

Corporate Presentation

May 2026



A DIFFERENT KIND OF ENERGY COMPANY



CALIFORNIA'S LARGEST O&G PRODUCER¹
WITH ACCESS TO PREMIUM MARKETS

LEADING CARBON MANAGEMENT BUSINESS

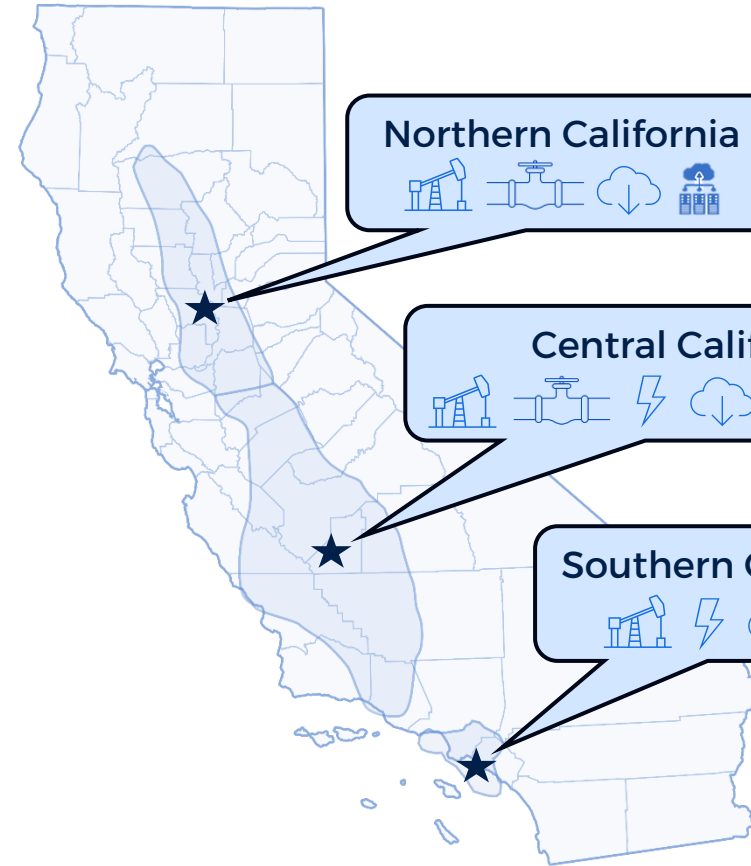
STRONG CASH FLOW GENERATION &
DISCIPLINED CAPITAL ALLOCATION

PREMIER BALANCE SHEET

SUSTAINABLE SHAREHOLDER RETURNS

See slide 31 for "Assumptions, Estimates and Endnotes".

Diversified and Complementary Energy Platform



~154MBoe/d | 8% - 13%
1Q26 Total Net Production, 81% Oil | Est. Corporate PDP Decline

\$5.2B² | \$6.5B²
Market Capitalization | Enterprise Value



Low Carbon Intensity Oil & Gas Production



Midstream Infrastructure



Power Generation



Carbon Capture & Storage



3rd Party Power Opportunities



Solar Opportunities

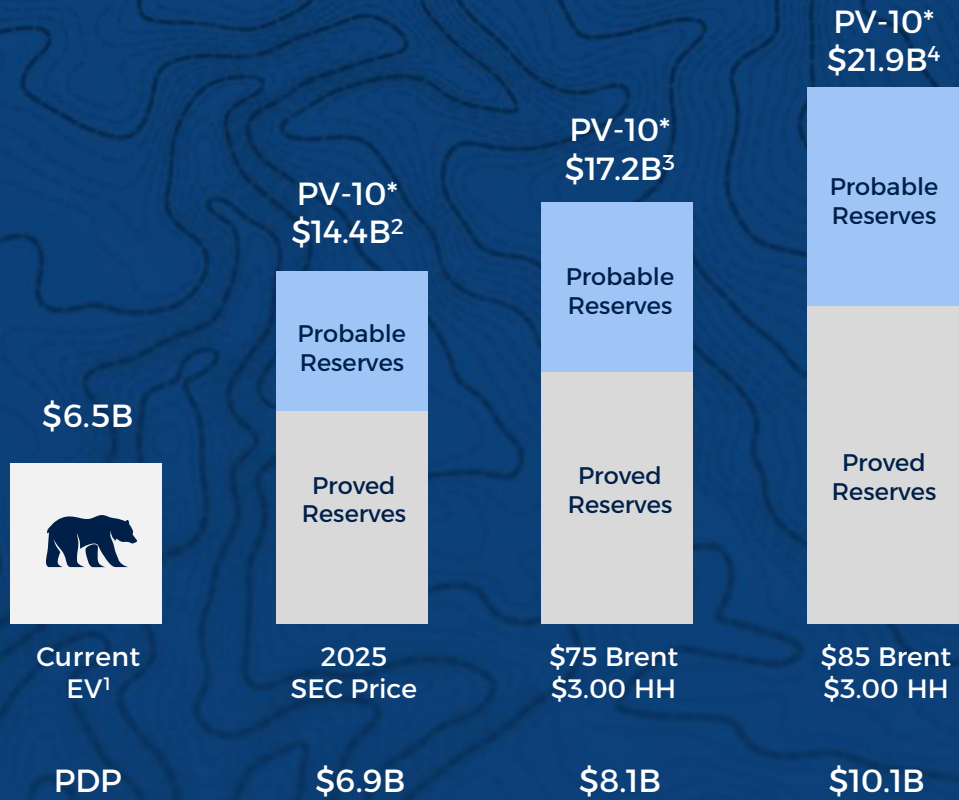


Geothermal Opportunities



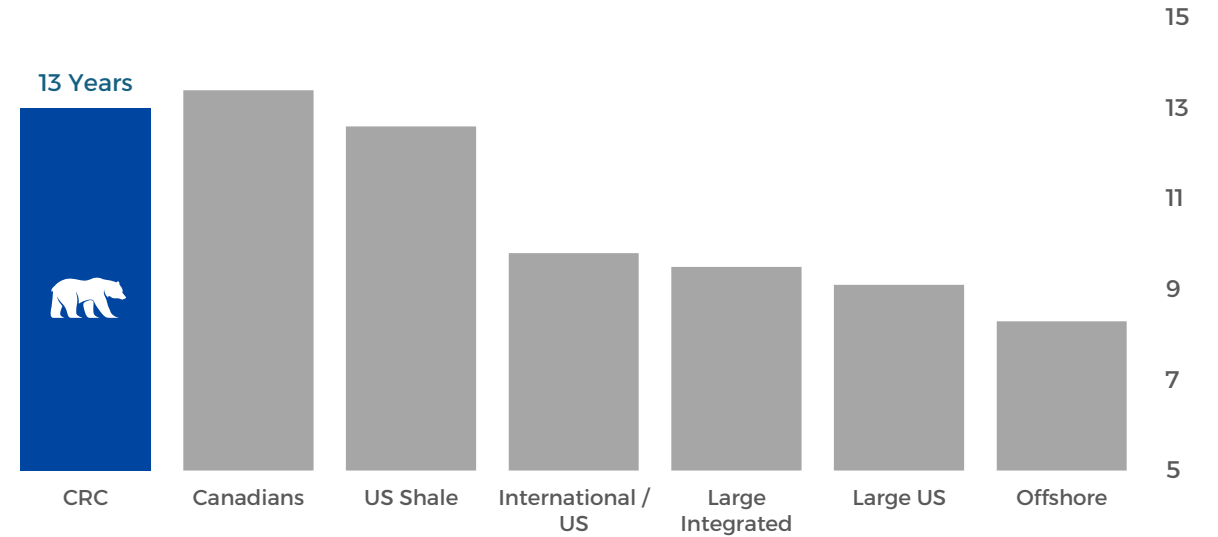
Significant Value From World-Class Conventional Reservoirs

Material Upside From Long Duration Assets



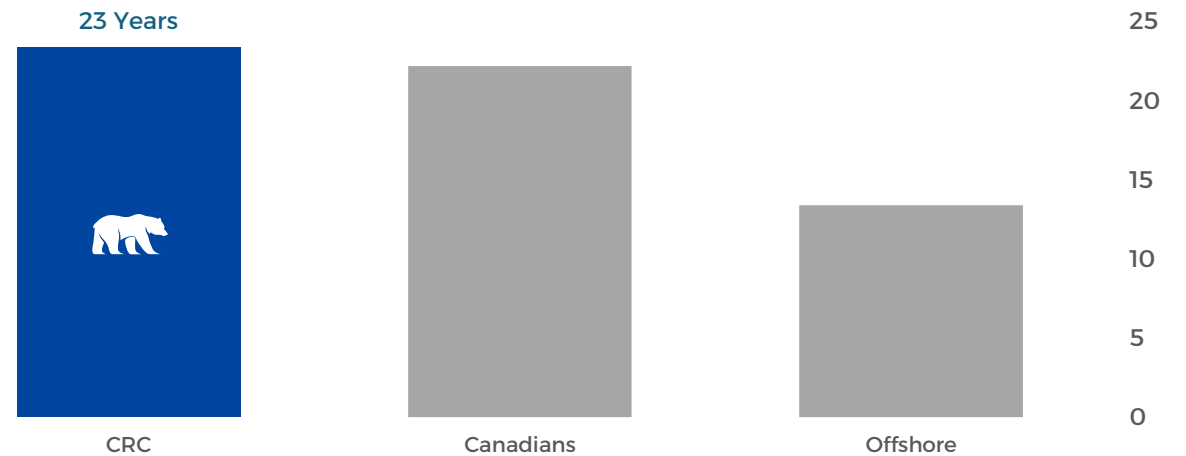
Long Proved Reserves Base

Proved Reserves / Annual Production (Years)⁵



Multi-Decade Conventional Runway

Proved + Probable Reserves / Annual Production (Years)⁵



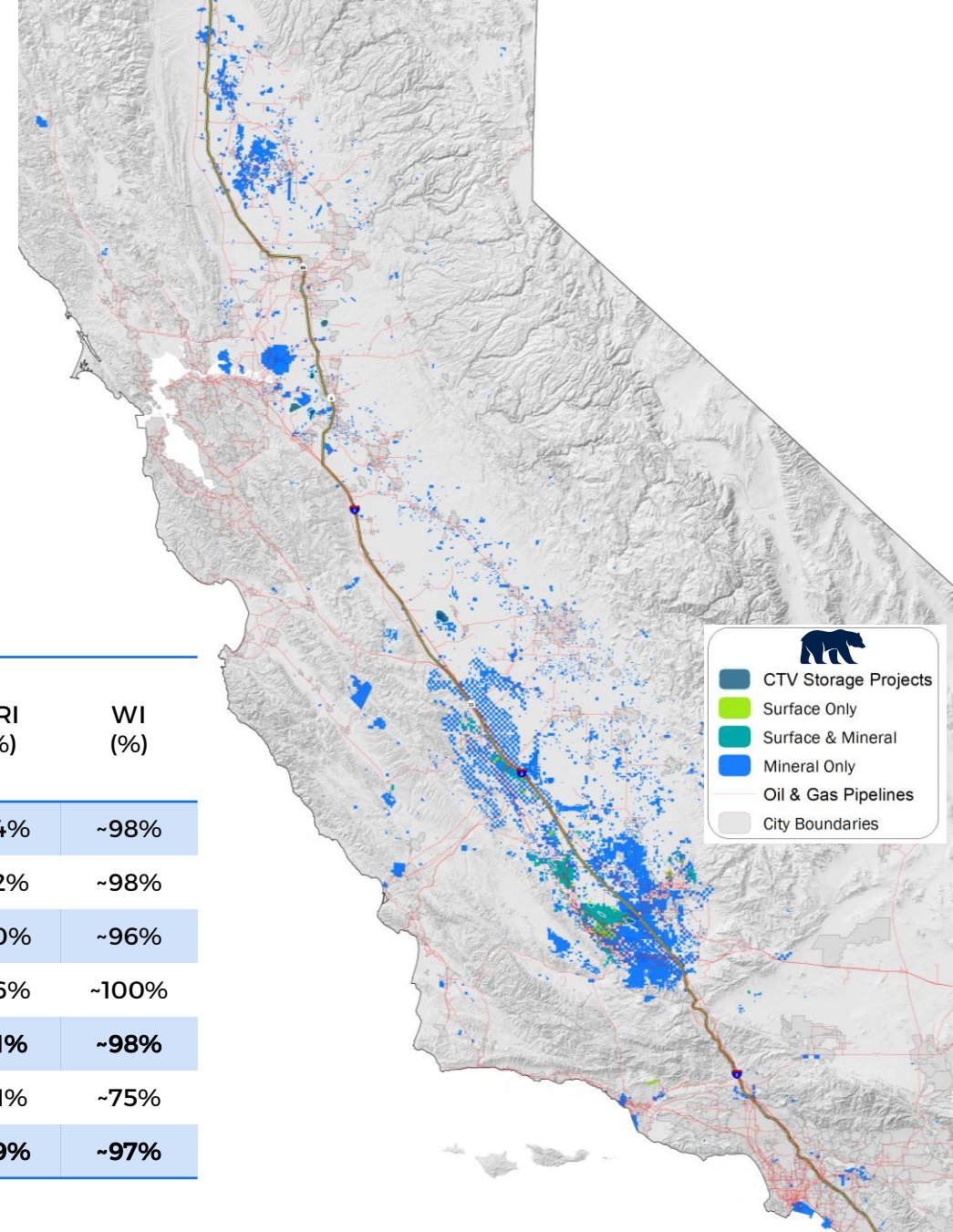
Premier California Energy Company

CRC's Advantaged Portfolio Characteristics

- Geographic Advantage
- High-Quality, Low-Decline Assets
- Robust Development Inventory
- Ready for Growth
- Superior Economics
- Existing O&G Midstream Network

CRC's Long Runway 1P Asset Inventory¹

Basin/Unit	PD ² (%)	Total Proved (MMBOE)	Oil (%)	Est. Annual Corporate PDP Decline (%)	R/p ³ (Years)	Surface Acreage ('000)	Mineral Acreage ('000)	NRI (%)	WI (%)
San Joaquin	84%	529	81%	~11%	13	~206	~1,304	~94%	~98%
Los Angeles	98%	65	98%	~7%	10	<1	~36	~72%	~98%
Sacramento	100%	1	0%	~9%	1	<1	~418	~80%	~96%
Other California	85%	27	93%	~11%	8	~3	~130	~86%	~100%
Total California	86%	622	83%	~11%	12	~210	~1,888	~91%	~98%
Uinta	19%	32	81%	~19%	18 ⁴	~2	~98	~61%	~75%
Total Company	83%	654	83%	~11%	13	~212	~1,986	~89%	~97%



CTV Commences First CO₂ Injection

"The Golden State is building the full suite of tools needed to meet our climate goals, and Carbon TerraVault I is proof that innovation and ambition are the California way . . . These are the kind of climate solutions that spur the industries and infrastructure needed to power a cleaner future and create good-paying jobs right here in our communities."

- Gavin Newsom, Governor of California



Emitter Pad and CO₂ Capture



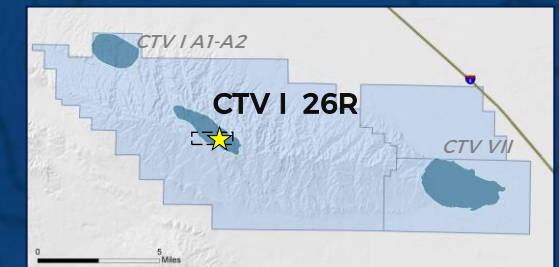
Injection Pad



California's First Active CCS Project

Elk Hills Cryogenic Gas Plant Project

- Received final EPA approval to inject and commenced operations in May 2026
- Project captures pre-combustion CO₂ from produced natural gas at CRC's Elk Hills cryogenic gas plant for storage in the nearby CTV I - 26R reservoir
- Targeting injection and storage of up to ~100KMPTA of CO₂ emissions
- Multiple Incentives: 45Q tax credits of \$85/MT, potential for LCFS credit generation and reduced C&I liabilities, pending CARB rulemaking
- Improved NGL recovery at CRC's cryogenic gas plant up to ~500Bo/d
- Emissions reductions at CRC's Elk Hills power plant from decarbonized feedstock natural gas

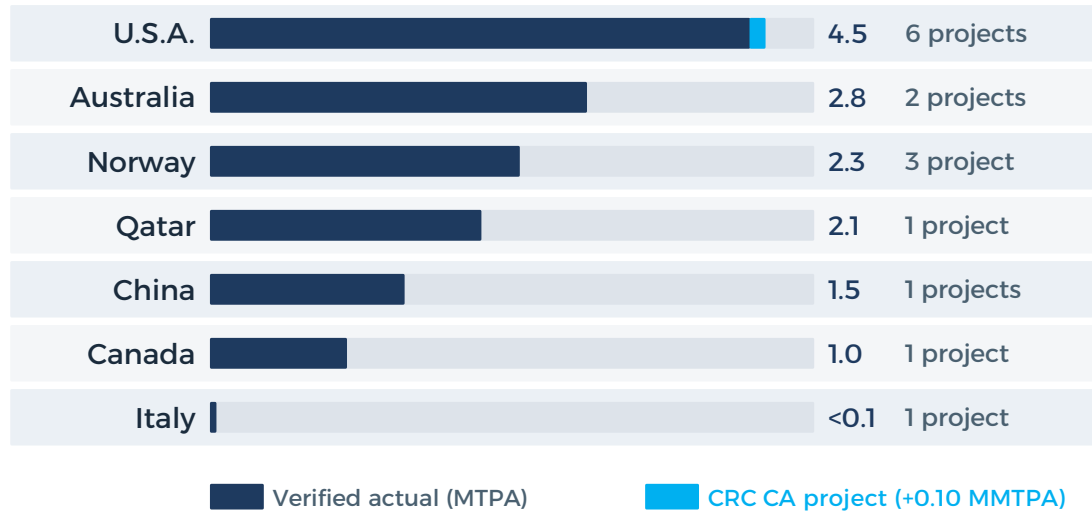


Joining the Ranks of Global CCS Leaders¹



CARBON TERRAVALT | A Differentiated Position in Global CCS

Permanent Geologic Sequestration by Country – Non-EOR, Non-Acid Gas Injection (MMTPA)



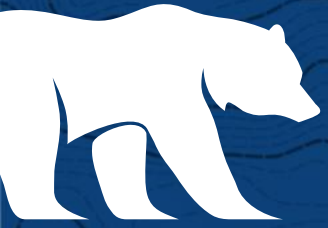
- 1 1 of only 2 U.S. oil & gas companies actively storing CO₂ underground through EPA Class VI geologic sequestration wells
- 2 1 of only 6 true commercial-scale CCS sequestration projects in the US permanently injecting and storing CO₂ in dedicated geologic formations (EPA class VI)
- 3 1 of 15 commercial-scale CCS projects globally actively injecting and storing CO₂ (Non-EOR, Non-Acid Gas Injection)
- 4 California's first and only commercial-scale CCS project operational and injecting CO₂ in the state

Amongst an Elite Global Sequestration Peer Group

Positioned alongside some of the world's proven commercial-scale CCS operators

CRC Elk Hills, California	Chevron Gorgon, Australia	ExxonMobil Strathcona, Canada
Shell Quest, Canada	Equinor Snøhvit, Norway	Santos Moomba, Australia





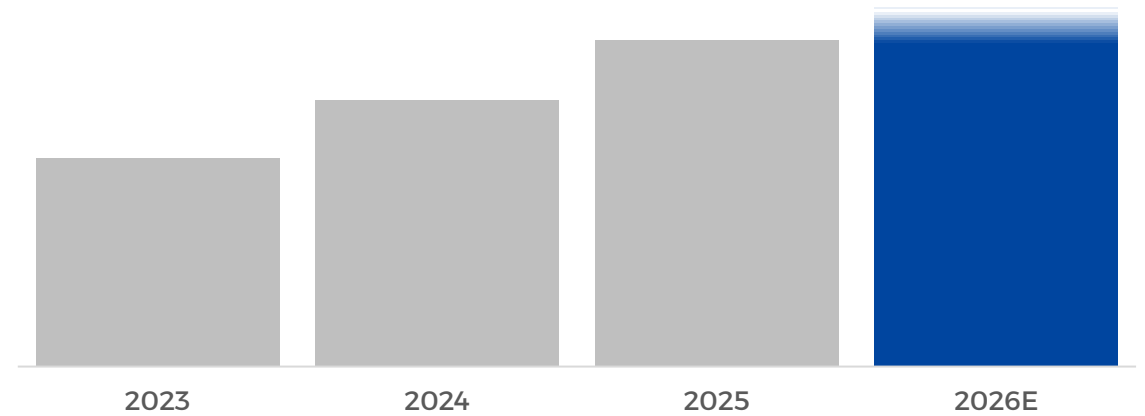
A Different Kind of Energy Company

- ✓ Integrated Portfolio Strategy
- ✓ Premier Capital Structure
- ✓ Superior Risk Management
- ✓ Focus on Cost Control
- ✓ Disciplined Capital Allocation
- ✓ Track Record of Strategic M&A

Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities". See slide 32 for "Assumptions, Estimates and Endnotes".

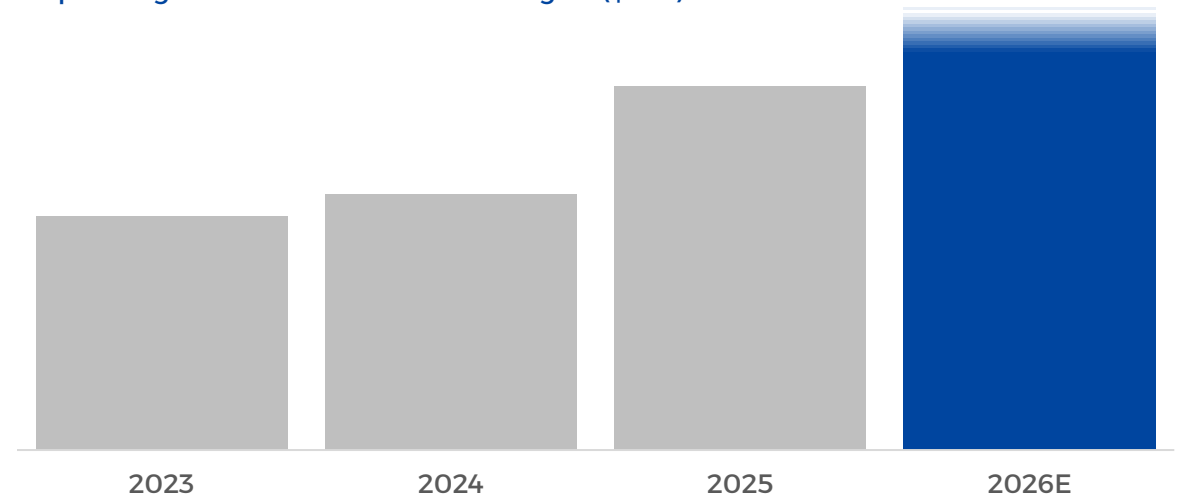
Gaining Scale

Gross Production (MBoe/d)¹



Growing Cash Flow

Operating Cash Flow Before WC Changes* (\$MM)¹



Weighted
Average Diluted
Shares (MM)

2023

72.5

2024

81.4

2025

87.4

2026E

~89²





1Q26 Results



Executing on Multiple Value Drivers

Accelerating Shareholder Value

- Increasing drilling activity in 2H26E by 3 rigs and fast-tracking long-term maintenance capital program (2 rigs in CA , 1 in UT)
- Highly contiguous Uinta development opportunity provides production and value upside
- Adding incremental capital-efficient workover opportunities

Improved Operating Efficiencies

- Lowered 2026E facilities capital by \$10MM driven by operating efficiencies¹
- Increased Berry merger synergy target by ~12%

Raised 2026E Outlook

- Targeting ~1% entry-to-exit gross production growth
- Raised 2026E adj. EBITDAX* guidance by nearly 42%, outpacing a 38% increase in Brent¹



Delivering Through 1Q26 Macro Uncertainty – Returning To Growth

STRONG FINANCIAL AND OPERATING RESULTS

BENEFITTED FROM BRENT-LINKED PRODUCTION

1Q26 Brent Price ~17% Above Guidance
1Q26 Net Production ~81% Oil-Weighted

Delivered
\$304MM
Adj. EBITDAX*

IMPROVED CAPITAL STRUCTURE

Refinanced \$350MM in Long-Term Debt
Retains Balance Sheet Strength and Duration

Maintained
<1.1x
Net Leverage*

CONTINUED SHAREHOLDER RETURNS FOCUS

Attractive ~2.4% Dividend Yield¹
Opportunistic and Disciplined Share Repurchases

Returned
\$46MM
Dividends
and SRP²

HIGHLIGHTS

Increasing 2H26E Activity by

3 Drilling Rigs

2 Rigs in CA + 1 in UT
Targeting ~1% Entry to Exit Growth

Increased BRY Synergy Target to

\$90 – \$100MM

~12% Increase at Midpoint

Lowered
2026E Facilities Capital by

~\$10MM³

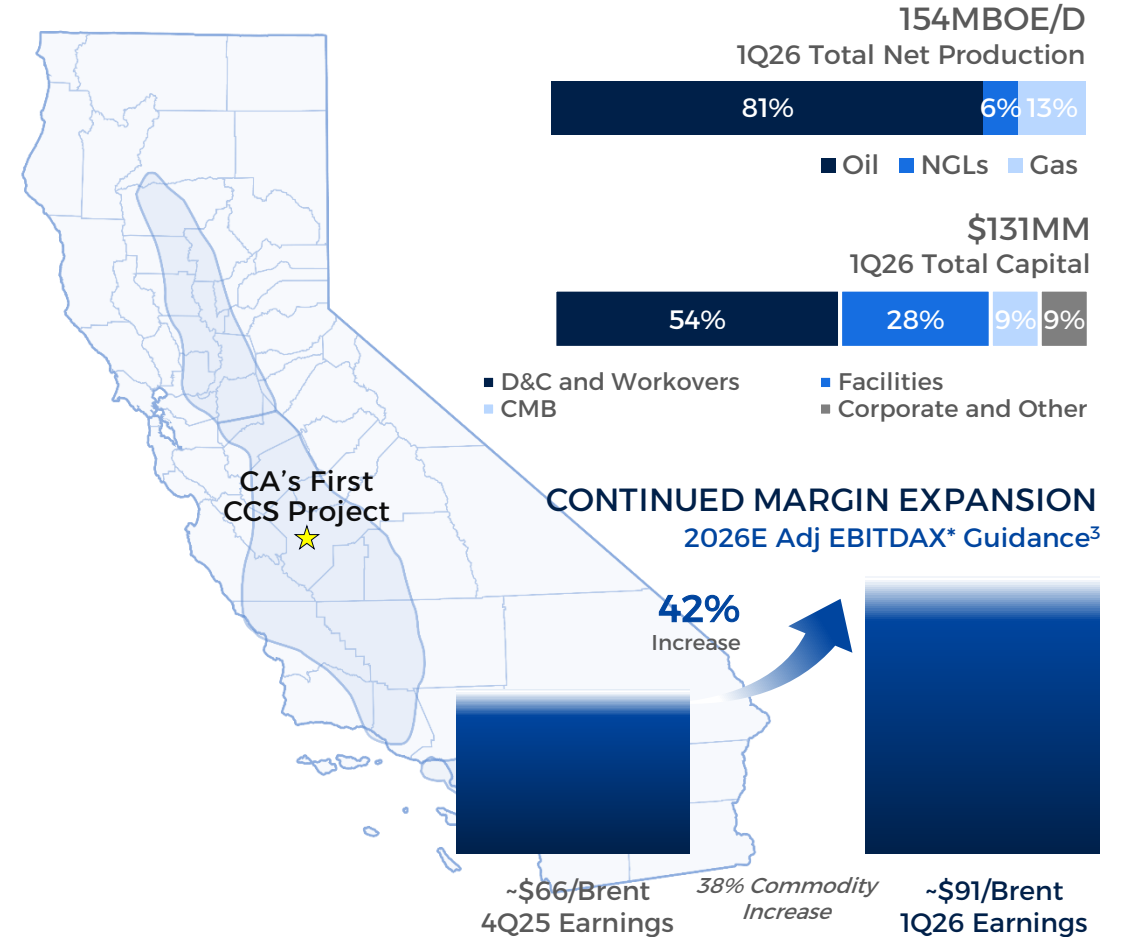
Driven by Operating Efficiencies

Raised
2026E Adj. EBITDAX* Guidance

\$1,400 – \$1,500MM³

at \$91 Brent

California's Premier Energy Platform

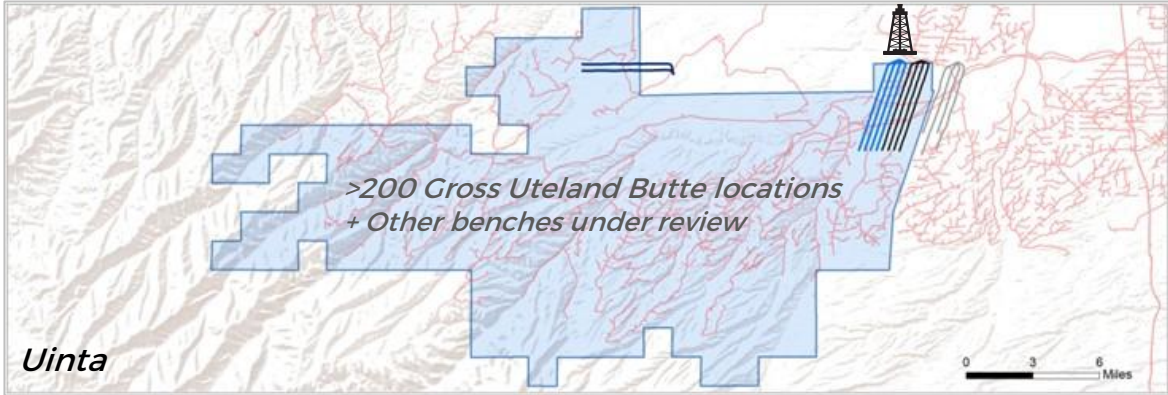


Delivering Through a Portfolio Approach

Starting in Summer 2026
 Adding 1 Rig in Central and 1 Rig in Southern California

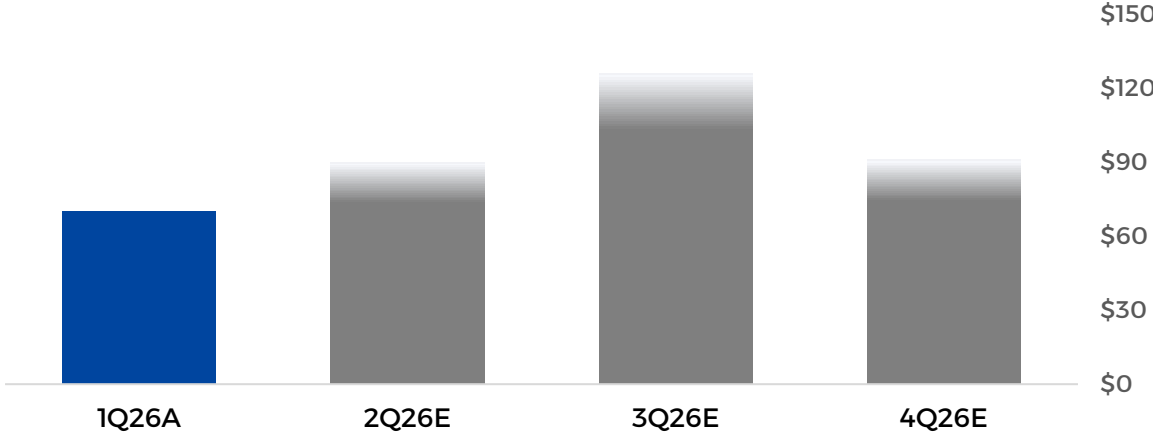


Planning a 4-Well Pad in Northern Uinta
 Targeting First Production in 4Q26



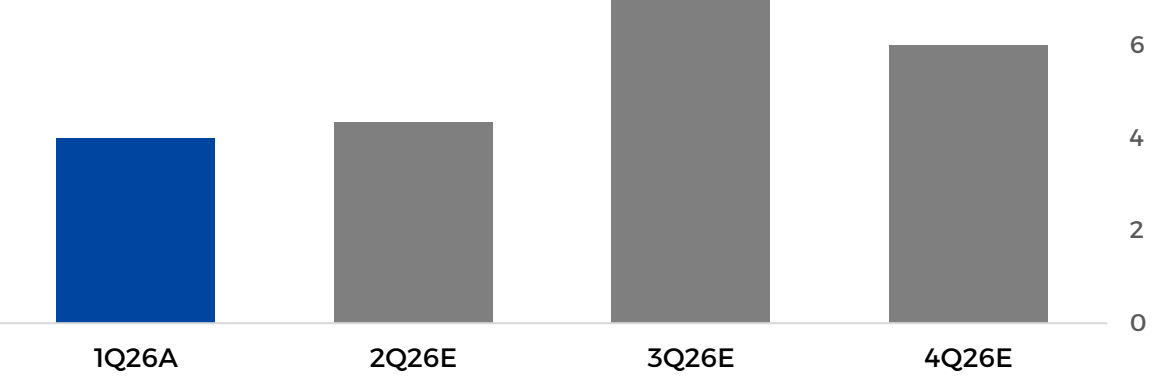
Disciplined Capital Allocation

2026E D&C and Workover Capital¹



Planning to Scale Activity

2026E Rig Program¹

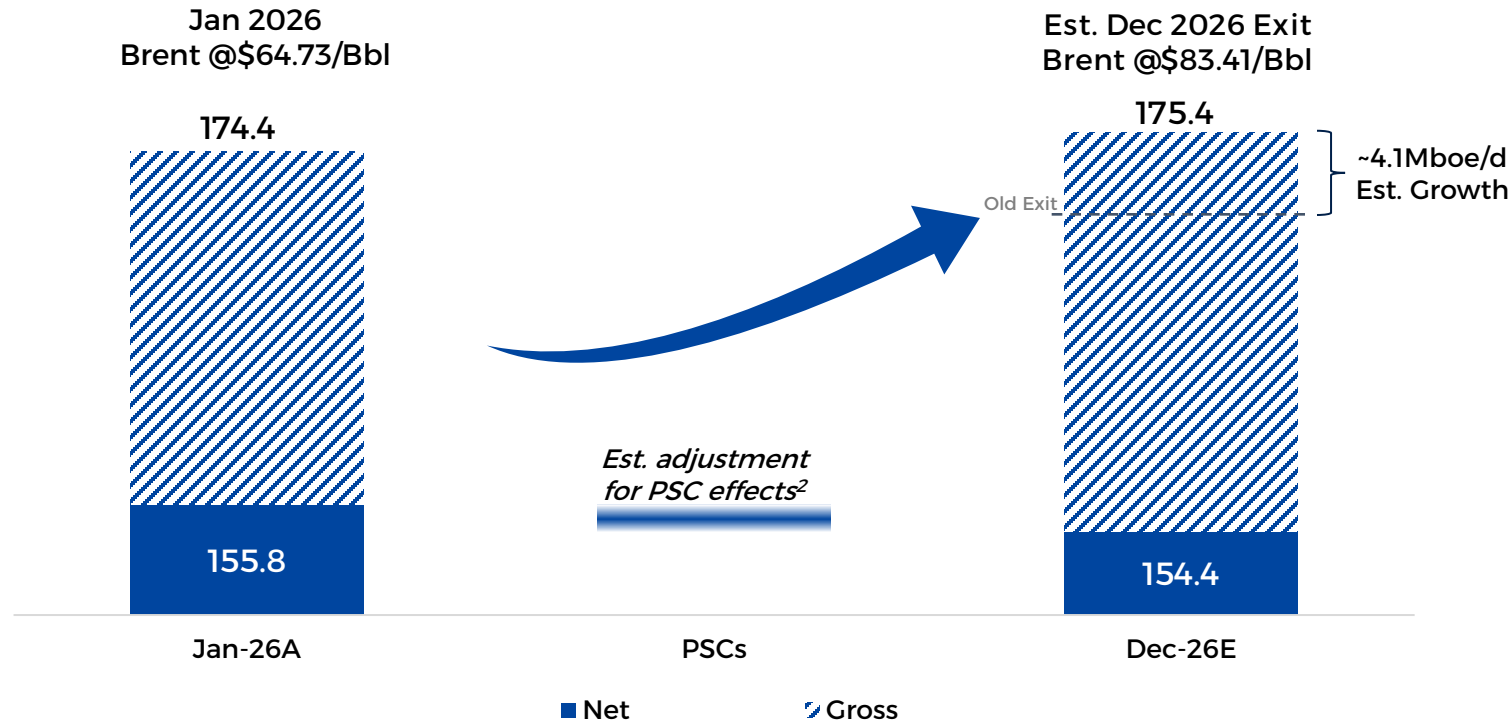


See slide 33 for "Assumptions, Estimates and Endnotes".

Stepping Up Activity Driving Entry-to-Exit Growth

Raised Production Outlook

2026E CRC Production (MBoe/d)¹



- Scaling activity from 4 to 7 rigs adding 1 Uinta rig in June (4-well program) and 2 California rigs in July
- Currently operating 4 of 7 active California rigs³ with all 2026 drilling permits on hand
- Targeting net entry-to-exit 2026 production to be flat at ~156 MBoe/D before PSC effects

Improved Capital Efficiency in 2026

Prior



New⁴



CRC Continues to Target Long-Term Maintenance Program⁵
~7 rigs with D&C + workover capital range of \$480-\$500MM

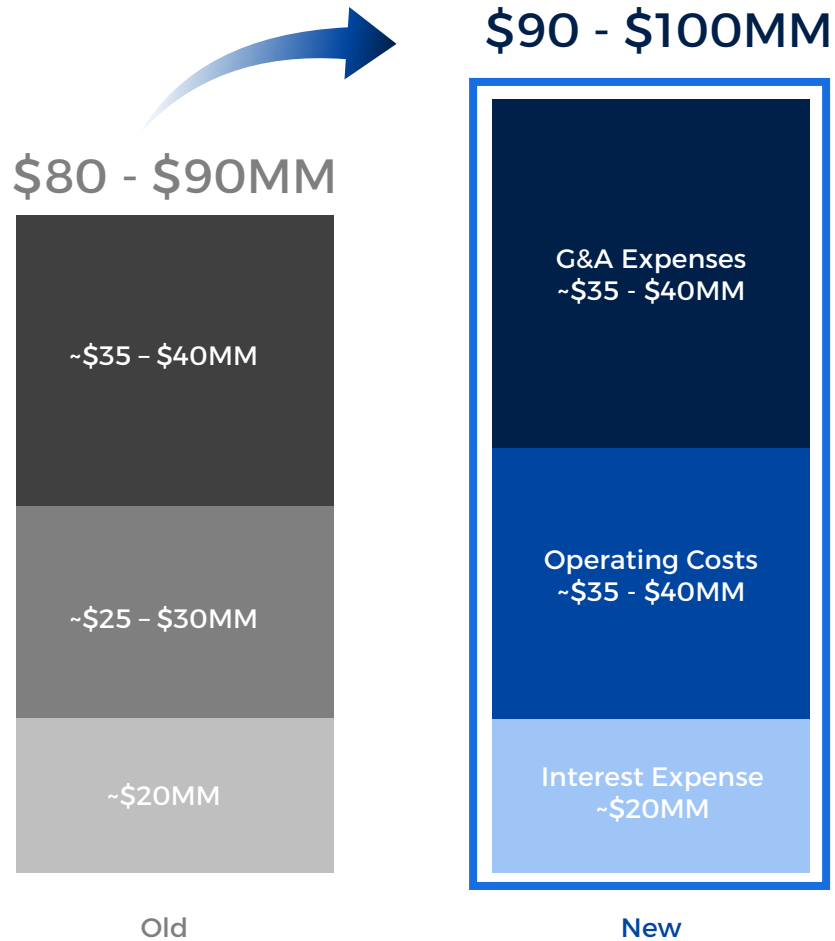


Continued Structural Cost Reductions Drive Margin Expansion

With >80% of Synergies Implemented to Date

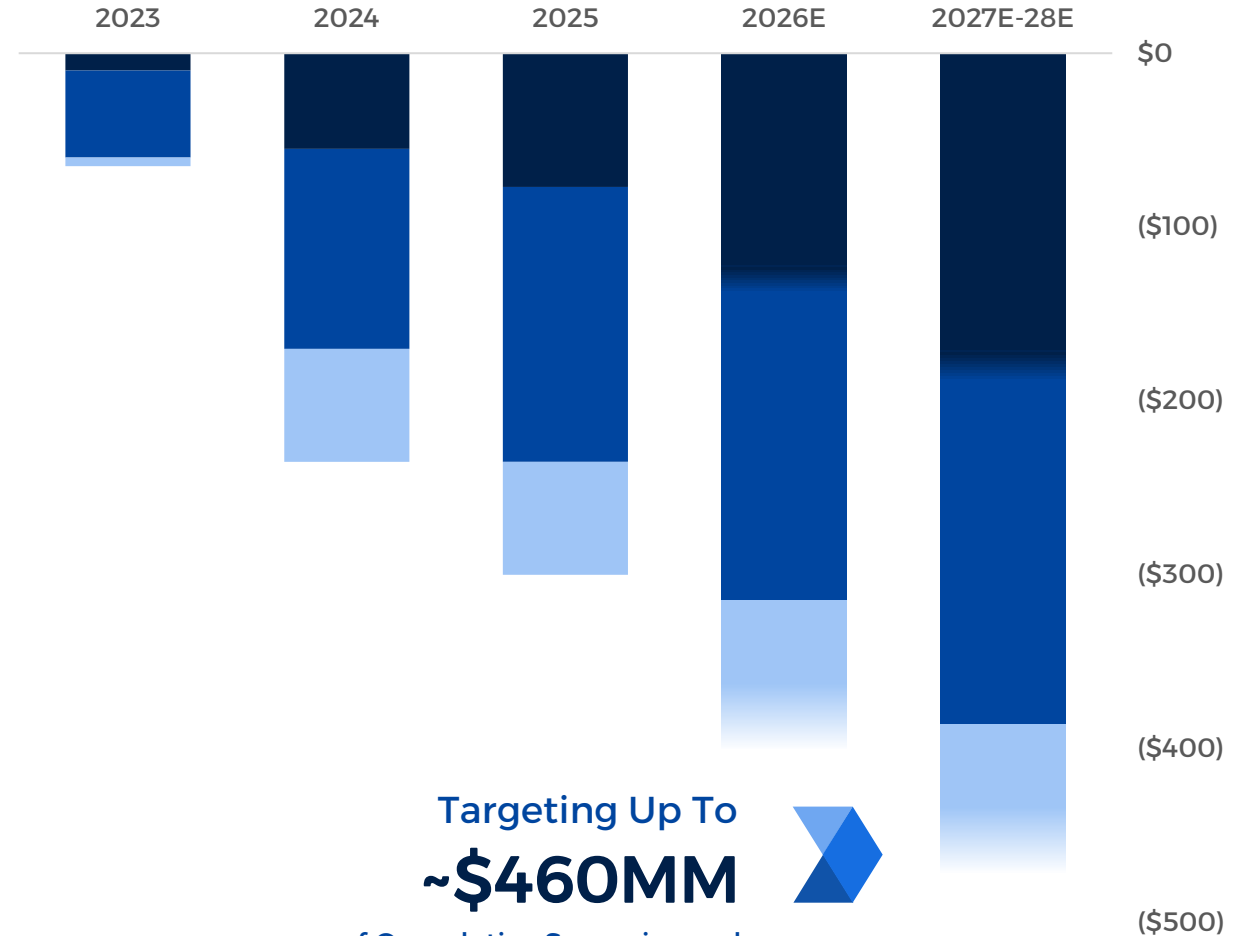
12% Increase in Targeted Synergies

2026 Estimated Berry-Related Synergies (\$MM)



Benefits of a Leaner CRC

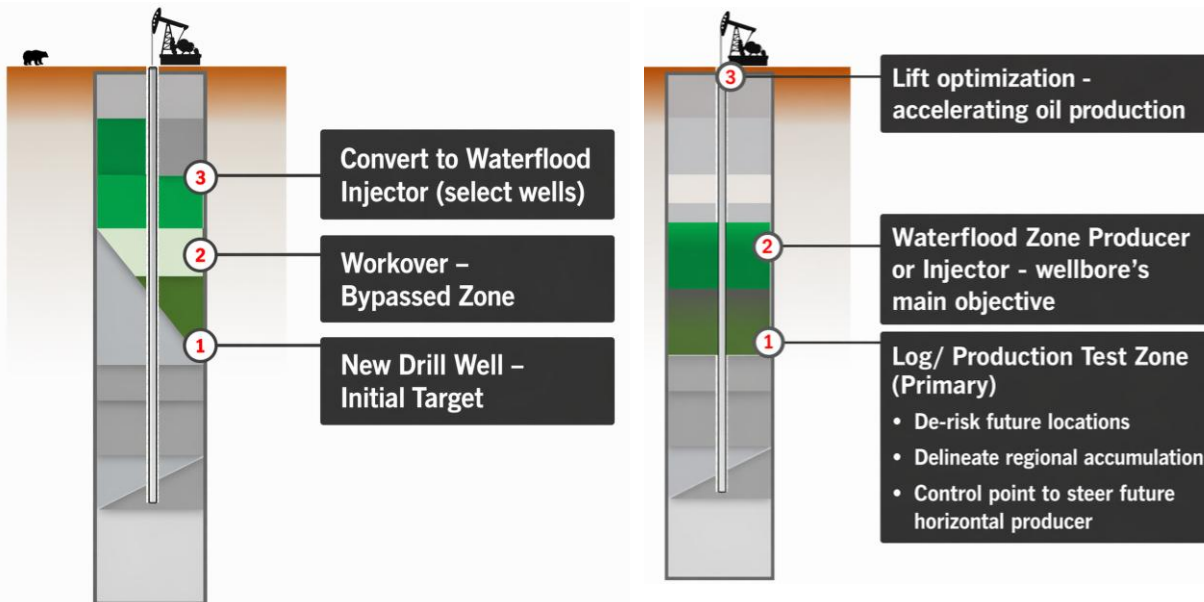
Targeted Cumulative Synergies and Structural Cost Reductions (\$MM)



Low-Decline Assets - Quick Returns

2026E Key Operational Updates

- Reduced 2026E facilities capex by \$10MM¹ driven by field consolidation, underlying ongoing operating efficiencies
- Targeting ~1% entry-to-exit gross production growth with an annual average of ~5 operated rigs
- With a large base of artificial lift wells in CA, an existing remediation backlog and an improved commodity environment, CRC can deploy targeted discretionary OPEX to quickly grow high-impact production, delivering fast and capital-efficient uplift to PDP volumes
- Continued focus on sustainable, efficiency gains to structurally improve reservoir productivity



See slide 33 for "Assumptions, Estimates and Endnotes".

Program Built for Value Creation

Updated 2026E O&G Program Economics^{1,2}

~4.5x
MOIC³

~69%
IRR

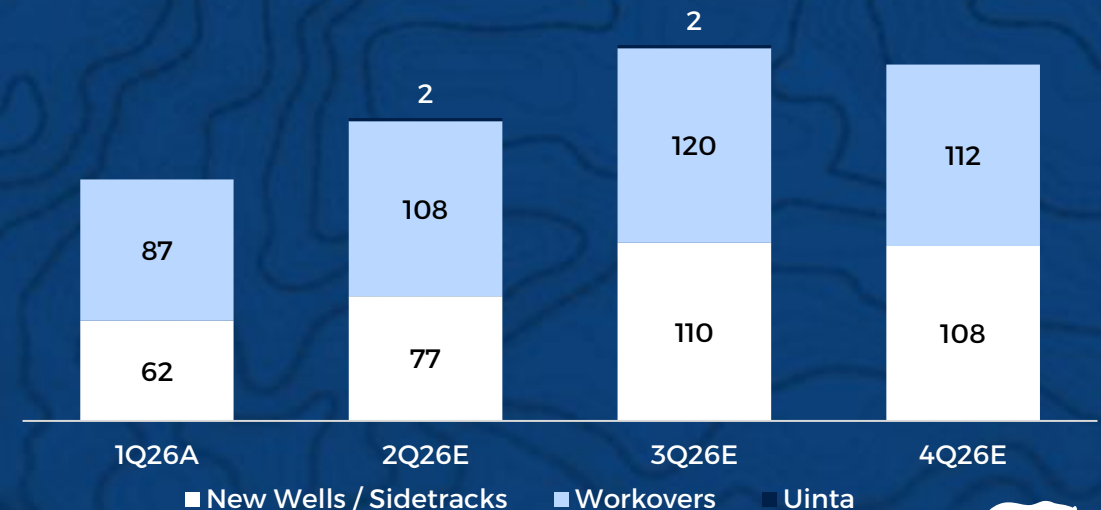
2026E E&P Capital¹

\$500 - \$525MM

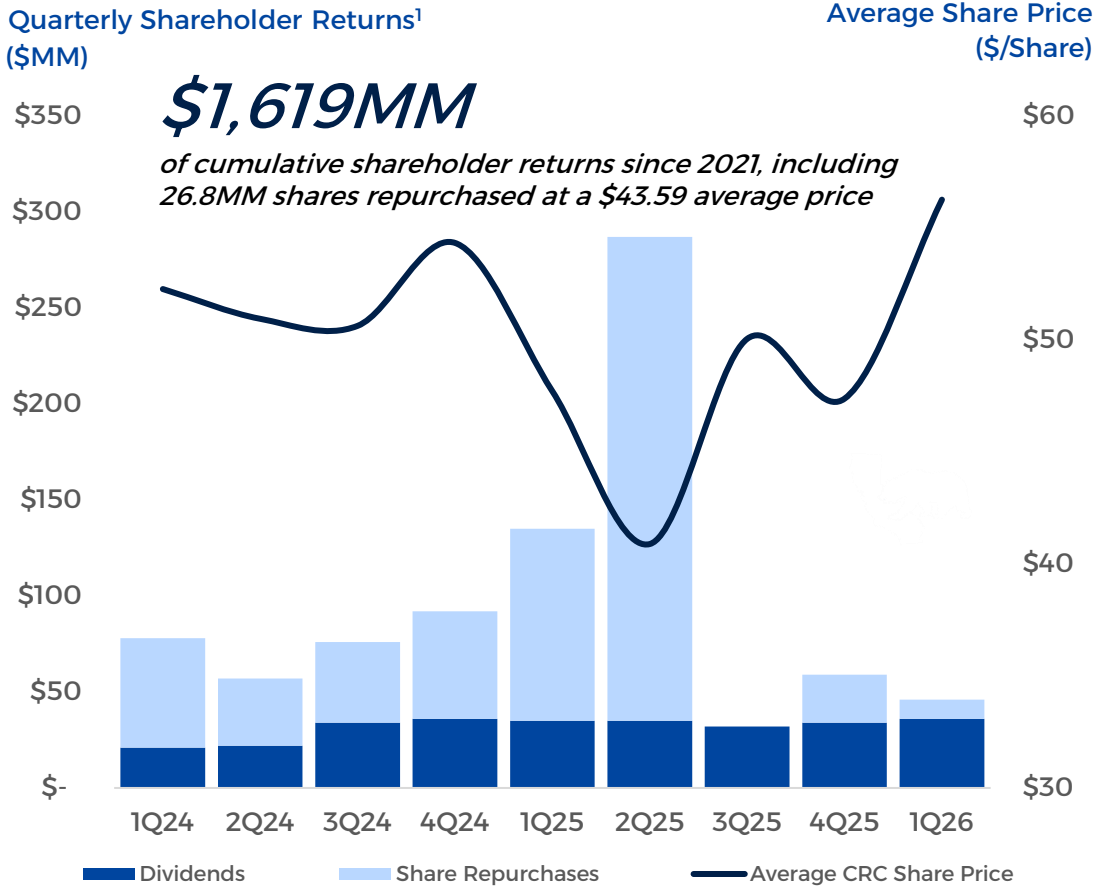


Accelerating 2026E D&C and Workover Activity Cadence¹

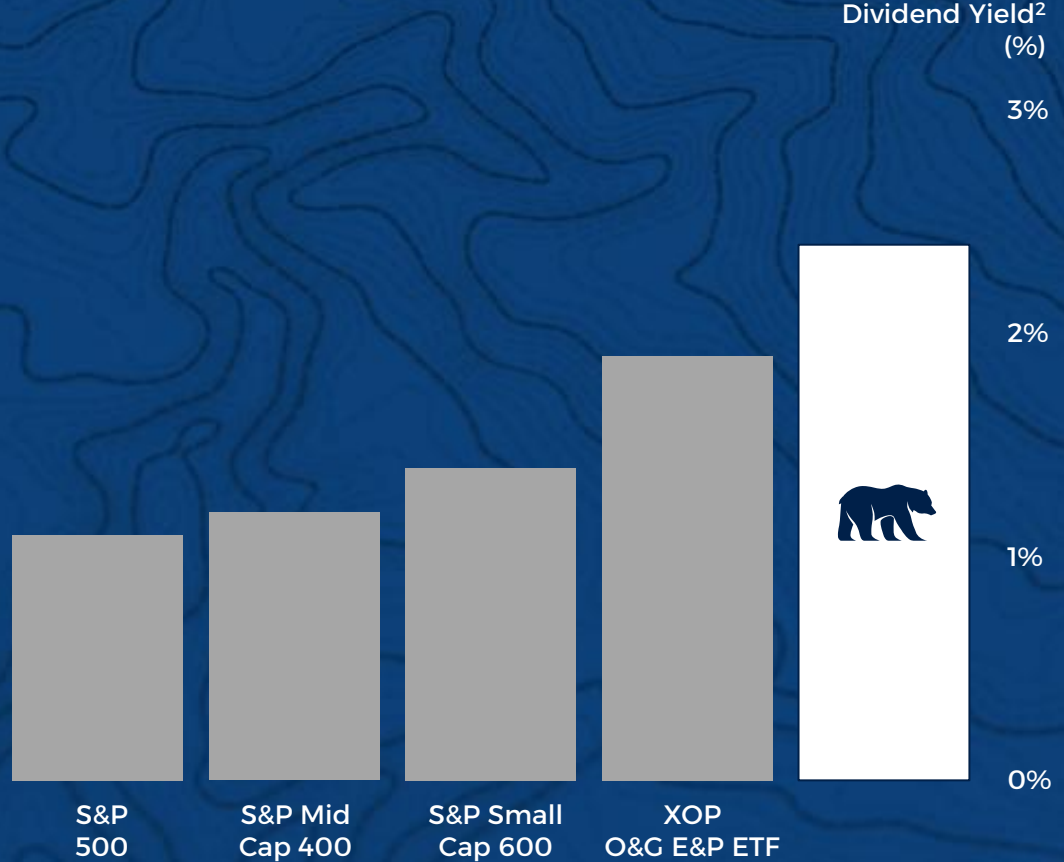
Planned Quarterly Wells



Opportunistic Share Repurchases Create Observable Value



Attractive Fixed Dividend vs Market



See slide 33 for "Assumptions, Estimates and Endnotes".

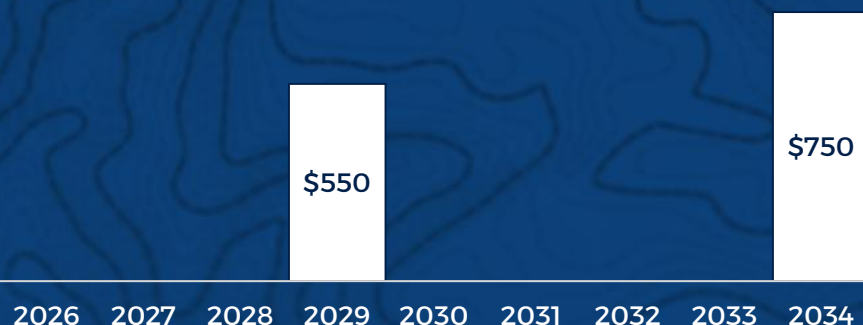
Capital Structure Provides Flexibility

1Q26 Highlights

- Issued \$350MM in 7.000% 2034 Senior Notes
- Redeemed \$350MM in 8.250% 2029 Senior Notes
- Borrowing base reaffirmed at \$1.5B in April 2026

Long Dated Debt Maturity Profile

Unsecured Senior Notes (\$MM)



Strong Balance Sheet and Ample Liquidity

Ample Liquidity

Net Debt* Snapshot as of March 31, 2026

	(\$MM)
Revolving Credit Facility (RCF)	\$ 25
8.250% 2029 Senior Notes	550
7.000% 2034 Senior Notes	750
Face Value of Debt	\$ 1,325
Less Available Cash & Cash Equivalents ¹	(25)
Net Debt*	\$ 1,300
Liquidity ^{*, 2}	\$ 1,276

Strong Coverage Ratios

	(\$MM)
RCF Borrowing Base	\$1,500
1Q26 Free Cash Flow*	(\$32)
1Q26 Net Debt* / LTM Adj. EBITDAX ^{*, 3}	1.1x
LTM Adj. EBITDAX* / LTM Interest Expense ^{*, 4}	11.3x

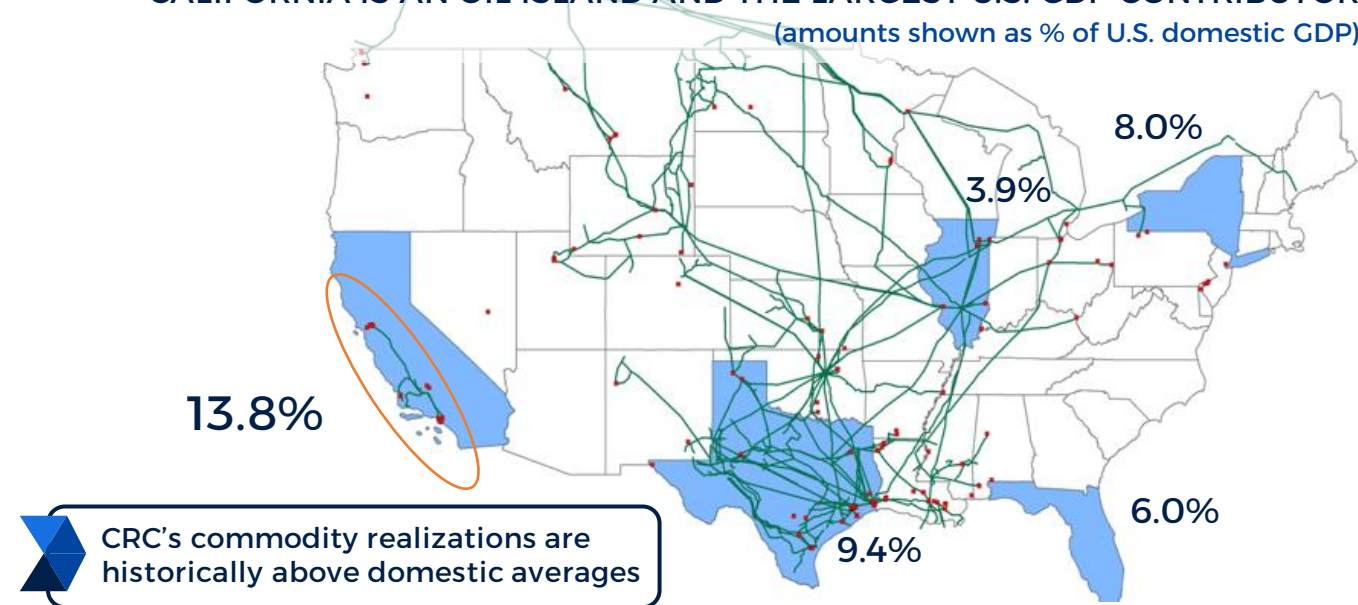


Strong Commodity Price Realizations

- **Crude:** 1Q26 Brent crude prices rose Q/Q and Y/Y as both Middle East and incremental Russian liquids exports were sharply curtailed due to military conflicts. California realizations were in line with seasonal expectations.
- **Natural Gas:** 1Q26 North American natural gas prices were generally higher Q/Q and Y/Y as the Eastern 80% of the country experienced prolonged, unseasonably cold weather. California natural gas prices – as with prices across the Western US – remained comparatively tepid as an absence of weather demand and an abundance of storage kept prices in check.
- **NGLs:** 1Q26 NGL prices were higher Q/Q but lower Y/Y as North American propane inventories continued to build. California NGLs continue to carry a material premium to the broader North American market.

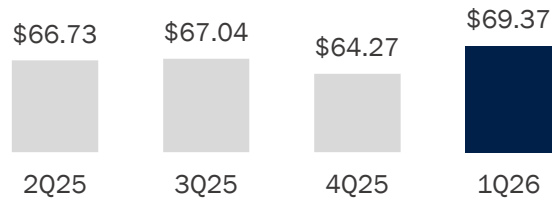
CALIFORNIA IS AN OIL ISLAND AND THE LARGEST U.S. GDP CONTRIBUTOR

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



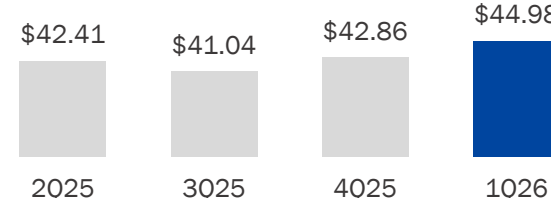
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 4Q25; EIA

Oil w/ Hedges (\$/BBL)



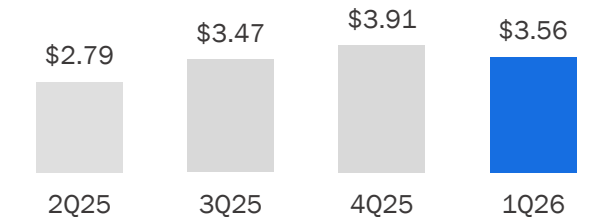
Average Benchmark Prices ¹	\$66.76	\$68.13	\$63.08	\$77.90
% of Benchmark ¹	97%	97%	97%	96%
Hedge Settlements	\$1.66	\$0.72	\$3.13	(\$5.16)
Average Realized Prices ²	\$66.73	\$67.04	\$64.27	\$69.37

NGLs (\$/BBL)



Average Benchmark Prices ¹	\$66.76	\$68.13	\$63.08	\$77.90
% of Benchmark ¹	64%	60%	68%	58%
Hedge Settlements	-	-	-	-
Average Realized Prices ²	\$42.41	\$41.04	\$42.86	\$44.98

Natural Gas (\$/MCF)



Average Benchmark Prices ¹	\$3.44	\$3.07	\$3.55	\$5.04
% of Benchmark ¹	81%	113%	110%	71%
Hedge Settlements	-	-	-	-
Average Realized Prices ²	\$2.79	\$3.47	\$3.91	\$3.56

Hedge Portfolio *(as of March 31, 2026)*

OIL		2Q26E	3Q26E	4Q26E	2027E	2028E
SOLD CALLS						
Brent	Barrels per Day	36,000	36,000	36,000	2,465	17,534
	Weighted-Average Price	\$83.51	\$83.51	\$83.51	\$71.06	\$81.28
SWAPS						
Brent	Barrels per Day	44,487	42,869	41,703	69,610	7,285
	Weighted-Average Price	\$68.52	\$68.20	\$67.98	\$65.69	\$66.98
PURCHASED PUTS¹						
Brent	Barrels per Day	36,000	36,000	36,000	2,465	17,534
	Weighted-Average Price	\$61.11	\$61.11	\$61.11	\$61.01	\$62.74
NATURAL GAS		2Q26E	3Q26E	4Q26E	2027E	2028E
SWAPS						
SoCal Border	MMBtu per Day	13,250	10,750	9,908	3,463	-
	Weighted-Average Price	\$4.82	\$4.83	\$4.84	\$4.77	\$-
NWPL Rockies ²	MMBtu per Day	91,750	91,750	91,750	88,254	11,475
	Weighted-Average Price	\$3.77	\$3.76	\$4.17	\$4.00	\$3.51
EST. HEDGE CONTRACT SETTLEMENTS³		2Q26E	3Q26E	4Q26E	2027E	2028E
Combined Hedge Portfolio (\$MM)		(\$252)	(\$157)	(\$89)	(\$359)	(\$21)



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

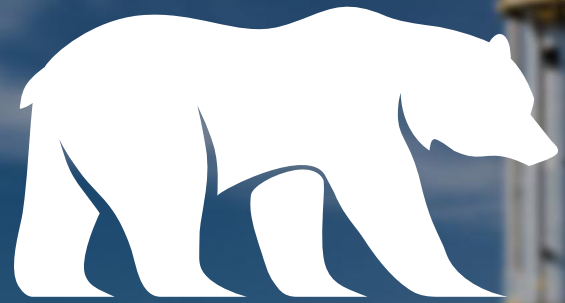
~65% of remaining 2026E net oil production hedged at an average Brent floor price of ~\$65/Bbl⁴



OPERATIONS

~61% of remaining 2026E internal fuel consumption hedged at an average natural gas price of ~\$4.00/MMBtu⁴





Appendix



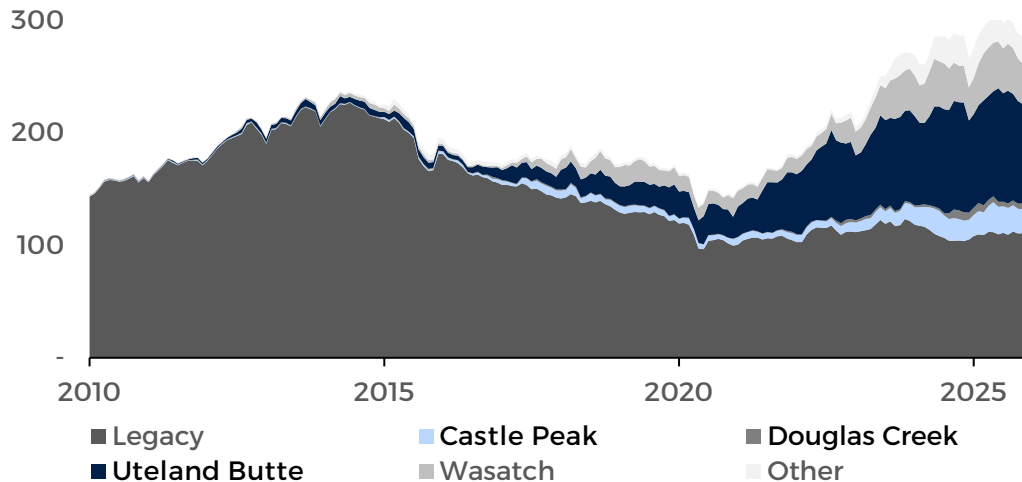
Top-Quartile Well Performance Puts Uinta on the Map

Uinta Basin Performance Rivals Permian & Bakken

- Growth activity driven by development in the Uteland Butte, Castle Peak, Douglas Creek and Wasatch intervals
- Lateral length average of ~10,500' over past three years, with some extended laterals being drilled (20 three-mile wells drilled)
- Peer drilled 12 four-mile wells on the Sandlot and Talladega pads over the past six months
- Extended laterals performing in-line with shorter laterals on a per foot basis
- Operators reporting ~10% reduction in D&C costs over last year, down to ~\$850/ft; the CJ Pad/Moon Tribal averaged \$668/ft (\$707/ft when including equip.)

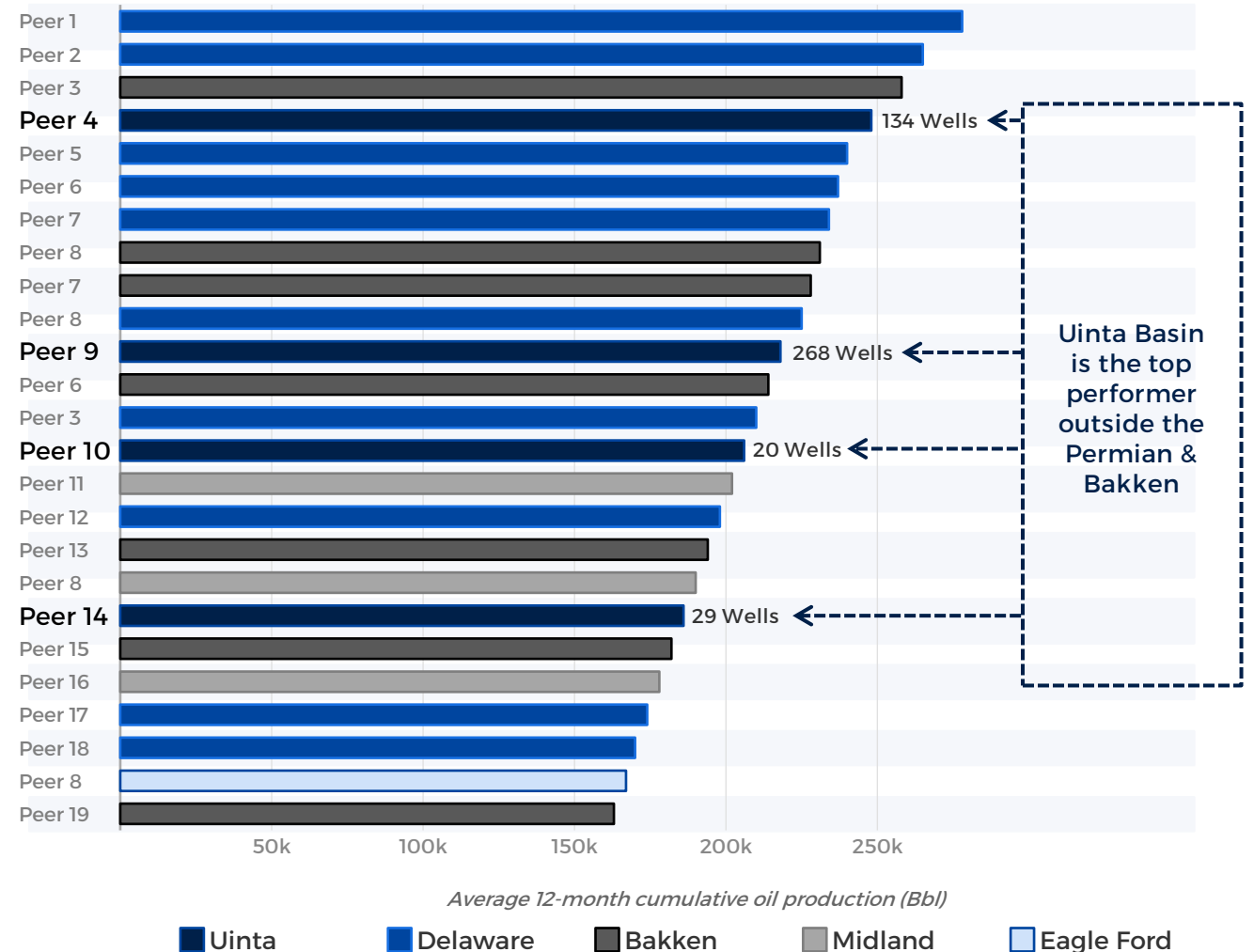
Since YE2020, 2x Rise in Basin Production

Uinta Basin Gross Production (MBoe/d)¹



Recent Wells are Competitive on First 12-Month Oil Rates

Top 25 Lower 48 Operators Ranked by 2019+ Well Performance²



Uinta Basin is the top performer outside the Permian & Bakken

Production Sharing Contracts (PSC) at Higher Prices

For every ~\$1/Bbl change in Brent price, we expect a ~90 Bo/d decrease/increase in our net oil production related to PSCs¹

Approximately 12% of CRC’s gross oil production is subject to PSCs Mechanics:

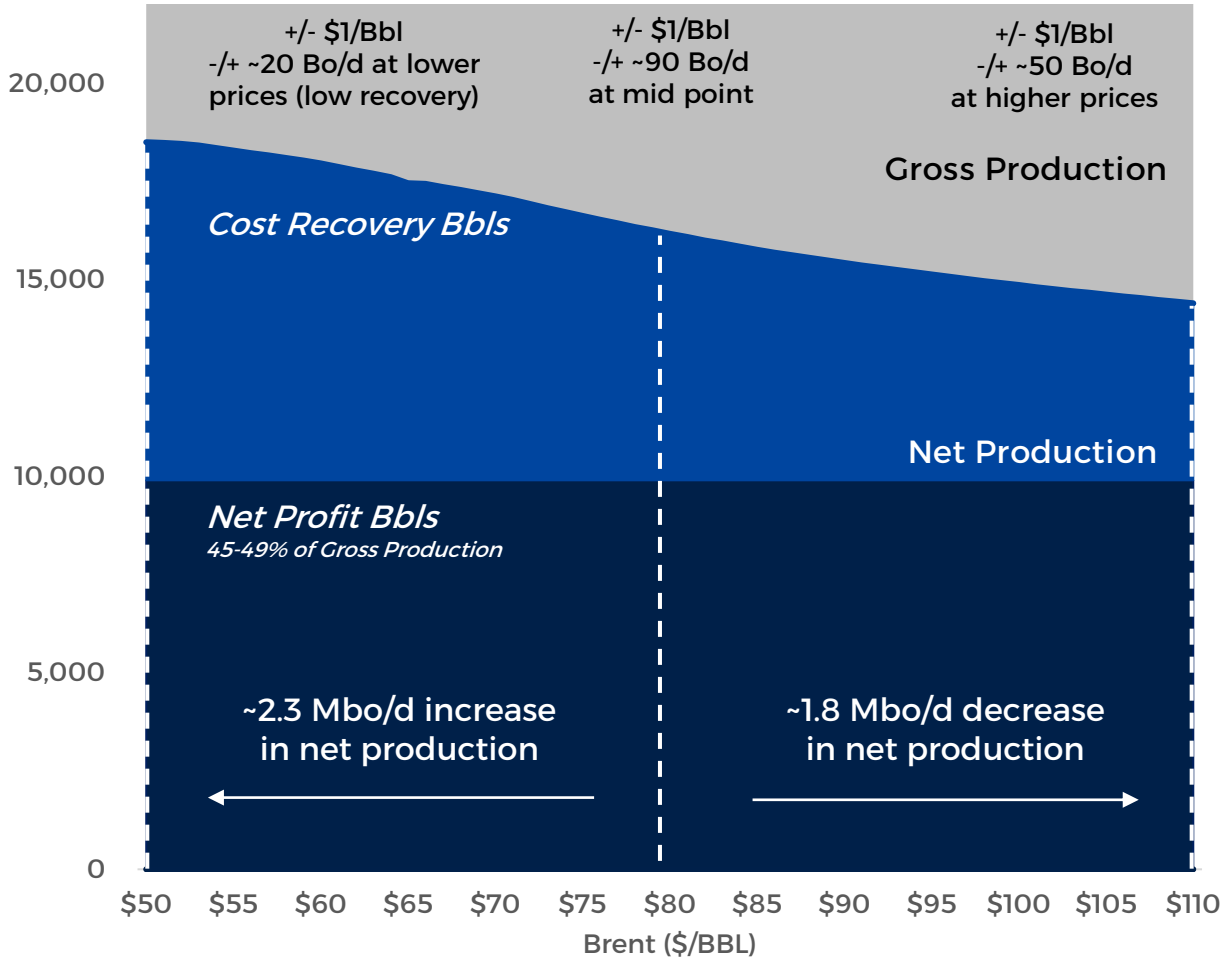
- CRC pays its partners’ share of operating and capital cost
- CRC recovers partners’ share of operating and capital costs through production sharing, where CRC’s cost recovery is reported as revenue
- CRC receives ~45-49% of the gross production as “Profit Barrels” after cost recovery
- CRC’s net share of production includes cost recovery and “profit barrels”

As prices rise, fewer barrels are assigned as cost recovery

CRC sees a difference of ~4.1 MBO/D in net oil production between \$50/Bbl and \$110/Bbl²

Effect Of Oil Price On Net Production²

Wilmington Field Production (Bo/d)



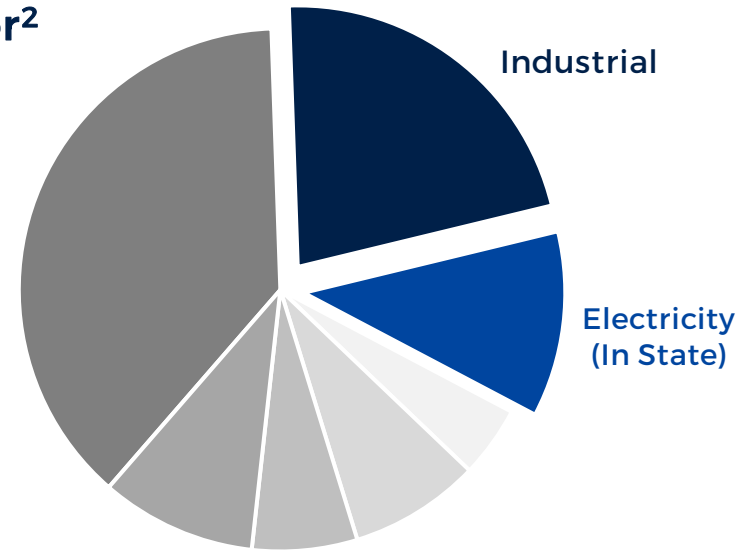
See slide 34 for “Assumptions, Estimates and Endnotes”.

Well Positioned to Decarbonize California's Largest Industries

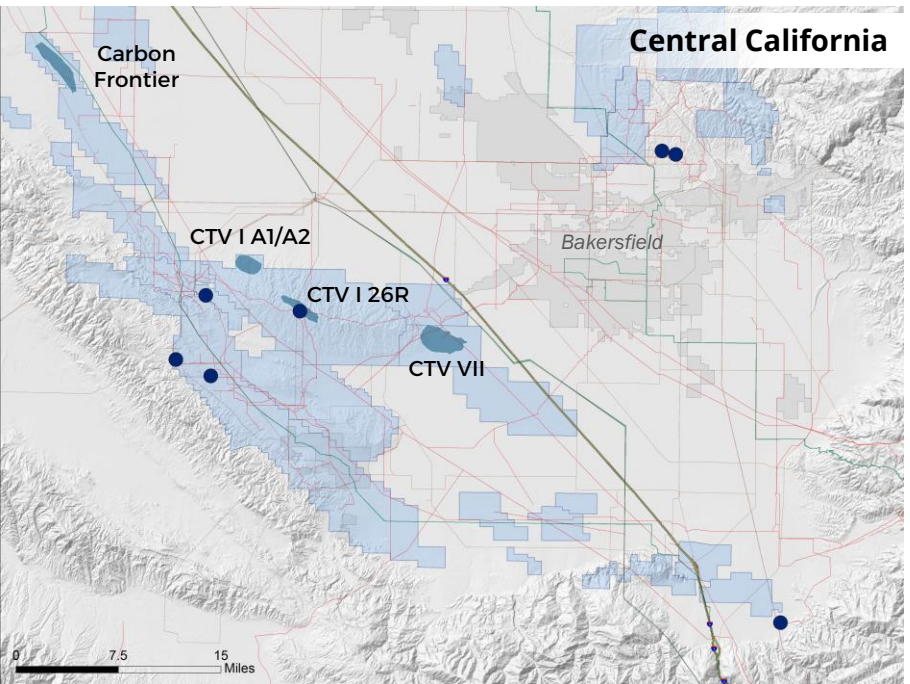
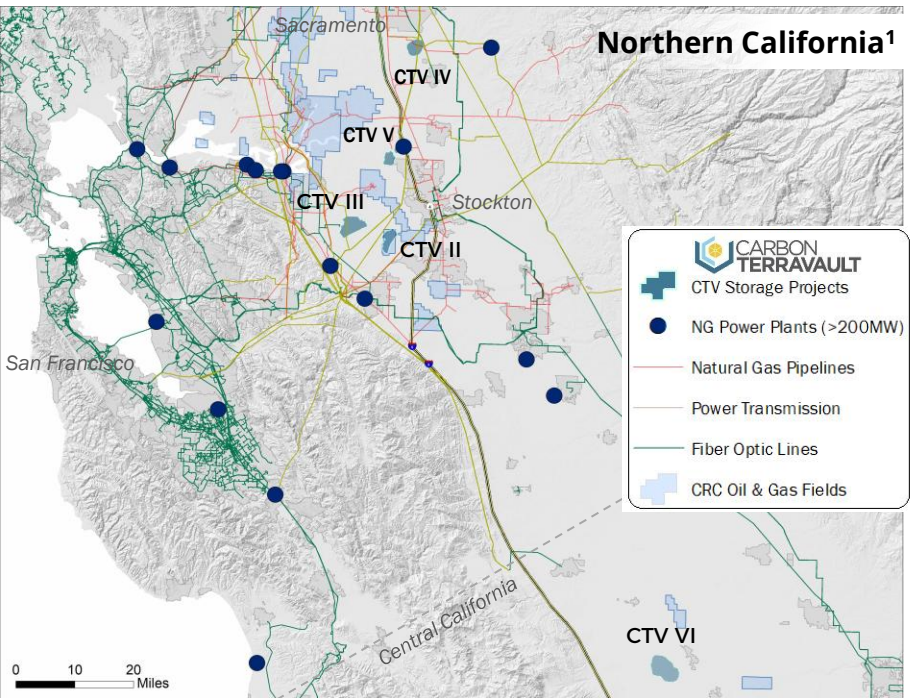
- CTV reservoirs are in proximity to the state's highest emitting industries
- Resource inventory and infrastructure in place to supply energy today
- Ability to provide power services with:
 - Accelerated time-to-market
 - Access to natural gas and interconnection
 - Proximity to fiber network
- Developing carbon free power solutions in San Joaquin Valley

California GHG Emissions by Sector²

- Transportation
- Industrial
- Electricity (In State)
- Electricity (Imports)
- Agriculture
- Commercial
- Residential



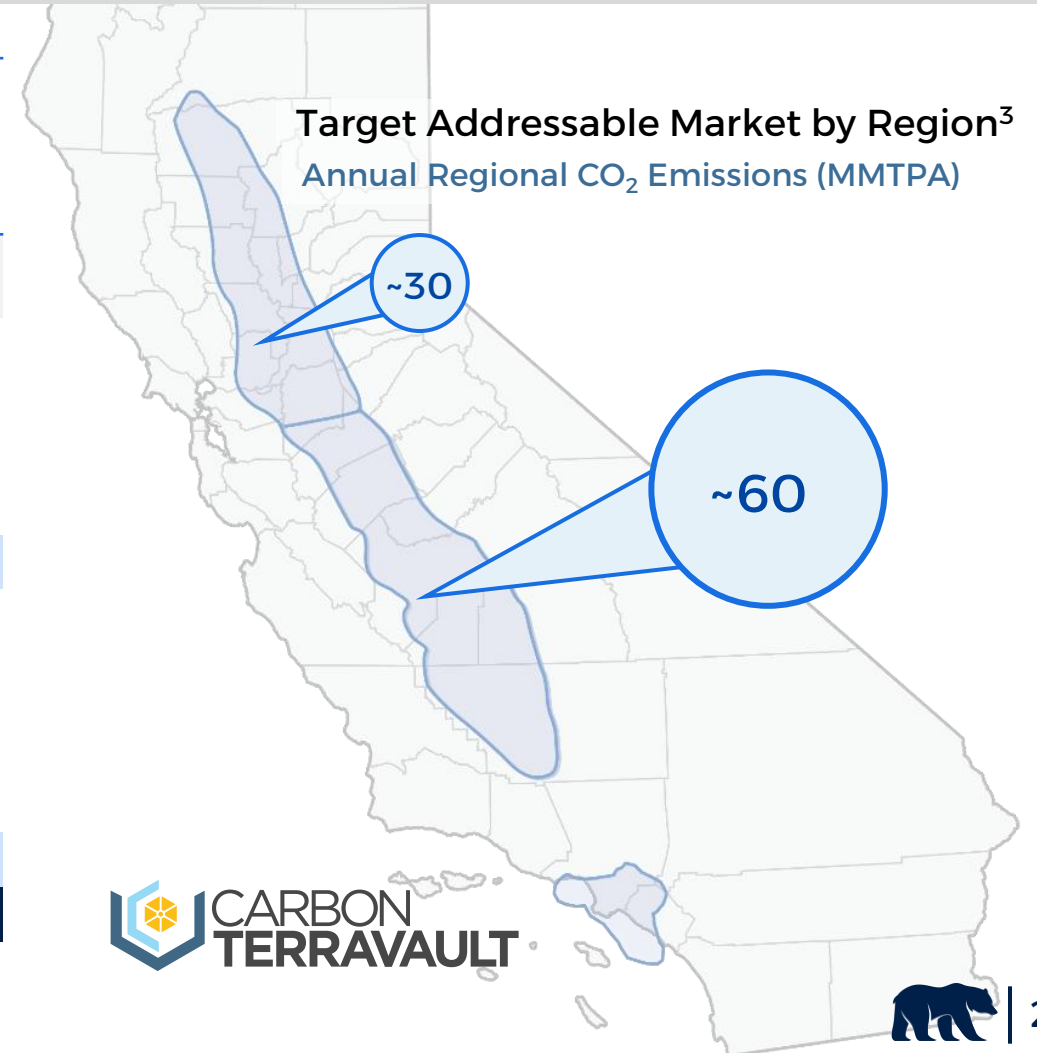
See slide 34 for "Assumptions, Estimates and Endnotes".



California's Premier Carbon Management Provider

- In May 2026, started sequestering CO₂ at California's first CCS project at CRC's Elk Hills cryogenic gas plant
- Anticipating the receipt of Class VI draft permits for additional reservoirs in 2026¹

Vault / Reservoir	Targeted Final EPA Class VI Permit Decision ¹	Est. Annual Injection Rate ¹ (MMTPA)			Permit Volumes ¹ (MMT)
		EPA Class VI Permit	20 Years	40 Years	
CTV I 26R	Permit Received	~1.5 ²	~1.9	~1.0	~38
CTV I A1-A2	2026	~0.8	~0.4	~0.2	~8
Carbon Frontier	2026	~3.3	~1.6	~0.8	~32
CTV VI	2027	~3.4	~5.1	~2.5	~102
CTV VII	-	~1.4	~1.4	~0.7	~27
Central California		~10.4	~10.4	~5.2	~207
CTV II	2026	~1.0	~1.2	~0.6	~23
CTV III	2027	~2.5	~3.6	~1.8	~71
CTV IV	2027	~1.4	~1.7	~0.9	~34
CTV V	2027	~0.7	~0.8	~0.4	~17
Northern California		~5.6	~7.3	~3.7	~145
Total - Combined		~16.0	~17.7	~8.9	~352



Power-to-CCS Expansion

AI inference is driving rising demand for reliable in-state power

Grid capacity could expand through PG&E data center interconnects and CPUC procurement

Regulatory momentum supports Power-to-CCS optionality

Actively sequestering CO₂ at California's first CCS project

Current Market Dynamics

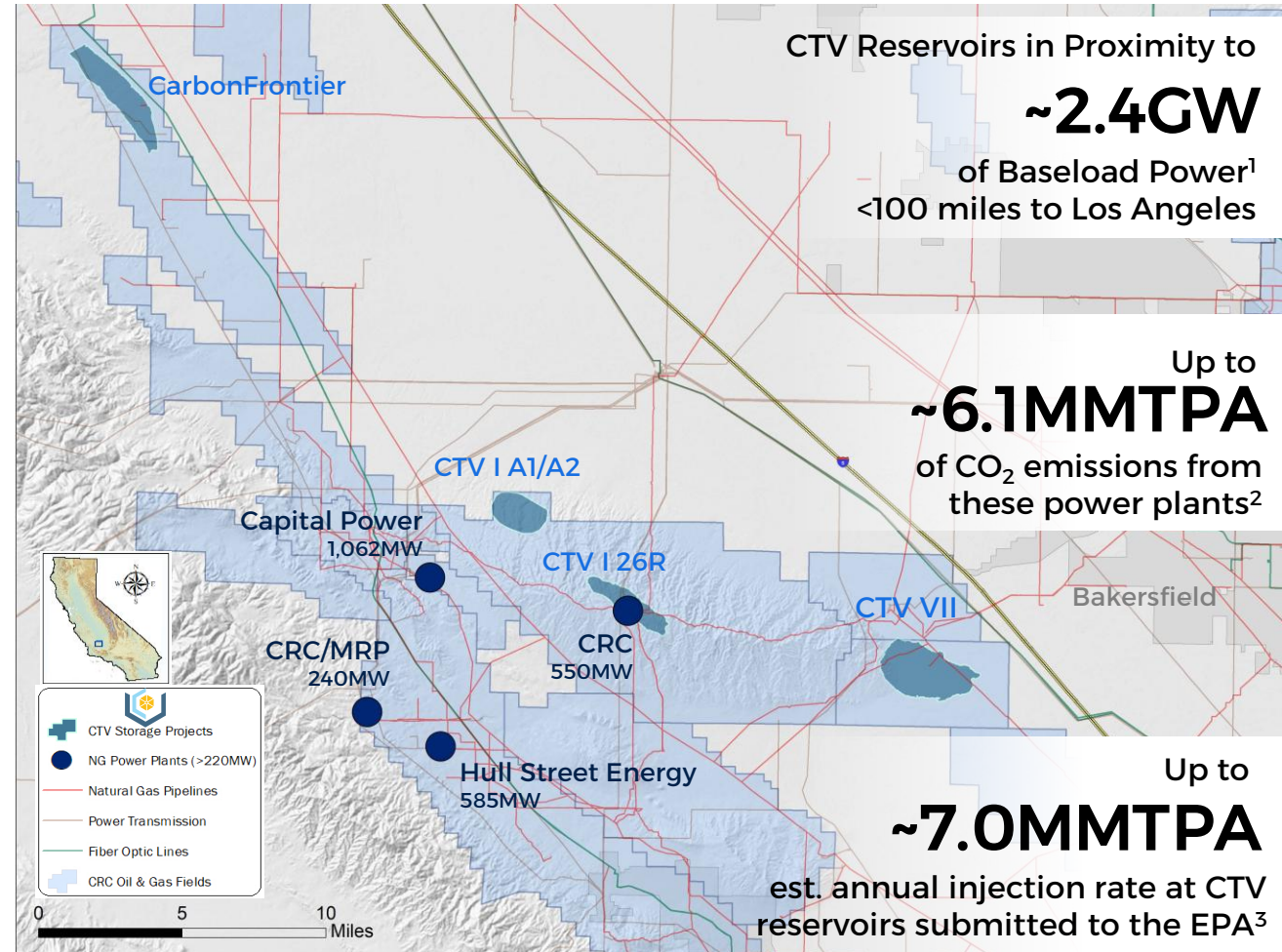
Opportunity	Customers	Clean Premium
1 FTM Utility Sale	Utilities	✓
2 FTM Sale	Existing Data Centers, Industrials	✓
3 BTM Industry Sale	New Data Centers, Industrials	✓

See slide 35 for "Assumptions, Estimates and Endnotes".

Kern County CCS Opportunity

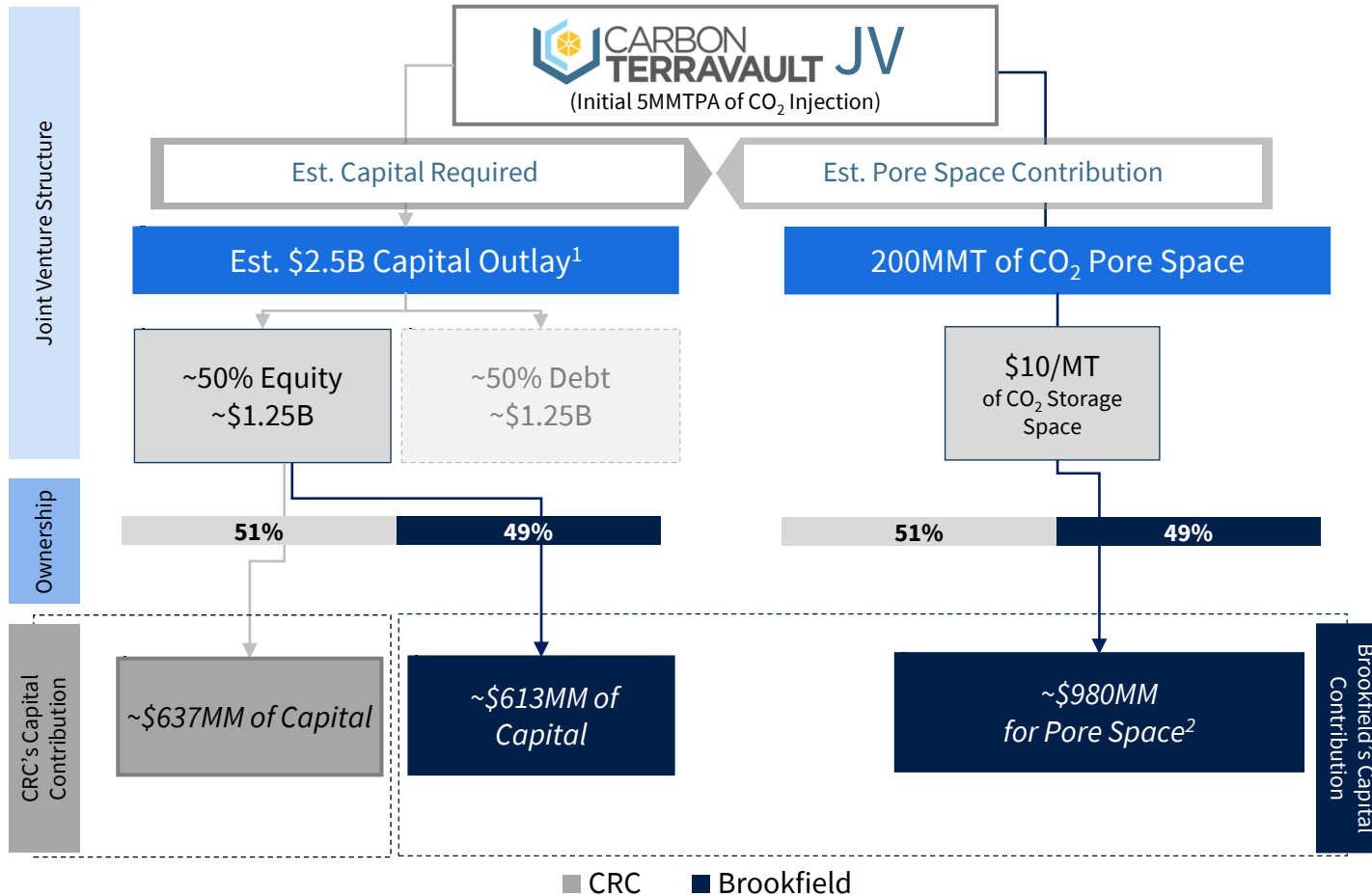
- Natural gas pipeline connectivity
- Power interconnect
- Water availability and supply
- Proximity to major fiber networks
- Access to premier CO₂ storage reservoirs
- Possible CO₂ pipeline connectivity

Powered Land



Strategic Carbon Management Partnership

Illustrative CO₂ Storage/Injection Goal Capital Funding Needs¹ *assumes Brookfield fully participates in the initial 5MMTPA of CTV JV projects*



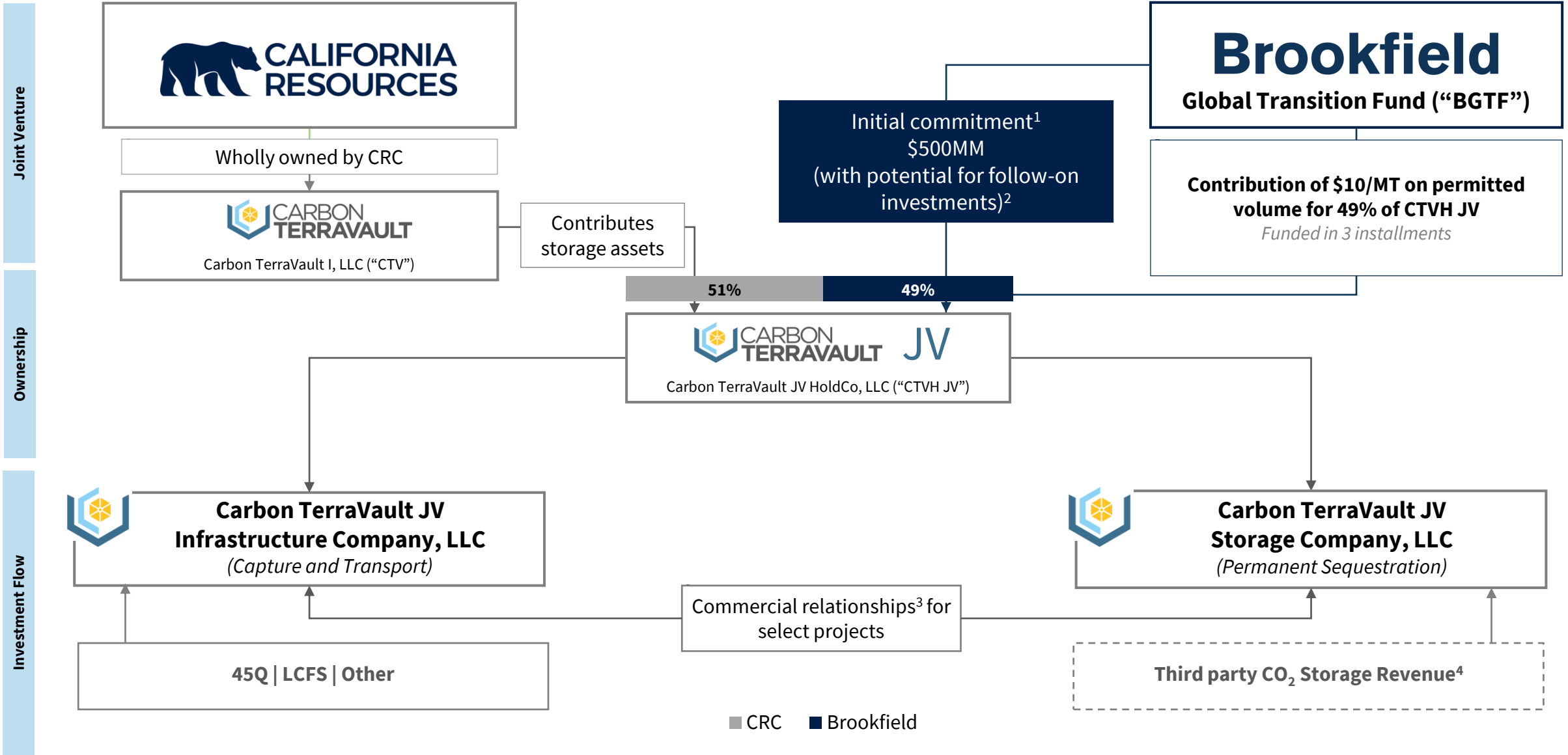
Improves & Increases Flexibility of CRC's Capital Allocation Framework

- Capitalizes first 5MMTPA of projects and provides potential funding for CRC's development of 200MMT of CO₂ storage
- CRC's equity commitments for the first 5MMTPA are more than 2x covered by Brookfield's initial commitment for projects jointly approved through the CTV JV
- Allows CRC to increase flexibility for shareholder returns strategy and explore strategic alternatives for low CI E&P business expansion

Projected Excess Capital Available for Early Stage CMB Expenses and Capital³

~\$980MM	Est. Brookfield Pore Space Contribution
-	
~\$637MM	Est. CRC's Capital Contribution
<hr/>	
~\$343MM	Available to fund CRC early stage CMB expenses and capital (represents approximately 5 years of early stage CMB capital spending)

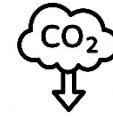
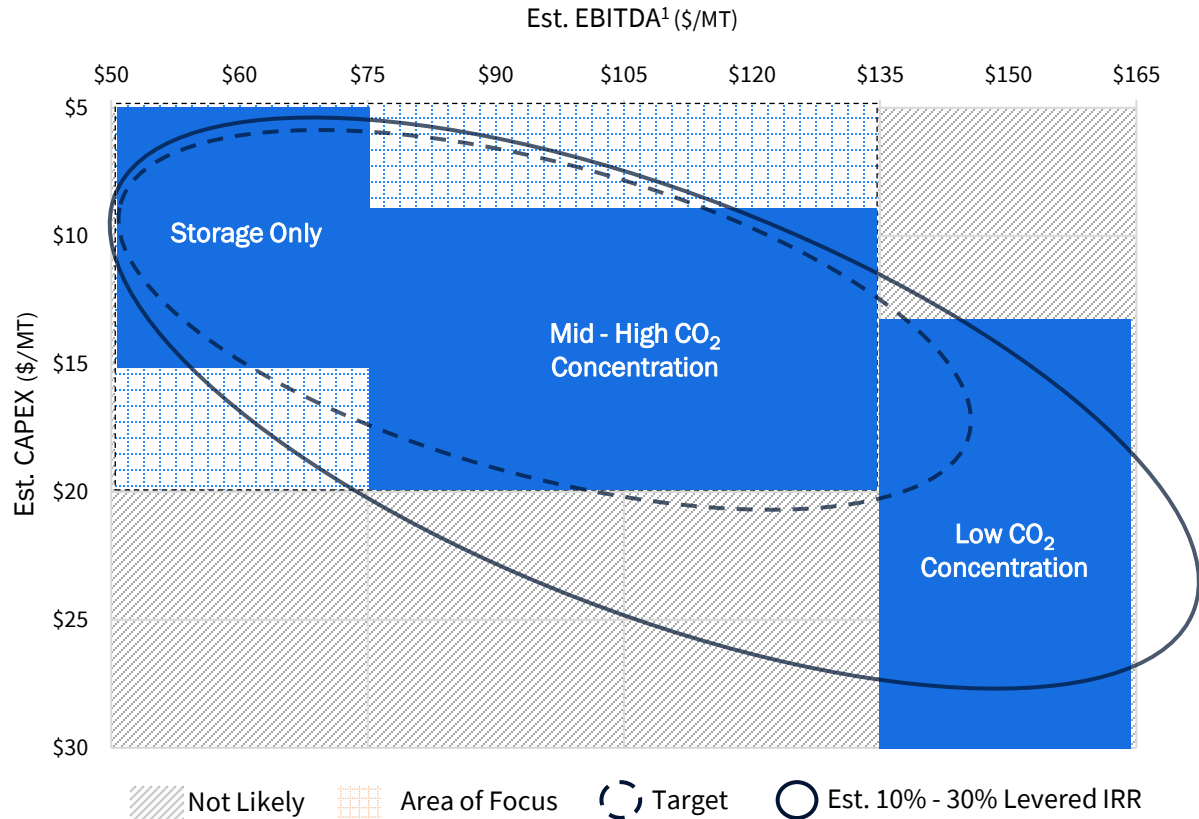
Carbon TerraVault Joint Venture Details



Note: Diagram for illustrative purposes only. See slide 35 for "Assumptions, Estimates and Endnotes".

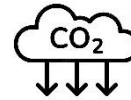
Strategic Partnership – A Structural Capital Advantage

ILLUSTRATIVE EBITDA¹ VS CAPEX REQUIREMENTS
FOR VARIOUS CO₂ PROJECTS



STORAGE ONLY PROJECTS

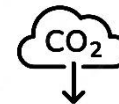
- CTV JV is the off-taker of CO₂ at storage site through Storage Co.
- Lower expected capital requirements for project development, including injection and monitoring wells, facilities and compression



MID - HIGH CO₂ CONCENTRATION PROJECTS

(≥15% CO₂ STREAM CONCENTRATION)

- CTV JV controls the entire value chain (capture to storage) and majority of the incentives
- Capital requirements for capture systems, while still significant, are expected to be on the lower end of the capture cost curve due to higher CO₂ concentration of stream
- Project financing more likely vs. storage only and provides opportunity to increase levered returns
- Potential LCFS expansion could provide further EBITDA potential



LOW CO₂ CONCENTRATION PROJECTS

(<15% CO₂ STREAM CONCENTRATION)

- CTV JV controls value chain and incentive but lower expected IRR due to higher costs of capture (Ex: Natural Gas Combined Cycle Power Plants)
- Inflation Reduction Act of 2022 expands potential project opportunities
- Advancements in capture technology to play key role in improving project economics
- CARB considering new incentive programs to unlock traditionally hard to decarbonize sectors (e.g. cement)
- CalCapture² is an advantaged low CO₂ concentration project given its proximity to storage (insignificant transport capital)

Progressing Huntington Beach Real Estate Asset Development



HUNTINGTON BEACH UPDATE | 92 ACRE PARCEL

- Sold Fort Apache (0.9-acre parcel) for total proceeds of ~\$10MM in February 2024 (1810 Pacific Coast Highway, Huntington Beach, CA)
- Anticipated to be a multi year process to maximize land value (20101 Goldenwest Street, Huntington Beach, CA)
- Submitted rezoning application to City of Huntington Beach in March 2025 for a mixed-use, community development
 - Up to 800 homes, up to 350 hotel rooms, retail and dining, and open space parks

TIMELINE

- Proposal will be reviewed by the City staff and community
- City will evaluate project under California Environmental Quality Act (CEQA) to ensure compliance with state environmental regulations
- Huntington Beach Planning Commission will review proposal and make recommendations to the City Council, which will conduct its own evaluation before making a final decision anticipated in late-2026
- Once approved by the City Council, the project would be presented to the California Coastal Commission for final review and approval

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 <i>(a subsidiary of CRC)</i>
CUP	Conditional Use Permit
DAC	Direct Air Capture
D&C	Drilling and Completions
E&P	Exploration and Production
EBITDAX	Earnings Before Interest, Taxes, Depreciation, Amortization and Exploration
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
g/MJ	Grams of CO ₂ Equivalent per Megajoule of Energy Produced
G&A	General and Administrative
GHG	Greenhouse Gas
IRR	Internal Rate of Return
JV	Joint Venture

Term	Definition
KMTPA	Thousand Metric Tons Per Annum
LCFS	Low Carbon Fuel Standard
LTM	Last Twelve Months
MMT	Million Metric Tons
MMTPA	Million Metric Tons Per Annum
MOIC	Multiple on Invested Capital
MOU	Memorandum of Understanding
MRV	Monitoring, Reporting and Verification Plan
MT	Metric Tons
MTPA	Metric Tons Per Annum
NG	Natural Gas
NGL	Natural Gas Liquid
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
SEC	United States Securities and Exchange Commission
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) Source: Enverus.
- 2) Market capitalization (as of May 8, 2026) using 88.8MM shares outstanding. Enterprise value calculated using net debt of \$1,300MM (as of March 31, 2026) plus market capitalization.

Slide 3:

- Proved Reserves: Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
 - Probable Reserves: Probable reserves are those reserves that are less certain to be recovered than proved reserves but, when aggregated with proved reserves, are as likely as not to be recovered. Probable reserves are subject to greater uncertainty regarding recoverability and economic viability and may not ultimately be recovered. Estimates of probable reserves have not been prepared in accordance with SEC definitions applicable to proved reserves and should not be construed as equivalent thereto. CRC's probable reserves are internally prepared estimates, are not independently audited, and are not subject to the same internal control framework applicable to proved reserves. A reserve adjustment factor has not been applied to PV-10, a non-GAAP measure.
 - CRC's proved reserves totaled 654 MMBOE and probable reserves totaled 526 MMBOE at 2025 SEC pricing (after adjustments for price realizations) of \$69.38 per barrel of oil and \$3.39 per MMBtu of natural gas.
 - PV-10 is a non-GAAP financial measure. GAAP prescribes a standardized measure of discounted future net cash flows only for proved reserves using SEC pricing. For a reconciliation of PV-10 of proved reserves using SEC prices to the standardized measure, please refer to CRC's Form 10-K for the fiscal year ended December 31, 2025. A comparable GAAP measure does not exist for probable reserves or for proved reserves on a basis other than SEC pricing. Accordingly, no reconciliation of PV-10 of probable reserves has been provided for those items.
 - Reserve estimates are inherently uncertain and constitute forward-looking statements based on assumptions regarding commodity prices, costs, development timing, and reservoir performance; actual results may differ materially. Estimates of future net revenues should not be construed as fair market value. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves require the application of professional judgment and geological and engineering knowledge to assess whether specific classification criteria have been satisfied. CRC's estimates of proved and probable reserves are presented herein because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, we note that the SEC prohibits companies from aggregating proved and probable reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
 - Peer Groups: "Canadians" includes: ARX, ATH, BIR, BTE, CNQ, CVE, IMO, NVA, PSK, SCR, SU, TOU, TPZ and WCP. "US Shale" includes: AR, BKV, CHRD, CNX, CRK, EQT, EXE, MTDR, NOG, PR, RRC, SM and VNOM. "Large Integrated" includes: BP, CVX, ENI, EQNR, PBR, SHEL, TTE and XOM. "Large US" includes: COP, DVN, FANG and OXY. "Offshore" includes: HBR, KOS, TALO, VAR and WTI. "International / US" includes: APA, EOG and MUR. Source: Company reports.
- 1) Enterprise value calculated using net debt of \$1,300MM (as of March 31, 2026) plus market capitalization as of May 8, 2026 using 88.8MM shares outstanding.
 - 2) PV-10 of proved reserves (\$8.7B) and probable reserves (\$5.7B) as of December 31, 2025 were calculated using SEC prices (after adjustments for price realizations) of \$69.38 per barrel of oil and \$3.39 per MMBtu of natural gas.
 - 3) PV-10 of proved reserves (\$10.3B) and probable reserves (\$6.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of \$75.00 per barrel of oil and \$3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.
 - 4) PV-10 of proved reserves (\$13.0B) and probable reserves (\$8.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of \$85.00 per barrel of oil and \$3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.



Assumptions, Estimates and Endnotes

Slide 3 (Cont.):

- 5) CRC data reflect reserves and annual production volumes as of December 31, 2025. CRC's production volumes include Berry Corporation's volumes for 14 days following the transaction close. Production amounts used are reported results and are not presented on a pro forma basis. Peer reserves and production data reflect reserves and annual production volumes as of December 31, 2025.

Slide 4:

- 1) Proved reserves estimated as of December 31, 2025 using SEC Prices of \$69.38 per barrel for oil and \$3.39 per MMBtu for natural gas. For more information on CRC's proved reserves, including a reconciliation to the most comparable GAAP measure, please see CRC's Forms 10-K for the fiscal year ended December 31, 2025.
- 2) Proved developed (PD) reserves include proved developed producing (PDP) and proved developed non-producing (PDNP) reserves.
- 3) Calculated using 2025 net production.
- 4) Uinta Basin production for full-year 2024 and the first nine months of 2025 is derived from Berry Corporation's publicly reported data prior to its merger with California Resources Corporation. Fourth quarter 2025 net production reflects CRC internal estimates following the closing of the merger and is unaudited. These amounts may not reconcile to CRC's consolidated reported production or pro forma financial results.

Slide 6:

- 1) Source: Enverus. Peers include projects operated by ADM, Basin Electric Power Cooperative, Gevo, Harvestone Group, Shell, Equinor, Santos, Chevron, Qatar Energy, ENI and Huaneng Group.

Slide 7:

- 1) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.
- 2) Information assumes weighted average diluted shares as of March 31, 2026 and does not take into consideration future potential share repurchases in 2026.

Slide 9:

- 1) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.

Slide 10:

- 1) Source: FactSet. Represents CRC's current annual dividend policy of \$1.62 per share divided by CRC's market capitalization as of May 1, 2026.
- 2) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
- 3) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.

Assumptions, Estimates and Endnotes

Slide 11:

- 1) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.

Slide 12:

- 1) Information assumes forward commodity pricing as of April 29, 2026.
- 2) 2026E entry-to-exit production is expected to be negatively impacted by 1.4 MBo/d from production sharing contract (PSC) effects, consisting of a negative 1.8 MBo/d impact from higher commodity prices, partially offset by a positive 0.4 MBo/d impact from cost recovery effects.
- 3) Source: Baker Hughes North American rig count as of May 8, 2026.
- 4) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.
- 5) See slide 14 of CRC's 4Q25 presentation for additional information.

Slide 14:

- 1) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.
- 2) Source: CRC internal estimates. Program economics reflect available inventory supported by permits in hand.
- 3) Multiple on Invested Capital (MOIC) refers to the total value generated by a drilling program relative to the capital originally invested in it, calculated by dividing total returns by the initial capital deployed.

Slide 15:

- 1) Source: CRC internal estimates.
- 2) Total year 2026E guidance assumes a 2026E Brent price of \$90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of \$3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.

Slide 16:

- 1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
- 2) Source: FactSet. Represents CRC's current annual dividend policy of \$1.62 per share divided by CRC's market capitalization as of May 1, 2026.

Assumptions, Estimates and Endnotes

Slide 17:

- 1) Available cash and cash equivalents excludes \$15MM of restricted cash.
- 2) Liquidity on March 31, 2026 is calculated as \$25MM of cash and cash equivalents (excluding \$15MM of restricted cash) plus \$1,251MM of borrowing capacity on CRC's revolving credit facility less \$184MM in outstanding letters of credit and \$25MM outstanding on the revolving credit facility.
- 3) Net leverage is calculated as 1Q26 net debt of \$1,300MM (excluding restricted cash of \$15MM) divided by LTM adjusted EBITDAX of \$1,217MM.
- 4) Interest coverage is calculated as LTM adjusted EBITDAX of \$1,217MM and LTM interest expense of \$108MM.

Slide 18:

- 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 19:

- 1) Purchased and sold puts with the same strike price have been netted together.
- 2) NPWL volumes require transportation to where the gas is consumed. These costs are reflected in our 2026E transportation guidance. See slide 14 of CRC's 1Q26 presentation for 2026E guidance.
- 3) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of April 29, 2026.
- 4) Subject to commodity prices and market factors.

Slide 21:

- 1) Source: Enverus and Novi Labs. Gross 2-stream wellhead production through December 2025.
- 2) Source: Enverus and Novi Labs. Horizontal operated wells with first production 2019 or later. Includes wells drilled by predecessor operators. Peers include Birch Operating, Chord Energy, ConocoPhillips, Continental Resources, Coterra Energy, Devon Energy, EOG Resources, ExxonMobil, FourPoint Energy, Hibernia Resources, Jonah Energy, Kaiser Francis, Kraken Resources, Mewbourne Oil, Occidental, Scout Energy Partners, SM Energy, TRP Operating and WEM Operating.

Slide 22:

- 1) Based on Brent price of \$80 per barrel of oil.
- 2) Net Production from Wilmington field only. Includes the effects of a development program in the Los Angeles basin.

Slide 23:

- 1) CTV VI is located in Central California but is shown in the Northern California due to map scale.
- 2) Source: California Air Resources Board, "Current California GHG Emission Inventory Data 2000-2023," 2025 edition.

Slide 24:

- 1) Source: EPA as of April 24, 2026, www.epa.gov/uic/class-vi-wells-permitted-epa. "Permit Volumes" refers to carbon storage shown in EPA Class VI permits that CTV has received or submitted. The actual volumes that CTV may ultimately store may differ from the permit volumes as additional technical and commercial data is acquired and evaluated. Injection rates are average rates based on estimated maximum permit volumes over the assumed life of project. Actual volumes and the injection period may vary over time.
- 2) 26R injection volumes as per the draft EPA permit is ~38MMT. Assuming the maximum expected injection rate of 1.46MMTPA, the reservoir would reach permitted volumes 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.
- 3) Source: CARB 2020.

Assumptions, Estimates and Endnotes

Slide 25:

- 1) Source: Company reports.
- 2) Based on signed memoranda of understanding (MOUs) and existing CRC power assets.
- 3) Includes EPA Class VI permit estimated annual CO₂ injection rates for CTV I 26R, CTV I A1-A2, CarbonFrontier and CTV VII.

Slide 26:

- 1) Assumes the average capital needs for 5MMTPA of Carbon Sequestration from the CTV JV economic “Type Curve”. See slide 19 and 20 from CRC’s 1Q23 Earnings Presentation for detailed information on the previously disclosed Type Curve. Brookfield made an initial commitment of \$500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. The partnership is targeting 5MMTPA of CO₂ injection by YE 2027, aligned with CRC’s 2027 goals, thereby requiring an estimated ~\$2.5B of capital.
- 2) ~\$980MM assumes 200MMT of CO₂ pore space for \$10/MT of CO₂ storage space and 49% Brookfield ownership which assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of CO₂ storage.
- 3) Results subject to effects of taxes, timing, pace of project development and Brookfield further approval to fund capital.

Slide 27:

- 1) Commitment applies to CCS projects that are jointly approved through the JV.
- 2) Assumes Brookfield fully participates in CCS projects up to JV target of 5 MMTPA of injection and 200MMT of CO₂ storage
- 3) Additionally, CRC will provide operational and other services to the joint venture.
- 4) Independent of Infrastructure Co.

Slide 28:

- 1) EBITDA is a non-GAAP measure. EBITDA estimates include 45Q tax credits which may change based on further guidance from IRS and other factors and assumes that 45Q wage and apprenticeship requirements are met.
- 2) CalCapture refers to CRC’s project at its Elk Hills Power Plant.

Forward-Looking / Cautionary Statements – Certain Terms

Forward-Looking Statements:

Information set forth in this communication, including financial estimates and statements as to the effects of the Berry Merger, constitute “forward-looking statements” within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and other securities laws. All statements other than historical facts are forward-looking statements, and include statements regarding the benefits of the Berry Merger, CRC’s future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives and intentions 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. These forward-looking statements are based upon the current beliefs and expectations of the management of CRC and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, projected 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 are described in its most recent Annual Report on Form 10-K and its other periodic filings with the SEC. These factors include, but are not limited to: fluctuations in commodity prices; production levels and/or pricing by OPEC+ or U.S. producers; government policy, war and political conditions and events; integration efforts and projected synergies and other benefits in connection with the Berry Merger and other acquisitions; divestitures and joint ventures; regulatory actions and changes that affect the oil and gas industry generally and us in particular; the efforts of activists to delay or prevent oil and gas activities or the development of CRC’s carbon management segment; changes in business strategy and the ability and financial resources to execute our capital plan in a timely manner; lower-than-expected production; changes to estimates of reserves and related future cash flows; the recoverability of resources and unexpected geologic conditions; general economic conditions and trends; 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; the benefits contemplated by its energy transition strategies and initiatives; CRC’s ability to successfully identify, develop and finance carbon capture and storage projects, power projects and other renewable energy efforts; delays from government approvals and otherwise that could affect the timing of first injection of CO₂; future dividends and share repurchases and de-leveraging efforts; and natural disasters, accidents, mechanical failures, power outages, labor difficulties, cybersecurity breaches or attacks or other catastrophic events.

CRC cautions you not to place undue reliance on forward-looking statements contained in this communication, which speak only as of the date hereof, and CRC is under no obligation, and expressly disclaims any obligation to update, alter or otherwise revise any forward-looking statements, whether as a result of new information, future events or otherwise. This communication 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.

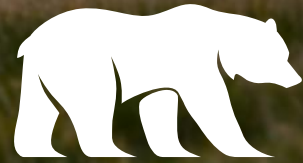
Forward-Looking / Cautionary Statements – Certain Terms

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, Drilling, Completion and Workover Capital, Reserve Replacement Ratio, per Bbl Brent O&G Only Breakeven Price, Cash Flow from Operations before WC Changes, Adjusted G&A Expense, Other Operating Expenses Net of Other Revenue, Margin from Purchased Commodities, Electricity Margin, PV-10, 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. Additionally, this presentation includes forward-looking non-GAAP financial measures, including adjusted EBITDAX. CRC is unable to provide a reconciliation of such forward-looking non-GAAP measures to the most directly comparable forward-looking GAAP financial measures because certain information needed to reconcile these measures is dependent on future events, many of which are outside of CRC’s control and cannot be reasonably predicted at this time. These items include, but are not limited to, changes in working capital, the timing and amount of capital accruals, and other non-cash or unusual items. Accordingly, a quantitative reconciliation is not available without unreasonable efforts.

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.



CALIFORNIA
RESOURCES

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