidity, and Financial Flexibility

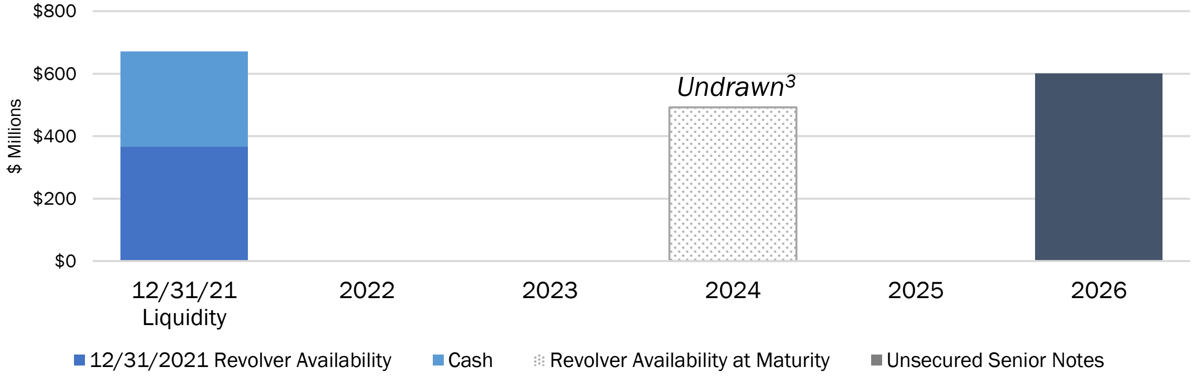
ESTIMATED LIQUIDITY ROLL FORWARD[1]



12/31/21 DEBT SNAPSHOT

($ in millions)	
Revolving Credit Facility (RCF)	$ 0
7.125% Senior Notes	600
Face Value of Debt	**$ 600**
Less Available Cash	(305)
Net Debt	**$ 295**

NO SIGNIFICANT MATURITIES UNTIL 2026



MULTIPLES DEMONSTRATE FLEXIBILITY

($ in millions)	
RCF Borrowing Base	$ 1,200
2022E Free Cash Flow[2]	$255 – $380
YE 2022E Net Debt[1,2] / 2022E Adjusted EBITDAX[2]	0.1x – 0.4x
2022E Adjusted EBITDAX[2] / 2022E Interest & Debt Expense, net	12.8x – 18.8x

(1) Liquidity at 12/31/21 calculated as cash of $305 million and $492 million capacity on CRC's Revolving Credit Facility less $125 million in outstanding letters of credit. Estimated YE 2022 liquidity assumes $492 million capacity on CRC's Revolving Credit Facility less $125 million in outstanding letters of credit. 2022 estimated increase in cash reflects the midpoint of 2022 Free Cash Flow guidance and proceeds for the Lost Hills transaction. 2022 estimated shareholder returns includes an annualized dividend payment of $0.17 over four quarters based on 78.744 million shares outstanding and the utilization of the remainder of the share repurchase program which are both subject to company discretion. (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 closest GAAP measure and other additional information. Reconciliations of 2021E Adj. EBITDAX, Net Debt and Free Cash Flow to their nearest GAAP equivalent can be found in the Supplemental Materials on slides 33 to 35. (3) Undrawn revolver as of December 31, 2021.

Example Project Economics Assumptions Used on Slide 26

Information presented on slide 26 shows example project economics for a CTV project. The structure of the project, financing and ownership of CTV project could take many forms and has not yet been negotiated. The terms and availability of third-party sources of financing could also affect returns and outcomes.

- Assumes 1MMT injected per year for 40-year project life.
- 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 27
- 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.
- Based on incentives available under current regulatory framework.
- The EBITDA[1] range has been reduced by ~20 – 50% to reflect uncertainties related to project structure, financing and ownership.
- Assumes total incentive potential can be monetized through tax equity brokers and LCFS monetized in the LCFS trading marketplace and recorded as revenue. For simplicity, a 5-year accelerated straight line depreciation and amortization is assumed. Assumes no bonus depreciation.
- Payback period is defined as total CRC investment / annual cash flow.

(1) Earnings before interest, taxes, depreciation and amortization (EBITDA) is a non-GAAP measure.

Adjusted EBITDAX Reconciliation

We define adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, infrequent and out-of-period items; and other non-cash items. We believe this measure provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry, the investment community and our lenders. Although this is a non-GAAP measure, the amounts included in the calculation were computed in accordance with GAAP. Certain items excluded from this non-GAAP measure are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as depreciation, depletion and amortization of our assets. This measure should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. A version of Adjusted EBITDAX is a material component of certain of our financial covenants under our Revolving Credit Facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. The following table represents a reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX.

	E&P 2022E		CMB 2022E		FY 2022E	
($ millions)	Low	High	Low	High	Low	High
Net income	$266	$306	($55)	($40)	$211	$266
Interest and debt expense, net	48	58	-	-	48	58
Depreciation, depletion and amortization	183	224	-	-	183	224
Exploration expense	7	9	-	-	7	9
Income Taxes	32	40	-	-	32	40
Unusual, infrequent and other items	199	225	-	-	199	225
Other non-cash items						
Accretion expense	50	61	-	-	50	61
Stock-based compensation	13	15	-	-	13	15
Post-retirement medical and pension	2	2	-	-	2	2
Estimated Adjusted EBITDAX	$800	$940	($55)	($40)	**$745**	**$900**

	E&P 2022E		CMB 2022E		FY 2022E	
($ millions)	Low	High	Low	High	Low	High
Net cash provided by operating activities	$685	$750	($55)	($40)	$630	$710
Cash Interest	44	54	-	-	44	54
Cash Income Taxes	32	40	-	-	32	40
Exploration expenditures	7	9	-	-	7	9
Working capital changes	32	87	-	-	32	87
Estimated Adjusted EBITDAX	$800	$940	($55)	($40)	**$745**	**$900**

Note: Management is not providing guidance on income taxes, acquisitions or divestitures or any other unusual or infrequent events at this time.

Leverage Ratio & Net Debt Reconciliations

Leverage Ratio and Net Debt

We calculate the leverage ratio by dividing net debt by adjusted EBITDAX for the applicable period. We define net debt as the face value of our debt less available cash. We believe the leverage ratio is an important metric of the operational and financial health of our Company and is useful to investors as an indicator of our ability to incur additional debt and to service our existing debt. The following table presents a reconciliation of our leverage ratio. The leverage ratio is a supplemental measure of our performance that is not required by or presented in accordance with U.S. generally accepted accounting principles ("GAAP").

($ in millions)	**FY 2021**
Face value of debt	$600
Available cash	(305)
Net Debt as of December 31, 2021	**$295**
2021 Adjusted EBITDAX	$860
2021 Leverage Ratio	**0.34x**

	FY 2022E	
($ in millions)	**Low**	**High**
Face value of debt	$600	$600
Estimated available cash[1]	(500)	(300)
Estimated Net Debt as of December 31, 2022	**$100**	**$300**
2022E Adjusted EBITDAX	$900	$745
2022E Leverage Ratio	**0.11x**	**0.40x**

Note: Adj. EBITDAX and Net Debt 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 closest GAAP measure and other additional information. (1) Inclusive of dividends and share repurchases. Please see slide 31 for a for a description of expected liquidity changes in 2022.

Free Cash Flow & Adjusted General & Administrative Expenses Reconciliations

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 at the right presents a reconciliation of net cash provided by operating activities to free cash flow.

	E&P 2022E		CMB 2022E		FY 2022E	
($ in millions)	Low	High	Low	High	Low	High
Net Cash Provided by Operating Activities	$685	$750	(55)	(40)	$630	$710
Capital Investment	(335)	(300)	(40)	(30)	(375)	(330)
Estimated Free Cash Flow	$350	$450	(95)	(70)	**$255**	**$380**

Adjusted General & Administrative Expenses

Management uses a measure called adjusted general and administrative (G&A) expense to provide useful information to investors interested in comparing our costs between periods and performance to our peers. The table below presents a reconciliation of G&A expense to adjusted G&A expense.

	E&P 2022E		CMB 2022E		FY 2022E	
($ in millions)	Low	High	Low	High	Low	High
General & Administrative Expenses	$170	$185	$10	$15	$180	$200
Stock-based Compensation	(15)	(10)	-	-	(15)	(10)
Adjusted General & Administrative Expenses	$155	$175	$10	$15	**$165**	**$190**

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