# Corporate Presentation

June 2026

CALIFORNIA RESOURCES

# A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA'S LARGEST O&G PRODUCER[1] 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".

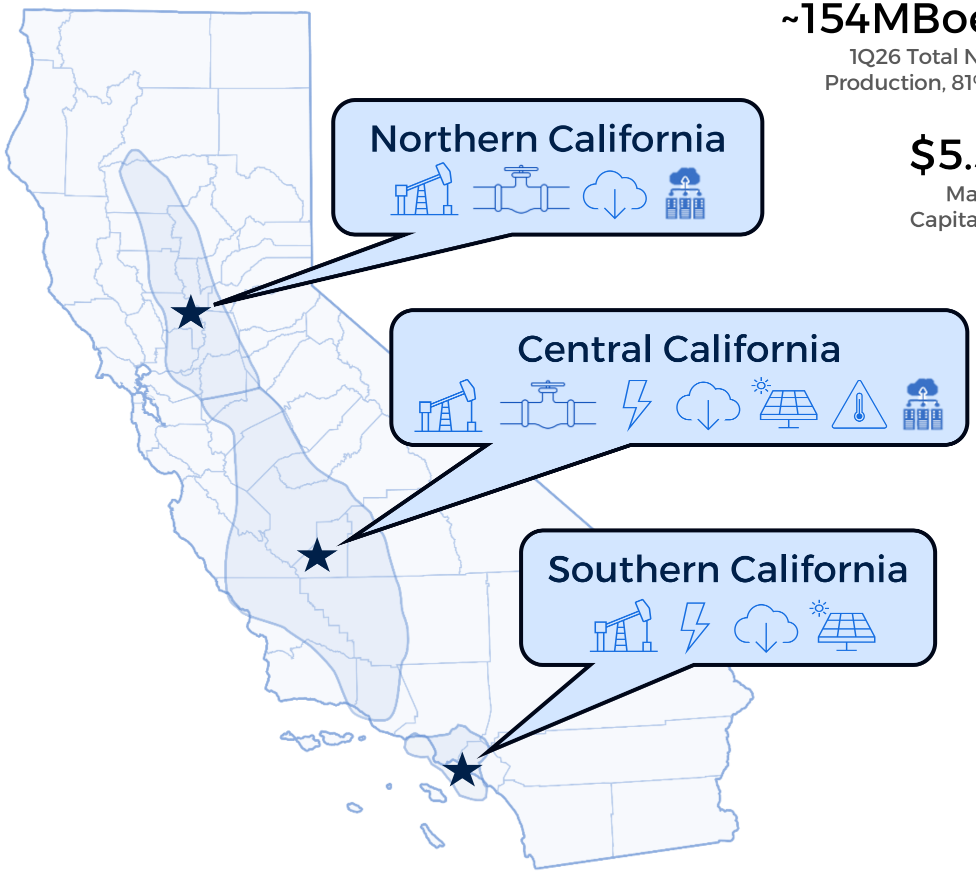
# Diversified and Complementary Energy Platform

~154MBoe/d | 8% - 13%

1Q26 Total Net Production, 81% Oil | Est. Corporate PDP Decline

$5.3B[2] | $6.6B[2]

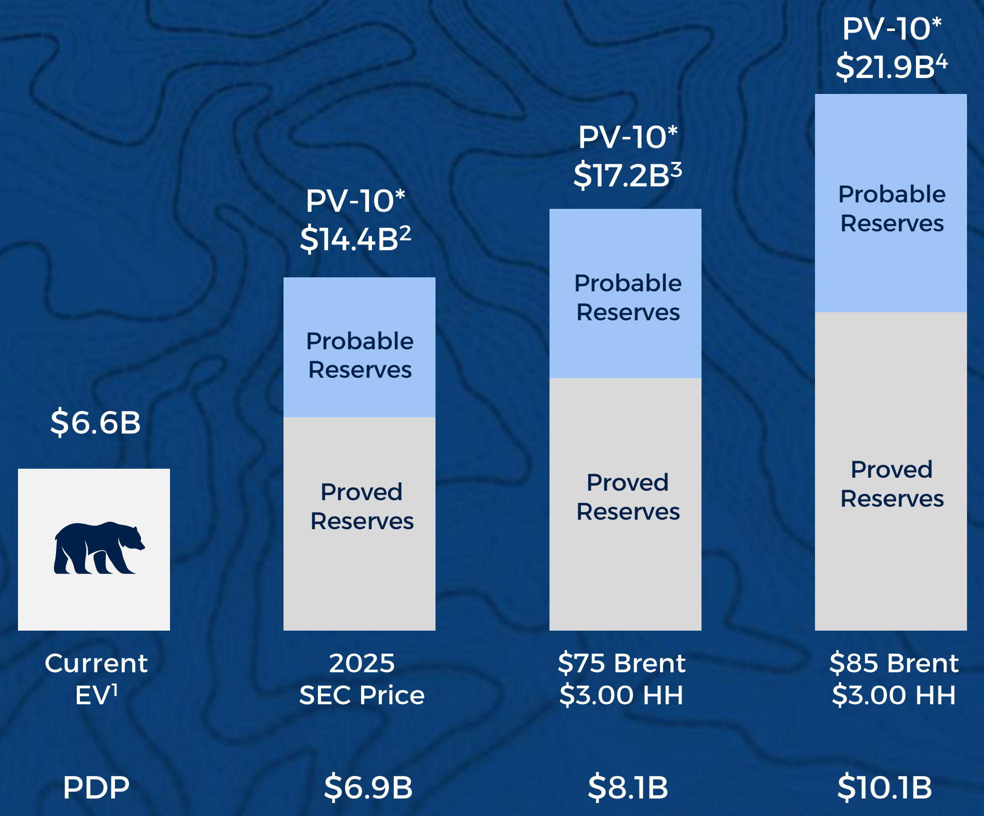
Market Capitalization | Enterprise Value




- Low Carbon Intensity Oil & Gas Production
- Midstream Infrastructure
- Power Generation
- Carbon Capture & Storage
- 3rd Party Power Opportunities
- Solar Opportunities
- Geothermal Opportunities

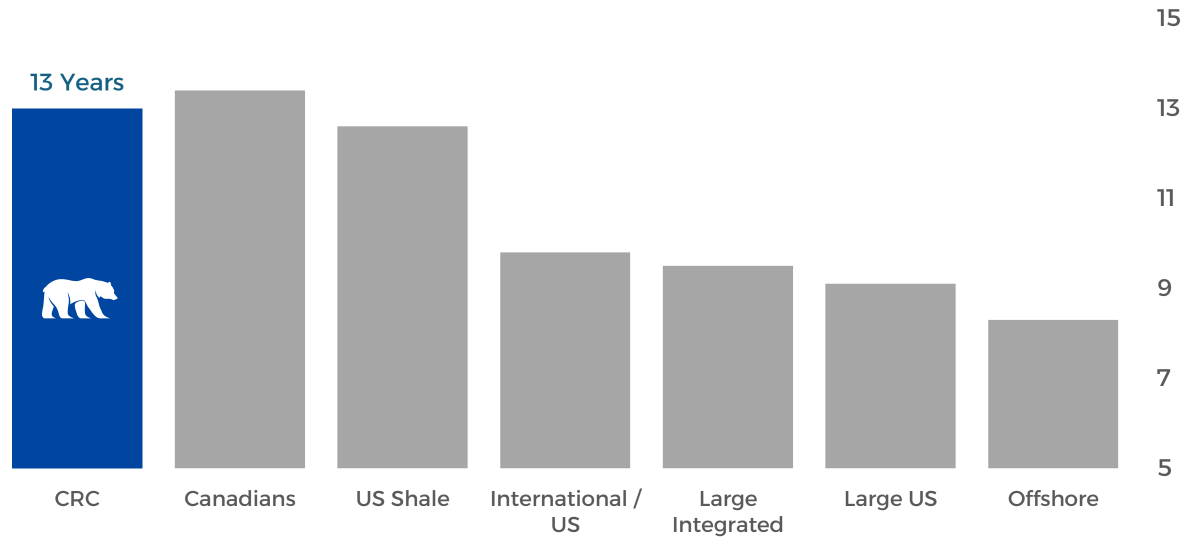
# Significant Value From World-Class Conventional Reservoirs

## Material Upside From Long Duration Assets



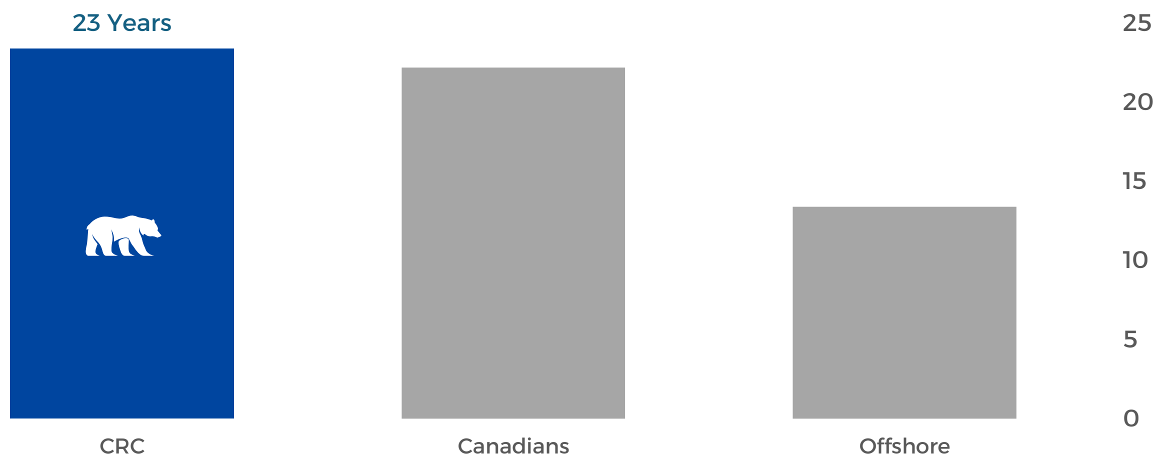

## Long Proved Reserves Base

Proved Reserves / Annual Production (Years)[5]




## Multi-Decade Conventional Runway

Proved + Probable Reserves / Annual Production (Years)[5]




See slides 31 and 32 for "Assumptions, Estimates and Endnotes".

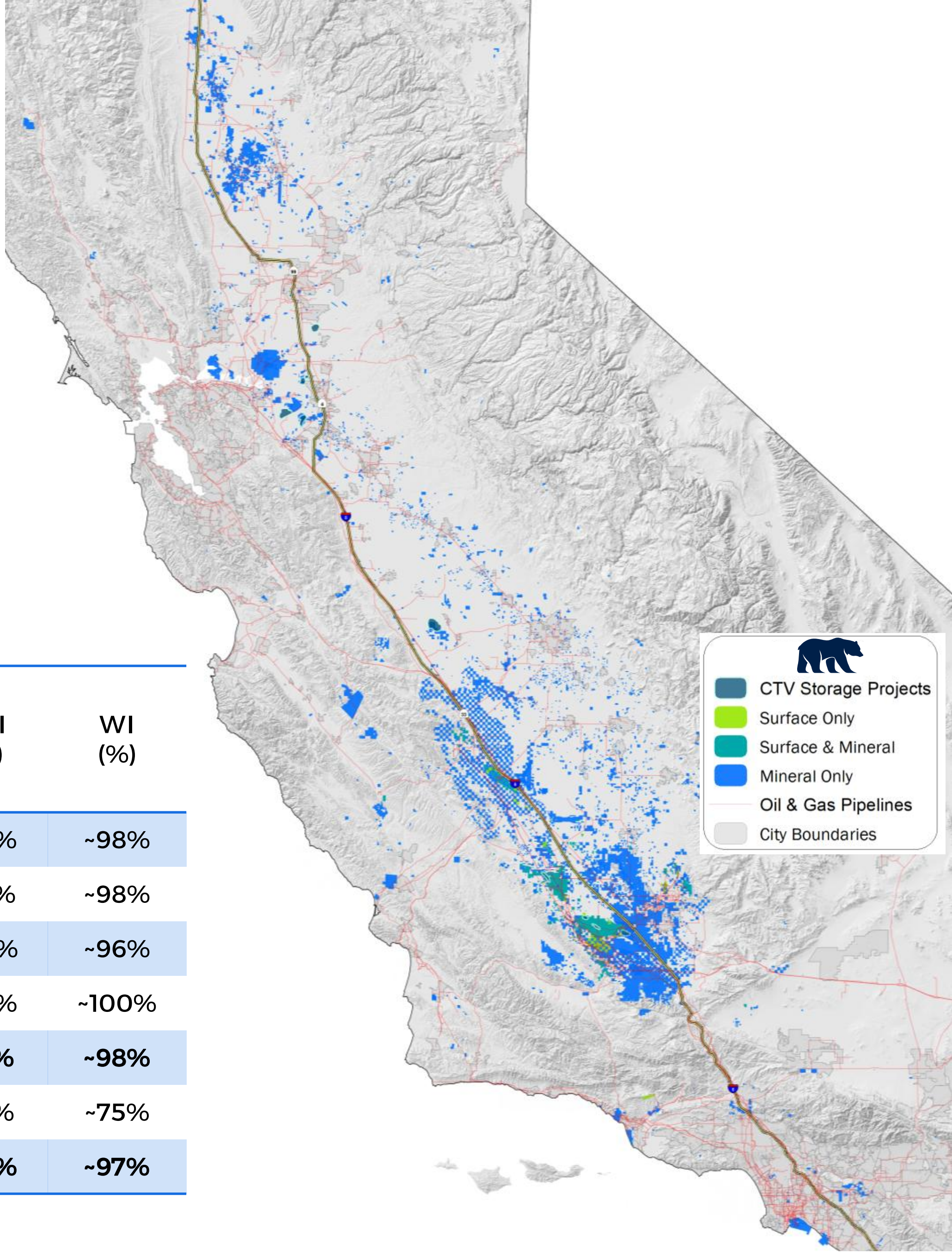
# Premier California Energy Company

## 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 Inventory[1]

| 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%** |




See slide 32 for "Assumptions, Estimates and Endnotes".

# CTV Commences First $CO_2$ 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*

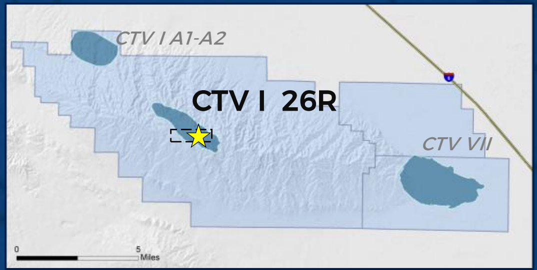
Emitter Pad and $CO_2$ Capture

Injection Pad


# California's First Active CCS Project

## Elk Hills Cryogenic Gas Plant Project

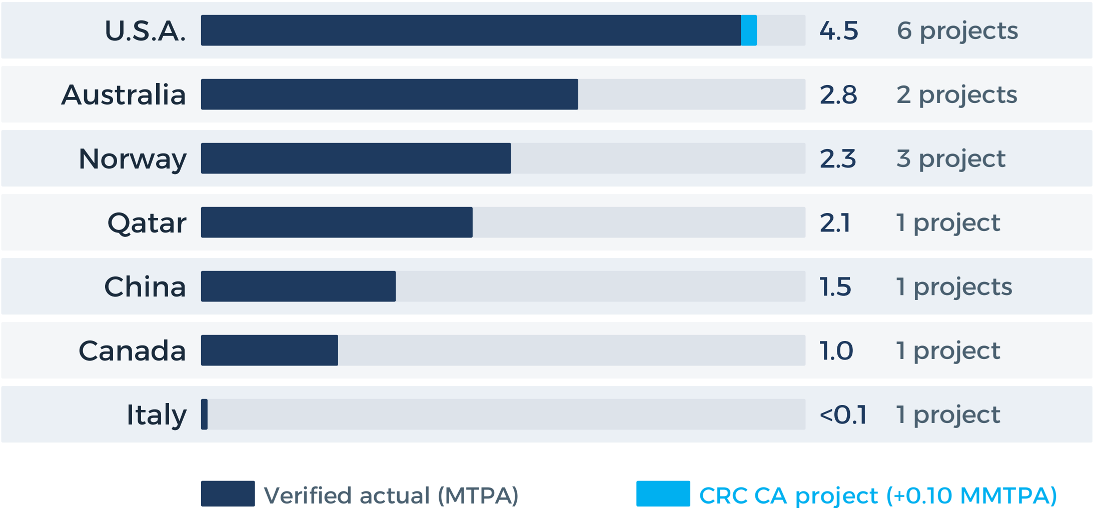
- Received final EPA approval to inject and commenced operations in May 2026
- Project captures pre-combustion $CO_2$ from produced natural gas at CRC's Elk Hills cryogenic gas plant for storage in the nearby CTV I - 26R reservoir
- Targeting injection and storage of up to ~100KMPTA of $CO_2$ emissions
- 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 Leaders[1]

## CARBON TERRAVAULT | 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 $CO_2$**
   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 $CO_2$ in dedicated geologic formations (EPA class VI)
3. **1 of 15 commercial-scale CCS projects globally**
   actively injecting and storing $CO_2$ (Non-EOR, Non-Acid Gas Injection)
4. **California's first and only commercial-scale CCS project**
   operational and injecting $CO_2$ in the state


EPA $CO_2$ Sample Collection


$CO_2$ Line to Injection Pad


Capture Equipment

### Amongst an Elite Global Sequestration Peer Group

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

| | | |
|---|---|---|
| **CRC**<br>Elk Hills, California | **Chevron**<br>Gorgon, Australia | **ExxonMobil**<br>Strathcona, Canada |
| **Shell**<br>Quest, Canada | **Equinor**<br>Snøhvit, Norway | **Santos**<br>Moomba, Australia |

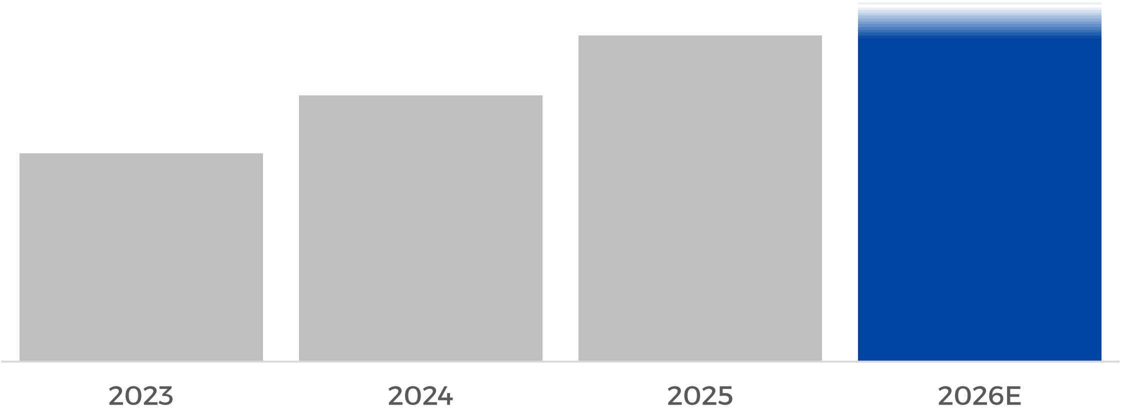
See slide 32 for "Assumptions, Estimates and Endnotes".

# 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

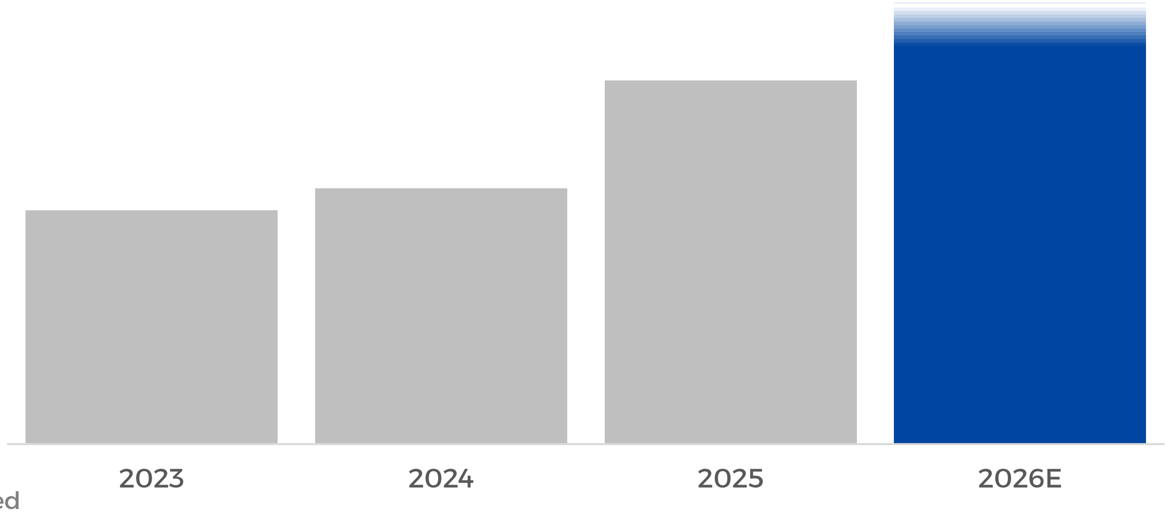
## Gaining Scale

Gross Production (MBoe/d)[1]




## Growing Cash Flow

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




| | 2023 | 2024 | 2025 | 2026E |
|---|---|---|---|---|
| Weighted Average Diluted Shares (MM) | 72.5 | 81.4 | 87.4 | ~89[2] |

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

# 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 efficiencies[1]
- 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 Brent[1]

See slide 32 for “Assumptions, Estimates and Endnotes”.

# 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 Yield[1]
Opportunistic and Disciplined Share Repurchases

Returned
**$46MM**
Dividends and SRP[2]

## HIGHLIGHTS

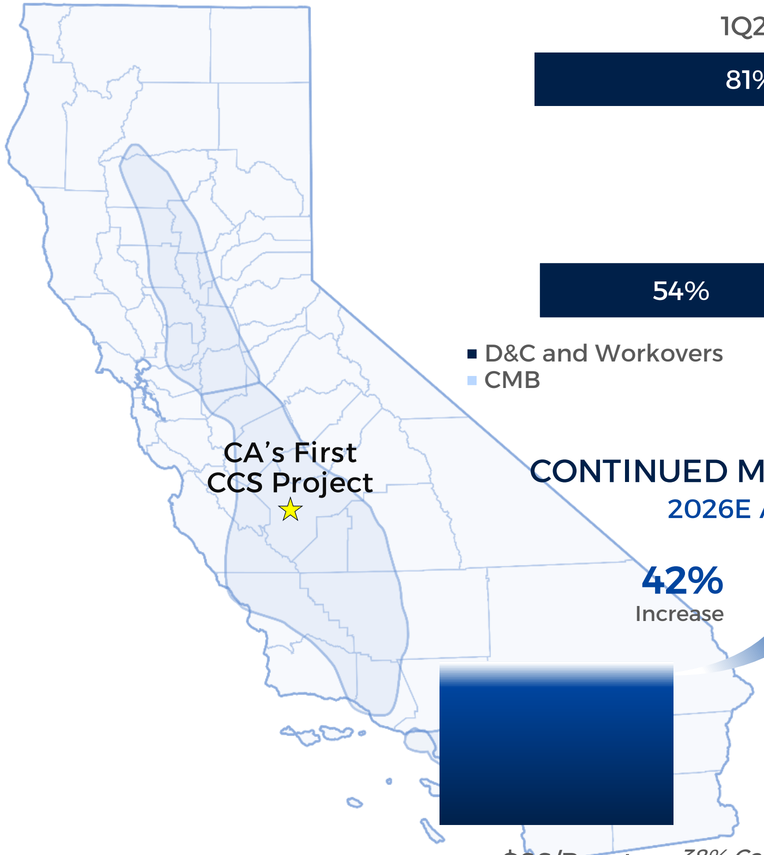
Increasing 2H26E Activity by
**3 Drilling Rigs**
2 Rigs in CA + 1 in UT
Targeting ~1% Entry to Exit Growth

Increased BRY Synergy Target to
**$90 – $100MM**
~12% Increase at Midpoint

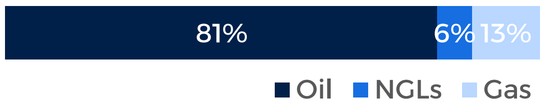
Lowered
2026E Facilities Capital by
**~$10MM[3]**
Driven by Operating Efficiencies

Raised
2026E Adj. EBITDAX* Guidance
**$1,400 – $1,500MM[3]**
at $91 Brent

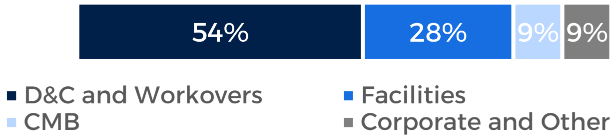
## California's Premier Energy Platform




154MBOE/D
1Q26 Total Net Production

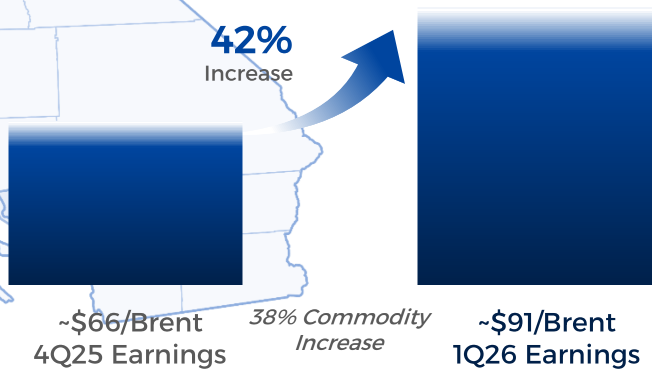



$131MM
1Q26 Total Capital




### CONTINUED MARGIN EXPANSION

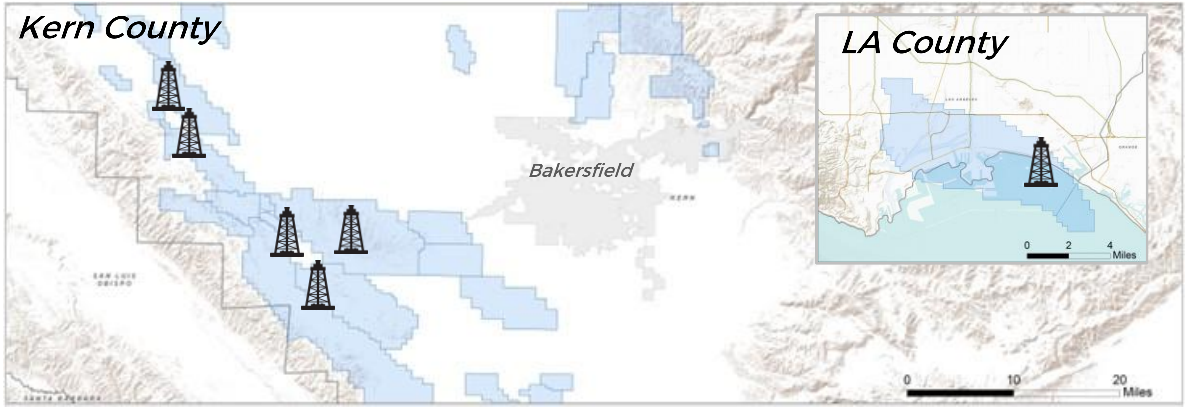
2026E Adj EBITDAX* Guidance[3]

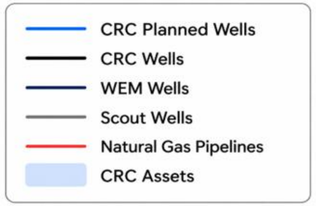



See slide 32 for "Assumptions, Estimates and Endnotes".

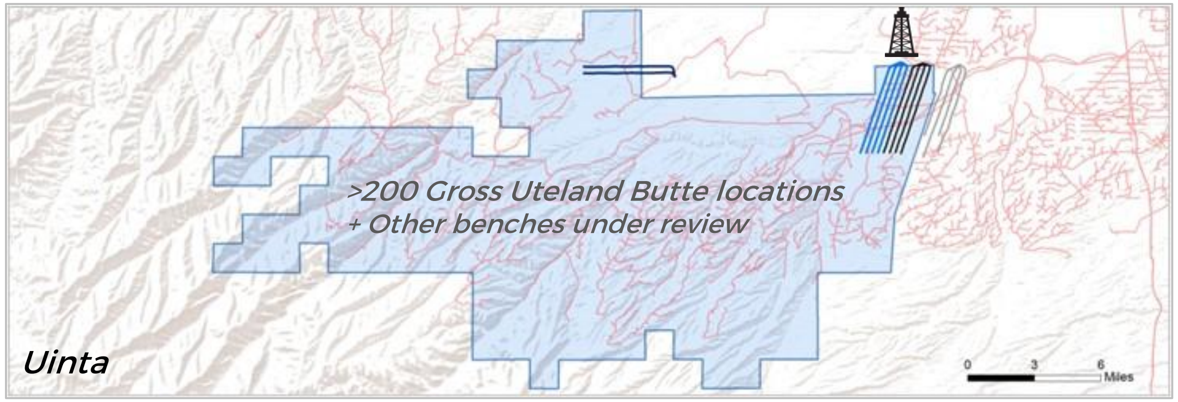
# Delivering Through a Portfolio Approach

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



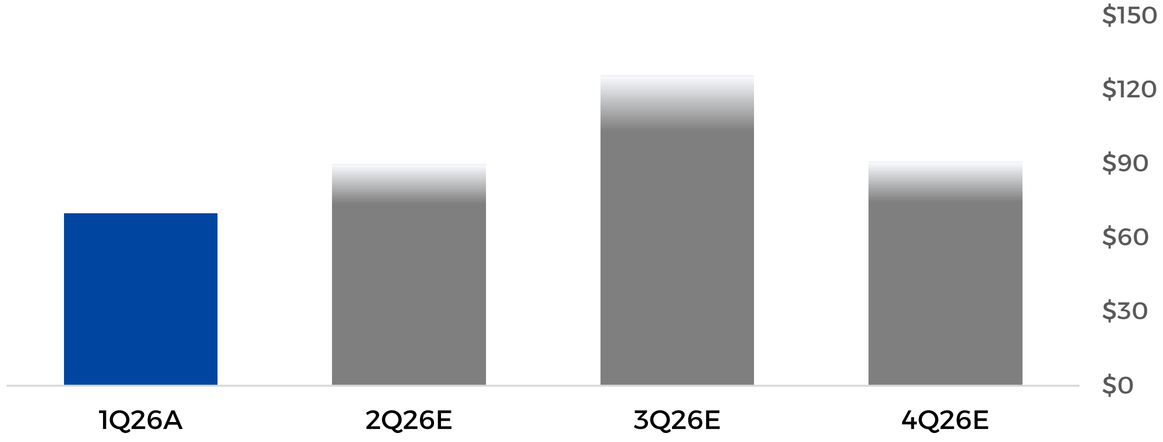




## Planning a 4-Well Pad in Northern Uinta
## Targeting First Production in 4Q26



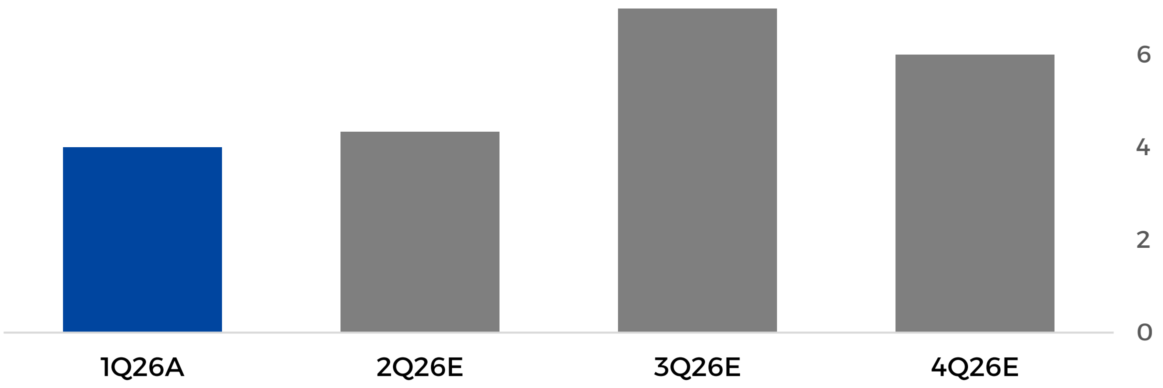

## Disciplined Capital Allocation

2026E D&C and Workover Capital[1]




## Planning to Scale Activity

2026E Rig Program[1]

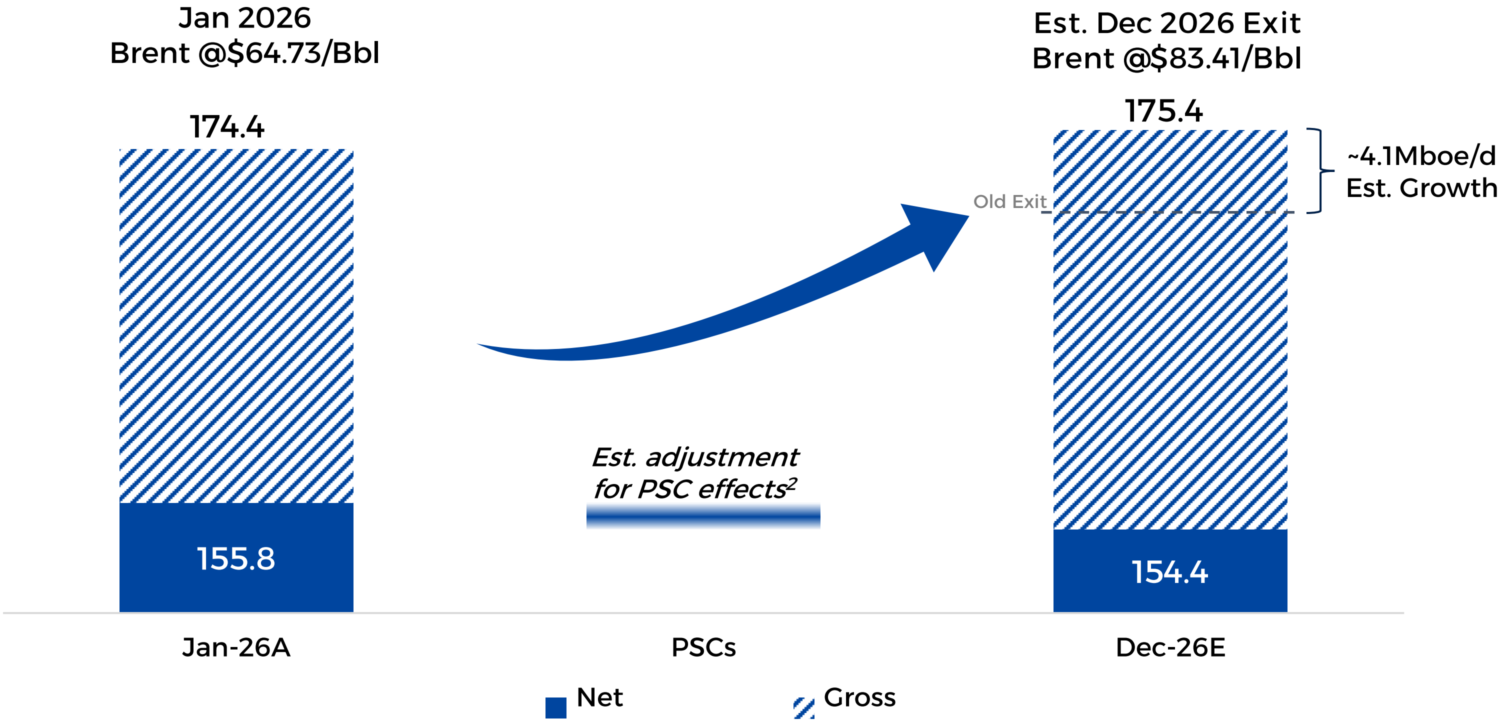



See slide 33 for “Assumptions, Estimates and Endnotes”.

# 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 rigs[3] 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

| Annual Cadence | Entry to Exit |
| --- | --- |
| 4 Rigs<br>$280 -$300MM<br>D&C and Workover Capital | ~(2%)<br>Gross Decline |

## New[4]

| Annual Cadence | Entry to Exit |
| --- | --- |
| ~5 Rigs<br>$380 -$400MM<br>D&C and Workover Capital | ~1%<br>Gross Growth |

CRC Continues to Target Long-Term Maintenance Program[5]
~7 rigs with D&C + workover capital range of $480–$500MM

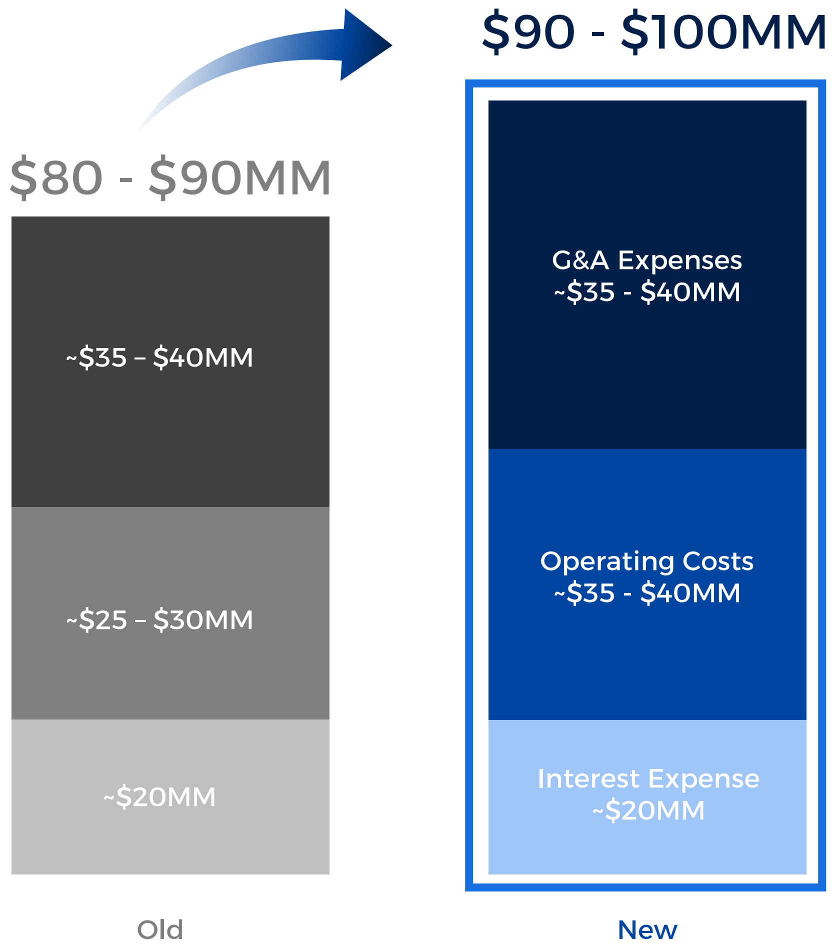
See slide 33 for "Assumptions, Estimates and Endnotes".

# Continued Structural Cost Reductions Drive Margin Expansion

## With >80% of Synergies Implemented to Date

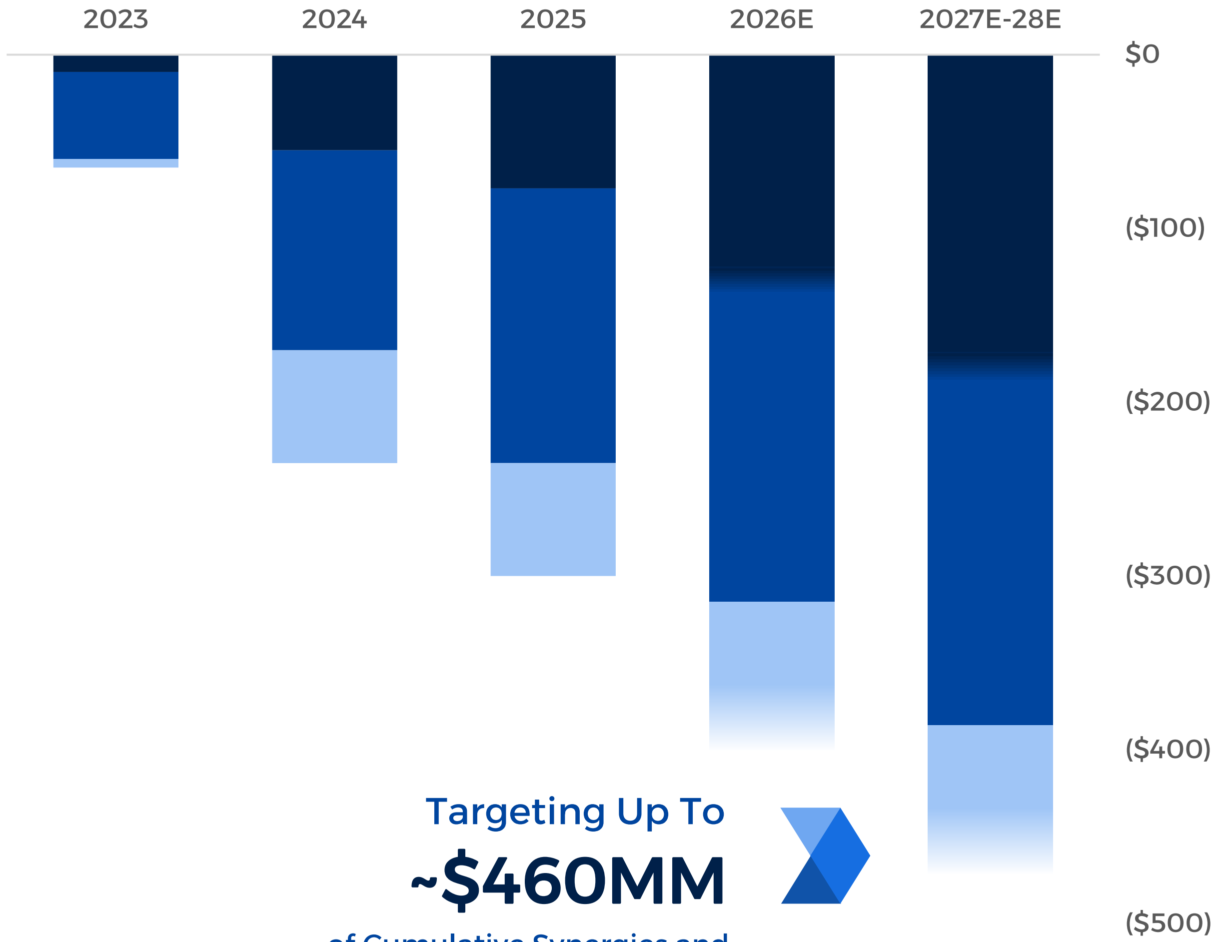
### 12% Increase in Targeted Synergies

2026 Estimated Berry-Related Synergies ($MM)




### Benefits of a Leaner CRC

Targeted Cumulative Synergies and Structural Cost Reductions ($MM)




Targeting Up To

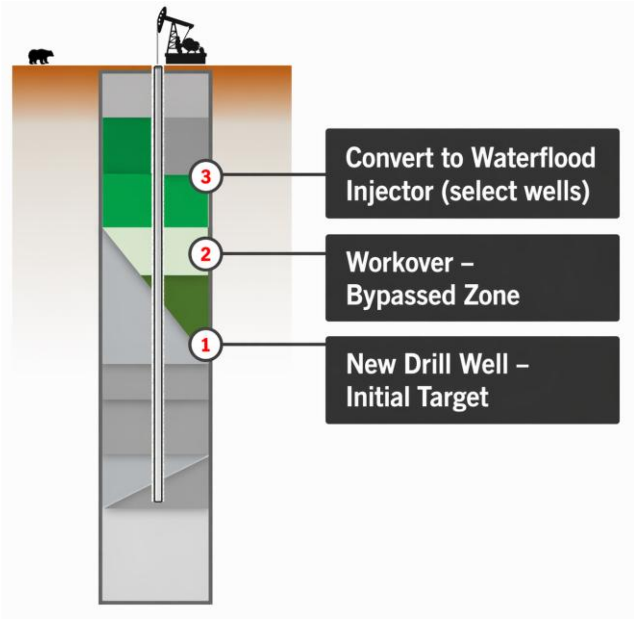
**~$460MM**

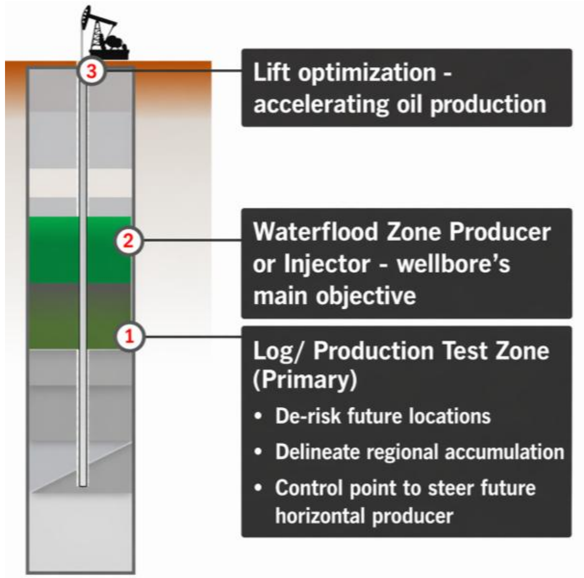
of Cumulative Synergies and Cost Reductions Through 2028

# Low-Decline Assets - Quick Returns

## 2026E Key Operational Updates

- Reduced 2026E facilities capex by $10MM[1] 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

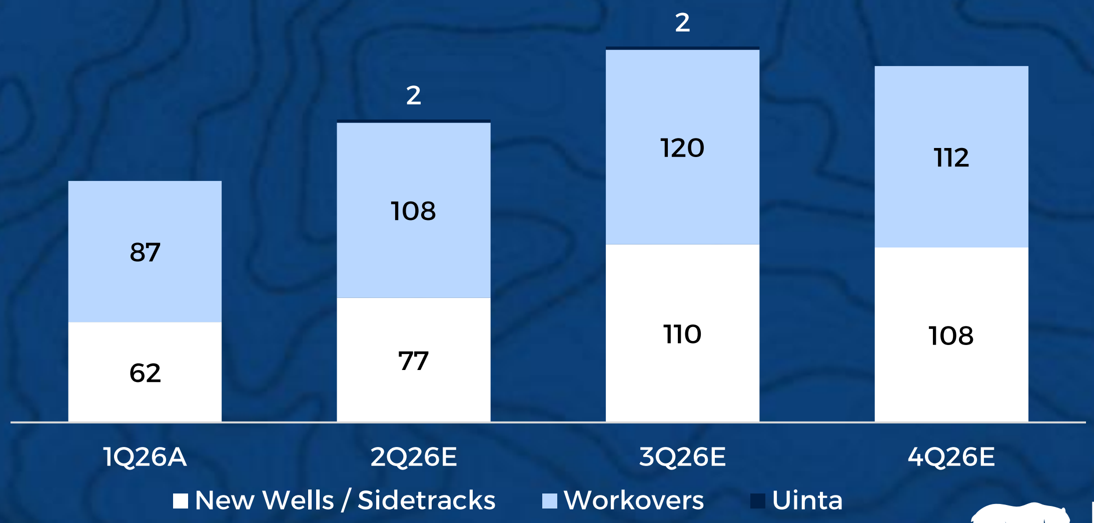
## Updated 2026E O&G Program Economics[1,2]

| ~4.5x | ~69% |
|---|---|
| MOIC[3] | IRR |

**2026E E&P Capital[1]** **$500 - $525MM**


## Accelerating 2026E D&C and Workover Activity Cadence[1]

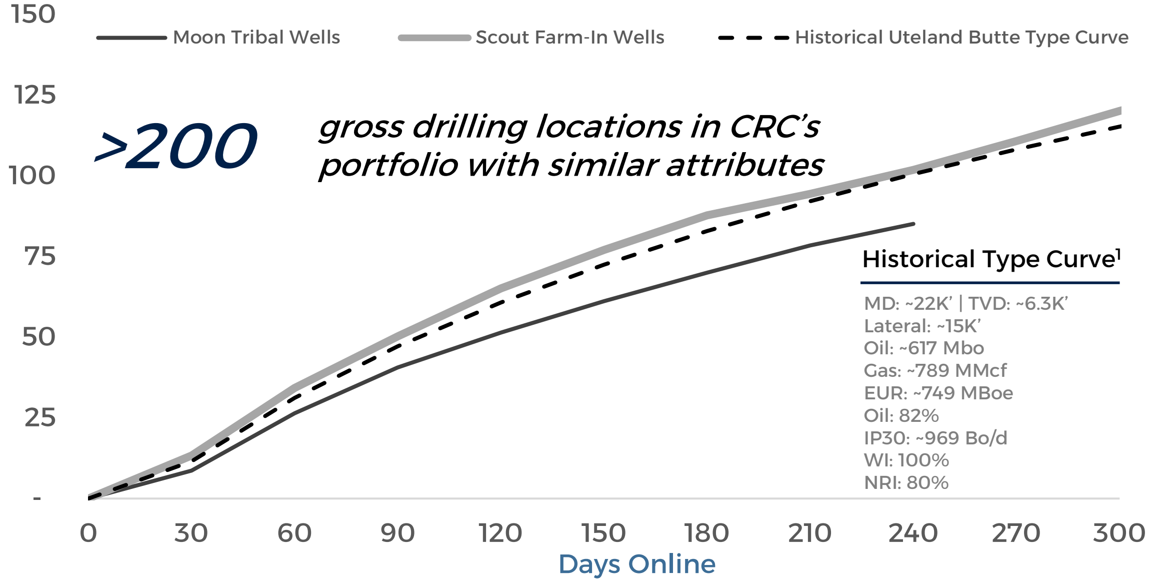
Planned Quarterly Wells



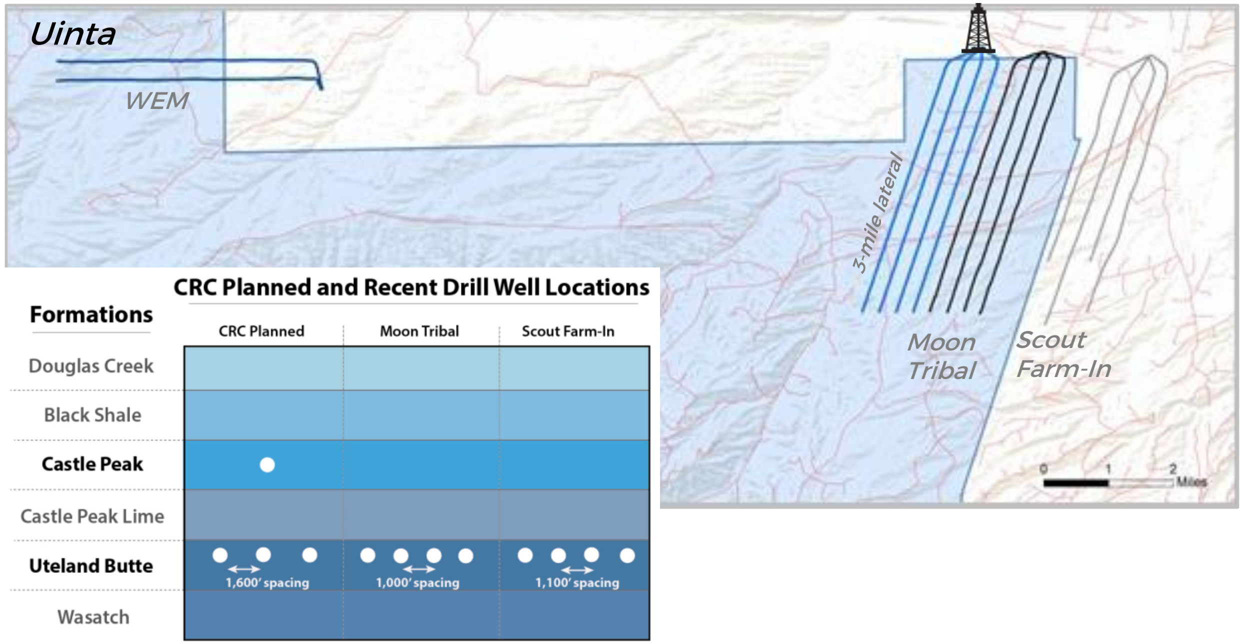
# Uinta: Highly Contiguous Asset with Abundant Stacked Pay Opportunities

## Nearby Type Curves Demonstrate Upside

Cumulative oil (MBo/10K' lateral)[1]

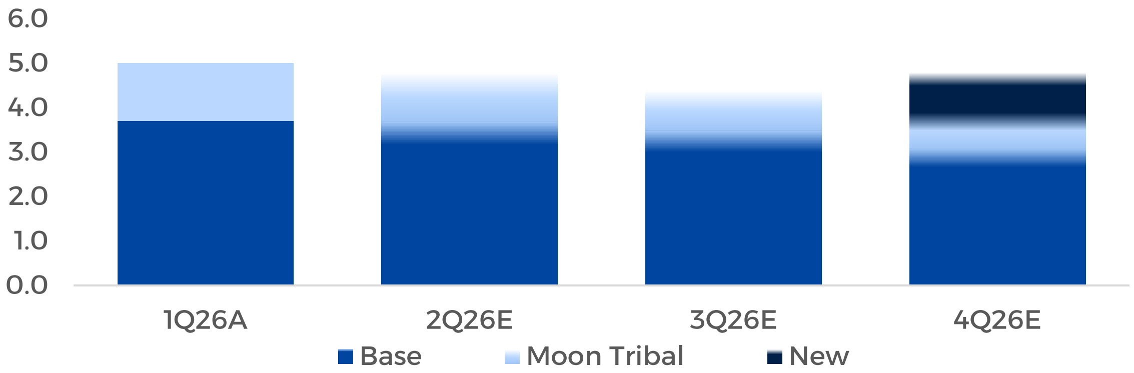



## De-Risking Acreage




## Accelerating Production

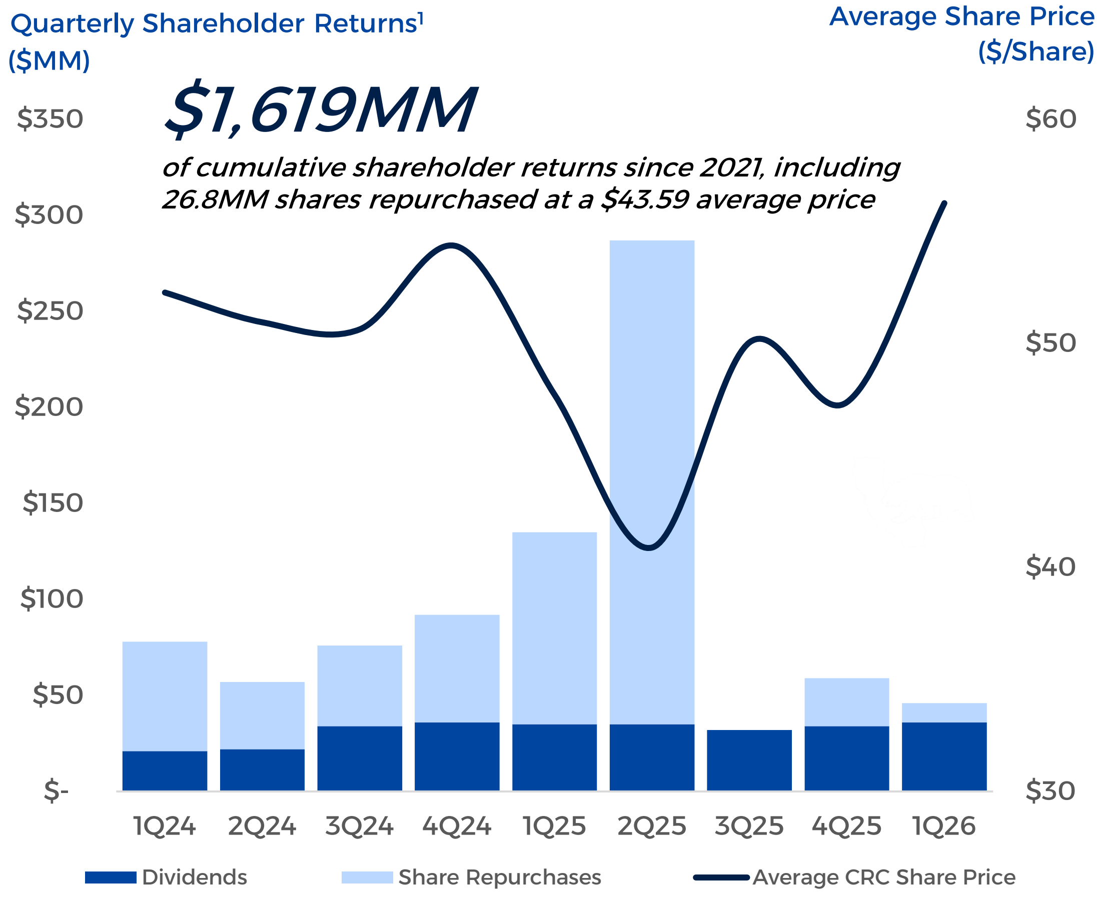
2026E Uinta Net Production (MBoe/d)[2]



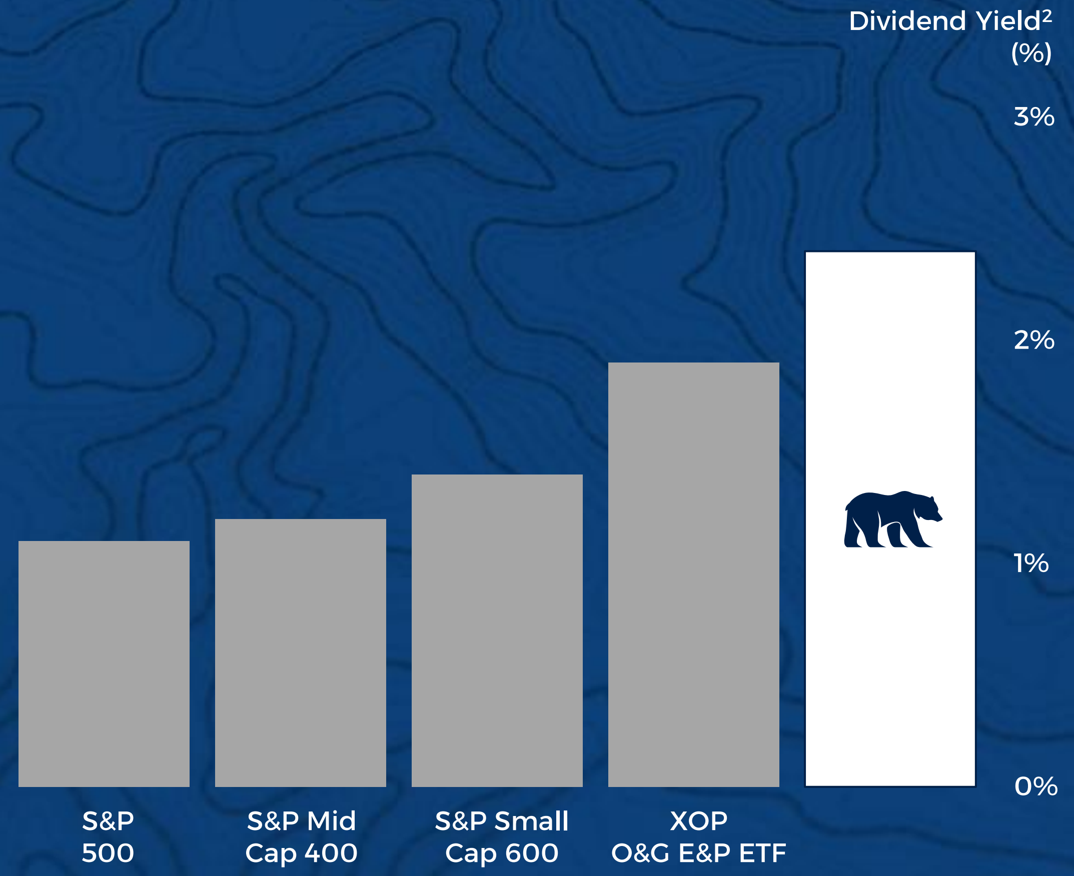

- Offset well production has substantially de-risked performance of CRC future wells
- Moon Tribal wells provided completion optimization learnings that are expected to lower future costs and improve productivity performance
- Allocating ~$46MM to D&C a new 4-well pad: 3 wells targeting Uteland Butte and 1 well targeting Castle Peak
- First production planned for 4Q26 with projected peak in 1Q27

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

# Opportunistic Share Repurchases Create Observable Value




# Attractive Fixed Dividend vs Market




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

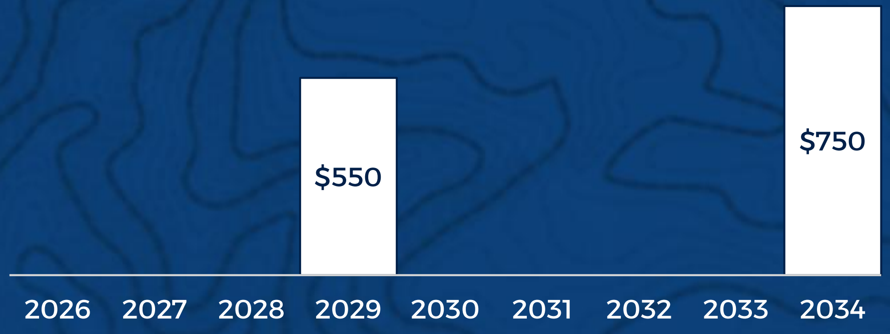
# Capital Structure Provides Flexibility

## 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)




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

# 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 |

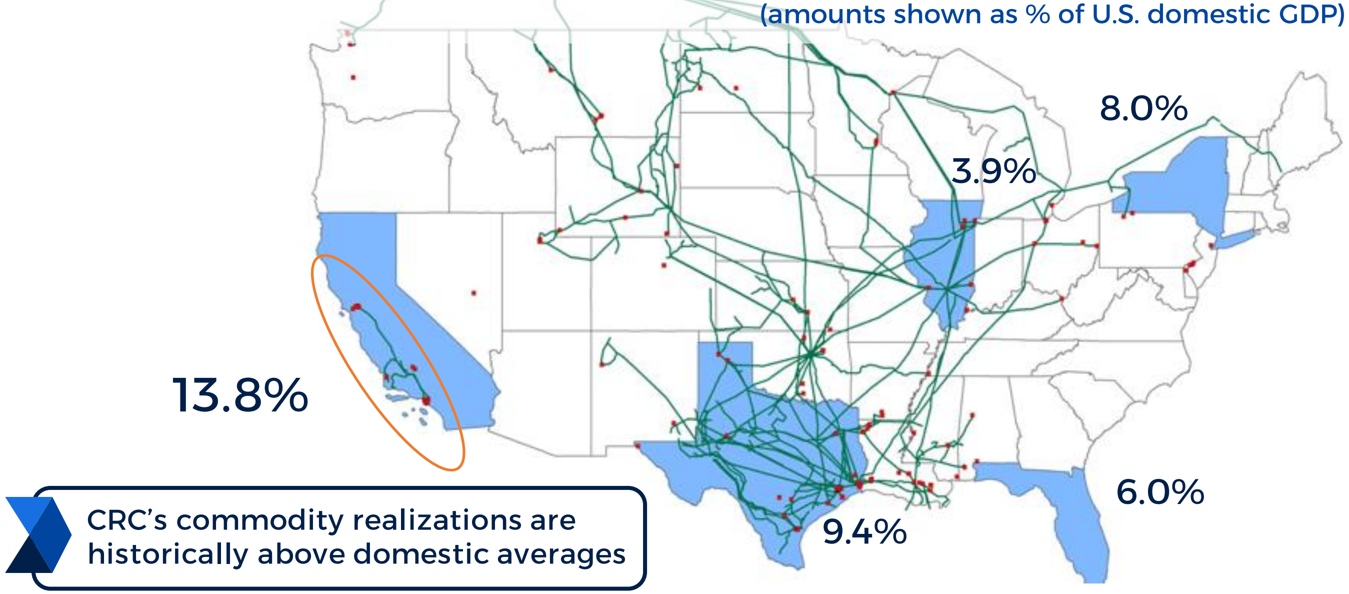
## Strong Coverage Ratios

| | ($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

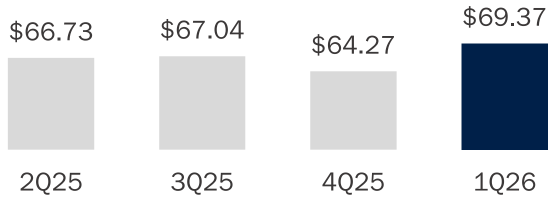
- Crude: 1Q26 Brent crude prices rose Q/Q and Y/Y as both Middle East and incremental Russian liquids exports were sharply curtailed due to military conflicts. California realizations were in line with seasonal expectations.
- Natural Gas: 1Q26 North American natural gas prices were generally higher 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)

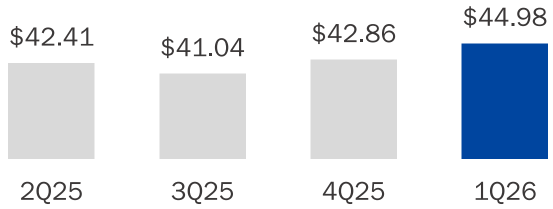



Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 4Q25; EIA

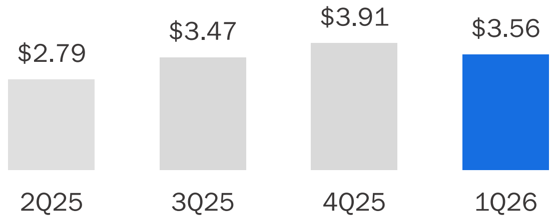
Oil w/ Hedges ($/BBL)




NGLs ($/BBL)




Natural Gas ($/MCF)




| | Oil 2Q25 | Oil 3Q25 | Oil 4Q25 | Oil 1Q26 | NGLs 2Q25 | NGLs 3Q25 | NGLs 4Q25 | NGLs 1Q26 | Gas 2Q25 | Gas 3Q25 | Gas 4Q25 | Gas 1Q26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Average Benchmark Prices[1] | $66.76 | $68.13 | $63.08 | $77.90 | $66.76 | $68.13 | $63.08 | $77.90 | $3.44 | $3.07 | $3.55 | $5.04 |
| % of Benchmark[1] | 97% | 97% | 97% | 96% | 64% | 60% | 68% | 58% | 81% | 113% | 110% | 71% |
| Hedge Settlements | $1.66 | $0.72 | $3.13 | ($5.16) | - | - | - | - | - | - | - | - |
| Average Realized Prices[2] | $66.73 | $67.04 | $64.27 | $69.37 | $42.41 | $41.04 | $42.86 | $44.98 | $2.79 | $3.47 | $3.91 | $3.56 |

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

# 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 PUTS[1]** | | | | | | |
| 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 | $3.51 |
| **EST. HEDGE CONTRACT SETTLEMENTS[3]** | | **2Q26E** | **3Q26E** | **4Q26E** | **2027E** | **2028E** |
| Combined Hedge Portfolio ($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/Bbl[4]

## OPERATIONS

~61% of remaining 2026E internal fuel consumption hedged at an average natural gas price of ~$4.00/MMBtu[4]

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


Appendix

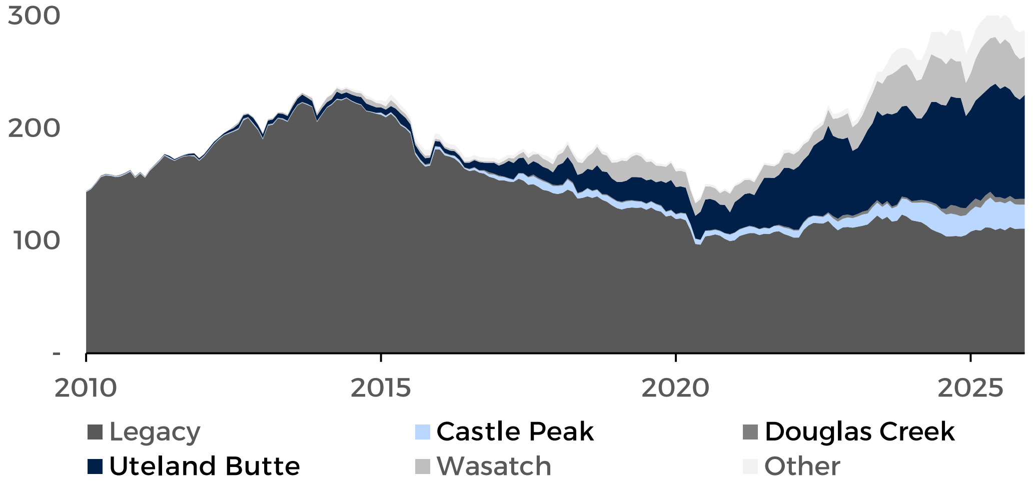
# Top-Quartile Well Performance Puts Uinta on the Map

## 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.)

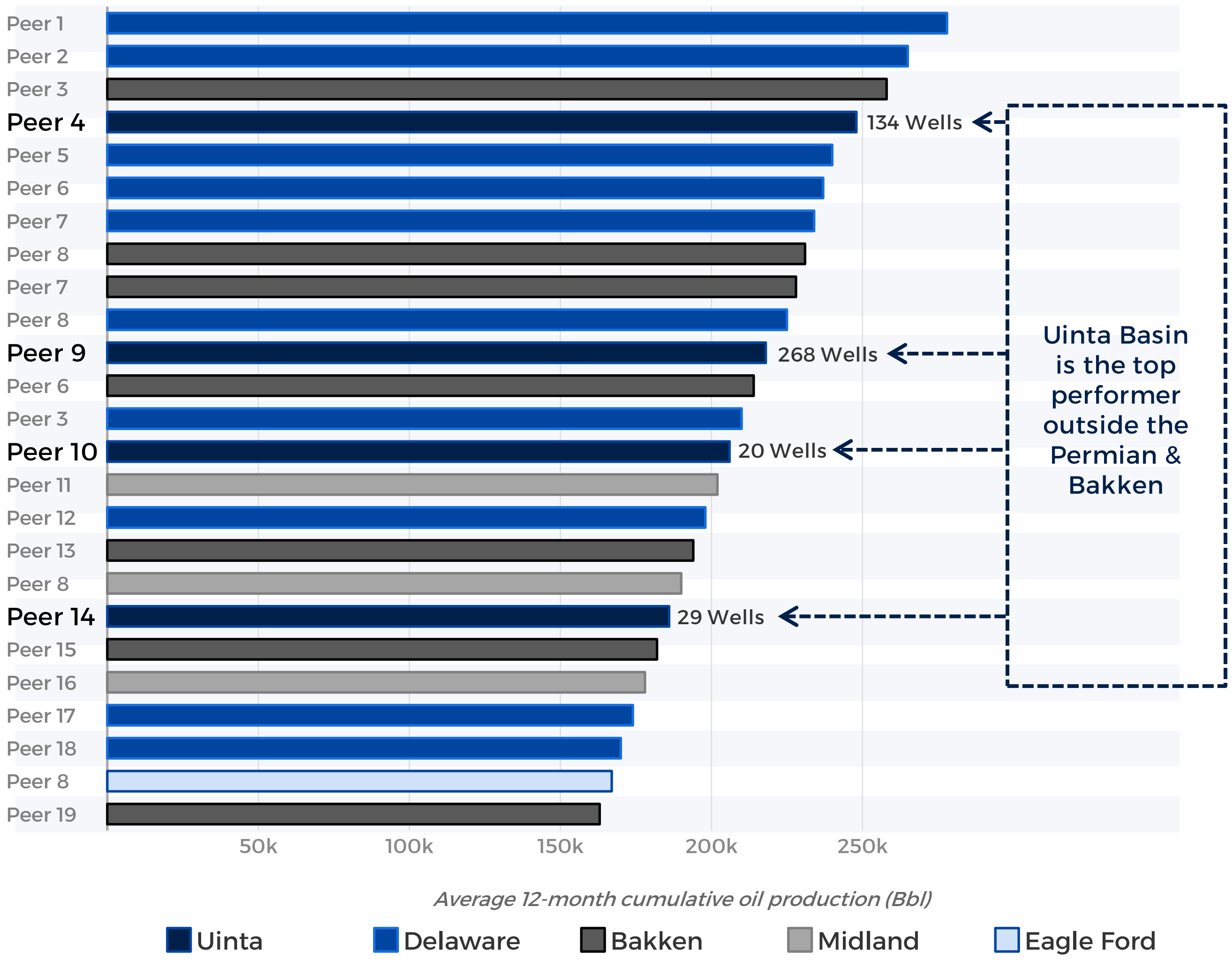
## Since YE2020, 2x Rise in Basin Production

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 Performance[2]




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

# 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 PSCs[1]

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

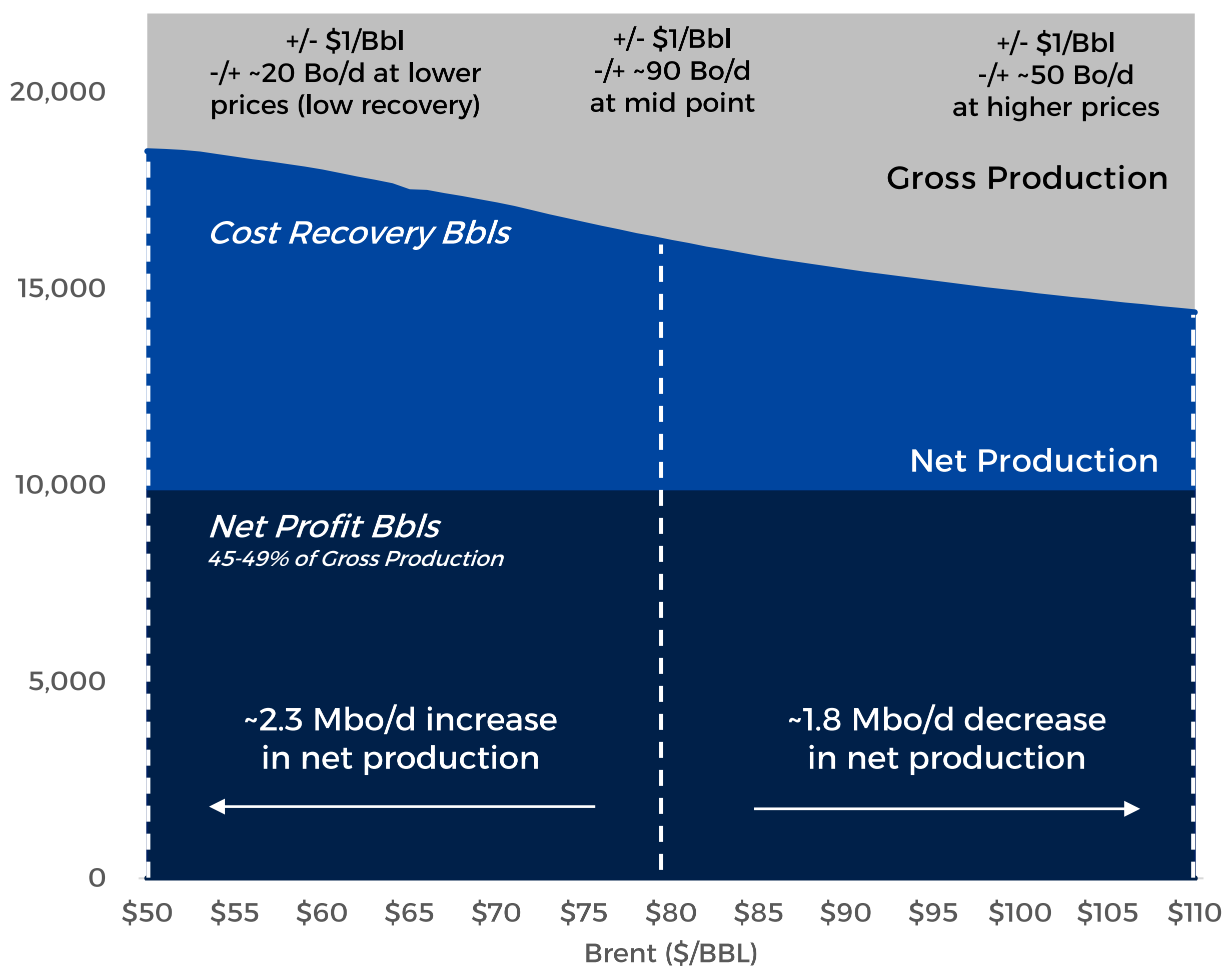
- CRC pays its partners' share of operating and capital cost
- CRC recovers partners' share of operating and capital costs through production sharing, where CRC's cost recovery is reported as revenue
- CRC receives ~45-49% of the gross production as "Profit Barrels" after cost recovery
- CRC's net share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

As prices rise, fewer barrels are assigned as cost recovery

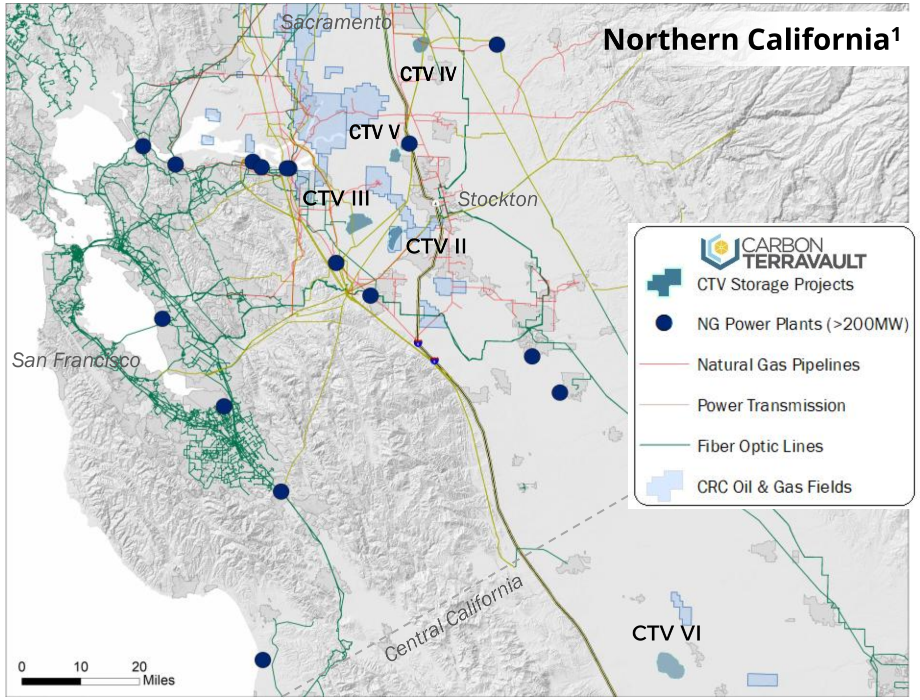
CRC sees a difference of ~4.1 MBO/D in net oil production between $50/Bbl and $110/Bbl[2]

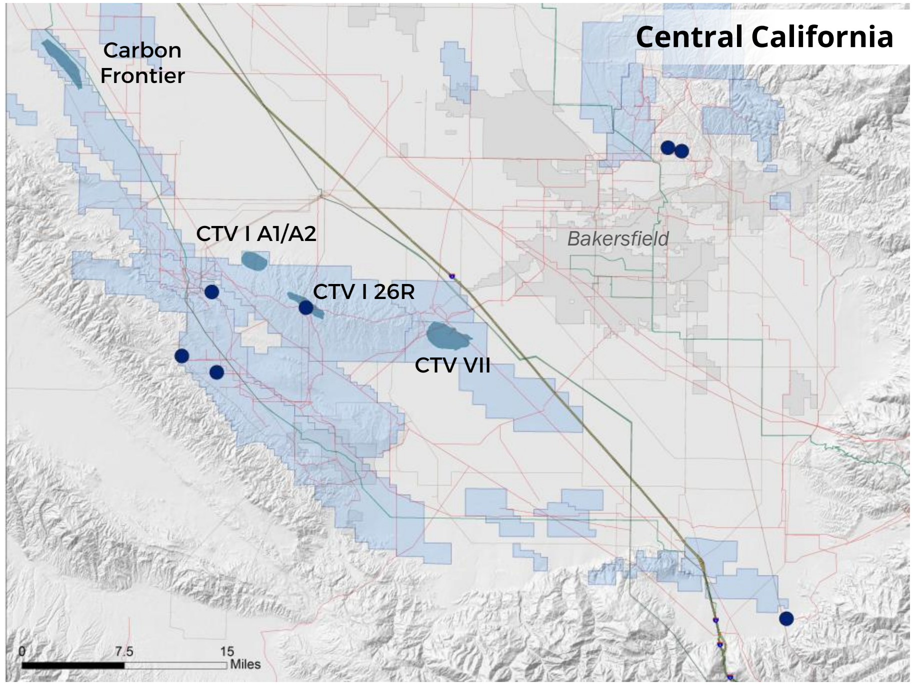
## Effect Of Oil Price On Net Production[2]

Wilmington Field Production (Bo/d)




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

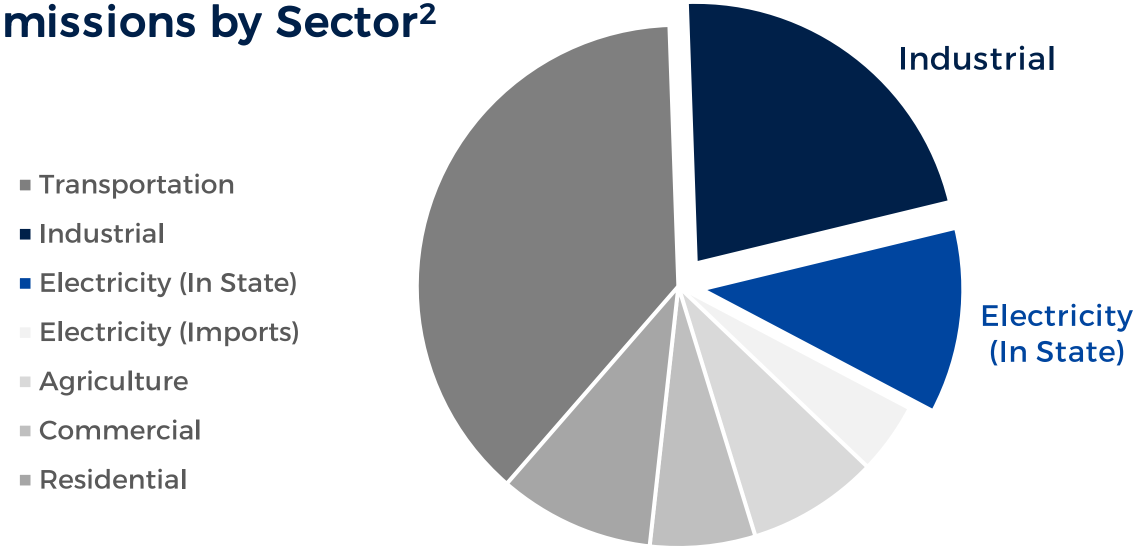



# Well Positioned to Decarbonize California's Largest Industries

- 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 Sector[2]

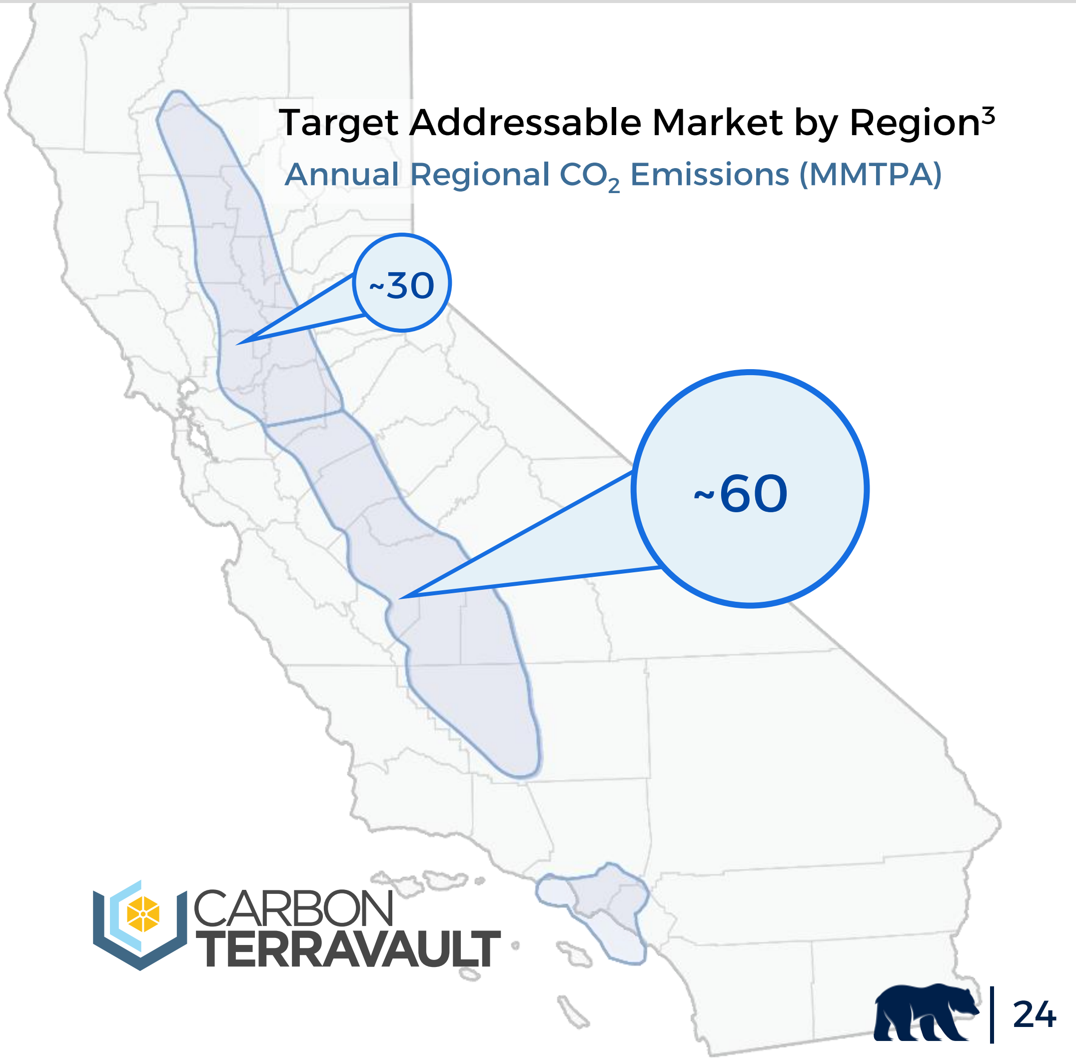



See slide 34 for "Assumptions, Estimates and Endnotes".

# California’s Premier Carbon Management Provider

- In May 2026, started sequestering $CO_2$ 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 2026[1]

| 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 |




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

# 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 $CO_2$ at California's first CCS project

## Current Market Dynamics

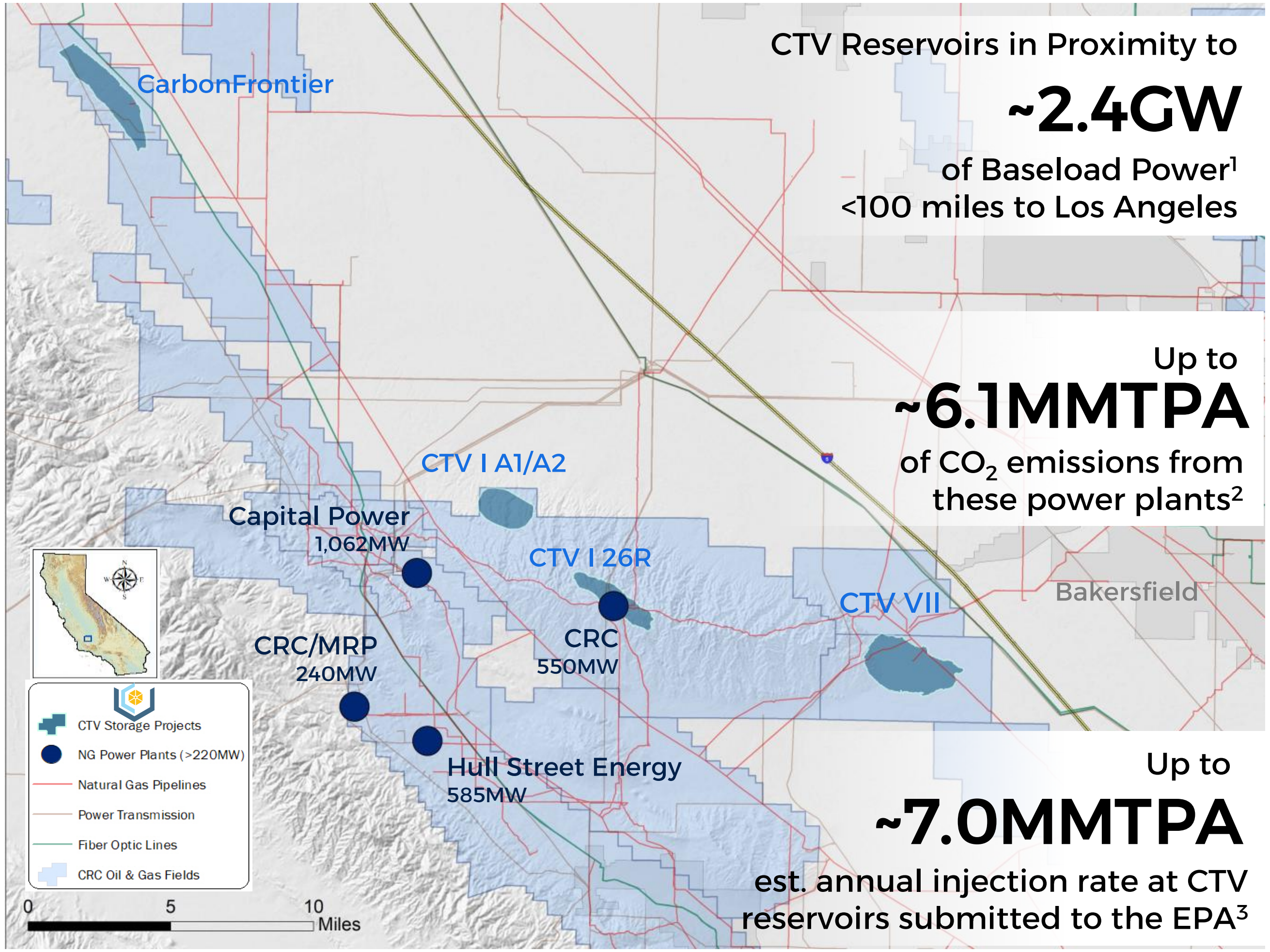
| Opportunity | Customers | Clean Premium |
|---|---|---|
| 1 FTM Utility Sale | Utilities | ✓ |
| 2 FTM Sale | Existing Data Centers, Industrials | ✓ |
| 3 BTM Industry Sale | New Data Centers, Industrials | ✓ |

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 $CO_2$ storage reservoirs
- Possible $CO_2$ pipeline connectivity

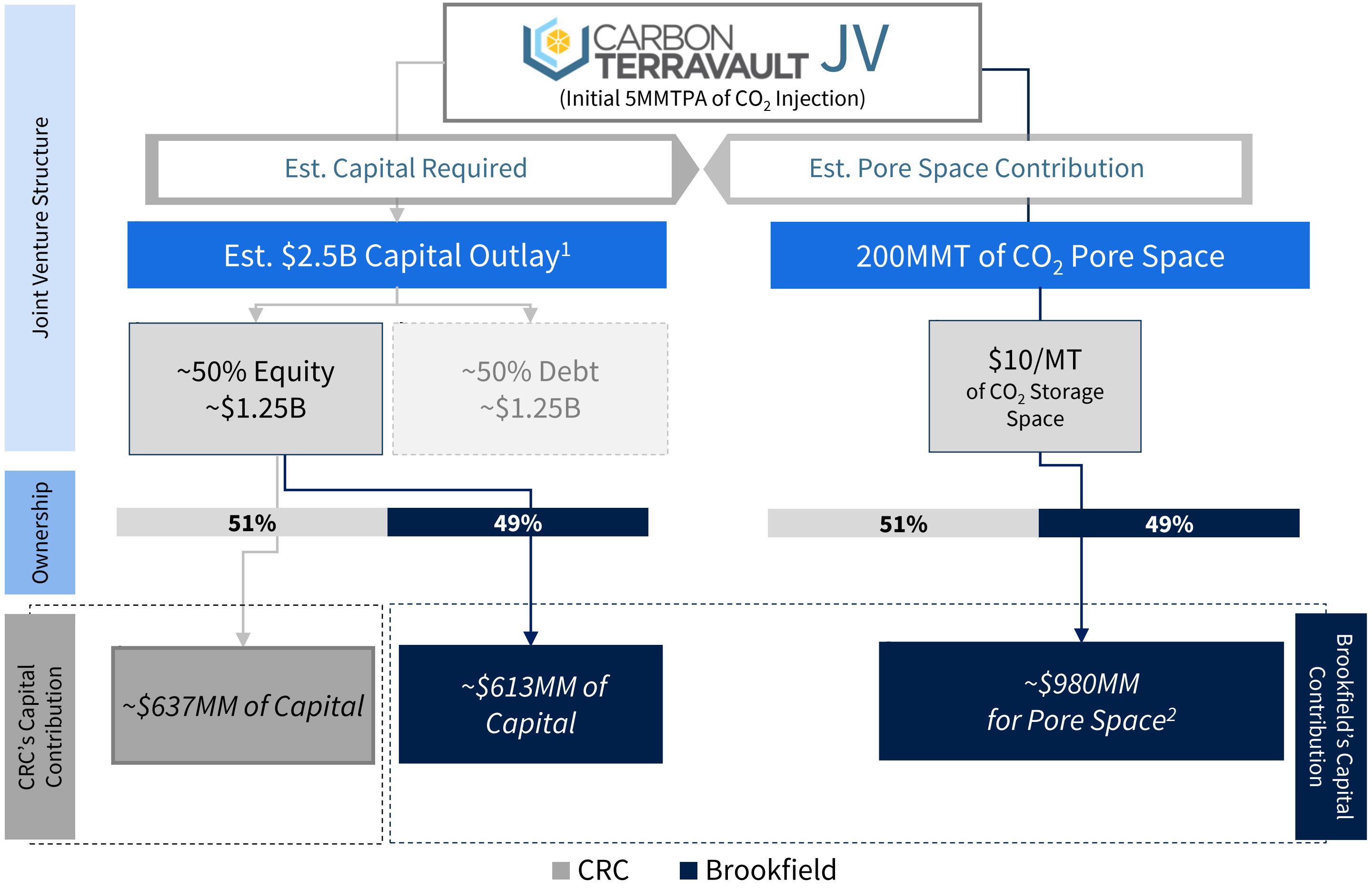
## Powered Land



# Strategic Carbon Management Partnership

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

*assumes Brookfield fully participates in the initial 5MMTPA of CTV JV projects*




### Improves & Increases Flexibility of CRC's Capital Allocation Framework

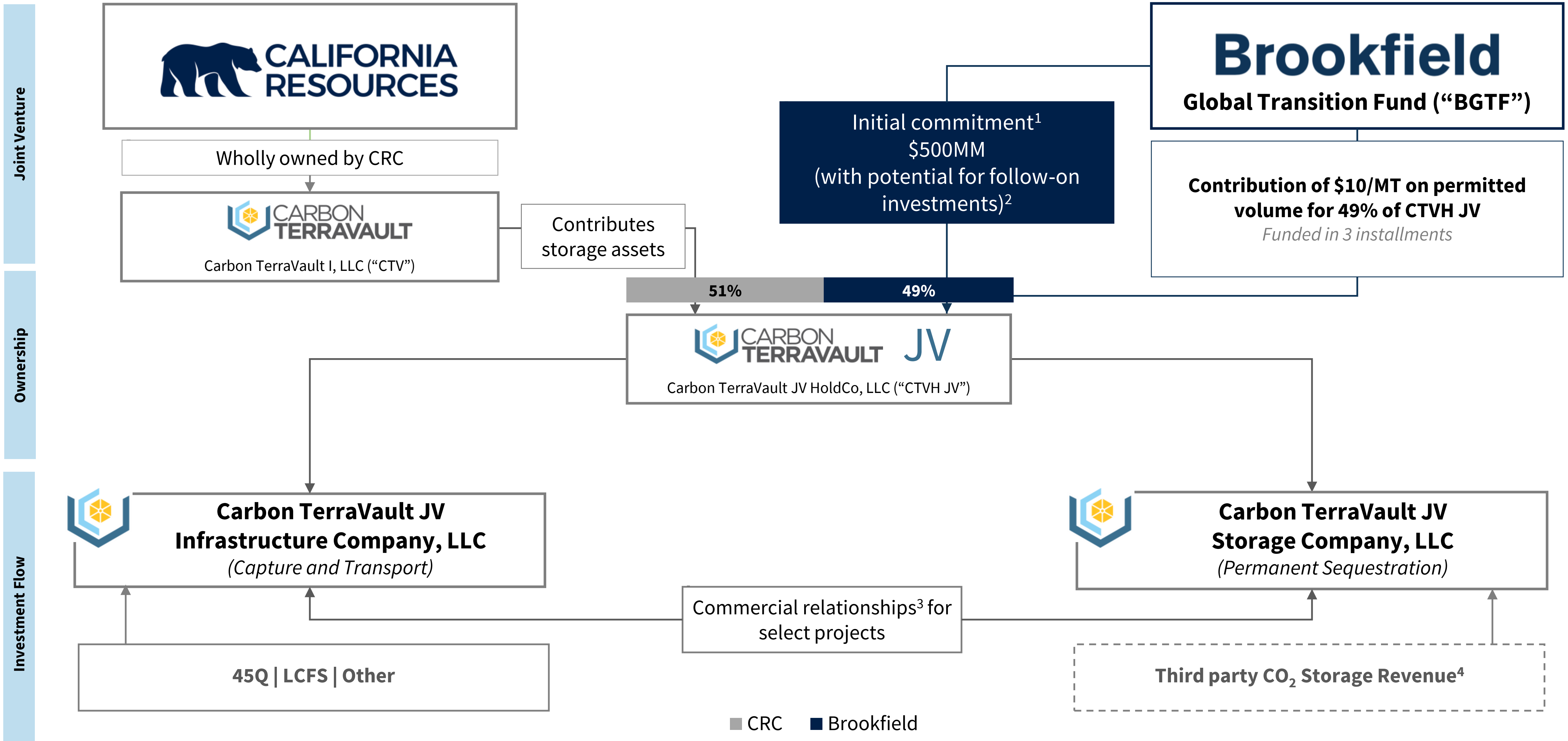
- Capitalizes first 5MMTPA of projects and provides potential funding for CRC's development of 200MMT of $CO_2$ storage
- CRC's equity commitments for the first 5MMTPA are more than 2x covered by Brookfield's initial commitment for projects jointly approved through the CTV JV
- Allows CRC to increase 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 Capital[3]

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

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

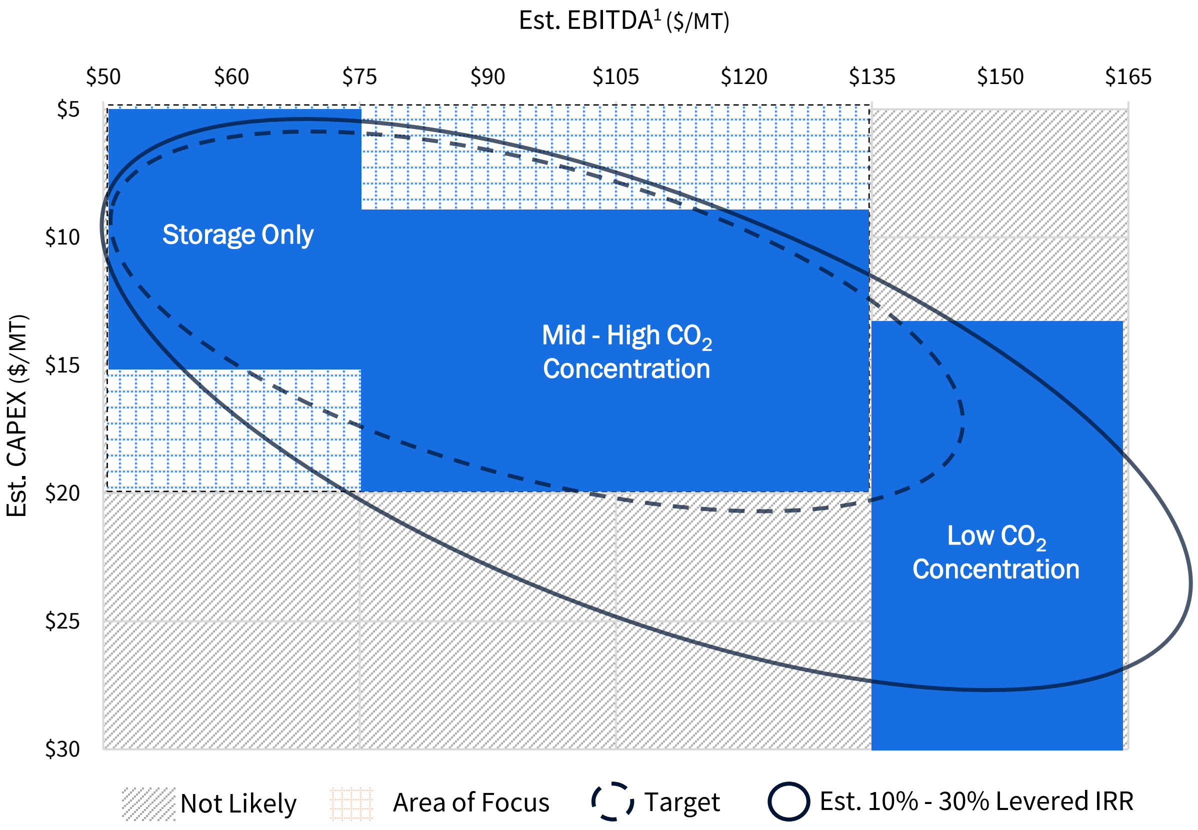
# Carbon TerraVault Joint Venture Details




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

# Strategic Partnership – A Structural Capital Advantage

**ILLUSTRATIVE EBITDA[1] VS CAPEX REQUIREMENTS FOR VARIOUS $CO_2$ PROJECTS**




## STORAGE ONLY PROJECTS

- CTV JV is the off-taker of $CO_2$ at storage site through Storage Co.
- Lower expected capital requirements for project development, including injection and monitoring wells, facilities and compression

## MID - HIGH $CO_2$ CONCENTRATION PROJECTS

(≥15% $CO_2$ 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 $CO_2$ 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 $CO_2$ CONCENTRATION PROJECTS

(<15% $CO_2$ 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)
- CalCapture[2] is an advantaged low $CO_2$ concentration project given its proximity to storage (insignificant transport capital)

Note: Depicts illustrative examples of expected and estimated IRR, EBITDA and capital expenditure requirements based on internal estimates. Actual results could differ materially. See slide 35 for "Assumptions, Estimates and Endnotes".

# Progressing Huntington Beach Real Estate Asset Development


**1.2 miles** of direct access to Pacific Coast Highway

## 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

Source: CRC internal estimates. See www.crchbproperty.com for additional information.

# 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 |
| 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 29, 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 29, 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 $CO_2$ 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 $CO_2$ injection by YE 2027, aligned with CRC's 2027 goals, thereby requiring an estimated ~$2.5B of capital.
2) ~$980MM assumes 200MMT of $CO_2$ pore space for $10/MT of $CO_2$ storage space and 49% Brookfield ownership which assumes Brookfield fully participates in CCS projects up to JV target of 5MMTPA of injection and 200MMT of $CO_2$ storage.
3) Results subject to effects of taxes, timing, pace of project development and Brookfield further approval to fund capital.

**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 $CO_2$ 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.

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# Forward-Looking / Cautionary Statements – Certain Terms

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