A DIFFERENT
KIND OF ENERGY
COMPANY

CALIFORNIA
RESOURCES CORPORATION

Third Quarter 2024 Results

November 6, 2024

Higher **Cash Flow** Less **Carbon** Better **California**

Key Takeaways

1

STRONG OPERATIONAL AND FINANCIAL RESULTS

Net production sold at **high end of quarterly guidance range on less than expected capital**

Generated $402MM of adjusted EBITDAX* and **$141MM of Free Cash Flow***

On-track to deliver approximately **$235MM of estimated synergies by the end of 3Q25** and continuing to target **0.5x net leverage* by the end of 2Q25**

2

COMMITMENT TO RETURN SIGNIFICANT CASH TO SHAREHOLDERS[1]

Robust returns through fixed dividend and **opportunistic share repurchases**

Returned $76MM in 3Q24 and **$211MM in 2024 YTD**

Returned $967MM since May 2021

3

LEADING CARBON MANAGEMENT PLATFORM

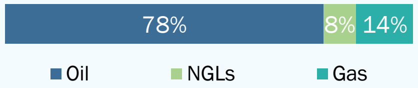
Announced an MOU[2] for up to 1.5MMTPA of brownfield CO_2 emissions with Hull Street Energy, a leading California power provider

Received Kern County Board of Supervisors' **approval of the conditional use permits** for the first **CTV I CCS project**

Expect to receive **California's first EPA Class VI permits** for CTV I – 26R **in late 2024** with **FID of cryogenic gas plant project expected shortly thereafter**

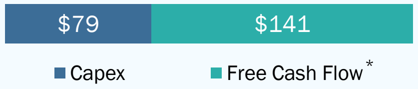
145MBOE/D

3Q24 NET PRODUCTION SOLD



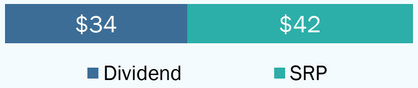
$220MM

3Q24 OPERATING CASH FLOW



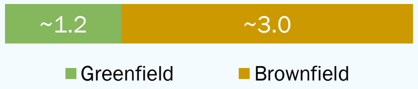
$76MM

3Q24 TOTAL SHAREHOLDER RETURN[1]



~4.2MMTPA

OF CCS PROJECTS UNDER CONSIDERATION



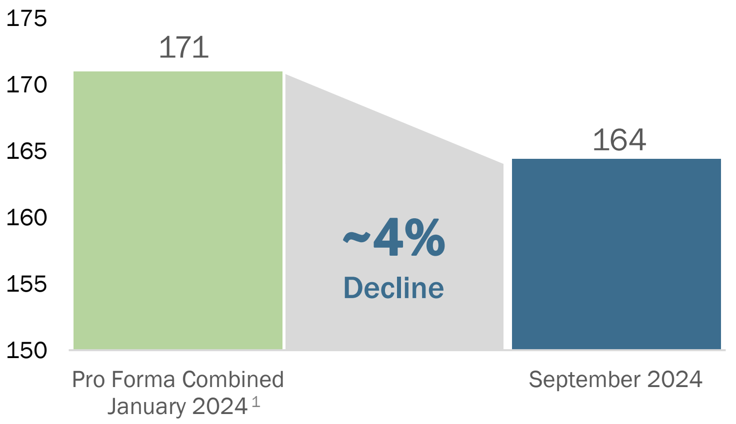
Strong Performance

A DIFFERENT KIND OF ENERGY COMPANY

Enhancing Operational and Capital Efficiencies

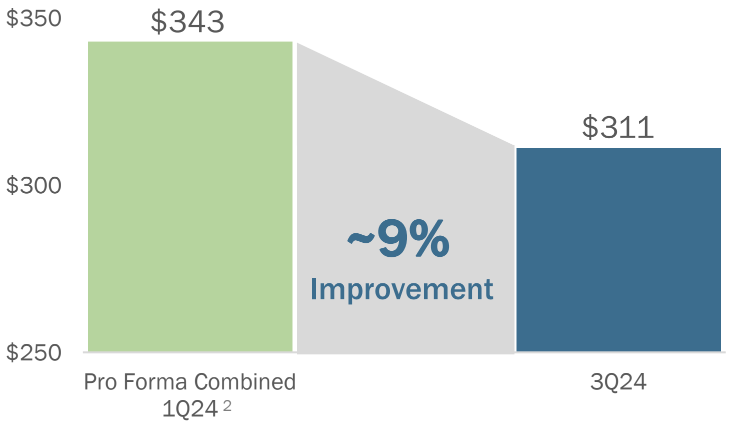
Resilient Reservoir Performance

Gross Production (MBoe/d)



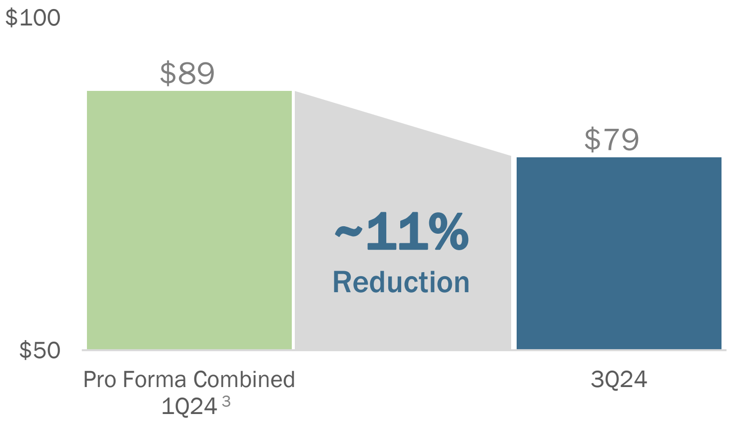
Lower Operating Costs

Operating costs ($MM)



Lower Capital

Capital ($MM)



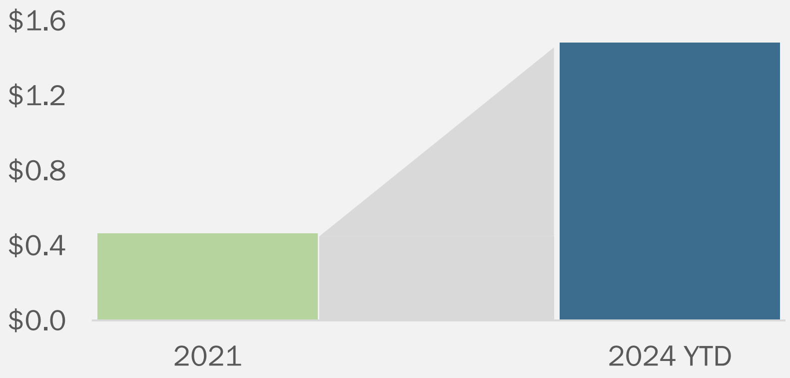
Delivered

~$1.5B

of Cumulative Free Cash Flow* since 2021

Strong Free Cash Flow* Generation

Cumulative Free Cash Flow* ($B)



Commitment to Returning Cash to Shareholders[1]

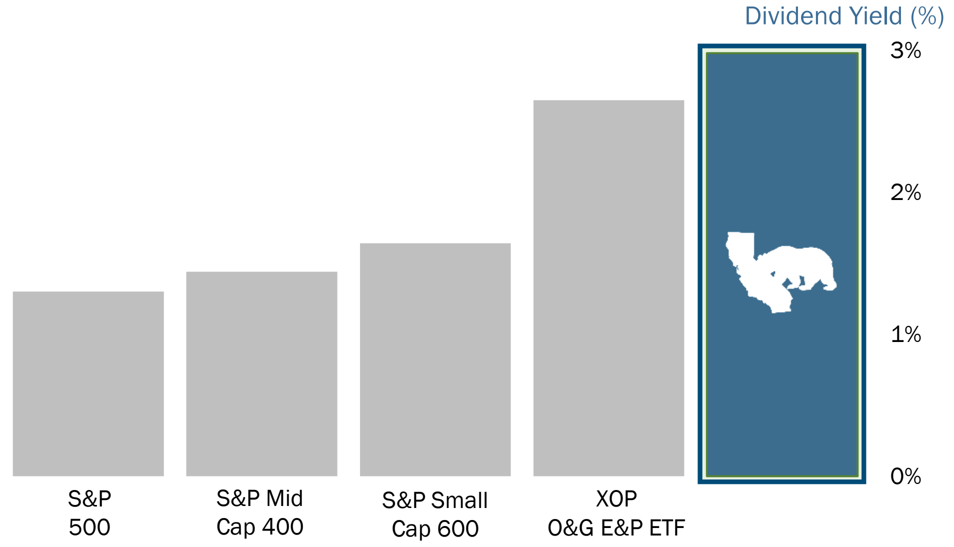
Returned

$76MM in Dividends and Buybacks in 3Q24

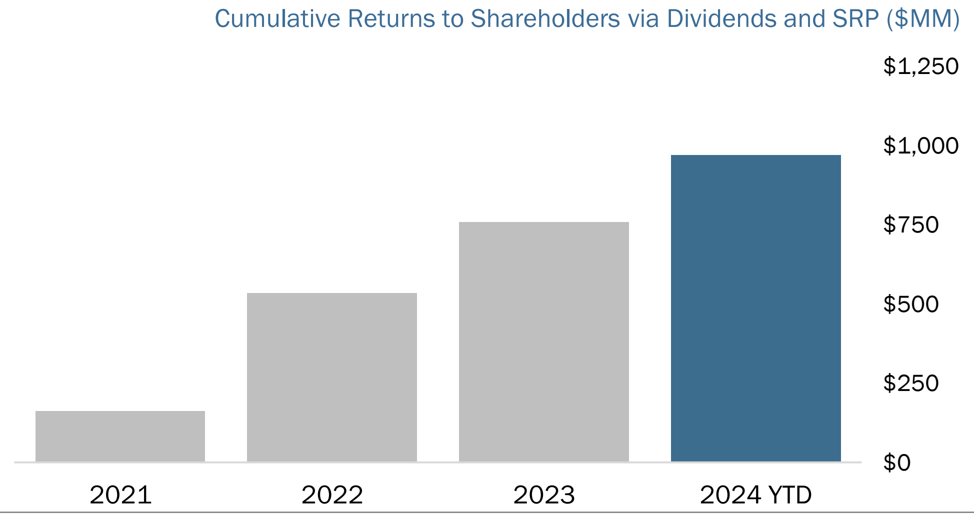
$211MM in Dividends and Buybacks Year-to-Date[3]
$967MM since May 2021

~89% of Free Cash Flow* Year-to-Date
~65% since May 2021

Competitive Dividend Yield vs. Market[2]

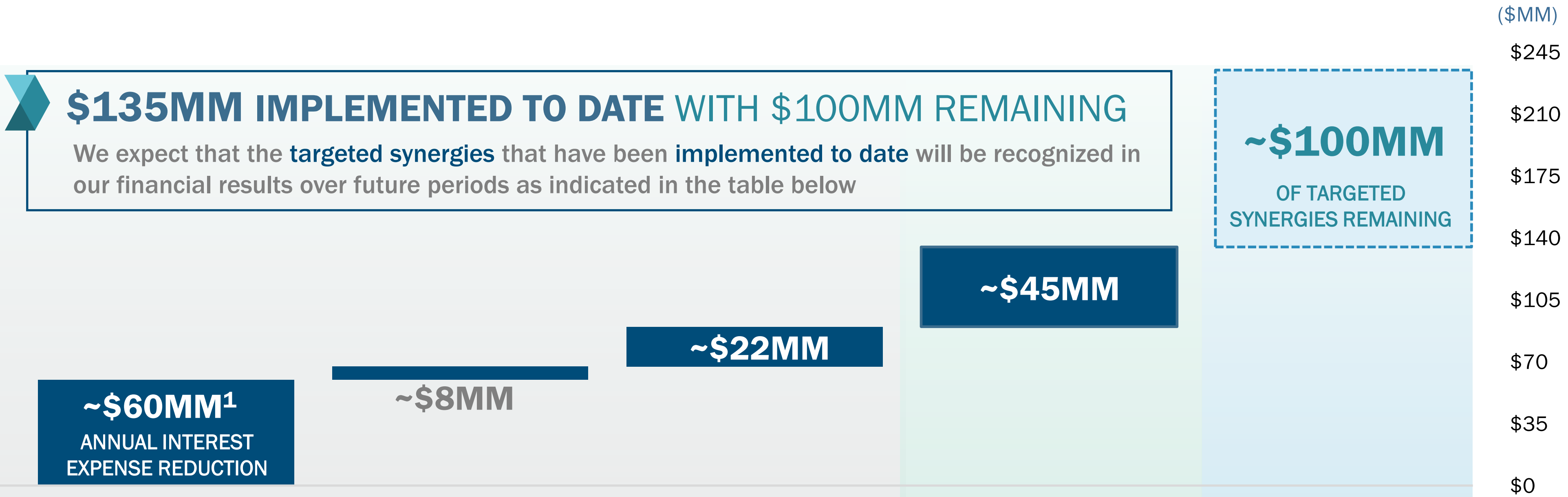


Significant Return of Capital to Shareholders[1]



Executing on ~$235MM in Targeted Aera Merger Synergies

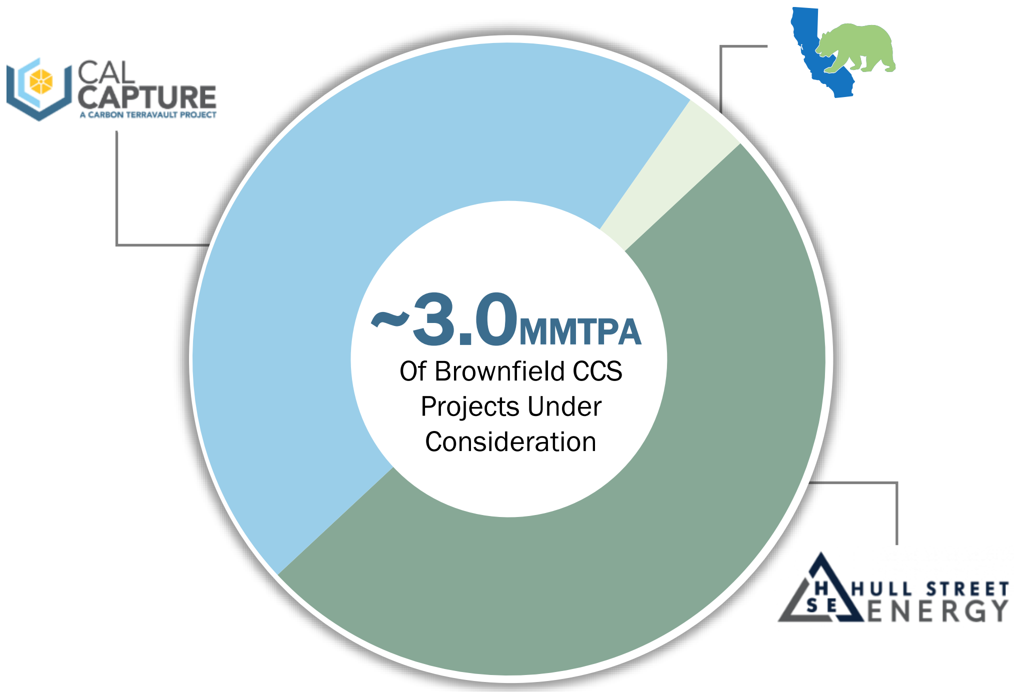
Annualized Aera Merger Run-rate Savings



Operations ($MM)	-	~$3	~$8	~$13[2]	~$80[2]
G&A ($MM)	-	~$5	~$14	~$32	~$20
Other[3] ($MM)	~$60	-	-	TBA[2]	TBA[2]
Total ($MM)	**~$60**	**~$8**	**~$22**	**~$45**	**~$100**
Impact	**2H 2024**	**3Q24**	**4Q24E**	**2025E**	**2025E – 2026E**
Implementation (%)	100%	100%	100%	100%	0%

(1) When accounting for estimated cash interest income, CRC's net interest savings were ~$36 million. (2) Impacts resulting from operational Aera merger synergies are expected to reduce operating costs, AROs and capital and may ultimately not be classified as Operating Costs. CRC will provide additional details on the breakdown of these operations synergies with its FY25 guidance during its 4Q24 earnings call. (3) Includes financial, AROs, capital and other synergies.

New Brownfield Agreement Enhances Carbon Management Portfolio



DECARBONIZING CALIFORNIA'S ESSENTIAL & HARD TO ABATE INDUSTRIAL SECTORS

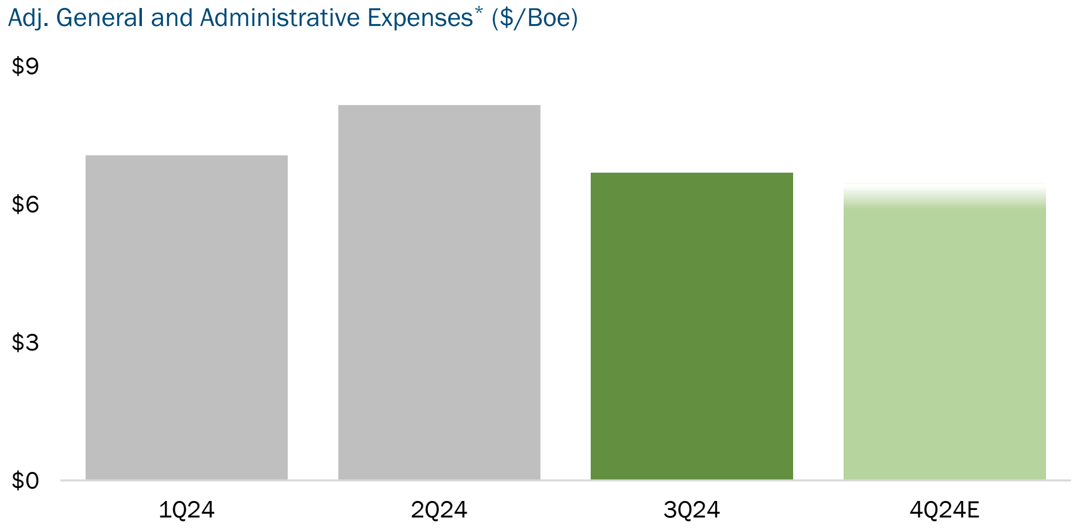
	Emitter	Project Type	Service	CO_2 Emissions (MMTPA)	Agreement Type[1]
NEW	**Hull Street Energy**	**Post - Combustion**	**Capture to Storage**	**~1.5**	**MOU**
	Cal Capture (A Carbon TerraVault Project)	Post - Combustion	Capture to Storage	~1.4	In House
	California Resources Corporation	Pre - Combustion	Capture to Storage	~0.1	In House
	CarbonFrontier	Post - Combustion	Capture to Storage	Under Evaluation	In House

3Q24 Results & Outlook

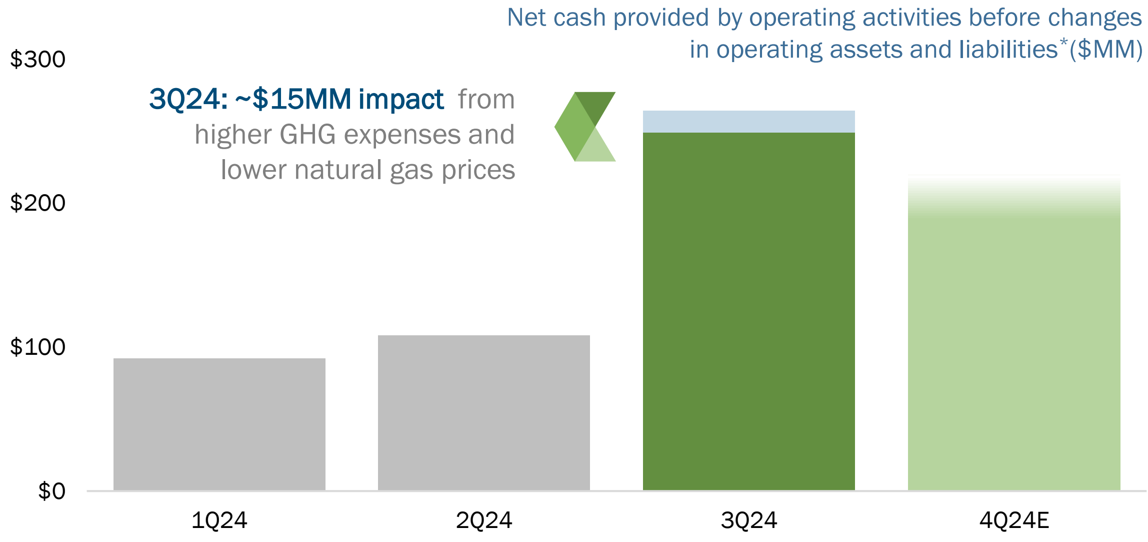
A DIFFERENT KIND OF ENERGY COMPANY

Driving Down Costs and Delivering Durable Cash Flow

Declining Adj. G&A* Enhances Margins



Durable Cashflow Generation



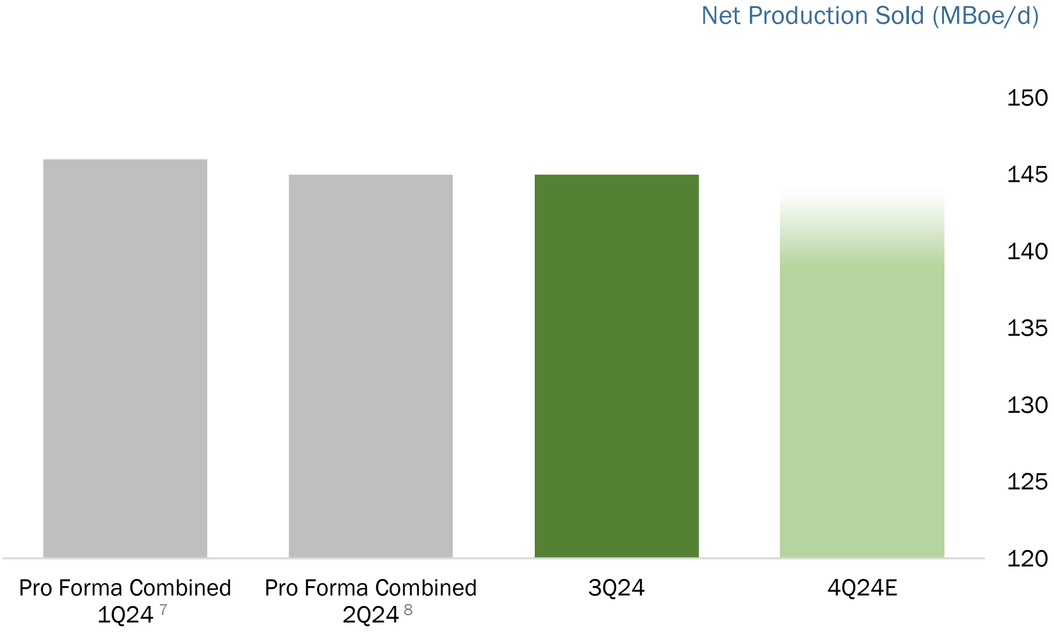
FOCUS ON KEY DELIVERABLES

- 2023: $65MM run rate savings from business transformation
- 2024: Aera Merger completion and businesses integration
- **2025: Targeting $235MM in Aera Merger synergies**

3Q24 Results

Guidance	3Q24E[1]	3Q24A
Brent ($/Bbl)	$84.23	**$78.54**
Brent realized price with hedge ($/Bbl)	N/A	**$75.38**
Brent realized price without hedge (% of Brent)	94% - 98%	**98%**
Operational and Financial		
Net Production Sold (MBoe/d)	141 – 145	**145**
Net Oil Production Sold (%)	79%	**78%**
Operating Costs and CMB Expenses[2] ($MM)	$325 – $355	**$324**
G&A ($MM)	$100 – $120	**$106**
Adj. G&A* ($MM)	$80 – $100	**$89**
Taxes Other Than on Income ($MM)	$75 – $85	**$85** 1
Other Operating Revenue & Expenses, net[3] ($MM)	($100) – ($112)	**($66)** 2
Total Capital ($MM)	$90 – $110	**$79**
Adjusted EBITDAX* ($MM)	$375 - $415	**$402** 3
Other Items		
Margin from Marketing of Purchased Commodities[4] ($MM)	$10 – $16	**$8** 4
Electricity Margin[5] ($MM)	$45 – $65	**$60**
Transportation Expense ($MM)	$20 – $25	**$23**
Total Quarterly Return of Cash to Shareholders[6] ($MM)		
Share Repurchases ($MM)		**$42**
Dividend Payment ($MM)		**$34**
Total ($MM)		**$76**

Robust Production Management



3Q24 Financial Impacts:

1. Taxes Other Than on Income Expense increased by ~$6MM primarily due to higher than anticipated GHG expense
2. Lower than estimated Aera merger transaction and integration costs decreased Other Operating Revenue & Expenses, net[3] by ~30MM
3. Lower realized quarterly commodity prices before the impact of hedges reduced Adj. EBITDAX* by ~$40MM
4. Lower natural gas pricing reduced Margin from Marketing of Purchased Commodities[4] by ~$8MM

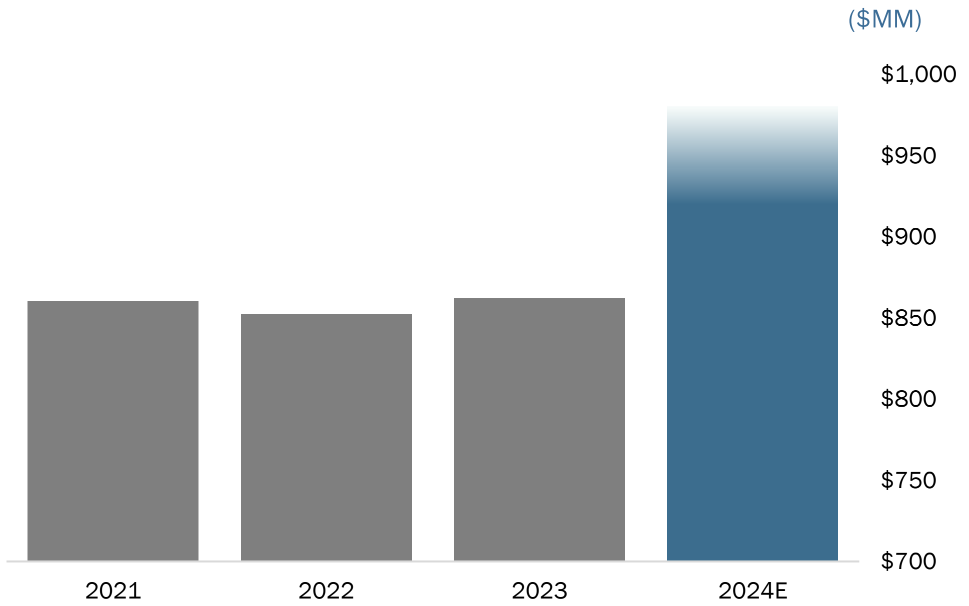
- Aera merger transaction and integration costs decreased third quarter 2024 cash flow from operations by ~$57MM

See Slide 23 "Assumptions, Estimates and Endnotes"

Guidance *(as of November 6, 2024)*

Guidance	4Q24E Consolidated	CMB	E&P, Corp. & Other
Net Production Sold (MBoe/d) ~79% Oil	**140 – 144**		
Margin from Marketing of Purchased Commodities[1] ($MM)	$5 – $10		
Electricity Margin[2] ($MM)	$15 – $20		
Operating Costs & CMB Expenses[3] ($MM)	$340 - $365	$15 - $25	$325 - $340
G&A ($MM)	$90 – $100	$2 – $4	$88 – $96
Adjusted G&A ($MM)*	*$80 – $90*	*$1 – $3*	*$79 – $87*
Other Operating Revenue & Expenses, net[4] ($MM)	($10) – ($20)		
Transportation Expense ($MM)	$20 – $25		
Taxes Other Than on Income ($MM)	$75 – $86		
Interest and Debt Expense ($MM)	$25 – $30		
Capital ($MM)	**$85 – $105**	$5 – $10	$80 – $95
Adj. EBITDAX* ($MM)	**$260 – $300**		

Adj. EBITDAX* Expectations



	2021	2022	2023	2024E
Brent ($/Bbl)	$70.79	$98.89	$82.22	$79.22[5]
Net Production Sold (MBoe/d)	100	91	86	109 - 110

Commodity Assumptions	4Q24E
Brent ($/Bbl)	$71.48
NYMEX ($/mcf)	$2.95
Oil - % of Brent	95% – 99%
NGL - % of Brent	65% – 69%
Natural Gas - % of NYMEX	128% – 138%

4Q24E Financial Guidance Commentary:

- 4Q24 guidance reflects ~75% of the impact of the initial $30MM in run-rate synergies actioned in 3Q24
- Higher 4Q24E operating costs are mainly due to higher forecasted gas prices and increase in maintenance activity
- 4Q24E free cash flow* is expected to be negatively impacted by $60 - 70MM primarily due to timing on cash payments on items such as income and property taxes, interest, severance and taxes other than on income (GHG)

See Slide 23 “Assumptions, Estimates and Endnotes”.

Preliminary 2025 Outlook

Targeting Higher Margins Through Operational Efficiencies

- **On track to achieve ~$235MM** in targeted Aera related synergies
  - Targeting a gradual **>5% YoY annual run-rate improvement in non-energy operating costs and adj. G&A* expenses**[1] by YE 2025
- Maintaining **capital discipline while growing cashflow per share**

Durable Capital Return Program Through Market-Cycles[2]

- Competitive dividend program (current annualized **dividend yield** of ~3%[3])
- Opportunistic share repurchases with $614MM remaining authorization
- **Hedge portfolio provides cash flow certainty; ~$67/Bbl Brent floor price** *(~72% hedged of est. total net production sold for 2025)*

On-Track For California's First CO_2 Injection

- Expect to receive **CA's first EPA Class VI permits for CTV I – 26R** in late 2024 with FID of cryogenic gas plant project shortly thereafter
- **Expanding California leading carbon management platform**[4] with additional CCS agreements and new class VI permits in the queue

Appendix

A DIFFERENT
KIND OF ENERGY
COMPANY

A Different Kind of Energy Company

California's Energy Solutions Provider

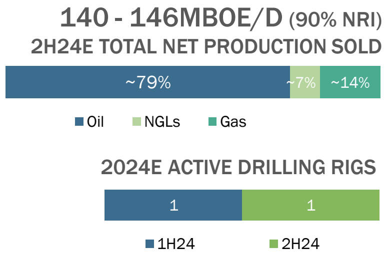
- California's Largest Oil & Gas Producer[1]
- Multi Decade Track Record of Operations in California
- Diversified, Complementary and Sustainable Energy Platform with O&G, Power, Midstream, Real Estate and Carbon Assets, and Access to Premium Pricing

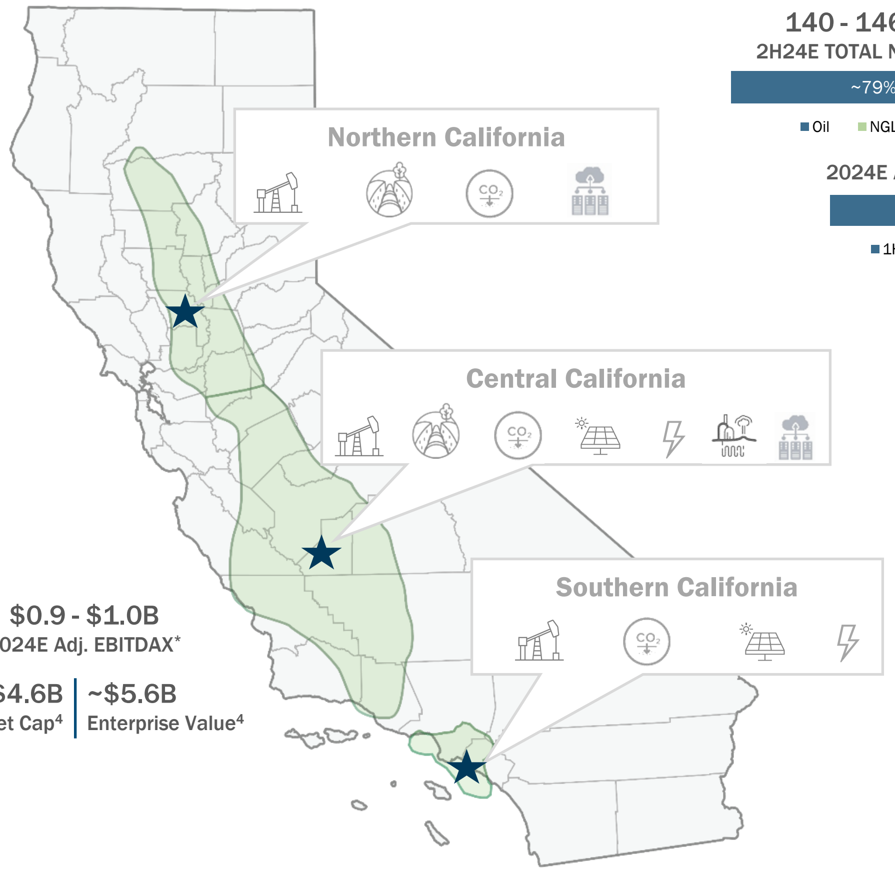
Leading Carbon Management Platform

- 8 Class VI Permit Applications with ~325MMT of CO_2 Storage Capacity Under EPA Review
- ~1BMT of Estimated Total CO_2 Storage Potential Across California[2]
- ~4.2MMTPA of CCS Projects Under Consideration

Sustainable Cash Flow Generation & Shareholder Returns

- Generated ~$1.5B of FCF* and Returned ~$1B to Shareholders Since 2021
- Disciplined Capital Allocation with Premier Balance Sheet (~0.7x Net Leverage*, 3)
- Track Record of Continuous Business Improvement





$0.9 - $1.0B
2024E Adj. EBITDAX*

~$4.6B Market Cap[4] | **~$5.6B** Enterprise Value[4]

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

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

Our Emerging Vision for Data Centers

CTV Offers Essential Solutions for Artificial Intelligence (AI) Data Centers:

Today	
Access to power infrastructure	✓
Ready to build land	✓
Accelerated time to market	✓
Access to natural gas and interconnection	✓
Close proximity to fiber network	✓

Tomorrow
Carbon-Free Power

Carbon Valley:
Where Silicon Valley and the Central Valley Meet

- CTV owns assets located in proximity to **heavily populated LA and Silicon Valley data center hubs and large industrial complexes**
- We are focused on the **maximizing the value of our land, mineral ownership and energy expertise to decarbonize existing and developing industries through CCS** and other emissions reducing projects to support California's Net Zero goals.

CARBON TERRAVAULT

Note: CRC internal data, research and estimates.

15

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]
	CAL CAPTURE	Post - Combustion	Capture to Storage	~1.4	In House
	CALIFORNIA RESOURCES CORPORATION	Pre - Combustion	Capture to Storage	~0.1	In House
	CarbonFrontier	Post - Combustion	Capture to Storage	Under Evaluation	In House
NEW	HULL STREET ENERGY	**Post - Combustion**	**Capture to Storage**	**~1.5**	**MOU**
	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
	NLC energy	Renewable Natural Gas	Storage-Only	~0.43	CDMA
	VERDE CLEAN FUELS	Renewable Gasoline	Storage-Only	~0.1	CDMA
	YOSEMITE CLEAN ENERGY	Renewable Green Hydrogen	Storage-Only	~0.04	CDMA
	DAC DIRECT AIR CAPTURE HUB	Direct Air Capture	Storage-Only	TBD	Lead Consortium Member

California's Premier Carbon Management Provider

CARBON TERRAVAULT

Received the Kern County Board of Supervisors approval of the conditional use permits for the CTV I CCS project

Expect to receive CA's first EPA Class VI permits for CTV I – 26R in late 2024 with FID of cryogenic gas plant project expected shortly thereafter

Vault	CTV I		CTV II	CTV III	CTV IV	CTV V	Carbon Frontier	CTV VI	Coles Levee
EPA Permit Application Administratively Complete	Yes (26-R)	Yes (A1-A2)	Yes	Yes	Yes	Yes	Yes	Yes	TBA
Targeting Class VI Draft EPA Permits Receipt	Public Comment Period Complete	~2025	~2025	~2025	~2025	~2025	~2025	~2027	TBA
Location	Central California		Northern California				Central California		
Annual Regional CO_2 Emissions[1] *(MMTPA)*	~30		~60				~30		
Est. Average Annual Injection Capacity[2] *(MMTPA)*	~1.5[3]	~0.2	~0.6	~1.8	~0.9	~0.4	~0.8	~2.6	TBA
Potential Total Storage Capacity *(MMT)*	~38	~8	~23	~71	~34	~17	~32	~102	TBA

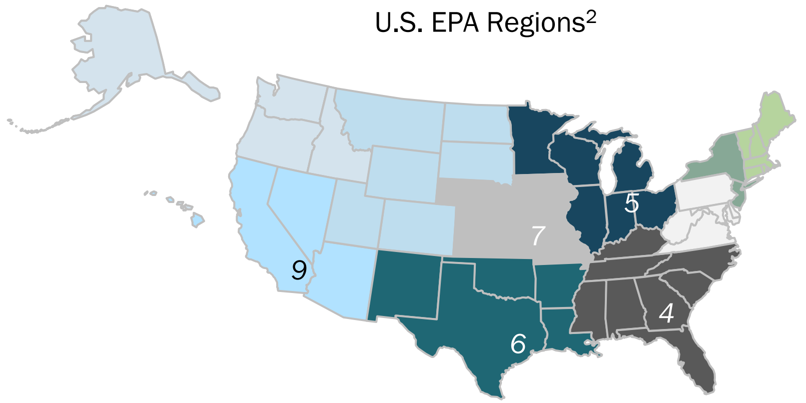
Numbers might not add up due to rounding. See Slide 24 "Assumptions, Estimates and Endnotes"

Class VI Permitting Leadership

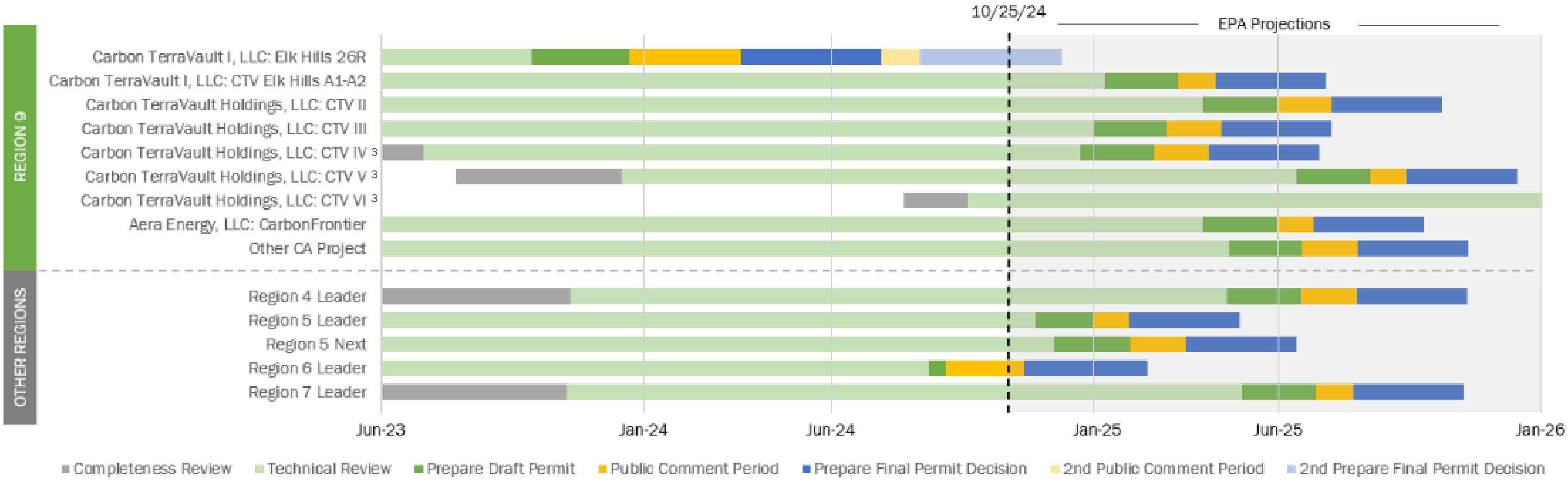
CTV Leads CA/Region 9 with EPA Class VI Permits Submissions

- CTV Elk Hills 26R (CTV I) is expected to receive final EPA permits in late 2024[1]
- CTV Elk Hills 26R (CTV I) EPA permits approval would be first in California and first permits for storage into a depleted oil and gas reservoir
- Proactively engaging with the local communities to communicate project benefits

U.S. EPA Regions[2]



EPA Projected Permit Timeline [2]

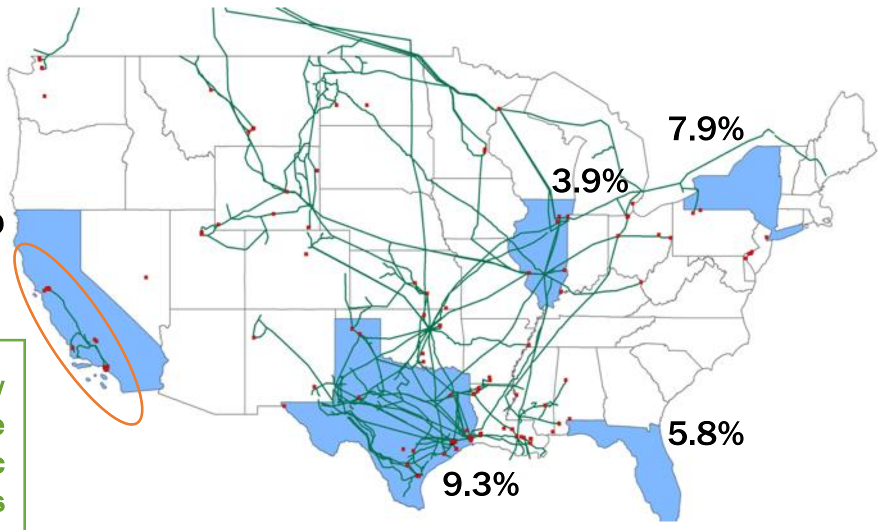


Strong Commodity Price Realizations in the State That Relies on External Energy Sources

- **Crude:** Crude price volatility in 3Q24 was driven by heightened geopolitical tensions and deteriorating international economic expectations. California demand supported by TMX blend stock requirements for California refiners.
- **Natural Gas:** Seasonally-high storage volumes continued to weigh on California natural gas prices in 3Q24. Current forward curve reflects expectations of improved market balance fundamentals in 2025 dependent upon winter weather conditions and producer discipline.
- **NGLs:** 3Q24 realizations and demand were generally stronger than expected as California remained a premium North American market.
- **Power:** Addition of incremental intermittent resources to the California (CAISO) grid continued to pressure energy prices for the majority of 3Q24 with some benefit from weather conditions in September.

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

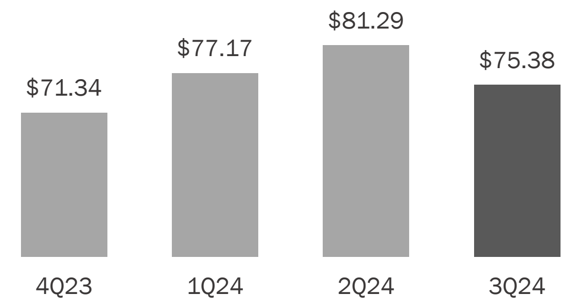
(amounts shown as % of U.S. domestic GDP)



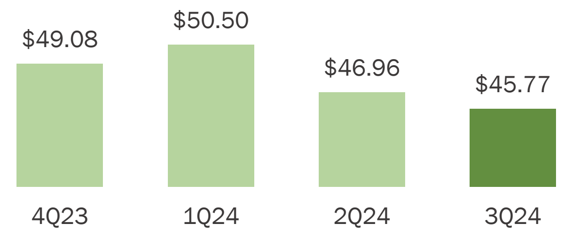
CRC's commodity realizations are above domestic averages

Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 2Q24; EIA

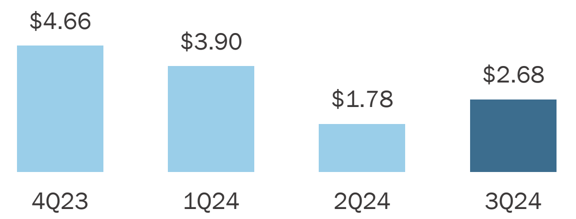
Oil w/ Hedges ($/BBL)



NGLs ($/BBL)



Natural Gas ($/MCF)



	Oil 4Q23	Oil 1Q24	Oil 2Q24	Oil 3Q24	NGLs 4Q23	NGLs 1Q24	NGLs 2Q24	NGLs 3Q24	Natural Gas 4Q23	Natural Gas 1Q24	Natural Gas 2Q24	Natural Gas 3Q24
Average Benchmark Prices[1]	$82.69	$81.84	$85.00	$78.54	$82.69	$81.84	$85.00	$78.54	$2.88	$2.24	$1.89	$2.16
% of Benchmark[1]	99%	98%	98%	98%	59%	62%	55%	58%	162%	174%	94%	124%
Hedge Settlements	($10.66)	($2.99)	($1.85)	($1.72)	-	-	-	-	-	-	-	-
Average Realized Prices[2]	$71.34	$77.17	$81.29	$75.38	$49.08	$50.50	$46.96	$45.77	$4.66	$3.90	$1.78	$2.68

Hedge Portfolio (as of September 30, 2024)

OIL		4Q24E	1Q25E	2Q25E	3Q25E	4Q25E	2026E	2027E	2028E
SOLD CALLS									
Brent	Barrels per Day	29,000	30,000	30,000	30,000	29,000	5,000	-	-
	Weighted-Average Price	$90.07	$87.08	$87.08	$87.08	$87.13	$85.00	-	-
SWAPS									
Brent	Barrels per Day	59,014	52,837	45,631	44,126	42,626	30,449	13,882	10,353
	Weighted-Average Price	$74.90	$72.48	$71.31	$70.62	$69.94	$67.95	$65.53	$65.00
PURCHASED PUTS[1]									
Brent	Barrels per Day	29,000	30,000	30,000	30,000	29,000	5,000	-	-
	Weighted-Average Price	$65.17	$61.67	$61.67	$61.67	$61.72	$60.00	-	-
NATURAL GAS		**4Q24E**	**1Q25E**	**2Q25E**	**3Q25E**	**4Q25E**	**2026E**	**2027E**	**2028E**
SWAPS									
SoCal Border	MMBtu per Day	20,000	10,000	29,074	25,750	22,408	-	-	-
	Weighted-Average Price	$5.49	$6.02	$3.44	$3.48	$3.53	-	-	-
NWPL Rockies	MMBtu per Day	50,999	50,999	51,750	51,750	51,750	35,336	12,616	9,613
	Weighted-Average Price	$4.67	$5.48	$2.95	$2.95	$4.22	$4.04	$4.34	$3.95
PG&E CityGate	MMBtu per Day	14,000	14,000	-	-	-	-	-	-
	Weighted-Average Price	$5.60	$6.10	-	-	-	-	-	-
EST. HEDGE CONTRACT SETTLEMENTS[2]		**4Q24E**	**1Q25E**	**2Q25E**	**3Q25E**	**4Q25E**	**2026E**	**2027E**	**2028E**
Combined Hedge Portfolio ($MM)		$7	($3)	($6)	($1)	($2)	($28)	($24)	($2)

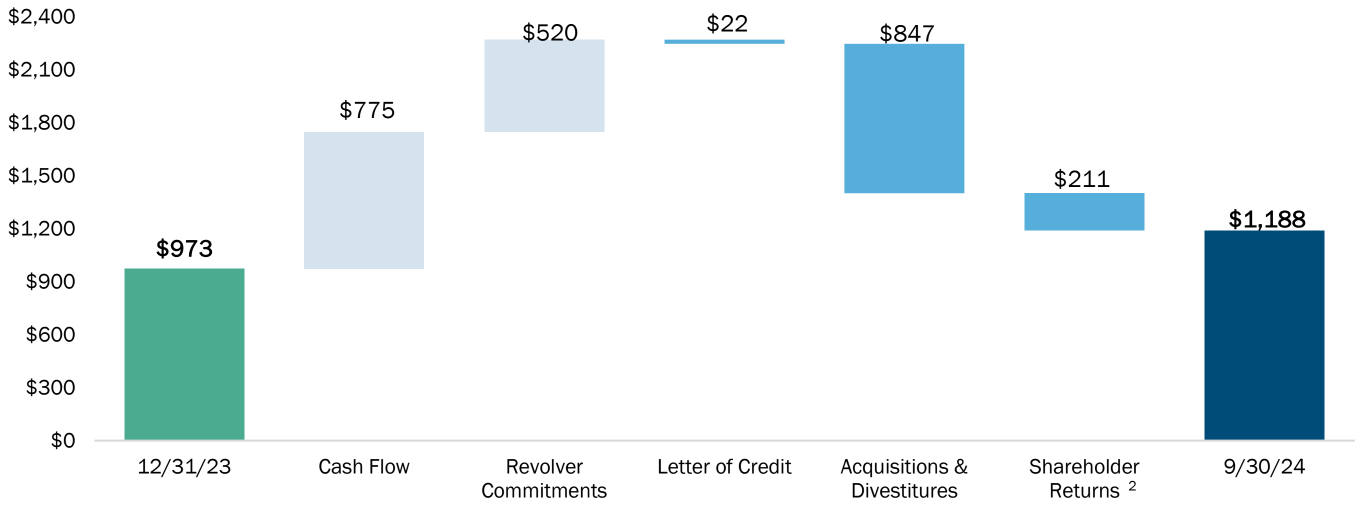
STRATEGY

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

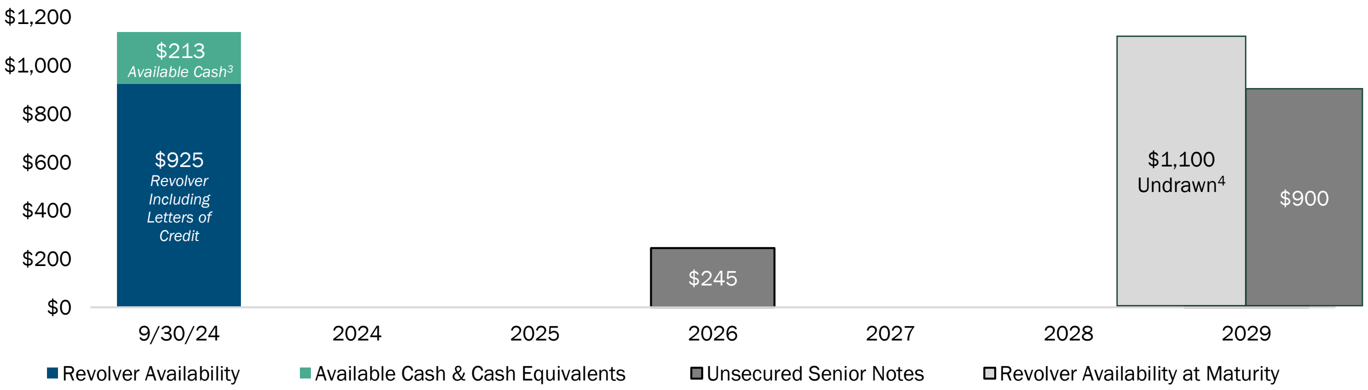
See Slide 24 "Assumptions, Estimates and Endnotes"

Strong Balance Sheet, Ample Liquidity and Financial Flexibility

LIQUIDITY[1] ($MM)



MATURITY PROFILE ($MM)



9/30/24 NET DEBT* SNAPSHOT

($MM)		
Revolving Credit Facility (RCF)	$	-
7.125% 2026 Senior Notes		245
8.250% 2029 Senior Notes		900
Face Value of Debt	**$**	**1,145**
Less Available Cash & Cash Equivalents[3]		(213)
Net Debt*	**$**	**932**

RECENT CREDIT UPDATES

- Moody's, Standard and Poor's and Fitch affirmed our credit ratings post Aera Merger announcement
- Completed add-on offering of $300MM in senior notes due 2029
- Completed $300MM tender offer for senior notes due 2026
- Extended the RBL maturity to March 2029

MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)	
RCF Borrowing Base	$1,500
3Q24 Free Cash Flow*	$141
3Q24 Net Debt* / Annualized 2H24E EBITDAX*, [5]	0.7x
Annualized 2H24 EBITDAX* / Annualized 2H24 Interest Expense	11.7x

See Slide 24 "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

Term	Definition
GHG	Greenhouse Gas
IRR	Internal Rate of Return
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
OCF	Operating Cash Flow
PD	Proved Developed
PUD	Proved Undeveloped
RSG	Responsibly Sourced Gas
ROFL	Right of First Look
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) The MOU is non-binding and subject to negotiation of definitive agreements.

Slide 4:

(1) Pro forma combined January 2024 average gross production is calculated from 94 thousand barrels of oil equivalent per day (Mboe/d) for legacy CRC and 77 Mboe/d for Aera.

(2) Pro forma combined 1Q24 operating costs is calculated as $176MM for legacy CRC plus $112MM for Aera and less $55MM in presentation and transaction adjustments. For additional information, see Form 8-K dated May 20, 2024.

(3) Pro forma combined 1Q24 capital is calculated as $54MM for legacy CRC plus $35MM for Aera. For additional information, see Form 8-K dated May 20, 2024.

Slide 5:

(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval.

(2) Source: FactSet. Represents current annual dividend policy of $1.55 per share divided by CRC's market capitalization as of November 1, 2024.

(3) Excludes excise taxes and commissions paid on share repurchases.

Slide 7:

(1) The MOU is non-binding and subject to negotiation of definitive agreements. The CDMA frames the anticipated contractual terms between parties and provides a path to reaching final definitive agreements.

Slide 10:

(1) 3Q24 guidance assumed a 3Q24 Brent price of $84.23 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $2.61 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 & Expenses, net is calculated as the difference between Other Revenue and Other Operating Expenses, net.

(4) Margin from Marketing of Purchased Commodities is calculated as the difference between Revenue from Marketing of Purchased Commodities and Costs Related to Marketing of Purchased Commodities.

(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) Pro forma combined 1Q24 average net production sold is calculated using 76 Mboe/d for legacy CRC plus 70 Mboe/d for Aera. For additional information, see Form 8-K dated May 20, 2024.

(8) Pro forma combined 2Q24 average net production sold is calculated using 76 Mboe/d for legacy CRC plus 69 Mboe/d for Aera.

Slide 11:

(1) Margin from Marketing of Purchased Commodities is calculated as the difference between Revenue from Marketing of Purchased Commodities and Costs Related to Marketing of Purchased Commodities.

(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 & Expenses, net is calculated as the difference between Other Revenue and Other Operating Expenses, net.

(5) Pricing as of November 6, 2024.

(6) Includes the impact of hedges.

Slide 12:

(1) 2025 run-rate cost improvement compares expected 2025 run-rate for operating costs and adjusted G&A expense including projected synergies, with annualized estimated 2H24 non-energy operating costs and adjusted G&A expense.

(2) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval.

(3) Source: FactSet. Represents annualized 3Q24 fixed dividend divided by CRC's market capitalization as of November 1, 2024.

(4) Source: EPA. Based on number of permit applications submitted.

Assumptions, Estimates and Endnotes

Slide 14:

(1) Source: Enverus. 2023 data as of May 8, 2024. In 2023, California's oil producers accounted for approximately 23% of oil consumed by local refiners in California, source: www.energy.ca.gov.

(2) CRC internal estimates.

(3) Net leverage is calculated as 3Q24 net debt of $932MM (excludes restricted cash of $28MM) divided by 2H24E annualized adjusted EBITDAX. 2H24E annualized adjusted EBITDAX is calculated from 3Q24 adjusted EBITDAX of $402MM plus the mid-point of 4Q24 adjusted EBITDAX guidance of $260MM.

(4) Source: FactSet. As of November 1, 2024. Enterprise value calculated using net debt of $932MM (excludes restricted cash of $28MM) plus market capitalization using 89.2MM shares outstanding.

Slide 16:

(1) The MOU is non-binding and subject to negotiation of definitive agreements. The CDMA frames the anticipated contractual terms between parties and provides a path to reaching final definitive agreements.

Slide 17:

(1) Source: CARB 2020.

(2) Injection rates are average rates based on max permit volumes over life of project using a 40-year basis. 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) Includes planned Class VI permit submission for ~27MMT of storage at the Coles Levee field.

Slide 18:

(1) CRC estimate. Subject to issuance of EPA class VI permits.

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

(3) Based on EPA approvals. CTV IV is projected to receive a final permit decision in July 2025, CTV V is projected to receive a final permit decision in December 2025 and CTV VI is project to receive a final permit decision in September 2026.

Slide 19:

(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 20:

(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 September 30, 2024. Assumes forward commodity prices as of September 30, 2024.

Slide 21:

(1) Liquidity on September 30, 2024, calculated as $213MM of cash and cash equivalents (excluding $28MM of restricted cash) plus $1,150MM of borrowing capacity on CRC's Revolving Credit Facility less $175MM in outstanding letters of credit.

(2) Shareholder returns includes $42MM of share repurchases and $34MM of dividends paid.

(3) Available cash and cash equivalents excludes $28MM of restricted cash.

(4) Undrawn Revolving Credit Facility as of September 30, 2024, excluding outstanding letters of credit.

(5) Net leverage is calculated as 3Q24 net debt of $932MM (excludes restricted cash of $28MM) divided by 2H24E annualized adjusted EBITDAX. 2H24E annualized adjusted EBITDAX is calculated from 3Q24 adjusted EBITDAX of $402MM plus the mid-point of 4Q24 adjusted EBITDAX guidance of $260MM.

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.

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, Yemen and the Red Sea;
- the ability to successfully execute integration efforts in connection with CRC's merger with Aera Energy LLC, and achieve projected synergies and ensure that such synergies are sustainable;
- regulatory actions and changes that affect the oil and gas industry generally and CRC 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 business; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (3) the protection of health, safety and the environment, or (4) the transportation, marketing and sale of CRC's products;
- the efforts of activists to delay or prevent oil and gas activities or the development of CRC's carbon management business 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 CRC's capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to CRC's estimates of reserves and related future cash flows, including changes arising from its 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 CRC 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 CRC's counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of CRC's operations;
- CRC's ability to claim and utilize tax credits or other incentives in connection with its 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 its CDMAs and MOUs to definitive agreements and enter into other offtake agreements;
- CRC's ability to maximize the value of its carbon management business 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 CRC's 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 its debt or obtain separate financing for its carbon management business;
- 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 CRC's 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 in CRC's Annual Report on Form 10-K and its other SEC filings available at www.crc.com.

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

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.

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