A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA RESOURCES CORPORATION

Executing Today, Building for Tomorrow

Fourth Quarter and Full Year 2024 Results

March 3, 2025

Delivered on All Fronts in 2024

A DIFFERENT KIND OF ENERGY COMPANY

STRONG FINANCIAL AND OPERATING RESULTS

SIGNIFICANTLY INCREASED SCALE WITH AERA MERGER

Demonstrated improved capital efficiency, robust reservoir management and strong balance sheet control

Delivered
$1,006MM
Adj. EBITDAX*

MEANINGFULLY LOWERED COST STRUCTURE

Delivered Aera merger synergies ahead of schedule
On track to capture remaining $65MM in 2025

Generated
$355MM
Free Cash Flow*

INCREASED SHAREHOLDER RETURNS

Raised dividend by 25%
Returned 85% of free cash flow* back to shareholders

Returned
$303MM
Dividends and SRP[1]

SOLIDIFIED U.S. CARBON MANAGEMENT LEADERSHIP

Received
Class VI
Permits for CTV I – 26R

Announced
~5.4MMTPA
Of New CCS Projects Under Consideration

Added
134MMT | ~6.7MMTPA
Of CO_2 Storage Permit Applications Under Review by the EPA

Approved California's First
CCS Project
At CRC's Cryogenic Gas Plant at Elk Hills

California's Premier Energy Platform

110MBOE/D (90% Average NRI)
2024 TOTAL NET PRODUCTION[2]

Oil	NGLs	Gas
73%	9%	18%

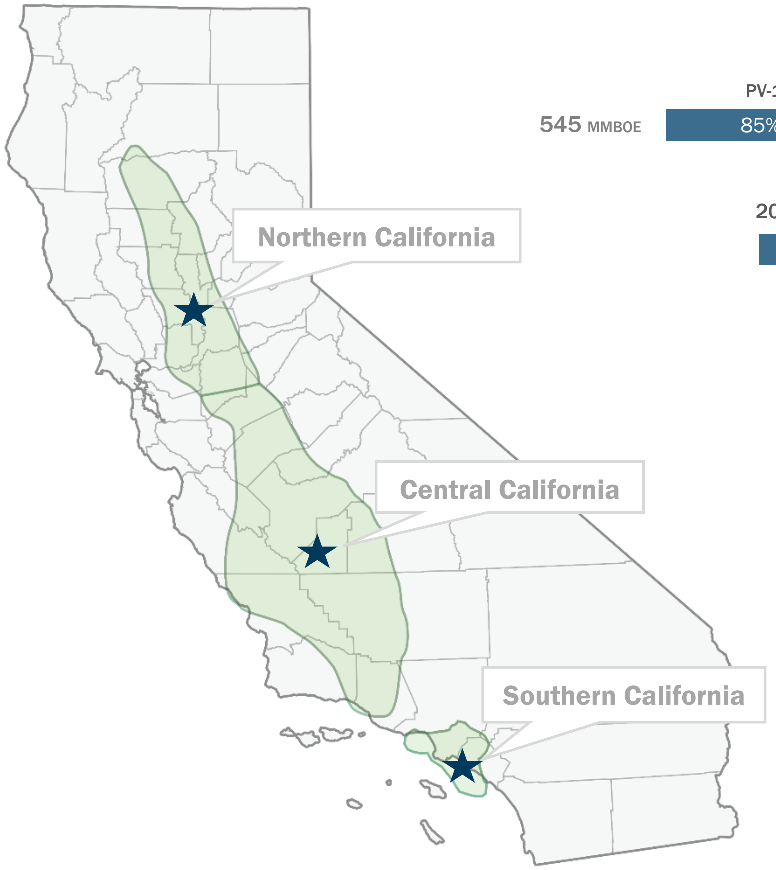
$8.9B
PV-10 OF 2024 PROVED RESERVES[3]

545 MMBOE

PDP	PDNP	PUD
85%	8%	7%

2024 ACTIVE DRILLING RIGS

1H24	2H24
1	1



National Cement's Trusted Decarbonization Partner[1]

"Lebec Net Zero" Aims to Produce California's First Carbon-Neutral Cement in Kern County

National Cement Company, a Vicat (XPAR:VST) private subsidiary, was established in 1974. The company manufactures and markets cement and ready-mix concrete with primary markets in California and the Southeast.

PARTNERSHIP HIGHLIGHTS

- CTV plans to develop transportation and sequestration solutions for up to 1.0 MMTPA of CO_2 emissions captured from National Cement's existing plant in Lebec, Kern County, California
- Project plans to utilize CTV's nearby underground storage reservoirs to safely store CO_2 emissions
- Intended to enable the creation of decarbonized product for an essential economic industry in California

"LEBEC NET ZERO" HIGHLIGHTS[3]

- Expected to be California's first net-zero cement facility
- Selected by the U.S. Department of Energy (DOE) for up to $500MM in matching funds to accelerate its development
- Aligned with Kern County's Carbon Management vision, promoting economic growth, job creation, and tax benefits for local communities
- Pending customary and regulatory approvals, operations are expected to start in 2031

See Slide 26 "Assumptions, Estimates and Endnotes".

2025 Strategy Drives Advantaged Business Model

Integrated Strategy

Enhances Asset Portfolio Value

Higher **Cashflow** | Less **Carbon** | Better **California**

OPTIMIZE & EXPAND PORTFOLIO

- Reinforce **California's leading O&G Business** through improved capital efficiencies
- Expand **Carbon Management Business** and advance EPA Class VI permits application pipeline
- Enhance **Power Business** with 3rd Party BTM PPA

RETURN CAPITAL TO SHAREHOLDERS

- Prioritize **free cash flow generation** for shareholder returns
- **Opportunistic buybacks** with $557MM remaining authorization[1]
- Support **long-term fixed dividend**[1]

MAINTAIN FINANCIAL STRENGTH

- **Maintain ample liquidity** and **low net leverage*** (<1.0x)
- **Redeemed $123MM** of **2026 Senior Notes** in February 2025, targeting to act on the balance in 2025
- Leverage **robust hedge portfolio** to support **cash flow durability**

2025E Outlook[2]

Net Total Production
132 – 138MBOE/D
79% oil; 5% to 8% entry to exit decline, 1.5 rigs

Non-Energy Operating Costs & G&A
$1,150 – $1,200MM
Includes 2025E Aera merger synergies

Adj. EBITDAX*
$1,100 – $1,200MM
$72.82 Brent, $3.47 NYMEX; includes 2025E Aera merger synergies

Capital
$285 – $335MM
$165 -$180MM in Drilling, Completion and Workover capital

See Slide 26 "Assumptions, Estimates and Endnotes".

Why California Resources Corporation?

A DIFFERENT KIND OF ENERGY COMPANY

Higher **Cashflow**

Less **Carbon**

Better **California**

LEADING CARBON MANAGEMENT BUSINESS

PREMIER BALANCE SHEET WITH STRONG FREE CASH FLOW GENERATION

STRONG SHAREHOLDER RETURNS STRATEGY

DISCIPLINED CAPITAL ALLOCATION

Executing Our Strategy

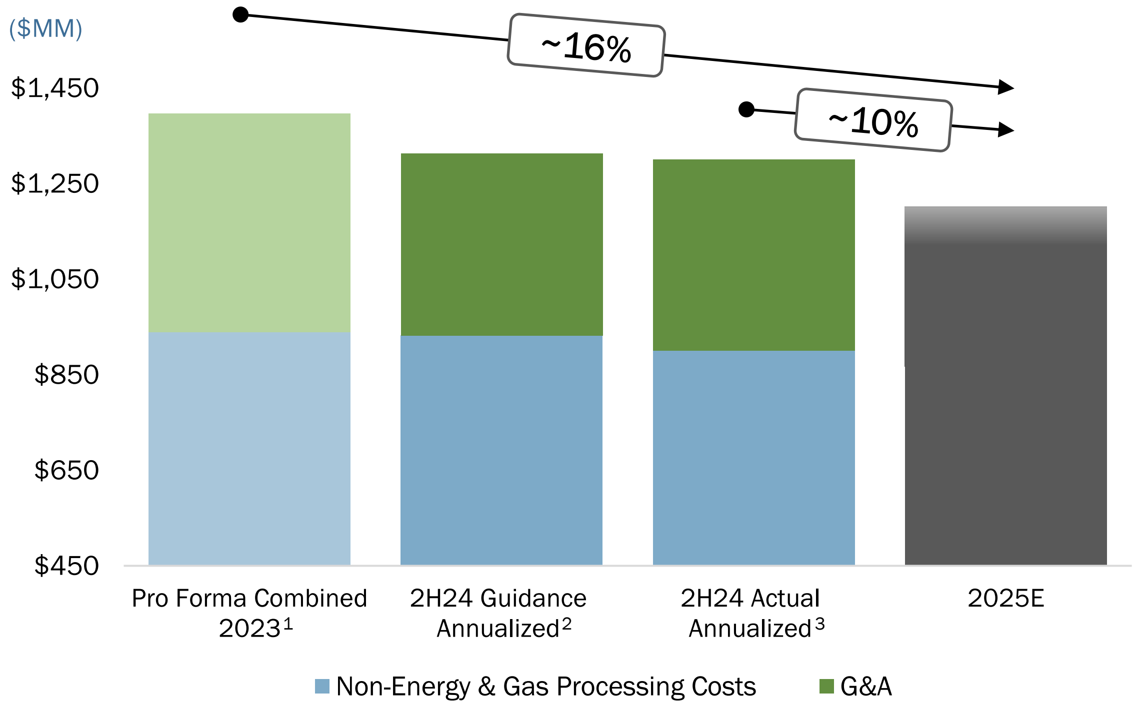
A DIFFERENT
KIND OF ENERGY
COMPANY

Significantly Reducing Our Cost Structure

Lower Costs for the Combined Company in 2025E:

~$220MM
2025E Improvement vs Pro Forma Combined 2023[1]

~$125MM
2025E Improvement vs Annualized 2H24 Actuals[3]



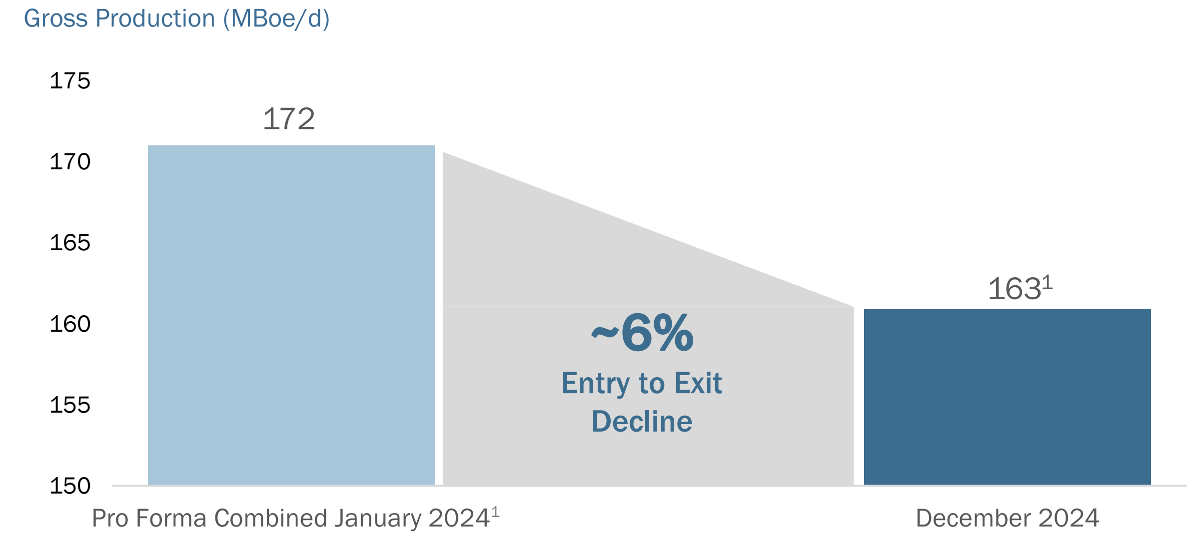
Ahead of Schedule on $235MM in Targeted Synergies

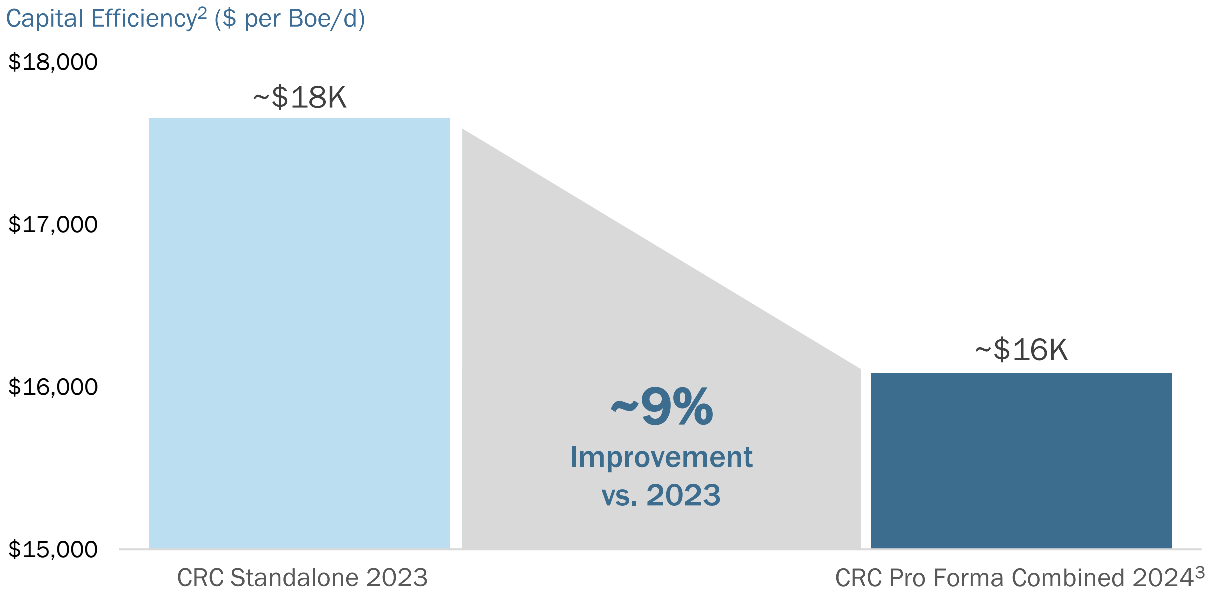
Annualized Aera Merger Run-rate Savings

Operations ($MM)	~$65	~$35
G&A ($MM)	~$45	~$10
Other[6] ($MM)	~$60	~$20
Total ($MM)	**~$170**	**~$65**
Impact	**2025E**	**2026E**
Implementation (%)	72%	28%

See Slide 26 "Assumptions, Estimates and Endnotes".

Driving Capital Efficiencies With Aera Merger





STRONG FOCUS ON BASE PRODUCTION DRIVES OPERATIONAL RESULTS

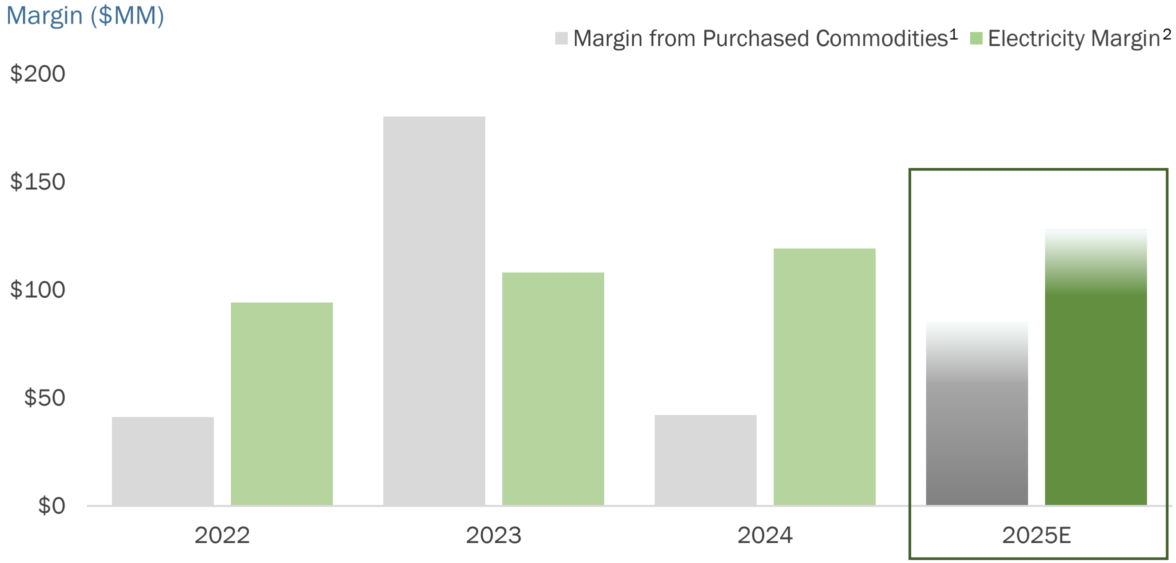
- Successfully integrated Aera operations
- Managing base declines through
  - Optimized and integrated operational remote surveillance systems reducing time to identify failures and remediation
  - Improved maintenance program crew efficiencies reducing well downtime and backlogs
  - Reservoir focus on optimizing injection rates to stabilize production decline
- Adding a 2nd rig in San Joaquin Basin in 2H25 and anticipating continuing improvement in O&G permitting environment
- With available workover and sidetrack permits on hand, CRC asset base can support 5% - 8% reservoir decline

COMBINED ASSET BASE PROVIDES HIGHER CAPITAL EFFICIENCY

See Slide 26 “Assumptions, Estimates and Endnotes”.

Enhancing Asset Portfolio Value Through Our Integrated Strategy

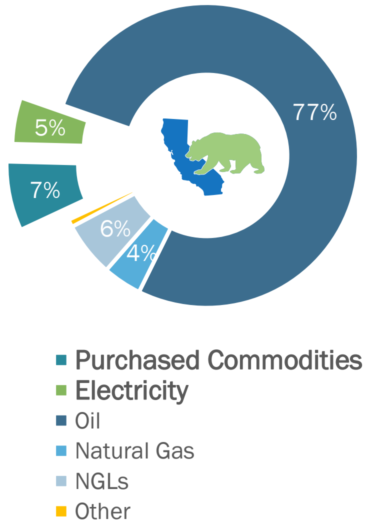
STRONG PERFORMANCE OVER THE PAST 3 YEARS

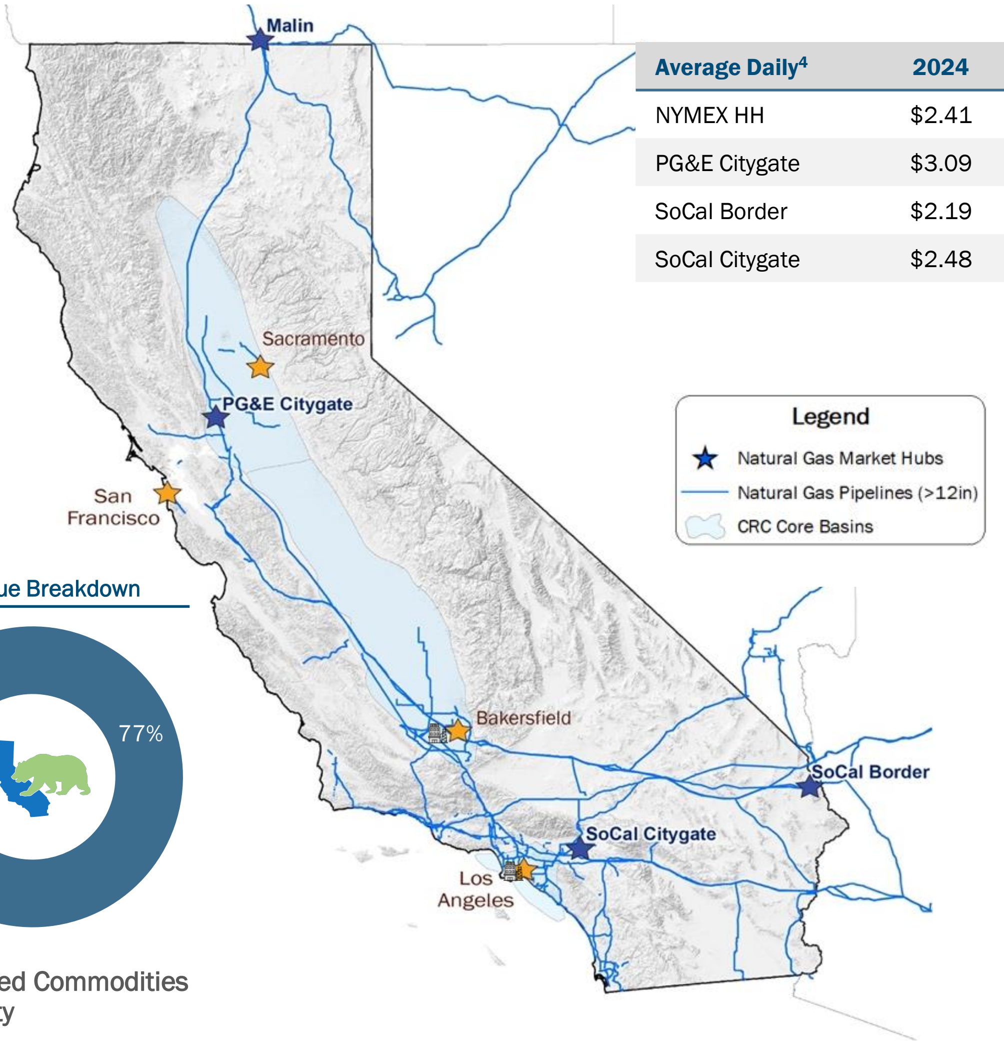


CRC'S INFRASTRUCTURE DRIVES VALUE IN CALIFORNIA POWER MARKET

- **Ownership of key infrastructure assets** helps respond to volatility and demand signals across the California natural gas market
- **Resource Adequacy (RA)** capacity payments increase to **~$150MM in 2025**
- **Targeting a power purchase agreement (PPA)** with a third party in 2025 for EHPP BTM spare power capacity
- **Large opportunity set for CTV to provide solutions for baseload carbon-free energy for power generation across its asset base** (~252[3] natural gas power plants in California with potential CCS retrofit opportunities)

2024 Revenue Breakdown





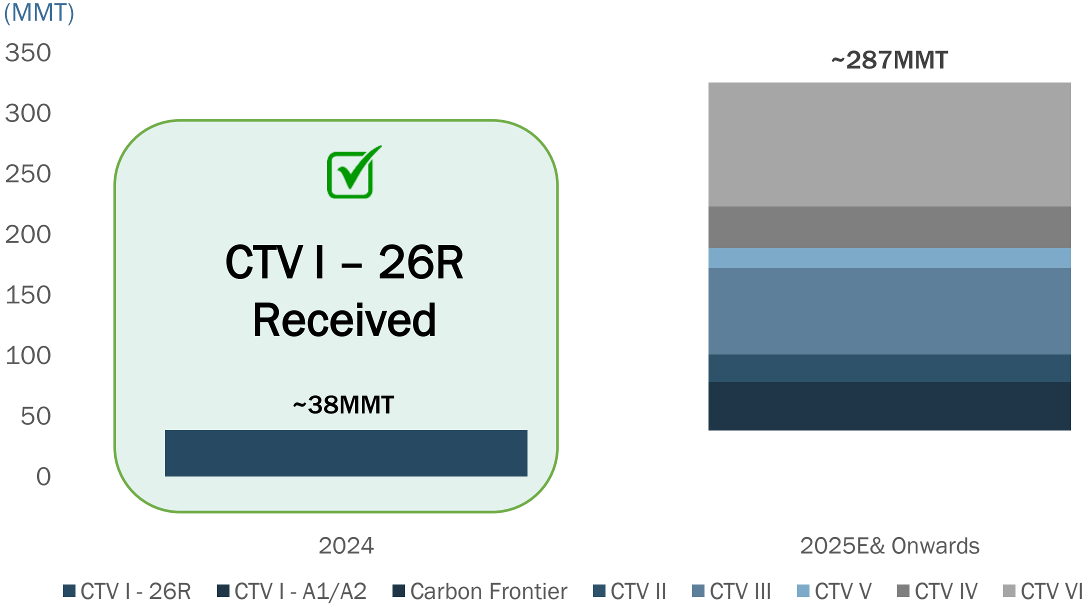
Average Daily[4]	2024
NYMEX HH	$2.41
PG&E Citygate	$3.09
SoCal Border	$2.19
SoCal Citygate	$2.48

Leading California's Decarbonization

EXPANDING OUR CO_2 PERMITTING LEADERSHIP

- Received CA's first EPA Class VI permits for CTV I – 26R
  - Permits became effective February 3, 2025
- 7 EPA Class VI permits in queue for ~287MMT of storage[1]
- Expecting to submit additional reservoirs to the EPA for Class VI permitting in 2025

CO_2 Storage Space Submitted to EPA for Class VI Permits[1]



ADVANCING DECARBONIZATION IN CALIFORNIA

- Approved California's first CCS project at cryogenic gas plant at Elk Hills
  - Ongoing engineering, equipment preparation and procurement with surface construction targeted to begin in 2Q25
  - Targeting first injection and initial cashflow by YE25
- Increased by nearly ~5x CCS projects under consideration in 2024 with efforts potentially enabling ~2.1 GW of new decarbonized power in California
- Attracting private and federal clean capital to California through Carbon Management efforts
- Largest amount of potentially available and stackable incentives for CCS development in the country
- Expecting support for CO_2 pipeline transportation from California in 2025

CARBON TERRAVAULT

Positioned to Be California's Premier Carbon Management Provider

Projects Under Consideration	Est. Remaining Injection Rate Capacity (Up to 1BMT of Storage)
~9 MMTPA	~36 MMTPA[2]

See Slide 26 "Assumptions, Estimates and Endnotes".

Returning Significant Cash to Shareholders[1]

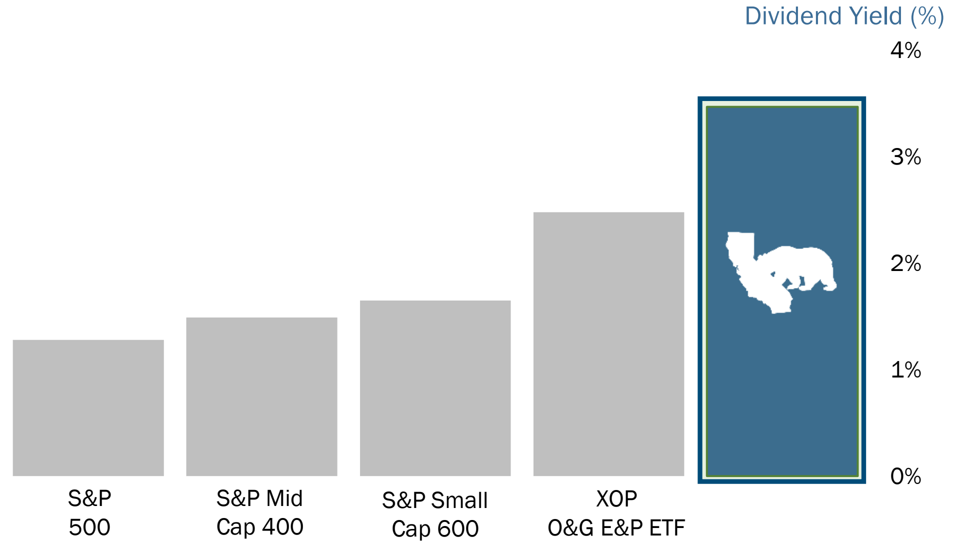
In 2024 Returned

$92MM in Dividends and Buybacks in 4Q24[1, 2]

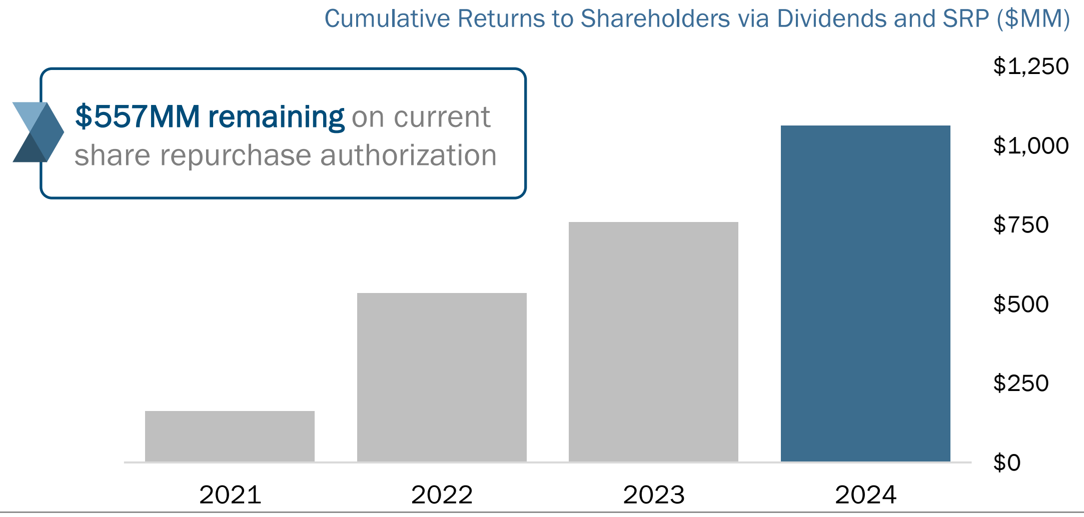
$303MM in Dividends and Buybacks in 2024[1, 2]
$1,060MM since May 2021[2]

~85% of Free Cash Flow* in 2024
~66% since May 2021

Competitive Dividend Yield vs. Market[3]



Significant Return of Capital to Shareholders[1]



See Slide 27 “Assumptions, Estimates and Endnotes”.

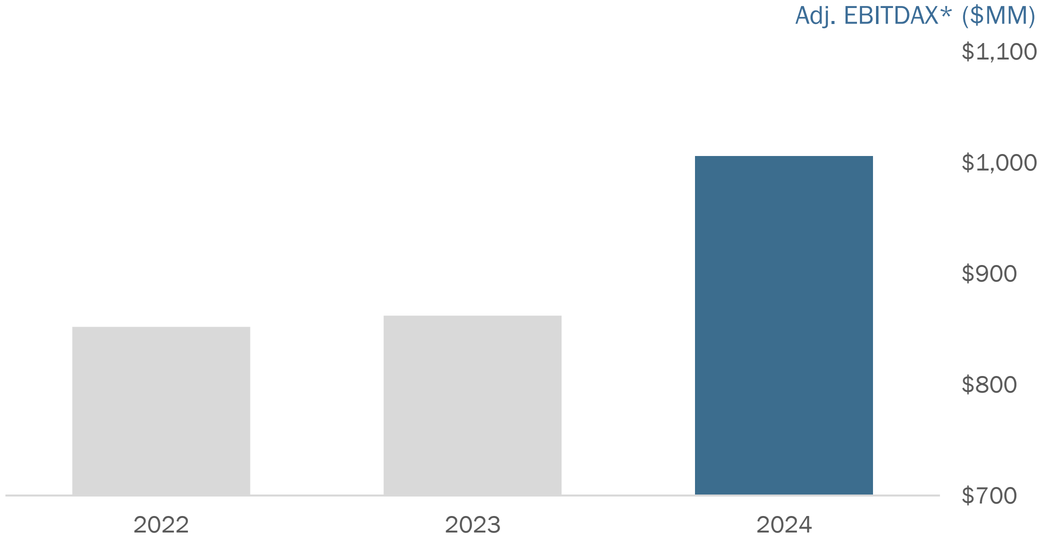
YE24 Results and 2025E Guidance

A DIFFERENT KIND OF ENERGY COMPANY

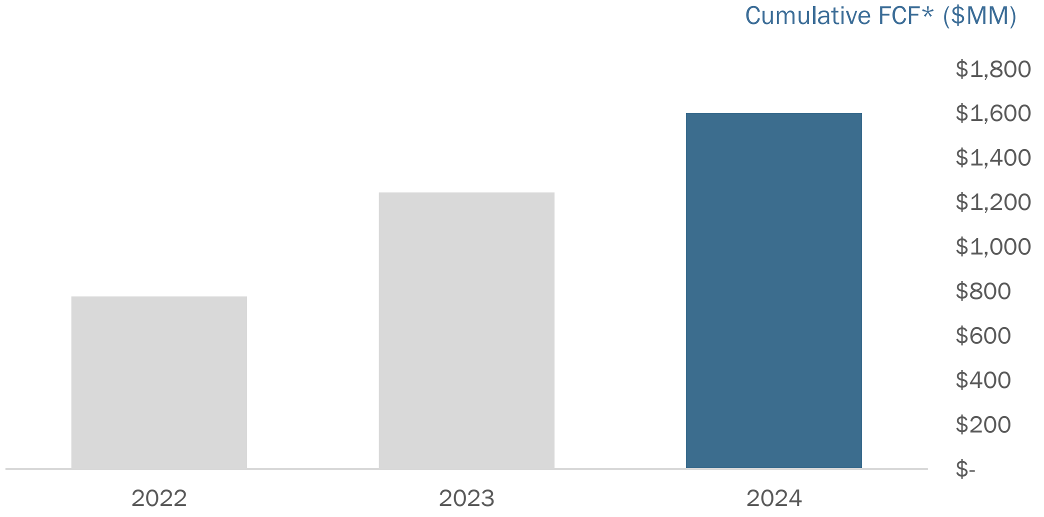
Delivered Strong 2024 Results

Commodity	4Q24E[1]	4Q24A	2024A
Brent ($/Bbl)	$71.48	$73.97	$79.84
Brent realized price with hedge ($/Bbl)	N/A	$73.00	$75.66
Brent realized price without hedge (% of Brent)	95% - 99%	98%	96%
Operational and Financial			
Net Production (MBoe/d)	140 – 144	141	110
Net Oil Production (%)	79%	79%	73%
Operating Costs and CMB Expenses[2] ($MM)	$340 – $365	$343	$1,022
G&A ($MM)	$90 – $100	$95	$321
Adj. G&A* ($MM)	$80 – $90	$85	$279
Taxes Other Than on Income ($MM)	$75 – $86	$80	$242
Other Operating Revenue and Expenses, net[3] ($MM)	($10) – ($20)	($36)	($173)
Total Capital ($MM)	$85 – $105	$88	$255
Adjusted EBITDAX* ($MM)	$260 - $300	$316	$1,006
Other Items			
Margin from Purchased Commodities[4] ($MM)	$5 – $10	$6	$42
Electricity Margin[5] ($MM)	$15 – $20	$30	$119
Transportation Expense ($MM)	$20 – $25	$21	$81
Total Return of Cash to Shareholders[6] ($MM)			
Share Repurchased[7] ($MM)		$56	$190
Dividends Paid ($MM)		$36	$113
Total ($MM)		$92	$303

Increased Scale Drives Adj. EBITDAX*



Consistent Free Cash Flow* Generation



See Slide 27 “Assumptions, Estimates and Endnotes”.

Strong Balance Sheet, Ample Liquidity and Financial Flexibility

12/31/24 NET DEBT* SNAPSHOT

($MM)

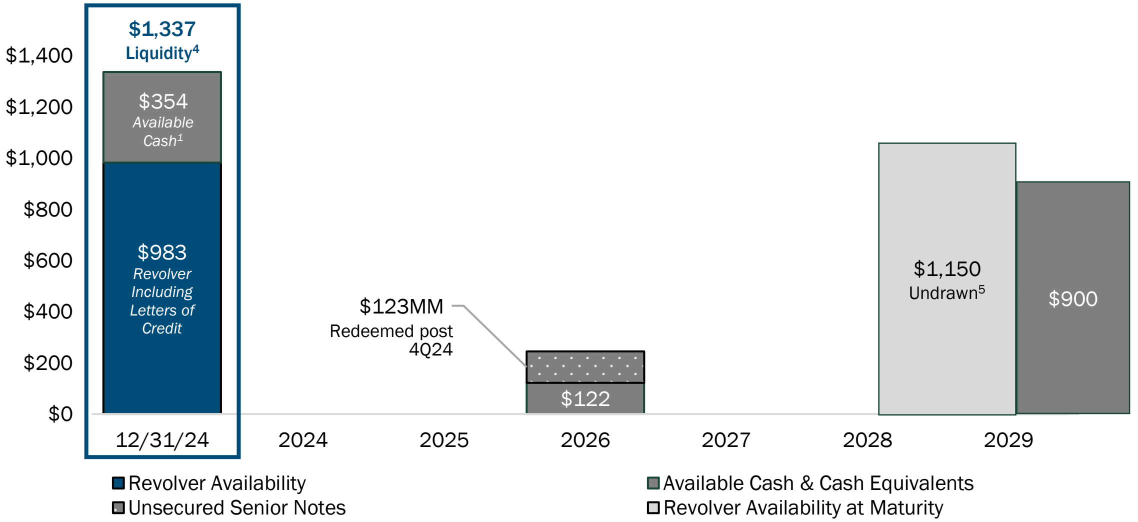
Revolving Credit Facility (RCF)	$	-
7.125% 2026 Senior Notes		245
8.250% 2029 Senior Notes		900
Face Value of Debt	**$**	**1,145**
Less Available Cash & Cash Equivalents[1]		(354)
Net Debt*	**$**	**791**

MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)

RCF Borrowing Base	$1,500
4Q24 Free Cash Flow*	$118
4Q24 Net Debt* / Annualized 2H24 EBITDAX*, [2]	0.6x
Annualized 2H24 EBITDAX* / Annualized 2H24 Interest Expense*, [3]	12.6x

MATURITY PROFILE ($MM)



RECENT CREDIT UPDATES

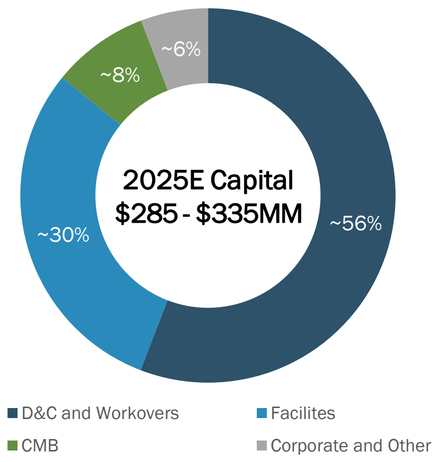
- Moody's, Standard and Poor's and Fitch affirmed our credit ratings of B1, B+ and B+, respectively
- Increased RBL elected commitments by $50MM in November 2024 to $1,150 million, reflecting additions to CRC's lender group
- Redeemed $123MM of the 2026 Senior Notes in February 2025, targeting to act on the balance in 2025

2025E Guidance *(as of March 3, 2025)*

Guidance	1Q25E Consolidated	Oil and Natural Gas	Carbon Management	2025E Consolidated	Oil and Natural Gas	Carbon Management
Net Production (MBoe/d) ~79% Oil	**138 – 142**			**132 – 138**		
Margin from Purchased Commodities[1] ($MM)	$10 – $15			$80 – $95		
Electricity Margin[2] ($MM)	$0 – $5			$120 – $145		
Operating Costs and CMB Expenses[3] ($MM)	$335 – $365	$320 – $340	$15 – $25	$1,325 – $1,425	$1,265 – $1,335	$60 – $90
Non-Energy Operating Costs and Gas Processing Costs ($MM)		*$210 – $225*			*$825 - $855*	
G&A ($MM)	$80 – $84	$10 – $12	$2 – $4	$325 – $345	$40 – $45	$10 – $15
Adjusted G&A ($MM)*	*$75 – $80*	*$10 – $12*	*$2 – $4*	*$300 – $320*	*$40 – $45*	*$10 – $15*
Depreciation, Depletion and Amortization ($MM)	$125 – $130	$117 – $121		$490 – $530	$465 - $480	
Other Operating Revenue and Expenses, net[4] ($MM)	($5) – $5			($15) – $10		
Transportation Expense ($MM)	$18 – $22	$5 – $10		$85 – $92	$25 – $30	
Taxes Other Than on Income ($MM)	$70 – $78	$57 – $61		$275 – $300	$225 – $235	
Interest and Debt Expense ($MM)	$26 – $30			$100 – $113		
Capital ($MM)	**$60 – $70**	$51 – $55	$5 – $10	**$285 – $335**	$250 – $280	$20 – $30
Adj. EBITDAX* ($MM)	**$275 – $295**	$295 - $319	($20) – ($24)	**$1,100 – $1,200**	$1,187 - $1,296	($87) – ($96)

Other Assumptions	1Q25E	2025E
Brent ($/Bbl)	$76.54	$73.05
NYMEX ($/mcf)	$3.38	$3.49
Oil - % of Brent	94% – 98%	94% – 98%
NGL - % of Brent	65% – 69%	60% – 68%
Natural Gas - % of NYMEX	110% – 115%	95% – 105%
Deferred Income Taxes	38% – 42%	35% – 45%
Effective Tax Rate	29%	29%

1Q25E cash flow from operations reflects **~$105MM impact** due to employee annual bonuses and one-time Aera merger-related retention payments



See Slide 27 "Assumptions, Estimates and Endnotes".

Appendix

A DIFFERENT
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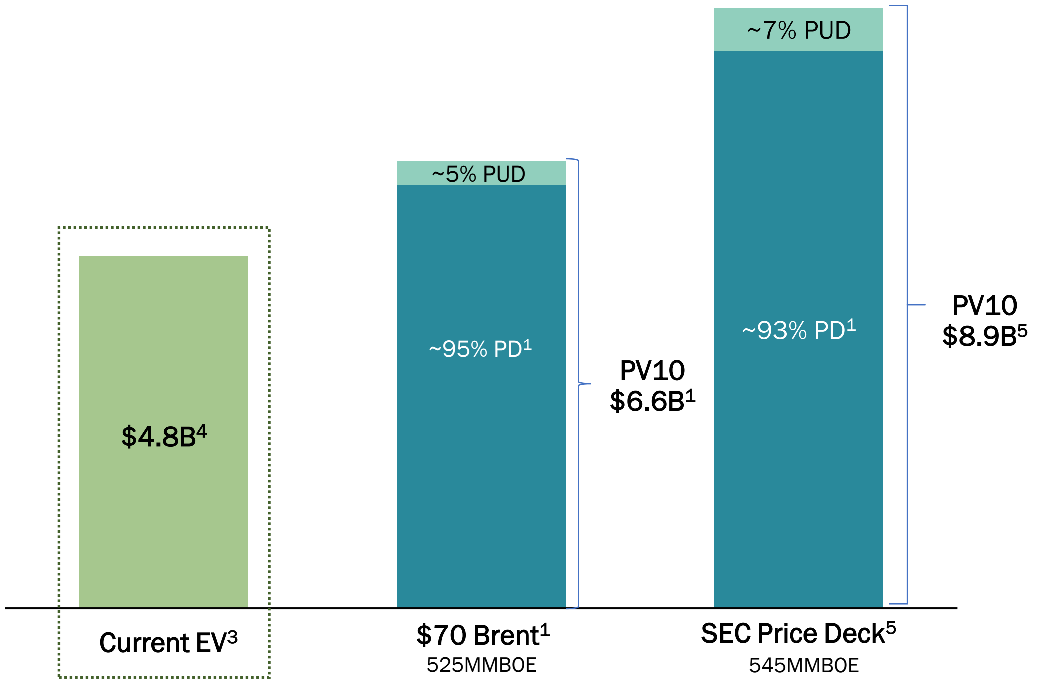
COMPANY

2024 Reserves

Durable 1P Asset Inventory	% PD[1]/PUD	MMBOE ($70 Brent)[2]	% Oil	Est. Annual Decline	4Q24 Net Production (MBOE/D)	R/P[3] (Years)
San Joaquin Basin	91% / 9%	431	77%	~12%	112	11
Los Angeles Basin	100%	72	99%	~8%	17	12
Sacramento Basin	84% / 16%	3	0%	~9%	2	4
Other Basins	100%	19	94%	~13%	10	5
Total	93% / 7%	**525**	**81%**	**~12%**	**141**	**11**

■ PDP ■ PUD



~236 MMBoe Proved Reserves Inventory Added in 2024[6]

RESERVES DETERMINATION INCLUDES:

1.5 rig program in 2025

2025E guidance assumes a two rigs scenario starting in 2H25

See Slide 27 "Assumptions, Estimates and Endnotes".

CTV Dropdown Mechanism

CARBON TERRAVAULT JV

Carbon TerraVault JV ("CTV JV")

26R

Milestone 1
First Installment

Brookfield $46MM

Reservoir
Vault Dropdown

Milestone 2
Second Installment

Brookfield $46MM

Permit Public
Comment Complete

Milestone 3 | Third
Installment

Brookfield: Up to $94MM[1]

26R Commercialized
Storage Capacity

TIMING

- 35% of annual CO_2 storage capacity for 26R reservoir under CCS contracts

Brookfield 49% Capital Call For Project Development

Project Capital Call

CRC's portion of capital calls can be satisfied with Brookfield's contribution retained by the CTV JV

CTV presented subsequent reservoirs to CTV JV with a combined capacity of 153MMT

A1-A2

CTV II

CTV …

Future Potential
Dropdowns

CTV JV Construct

- CRC presents reservoirs to Brookfield for acceptance into the JV
- Brookfield has the **option to accept, defer or reject** the reservoir
- Acceptance of a reservoir means Brookfield will pay its **share of the pore space** contribution in **three installments** upon the achievement of certain milestones **($10/Ton of Permitted Pore Space x 49%/3)**
- If deferred, projects to be re-presented to Brookfield at FID
  - *In the case that Brookfield elects to participate in a deferred project, Brookfield would reimburse CTV for their share of project development costs incurred up to that point plus % carry[2]*
- If rejected, CRC is free to develop the reservoir / project outside of the CTV JV

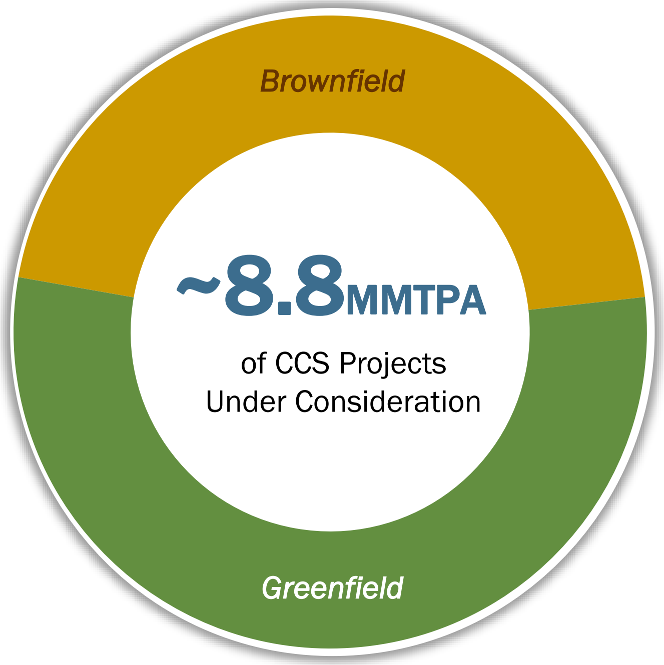
26R → A1-A2 → CTV II → CTV … → Future Potential Dropdowns →

~38MMT | ~287MMT

■ Contributed ■ Subject to ROFL

Note: CTV JV terms simplified for illustrative purposes. Source: Internal estimates. See Slide 28 "Assumptions, Estimates and Endnotes"

Making Tangible Steps Towards Decarbonizing California's Industries



WORKING ALONGSIDE OTHER INNOVATIVE COMPANIES TOWARD A DECARBONIZED CALIFORNIA

Emitter	Project Type	Service	CO_2 Emissions (MMTPA)	Agreement Type[1]
CRC | CalCapture	Post - Combustion	Capture to Storage	~1.4	In House
CRC | Cryogenic Gas Plant	Pre - Combustion	Capture to Storage	~0.1	In House
CRC | Carbon Frontier	Post - Combustion	Capture to Storage	Under Evaluation	In House
NEW **National Cement**	**Carbon-Neutral Cement**	**Transport to Storage**	**~1.0**	**MOU**
Hull Street Energy	Post - Combustion	Capture to Storage	~1.5	MOU
Brownfield Emitters			**~4.0**	
Grannus	Clean Ammonia	Storage-Only	~0.4	CDMA
InEnTec	rDME Facility	Storage-Only	~0.1	CDMA
Lone Cypress	Clean Hydrogen	Storage-Only	~0.2	CDMA
Net Power	Clean Power	Transport to Storage	~3.6	MOU
NLC Energy	Renewable Natural Gas	Storage-Only	~0.4	CDMA
Verde Energy	Renewable Gasoline	Storage-Only	~0.1	CDMA
Yosemite Clean Energy	Renewable Green Hydrogen	Storage-Only	<0.1	CDMA
DAC Hub	Direct Air Capture	Storage-Only	TBD	Lead Consortium Member
Greenfield Emitters			**~4.8**	

See Slide 28 "Assumptions, Estimates and Endnotes".

California's Premier Carbon Management Provider

- Received the Kern County Board of Supervisors approval of the conditional use permits for the CTV I CCS project
- Received CA's first EPA Class VI permits for CTV I – 26R; Approved California's first CCS project at cryogenic gas plant at Elk Hills
- Anticipating the receipt of Class VI permits for additional reservoirs in 2025[1]

Vault / Reservoir		Targeted Final EPA Class VI Permit Decision	Est. Annual Injection Rate[2] (MMTPA)			Est. Total Storage Capacity (MMT)
			EPA Class VI Permit	20 Years	40 Years	
CTV I	26R	Permit Received	~1.5[3]	~1.9	~1.0	~38
	A1-A2	2025E	~0.8	~0.4	~0.2	~8
Carbon Frontier		2025E	~3.3	~1.6	~0.8	~32
CTV VI		2026E	~3.4	~5.1	~2.5	~102
Coles Levee		*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Central California			**~9.0**	**~9.0**	**~4.5**	**~180**
CTV II		2025E	~1.0	~1.2	~0.6	~23
CTV III		2025E	~2.5	~3.6	~1.8	~71
CTV IV		2026E	~1.4	~1.7	~0.9	~34
CTV V		2025E	~0.7	~0.8	~0.4	~17
Northern California			**~5.6**	**~7.3**	**~3.7**	**~145**
Total - Combined			**~14.6**	**~16.3**	**~8.2**	**~325**

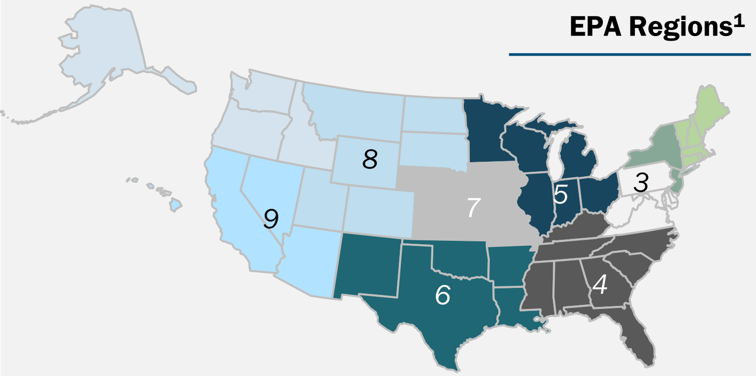
Target Addressable Market by Region[4]

Annual Regional CO_2 Emissions (MMTPA)

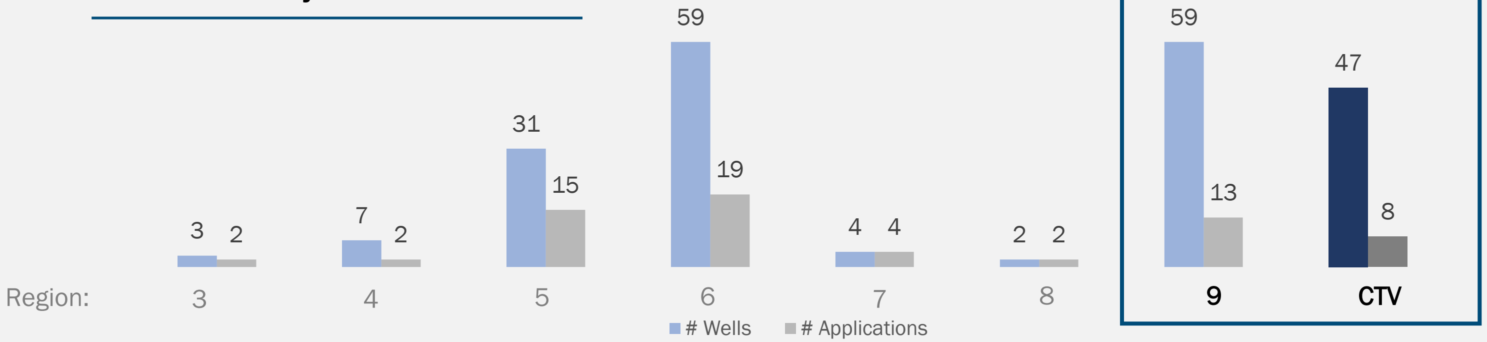
See Slide 28 "Assumptions, Estimates and Endnotes".

Leading EPA Class VI Permitting Pipeline *(As of February 14, 2025)*

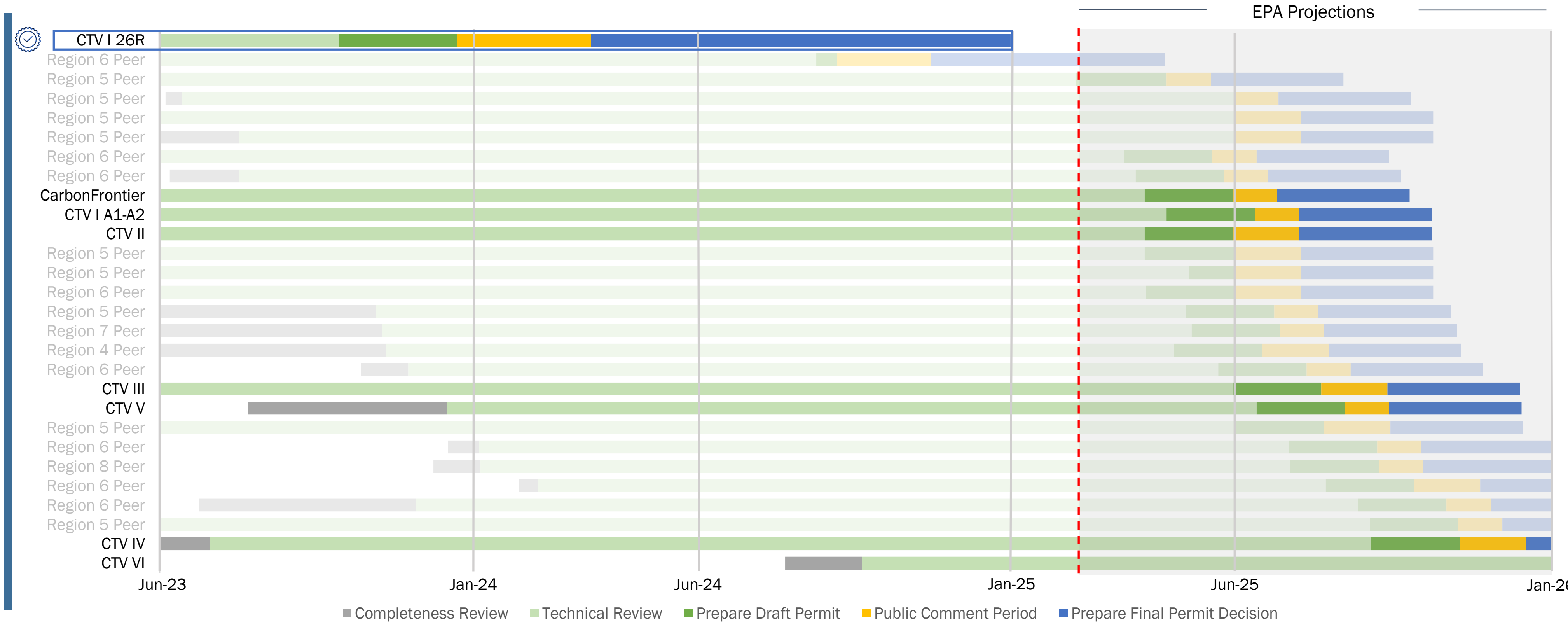
EPA Regions[1]



EPA Class VI Projects Under Review[1]



EPA Projected Permit Timeline[1]



Targeting **additional permitted CO_2** storage space in 2025

See Slide 28 "Assumptions, Estimates and Endnotes".

Commitment to Sustainability in 2024

Caring About Our Environment

- Received MiQ 'Grade A' certification for its methane emissions performance in the Los Angeles Basin
- Recertified Wildlife Habitat Council projects at THUMS, Bolsa Chica and Elk Hills
- Delivered more than 112 million barrels of water for agricultural use, or more than 3x the amount purchased for our internal use (5x the amount for legacy CRC)
- Met oil production freshwater consumption reduction goal of 30% by 2025 a year ahead

Helping Our Communities

- Donated $2.6MM in total charitable giving to non-profit organizations across California to help fund public health, safety, environmental; STEM/job training; and DEI initiatives
- Maintained low TRIR[1] of 0.39 following Aera merger
- Qualified for 23 National Safety Awards in 2024
- ~150 non-profits supported | ~500 employee volunteers | 1,900+ hours at community events

Improving Our Governance Practices

- 30% of the 2024 executive compensation scorecard metrics relating to Company performance tied to ESG-related carbon management, environmental stewardship, and worker safety
- Board exhibited diversity with 20% being gender diverse and 30% consisting of members from underrepresented communities

AWARDS

CDP Discloser 2024

GRI Empowering Sustainable Decisions

SASB Sustainability Accounting Standards Board

California Department of Fish & Wildlife

MiQ

nsc

Sustainable1 — Proud participant of the 2024 Corporate Sustainability Assessment (CSA) — S&P Global

WHC Certification — WHC-Certified

America's Most Responsible Companies 2025 — Newsweek — statista

MSCI ESG RATINGS — A

CCC	B	BB	BBB	A	AA	AAA

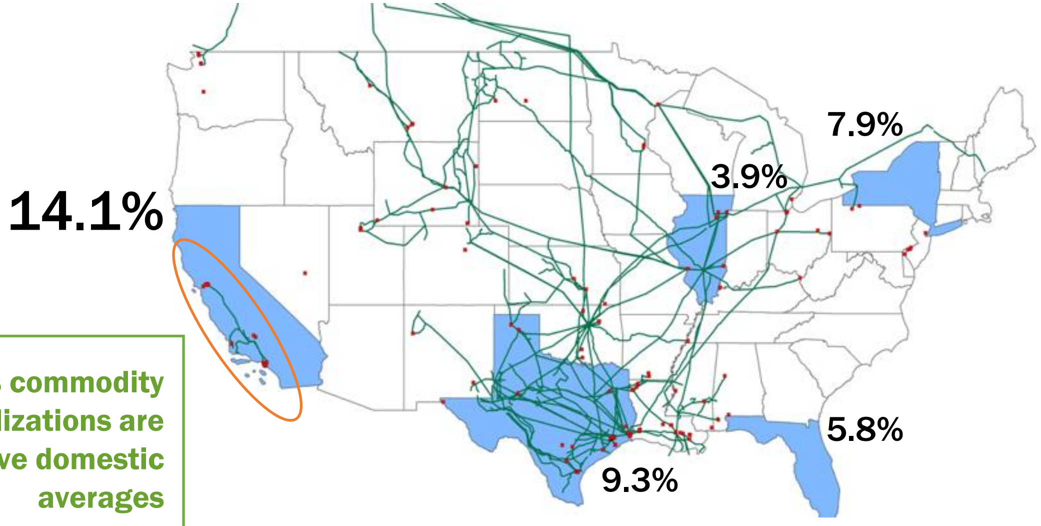
Note: We are in the process of evaluating the impact of our recently completed merger with Aera Energy on our ESG goals and ambitions. The ESG goals and ambitions communicated throughout this presentation are subject to change pending completion of this process. See Slide 28 "Assumptions, Estimates and Endnotes".

Strong Commodity Price Realizations

- **Crude:** Crude prices were generally firm in 4Q24 supported by evolving geopolitical dynamics following the US election and uncertain international economic expectations, particularly in China and India. California realizations (versus Brent) were strong as refining crack margins for local refiners seem to have steadied.
- **Natural Gas:** Seasonally-high storage volumes continued to weigh on California natural gas prices in 4Q24 as weather remained seasonal across the quarter.
- **NGLs:** 4Q24 demand and realizations were stronger than expected supported by blending markets and robust international exports. California continues to carry a premium to the broader North American NGL marketplace.
- **Power:** Seasonal weather, abundant hydro and the addition of intermittent resources to the California (CAISO) grid continued to cap California energy prices for 4Q24.

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

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

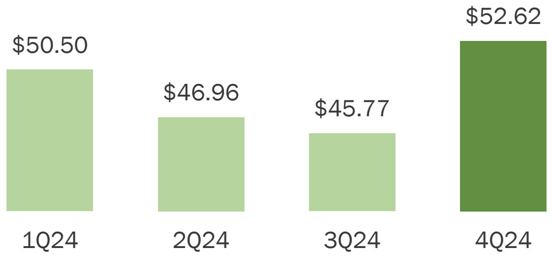


CRC's commodity realizations are above domestic averages

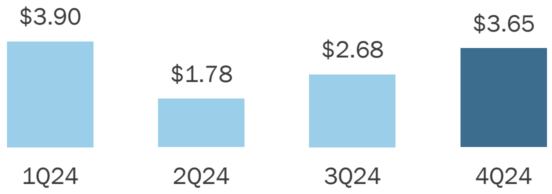
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 3Q24; EIA

Oil w/ Hedges ($/BBL)

NGLs ($/BBL)



Natural Gas ($/MCF)



	Oil 1Q24	Oil 2Q24	Oil 3Q24	Oil 4Q24	NGLs 1Q24	NGLs 2Q24	NGLs 3Q24	NGLs 4Q24	Gas 1Q24	Gas 2Q24	Gas 3Q24	Gas 4Q24
Average Benchmark Prices[1]	$81.84	$85.00	$78.54	$73.97	$81.84	$85.00	$78.54	$73.97	$2.24	$1.89	$2.16	$2.79
% of Benchmark[1]	98%	98%	98%	98%	62%	55%	58%	71%	174%	94%	124%	131%
Hedge Settlements	($2.99)	($1.85)	($1.72)	$0.18	-	-	-	-	-	-	-	-
Average Realized Prices[2]	$77.17	$81.29	$75.38	$73.00	$50.50	$46.96	$45.77	$52.62	$3.90	$1.78	$2.68	$3.65

See Slide 28 "Assumptions, Estimates and Endnotes".

Hedge Portfolio (as of December 31, 2024)

OIL		1Q25E	2Q25E	3Q25E	4Q25E	2026E	2027E	2028E
SOLD CALLS								
Brent	Barrels per Day	30,000	30,000	30,000	29,000	15,000	-	-
	Weighted-Average Price	$87.08	$87.08	$87.08	$87.13	$85.00	-	-
SWAPS								
Brent	Barrels per Day	52,837	46,506	44,126	42,626	30,449	13,882	1,697
	Weighted-Average Price	$72.48	$71.31	$70.62	$69.94	$67.95	$65.53	$65.00
PURCHASED PUTS[1]								
Brent	Barrels per Day	30,000	30,000	30,000	29,000	15,000	-	-
	Weighted-Average Price	$61.67	$61.67	$61.67	$61.72	$60.00	-	-
NATURAL GAS		**1Q25E**	**2Q25E**	**3Q25E**	**4Q25E**	**2026E**	**2027E**	**2028E**
SWAPS								
SoCal Border	MMBtu per Day	10,000	29,074	25,750	22,408	660	-	-
	Weighted-Average Price	$6.02	$3.44	$3.48	$3.53	$6.29	-	-
NWPL Rockies	MMBtu per Day	50,999	51,750	51,750	51,750	44,618	12,616	1,576
	Weighted-Average Price	$5.48	$2.95	$2.95	$4.22	$4.01	$4.34	$3.95
PG&E CityGate	MMBtu per Day	14,000	-	-	-	-	-	-
	Weighted-Average Price	$6.10	-	-	-	-	-	-
EST. HEDGE CONTRACT SETTLEMENTS[2]		**1Q25E**	**2Q25E**	**3Q25E**	**4Q25E**	**2026E**	**2027E**	**2028E**
Combined Hedge Portfolio ($MM)		($12)	($12)	($10)	($10)	($29)	($18)	($2)

STRATEGY

CRC's hedging strategy is designed to **meet our business objectives should market prices decline** and **participate in upside should market prices increase**

EXECUTION

~72% of 2025E total net production hedged with **Brent floor price of ~$67** per barrel

OPERATIONS

~62% of 2025E internal fuel consumption hedged with average **natural gas price of ~$3.95** per MMBtu

See Slide 28 "Assumptions, Estimates and Endnotes".

Glossary

Term	Definition
Bcf	Billion Cubic Feet
BMT	Billion Metric Tons
BTM	Behind-the-Meter
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
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)*
CUP	Conditional Use Permit
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
FEED	Front End Engineering and Design
FID	Final Investment Decision
FTM	Front-of-the-Meter
GHG	Greenhouse Gas
IRR	Internal Rate of Return

Term	Definition
KMTPA	Thousand Metric Tons Per Annum
LCFS	Low Carbon Fuel Standard
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MOU	Memorandum of Understanding
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
NRI	Net Revenue Interest
OCF	Operating Cash Flow
PDP	Proved Developed Producing
PDNP	Proved Developed Non-Producing
PPA	Power Purchase Agreement
PUD	Proved Undeveloped
RA	Resource Adequacy
ROFL	Right of First Look
RSG	Responsibly Sourced Gas
R/P	Reserves to Production Ratio
RTC	Round-the-Clock
SFDR	Sustainable Finance Disclosure Regulation
SMOG	Standardized Measure of Discounted Future Net Cash Flows
SRP	Share Repurchase Program
SJV	San Joaquin Valley
TBA	To Be Announced
Tcf	Trillion Cubic Feet
WI	Working Interest

Assumptions, Estimates and Endnotes

Slide 2:

(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Figures exclude excise taxes and commissions paid on share repurchases.

(2) 1H24 includes legacy CRC only.

(3) PV-10 of reserves estimated as of December 31, 2024 using SEC Prices (after factoring in price realizations) of $80.42 per barrel for oil and $2.13 per MMbtu for natural gas. PV-10 is a non-GAAP measure.

Slide 3:

(1) See "Carbon TerraVault and National Cement Sign MOU for California's First Net Zero Cement Facility" press release from March 3, 2025 for additional information.

(2) MOUs and CDMAs are non-binding agreements. The projects and transactions described in an MOU or CDMA are subject to certain conditions precedent, typically including the negotiation of definitive documents, a final investment decision by the parties and receipt of EPA Class VI permits and other regulatory approvals.

(3) See www.lebecnetzero.com for additional information.

Slide 4:

(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Figures exclude excise taxes and commissions paid on share repurchases.

(2) Total year 2025E guidance assumes a 2025E Brent price of $72.82 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.47 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline.

Slide 7:

(1) Pro forma combined for the Aera merger that closed on July 1, 2024. Pro forma combined 2023 non-energy & gas processing costs and G&A is calculated from $499MM in non-energy & gas processing costs and $267MM in G&A for legacy CRC, and $440MM in non-energy & gas processing costs and $191MM in G&A for Aera.

(2) 2H24 guidance provided with 2Q24 earnings results on August 6, 2024. See "California Resources Reports Second Quarter 2024 Financial and Operating Results" for additional information.

(3) 2H24 actual annualized is calculated from $449MM in non-energy & gas processing costs and $201MM in G&A.

(4) Includes gas processing costs.

(5) When accounting for estimated cash interest income, CRC's net interest savings were ~$36 million.

(6) Includes financial, AROs, capital and other synergies.

Slide 8:

(1) Pro forma combined for the Aera merger that closed on July 1, 2024. Pro forma combined January 2024 average gross production assumes 94 Mboe/d for legacy CRC and 78 Mboe/d for Aera.

(2) Capital efficiency is calculated as drilling and workover capital divided by the period's entry-to-exit incremental gross production per day above the assumed 10% to 15% base corporate decline rate. Capital efficiency provides investors with a measure of the effectiveness of capital investment on the marginal production of a barrel of oil equivalent.

(3) Pro forma combined for the Aera merger that closed on July 1, 2024. Pro forma combined 2024 capital efficiency is calculated using $149MM in pro forma combined 2024 drilling and workover capital which includes $123MM for CRC and $26MM for Aera during January through June 2024, and 172 Mboe/d in pro forma combined January 2024 gross production.

(4) Pro forma combined for the Aera merger that closed on July 1, 2024. Pro forma combined 2024 wells drilled of 324 includes 243 wells drilled by CRC and 81 wells drilled by Aera during January through June 2024.

Slide 9:

(1) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation.

(2) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.

(3) Source: gis.data.cnra.ca.gov.

(4) Source: MarketView.

Slide 10:

(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa.

(2) Assumes average reservoir life of EPA Class VI permits to date.

Assumptions, Estimates and Endnotes

Slide 11:

(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval.
(2) Excludes excise taxes and commissions paid on share repurchases.
(3) Source: FactSet. Represents current annual dividend policy of $1.55 per share divided by CRC's market capitalization as of February 28, 2025.

Slide 13:

(1) 4Q24 guidance assumed a 4Q24 Brent price of $71.48 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.95 per mcf. Generally, 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) Other operating revenue and expenses, net is calculated as the difference between other revenue and other operating expenses, net. 4Q24 guidance, 4Q24 actuals and 2024 actuals include net loss on natural gas purchase derivatives and measurement period adjustments. Actuals include exploration expense.
(4) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation.
(5) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
(6) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval.
(7) Excludes excise taxes and commissions paid on share repurchases.

Slide 14:

(1) Available cash and cash equivalents excludes $18MM of restricted cash.
(2) Net leverage is calculated as 4Q24 net debt of $791MM (excludes restricted cash of $18MM) divided by 2H24E annualized adjusted EBITDAX. 2H24 annualized adjusted EBITDAX is calculated from 3Q24 adjusted EBITDAX of $402MM and 4Q24 adjusted EBITDAX of $316MM.
(3) Interest coverage is calculated as 2H24 annualized adjusted EBITDAX divided by 2H24 annualized interest and debt expense. 2H24 annualized adjusted EBITDAX is calculated from 3Q24 adjusted EBITDAX of $402MM and 4Q24 adjusted EBITDAX of $316MM. 2H24 annualized interest and debt expense is calculated from 3Q24 interest and debt expense of $28MM and 4Q24 interest and debt expense of $29MM.
(4) Liquidity on December 31, 2024 is calculated as $354MM of cash and cash equivalents (excluding $18MM of restricted cash) plus $1,150MM of borrowing capacity on CRC's Revolving Credit Facility less $167MM in outstanding letters of credit.
(5) Undrawn Revolving Credit Facility as of December 31, 2024, excluding outstanding letters of credit.

Slide 15:

(1) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation.
(2) Electricity margin is calculated as the difference between electricity Sales and electricity generation expenses.
(3) CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.
(4) Other operating revenue and expenses, net is calculated as the difference between other revenue and other operating expenses, net and includes exploration expense.

Slide 17:

(1) Proved developed (PD) reserves include proved developed producing (PDP) reserves and proved undeveloped (PUD) reserves.
(2) Reserves information shown as of December 31, 2024 and based on $70.00 per barrel for oil and $3.00 per MMbtu 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 $70.00 per barrel for oil and $3.00 per MMbtu for natural gas has not been provided.
(3) Calculated using annualized 4Q24 net production.
(4) Enterprise value calculated using net debt of $791MM (as of December 31, 2024) plus market capitalization (as of February 28, 2025) using 90.8MM shares outstanding.
(5) PV-10 of reserves estimated as of December 31, 2024 using SEC Prices (after factoring in price realizations) of $80.42 per barrel for oil and $2.13 per MMbtu for natural gas. PV-10 is a non-GAAP measure.
(6) Aera proved reserves added in 2024.

Assumptions, Estimates and Endnotes

Slide 18:

(1) Total Brookfield payments to CRC corresponding to their 49% interest in the 26R reservoir are expected to total up to ~$185MM at FID. $92MM has been received to date with the third and final installment of the 26R pore space contribution from Brookfield to the CTV JV expected upon CTV JV securing storage contracts for 35% of annual CO2 storage capacity at 26R. The amount of the last milestone payment will be calculated in accordance with the final permit volumes subject to contractual adjustments.

(2) Calculated from date of initial ROFL presentation.

Slide 19:

(1) MOUs and CDMAs are non-binding agreements. The projects and transactions described in an MOU or CDMA are subject to certain conditions precedent, typically including the negotiation of definitive documents, a final investment decision by the parties and receipt of EPA Class VI permits and other regulatory approvals.

Slide 20:

(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa.

(2) Injection rates are average rates based on estimated maximum permit volumes over the assumed life of project. Actual volumes and the injection period will vary over time.

(3) 26R injection capacity as per the draft EPA permit is ~38MMT. Assuming the maximum expected injection rate of 1.46MMTPA, the reservoir would reach capacity in 26 years. Each CTV reservoir will have a unique set of operating, injection and life span parameters that will vary and will be reflected on the submitted permit.

(4) Source: CARB 2020.

Slide 21:

(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa.

(2) Based on EPA estimates and approvals. CTV IV is project to receive a final permit decision in March 2026 and CTV VI is project to receive a final permit decision in September 2026.

Slide 22:

(1) Total Recordable Incident Rate (TRIR) calculated as recordable incidents per 200,000 hours for all workers (employees and contractors).

Slide 23:

(1) Benchmark prices are based on Brent for oil and NGLs, and NYMEX average daily price for natural gas.

(2) Average realized prices include hedges on oil and natural gas.

Slide 24:

(1) Purchased and sold puts with the same strike price have been netted together.

(2) Represents estimated net cash settlement payments for derivative contracts as of December 31, 2024. Assumes forward commodity prices as of December 31, 2024.

Forward – Looking / Cautionary Statements – Certain Terms

This document contains statements that CRC believes 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 CRC's 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. Additionally, the information in this report contains forward-looking statements related to the recently announced Aera merger.

Although CRC believes the expectations and forecasts reflected in its 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 its 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 CRC's actual results to be materially different than those expressed in its forward-looking statements include:

- fluctuations in commodity prices, including supply and demand considerations for CRC's products and services, and the impact of such fluctuations on revenues and operating expenses;
- 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 military conflicts in Israel, Lebanon, Ukraine and the Middle East;
- the ability to successfully execute integration efforts in connection with the Aera Merger, and achieve projected synergies and ensure that such synergies are sustainable;
- 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, EPA and other governmental permits and approvals necessary for drilling or development activities or its carbon management segment; (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 its products;
- the efforts of activists to delay prevent oil and gas activities or the development of CRC's carbon management segment through a variety of tactics, including litigation;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to estimates of reserves and related future cash flows, including changes arising from CRC's 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 it operates;
- CRC's 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 its counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of its operations;
- CRC's ability to claim and utilize tax credits or other incentives in connection with our CCS projects;
- CRC's ability to realize the benefits contemplated by its energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- CRC's ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and its ability to convert CDMAs to definitive agreements and enter into other offtake agreements;
- CRC's ability to maximize the value of its carbon management segment and operate it on a stand alone basis;
- CRC's ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms;
- uncertainty around the accounting of emissions and its ability to successfully gather and verify emissions data and other environmental impacts;
- changes to CRC's dividend policy and share repurchase program, and its ability to declare future dividends or repurchase shares under its debt agreements;
- limitations on CRC's financial flexibility due to existing and future debt;
- insufficient cash flow to fund its capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- CRC's access to and the terms of credit in commercial banking and capital markets, including its ability to refinance debt or obtain separate financing for its carbon management segment;
- changes in state, federal or international tax rates, including CRC's ability to utilize its net operating loss carryforwards to reduce its income tax obligations;
- effects of hedging transactions;
- the effect of CRC's 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 its ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19 pandemic; and
- other factors discussed in Part I, Item 1A – Risk Factors.

Forward – Looking / Cautionary Statements – Certain Terms (Cont.)

CRC cautions you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and CRC undertakes 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 CRC has not independently verified them and does not warrant the accuracy or completeness of such third-party information.

Non-GAAP Financial Measures:
This presentation contains certain financial measures that are not prepared in accordance with generally accepted accounting principles ("GAAP"). These measures are identified with an "*" and include but are not limited to Adjusted EBITDAX, PV-10, Leverage Ratio, Net Debt, Liquidity and Free Cash Flow. 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.

Industry and Market Data:
This presentation has been prepared by CRC and includes market data and other statistical information from sources it believes to be reliable, including independent industry publications, governmental publications or other published independent sources. Some data is also based on our good faith estimates, which are derived from CRC's review of internal sources as well as the independent sources described above. Although CRC believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy and completeness. CRC owns or has rights to various trademarks, service marks and trade names that it uses in connection with the operation of its business. This presentation also contains trademarks, service marks and trade names of third parties, which are the property of their respective owners. CRC's use or display of third parties' trademarks, service marks, trade names or products in this presentation is not intended to, and does not imply, a relationship with CRC or an endorsement or sponsorship by or of CRC.

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Higher **Cashflow** Less **Carbon** Better **California**