CALIFORNIA RESOURCES CORPORATION

A DIFFERENT KIND OF ENERGY COMPANY

# Second Quarter 2025 Results

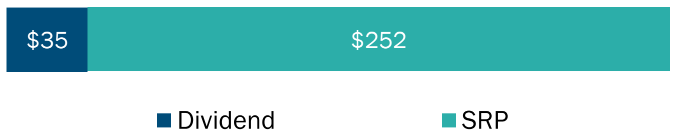
August 5, 2025

# 2Q25 Key Takeaways

## 1. RECORD QUARTERLY CAPITAL RETURNS TO SHAREHOLDERS[1]

- Repurchased **$228MM** of shares in a private deal at $46/sh and **$24MM in the open market** at avg. ~$43.41/sh
- **$205MM remaining** under the authorized share repurchase program
- **Share repurchase program extended** through June 30, 2026

**$287MM**
**2Q25 TOTAL SHAREHOLDER RETURN[1]**




## 2. ROBUST OPERATIONAL AND FINANCIAL PERFORMANCE

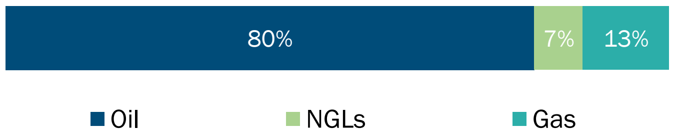
- **Delivered strong reservoir performance** with 1% gross and 3% net production QoQ declines; **added second rig in Kern County**
- **Implemented $235MM Aera merger targeted synergies,** 3 months ahead of schedule
- Generated **$324MM of Adj. EBITDAX*,** beating guidance

**$165MM**
**2Q25 OPERATING CASH FLOW**


## 3. OPERATIONAL MOMENTUM CONTINUES IN 2025

- **Reduced** 2025E **D&C and workover capital by ~3%; raised the midpoints** of 2025E **net production by ~1%** and **adj. EBITDAX* by ~7%**[2]
- **CTV JV received authorization to construct from the U.S. EPA**
- **CTV remains on track to complete construction of its first CCS project at Elk Hills at or around YE25;** first $CO_2$ injection in early 2026 pending final regulatory approvals

**137MBOE/D**
**2Q25 NET PRODUCTION**




See slide 24 for "Assumptions, Estimates and Endnotes".

# Execution, Execution, Execution

# Generating Record Shareholder Returns

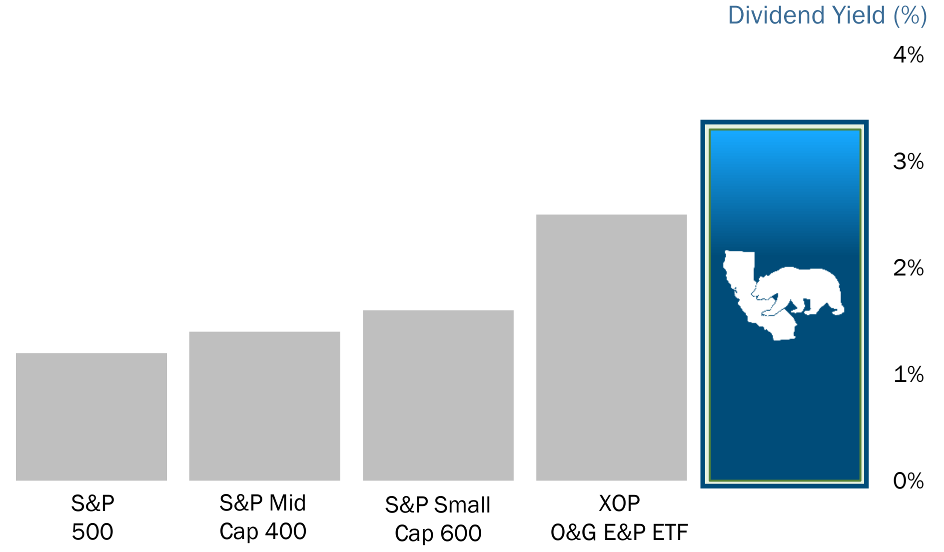
*Returned*

**$287MM** | Dividends and Buybacks in 2Q25[1]

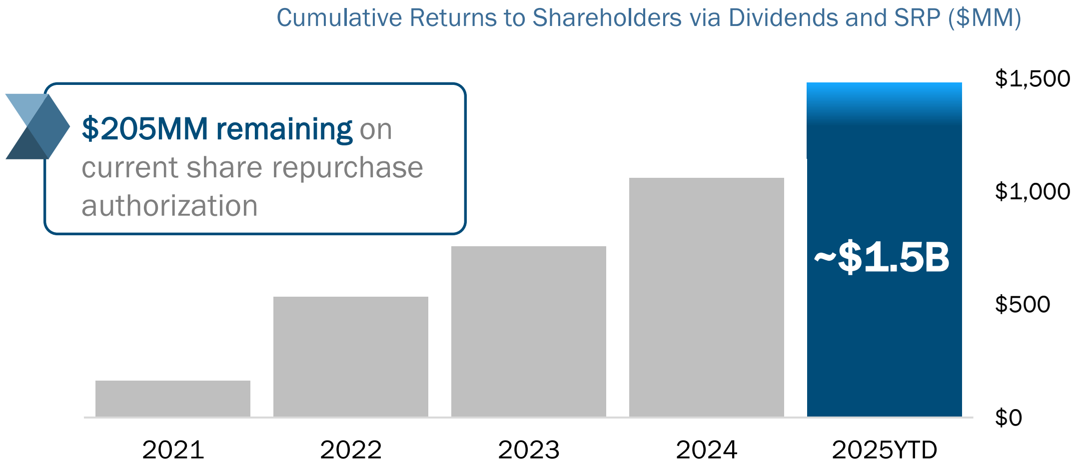
**~263%** | Of Free Cash Flow* in 2Q25
~86% since May 2021

**$422MM** | Dividends and Buybacks in 1H25[1]
$1,482MM since May 2021[1]

### Competitive Dividend Yield vs. Market[2]




### Significant Return of Capital to Shareholders[1]

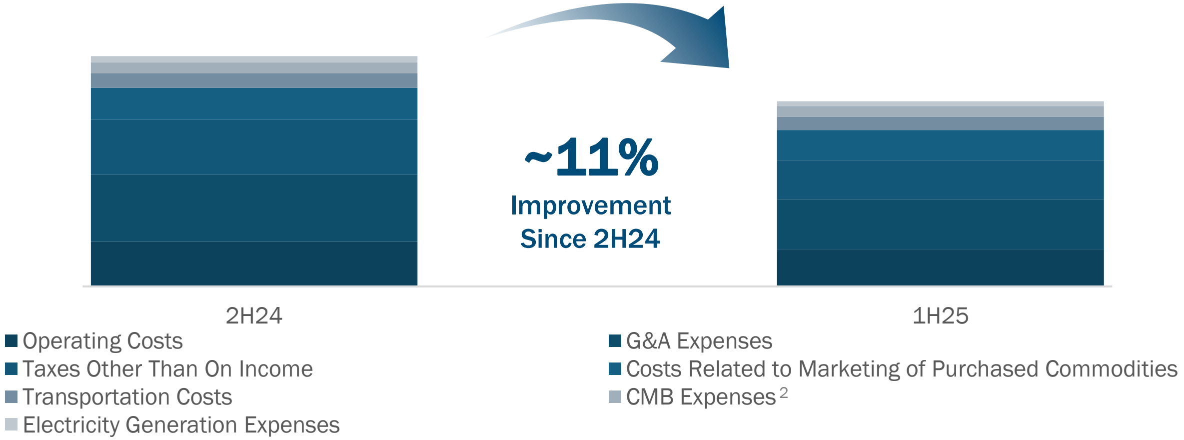



See slide 24 for "Assumptions, Estimates and Endnotes".

# Demonstrating Operational Excellence & Better Capital Efficiency

## Lower Costs

($MM)




## Lower Capital

D&C and Workover Capital ($MM)


See slide 24 for "Assumptions, Estimates and Endnotes".

- *Key drivers of lower 1H25 costs vs. 2H24: reductions in G&A, decrease in production and GHG taxes and lower non-energy operating costs[1]*
- *Reservoir outperformance driven by continuous focus on operational efficiencies and value capture at Belridge and Elk Hills*

**$240MM**

**1H25 Free Cash Flow***

*"We are trying to recover every cup from every underground barrel … All of them … 672 cups …"*

*- CRC Elk Hills Operator*

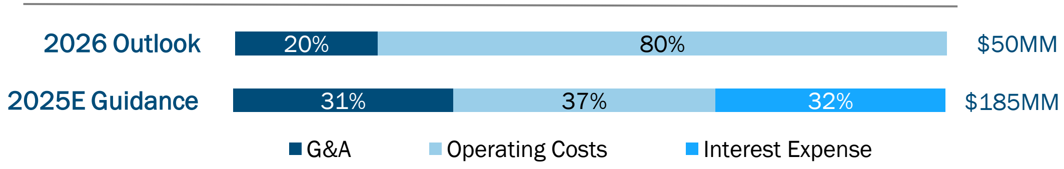
# Delivered on Aera Merger Synergies Goal

## One Year Post Close Implemented

**$235MM**

Aera Merger Synergies


### Synergies Impact




## Industrial Scale Logic

Solidified Cross-Asset Synergies

Improved Long-Term Operational Efficiencies

Enhanced Team Alignment and Collaboration

**~$1.4B** NPV @ 10% of Est. Organic Synergies Over 10 Years[1]

See slide 24 for "Assumptions, Estimates and Endnotes".

# Increasing Operational Intensity in 2H25

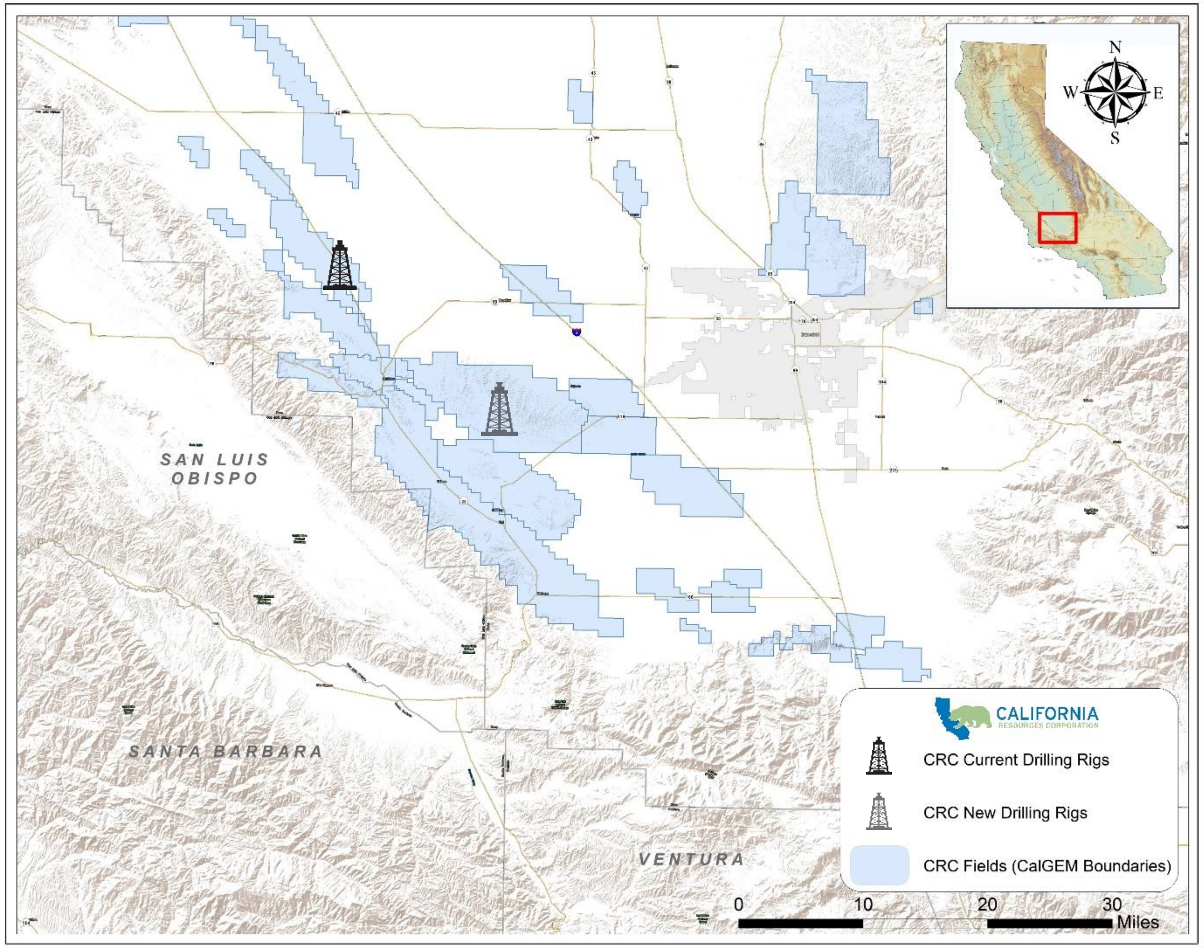
## Adding Activity in 2H25

- Added second rig in Kern County in late June 2025 for a total 16 well 2025 drilling program
- Investments focused on high-value, high-margin sidetracks and workovers
- Targeting development program IRRs of >30% at $63 Brent / $3.50 NYMEX

| CRC 2025E O&G Project Economics[1] | Brent >25% IRR ($/Bbl) | WTI >25% IRR ($/Bbl) |
|---|---|---|
| Workovers | ~$34 | ~$31 |
| New Drills *(Average of sidetracks)* | ~$58 | ~$55 |

## Improving 2025E Production Expectations, Capital Efficiency Driving Momentum into 2026[2]

- Raising 2025E net production guidance by 1MBoe/d at midpoint
- Targeting 5% - 7% entry-to-exit gross production decline for 2025
- 2025E D&C and workover capital reduced by $5MM




**$160 – $175MM**

Reduced
2025E D&C and Workover Capital[2]

**134 – 138MBoe/d**

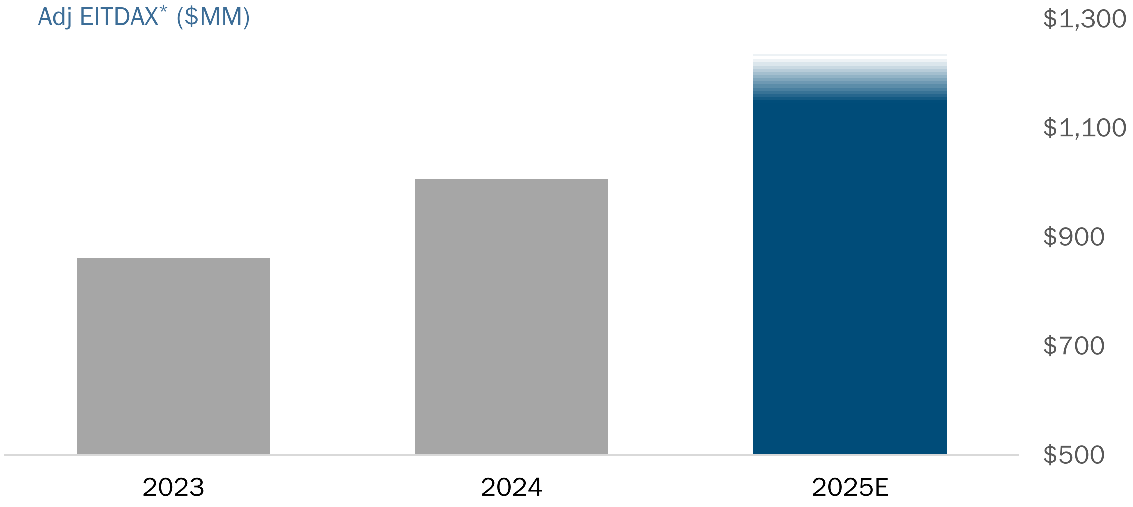
Increased Midpoint
2025E Net Production[2]

See slide 24 for “Assumptions, Estimates and Endnotes”.

# 2Q25 Results

| Commodity | 2Q25E[1] | 2Q25A |
|---|---|---|
| Brent ($/Bbl) | $63.00 | **$66.76** |
| Brent realized price with hedge ($/Bbl) | N/A | **$66.73** |
| Oil realization without derivative settlements (% of Brent) | 96% – 100% | **97%** |
| **Operational and Financial** | | |
| Net Production (MBoe/d) | 133 – 137 | **137** |
| Net Oil Production (%) | 79% | **80%** |
| Operating Costs ($MM) | $295 – $315 | **$295** |
| G&A Expenses ($MM) | $76 – $80 | **$79** |
| Adj. G&A* Expenses ($MM) | $69 – $74 | **$72** |
| Taxes Other Than on Income ($MM) | $60 – $65 | **$47** |
| Other Operating Expenses Net of Other Revenue*, [2] ($MM) | $5 – $20 | **$60** |
| Total Capital ($MM) | $81 – $92 | **$56** |
| Adjusted EBITDAX* ($MM) | $275 – $290 | **$324** |
| Operating Cash Flow Before Net Changes in Operating Assets and Liabilities* ($MM) | | **$221** |
| **Other Items** | | |
| Margin from Purchased Commodities*, [3] ($MM) | $20 – $25 | **$15** |
| Electricity Margin*, [4] ($MM) | $40 – $45 | **$53** |
| Transportation Costs ($MM) | $22 – $26 | **$20** |
| **Total Return of Cash to Shareholders[5] ($MM)** | | |
| Share Repurchases ($MM) | | **$252** |
| Dividends Paid ($MM) | | **$35** |
| **Total ($MM)** | | **$287** |

## Higher Adj. EBITDAX* Expectations




## 2Q25 Commentary: Stronger than Expected Quarter Across the Board

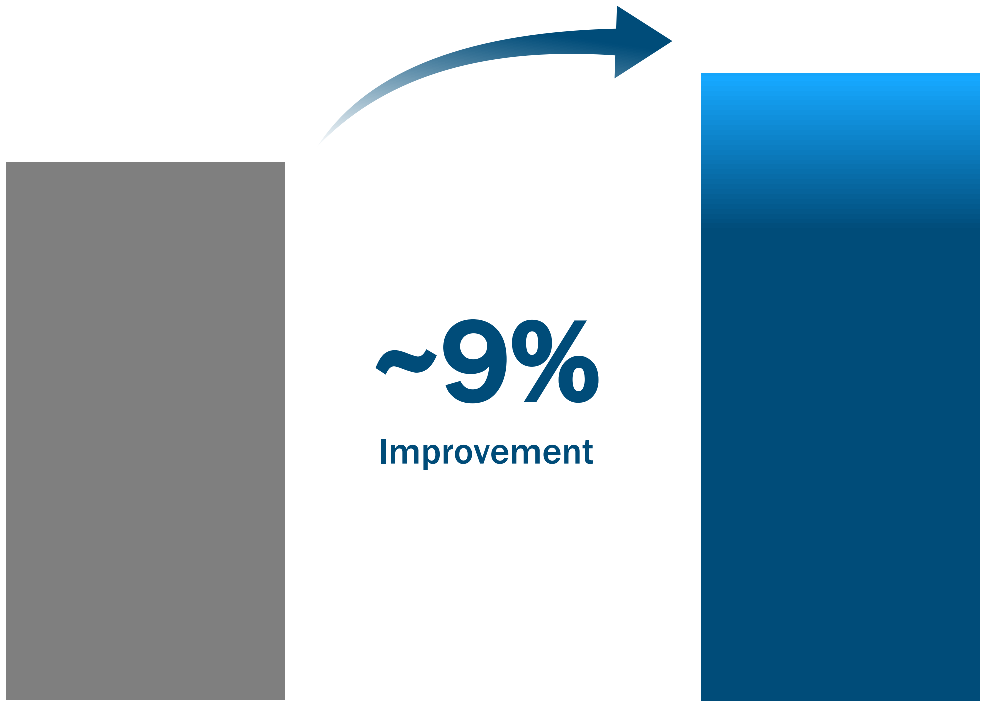
- Quarterly Brent pricing and production exceeded expectations, latter driven by asset and process optimization
- Synergies capture and disciplined cost control led to lower operating expenses
- Taxes other than on income came in below forecast due to lower production taxes and GHG prices
- Quarterly activity deferral to 2H25 through asset optimization resulted in lower-than-expected capital investments
- Stronger electricity margin* was related to capacity sales. Better energy operating costs were due to lower gas prices related to elevated in-state natural gas storage levels
- Cash flow was negatively impacted by a one-time $25MM payment for a legal matter

See slide 24 for "Assumptions, Estimates and Endnotes".

# Operational Momentum

## Stronger 2025 Free Cash Flow* Outlook Despite Lower Oil Price Forecast

Free Cash Flow Before Net Changes in Operating Assets and Liabilities[1] ($MM)




| 2025 Outlook Original Forecast | 2025 Outlook Current Forecast |
|---|---|
| Brent ($/Bbl) \| $73.05 | Brent ($/Bbl) \| $68.00 |
| NYMEX \| $3.49 | NYMEX \| $3.65 |

## 2025 Enhanced Outlook Driven By

- Strong Reservoir Performance
- Aera Merger Synergies
- Higher Electricity Margin
- Lower Production & GHG Taxes
- Lower Cash Taxes & Interest

See slide 24 for “Assumptions, Estimates and Endnotes”.

# 2025E Guidance

# Driving Operational Strength and Efficiency in 2025

| | | |
|---|---|---|
| EXPECTING EVEN LOWER COSTS[1, 2] IN 2025 | ~2% | DRIVEN PRIMARILY BY SYNERGIES, OPERATIONAL EFFICIENCIES AND ENERGY COST SAVINGS |
| REDUCED 2025E D&C AND WORKOVER CAPITAL GUIDANCE[2] | ~3% | DRIVEN PRIMARILY BY PROJECT OPTIMIZATION |
| RAISED PRODUCTION MIDPOINT OF 2025E GUIDANCE[2] | ~1% | DRIVEN PRIMARILY BY BETTER RESERVOIR PERFORMANCE AND IMPROVED OPERATIONS |
| RAISED ADJ. EBITDAX* MIDPOINT OF 2025E GUIDANCE[2] | ~7% | DRIVEN PRIMARILY BY HIGHER COMMODITY PRICE, STRONGER PRODUCTION EXPECTATIONS AND LOWER COSTS |

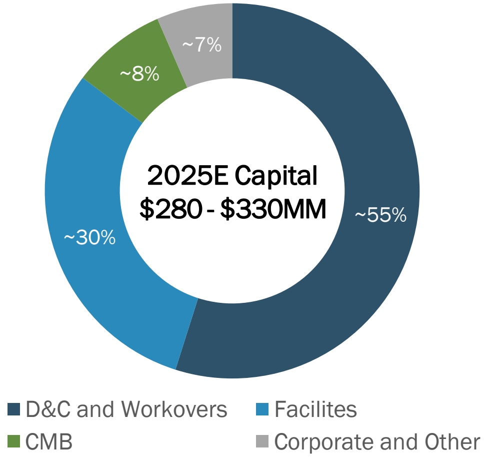

See slide 24 for “Assumptions, Estimates and Endnotes”.

# 2025E Guidance *(as of August 5, 2025)*

| CRC Guidance | 3Q25E Consolidated | Oil and Natural Gas | Carbon Management | 2025E Consolidated | Oil and Natural Gas | Carbon Management |
|---|---|---|---|---|---|---|
| **Net Production (MBoe/d) ~79% Oil** | **135 – 139** | | | **134 – 138** | | |
| Margin from Purchased Commodities*, [1] ($MM) | $17 – $25 | | | $65 – $80 | | |
| Electricity Margin*, [2] ($MM) | $75 – $100 | | | $175 - $190 | | |
| Operating Costs ($MM) | $300 – $330 | $300 – $330 | | $1,220 – $1,280 | $1,220 – $1,280 | |
| G&A ($MM) | $74 – $88 | $10 – $14 | $2 – $4 | $310 – $335 | $40 – $55 | $10 – $15 |
| *Adjusted G&A* ($MM)* | *$70 – $80* | *$10 – $14* | *$2 – $4* | *$290 – $310* | *$40 – $55* | *$10 – $15* |
| Depreciation, Depletion and Amortization ($MM) | $131 – $135 | $112 – $118 | | $515 – $530 | $447 – $462 | |
| Other Operating Expenses Net of Other Revenue*, [3] ($MM) | $0 – $20 | | $7 – $13 | $80 – $135 | | $45 – $60 |
| Transportation Expense ($MM) | $20 – $26 | $9 – $13 | | $82 – $94 | $39 – $43 | |
| Taxes Other Than on Income ($MM) | $64 – $74 | $52 – $57 | | $235 – $260 | $190 – $220 | |
| Interest and Debt Expense ($MM) | $25 – $29 | | | $100 – $110 | | |
| **Capital ($MM)** | **$84 – $108** | **$71 – $89** | **$8 – $10** | **$280 – $330** | **$245 – $275** | **$20 – $30** |
| **Adj. EBITDAX* ($MM)** | **$310 – $340** | **$280 – $305** | **($15) – $(11)** | **$1,195 – $1,275** | **$1,210 – $1,340** | **($68) – ($64)** |

| Other Assumptions | 3Q25E | 2025E |
|---|---|---|
| Brent ($/Bbl) | $66.00 | $68.00 |
| NYMEX ($/mcf) | $3.40 | $3.65 |
| Oil – % of Brent | 94% – 100% | 95% – 99% |
| NGL – % of Brent | 54% – 60% | 60% – 68% |
| Natural Gas – % of NYMEX | 94% – 104% | 90% – 110% |
| Deferred Income Taxes | 95% – 105% | 35% – 45% |
| Effective Tax Rate | 29% | 29% |

**Preliminary 4Q25 Net Production Range of 131 – 135 MBoe/d**




See slide 24 for “Assumptions, Estimates and Endnotes”.

# Why California Resources Corporation?

A DIFFERENT KIND OF ENERGY COMPANY

Higher **Cashflow**

Less **Carbon**

Better **California**

LEADING CARBON MANAGEMENT BUSINESS

PREMIER BALANCE SHEET WITH STRONG FREE CASH FLOW GENERATION

SUSTAINABLE SHAREHOLDER RETURNS

DISCIPLINED CAPITAL ALLOCATION

# Appendix

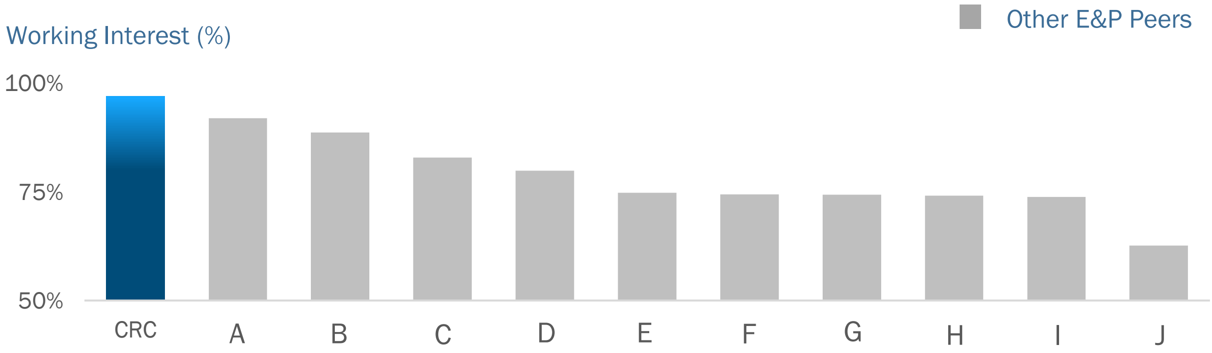
# Unique California Based Pure–Play Footprint

## Superior Portfolio Characteristics

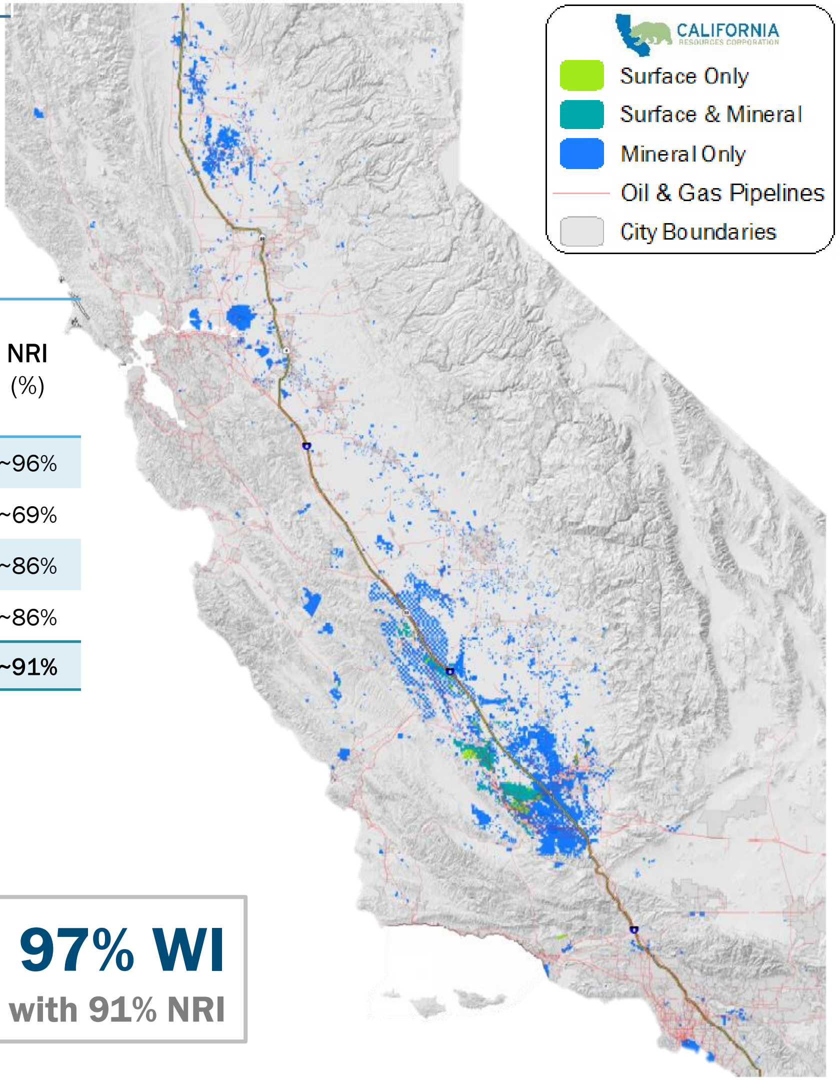
- **Strategic Acreage Footprint:** Advantaged position in key California basins provides capital deployment flexibility
- **High-Quality, Low-Decline Assets:** Conventional reservoirs with low capital intensity and stable production
- **Robust Development Inventory:** Diverse recovery methods (primary, secondary, tertiary) support long-term production
- **Ready for Growth:** Ability to accretively grow volumes as permits become available
- **Superior Economics:** High net revenue interest (NRI) drives stronger margins and value capture

| Durable 1P Asset Inventory[1] | PDP (%) | Total Proved (MMBOE) | Oil (%) | Est. Annual PDP Decline (%) | 4Q24 Net Production (MBOE/D) | R/P[2] (Years) | Recovery Factor (%) | Surface Acreage ('000) | Mineral Acreage ('000) | NRI (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| San Joaquin Basin | 83% | 441 | 78% | ~12% | 112 | 11 | ~31% | 190 | 1,277 | ~96% |
| Los Angeles Basin | 95% | 78 | 99% | ~8% | 17 | 13 | ~36% | <1 | 35 | ~69% |
| Sacramento Basin | 66% | 3 | 0% | ~9% | 2 | 4 | ~59% | <1 | 421 | ~86% |
| Other Basins | 95% | 23 | 95% | ~12% | 10 | 6 | ~27% | 3 | 130 | ~86% |
| **Total** | **85%** | **545** | **81%** | **~11%** | **141** | **11** | **~32%** | **193** | **1,863** | **~91%** |

## CRC's WI vs Peers[3]




**CRC has a 97% WI**
**with 91% NRI**



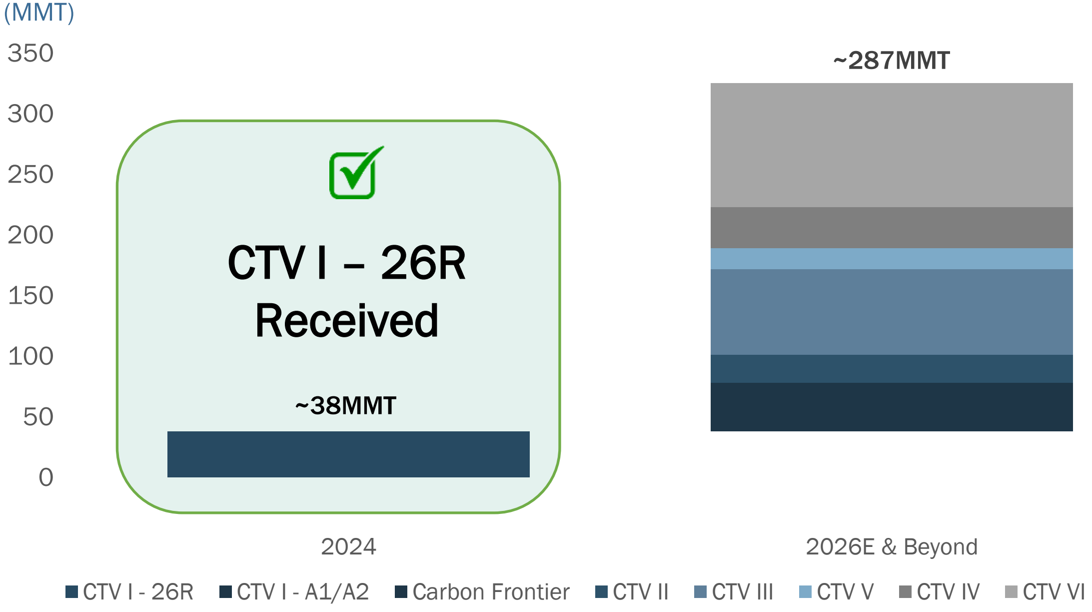

See slide 24 for "Assumptions, Estimates and Endnotes".

# Leading California's Decarbonization

## EXPANDING OUR $CO_2$ PERMITTING LEADERSHIP

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

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




## ADVANCING DECARBONIZATION IN CALIFORNIA

- Third party funding through partnership with Brookfield Renewable - Global Energy Transition Fund *(Initial commitment of up to $500MM)*[2]
- Approved California's first CCS project at Elk Hills Cryogenic Gas Plant
  - Ongoing engineering, equipment preparation and procurement for construction underway
- Attracting private and federal clean energy capital to California[3] through carbon management efforts
- Largest amount of potentially available and stackable incentives for CCS development in the country
- Expecting support for $CO_2$ pipeline transportation from California legislators in 2025
- Identified up to 1BMT[4] of potential $CO_2$ storage in California

CARBON TERRAVAULT

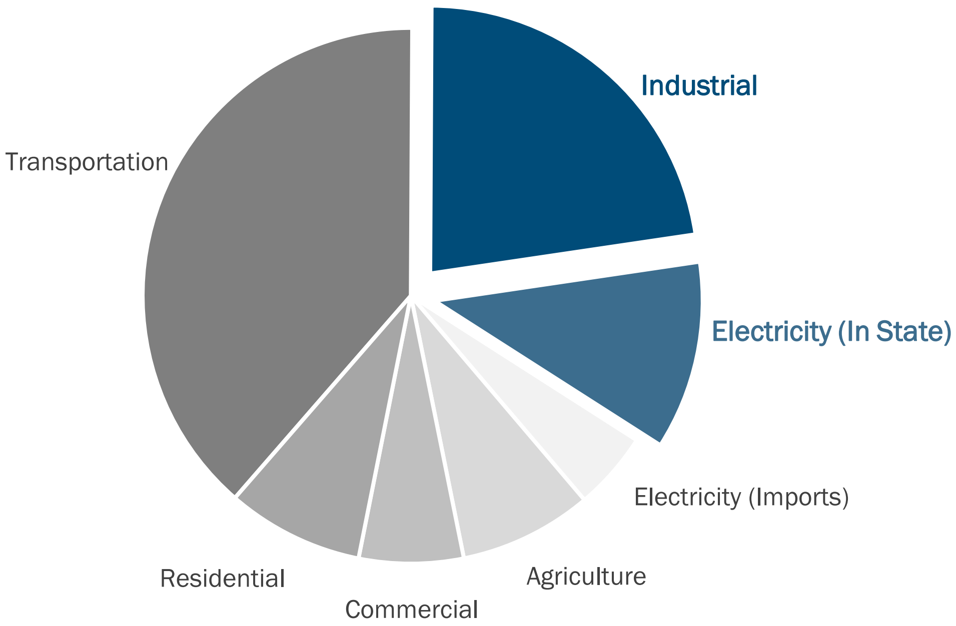
**Positioned to Be California's Premier Carbon Management Provider**

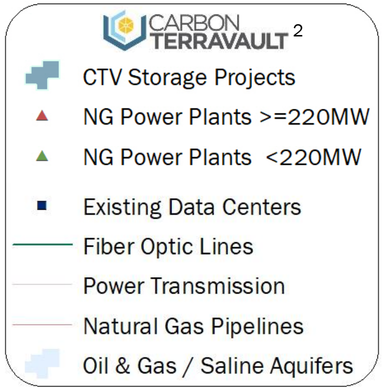
See slide 25 for "Assumptions, Estimates and Endnotes".

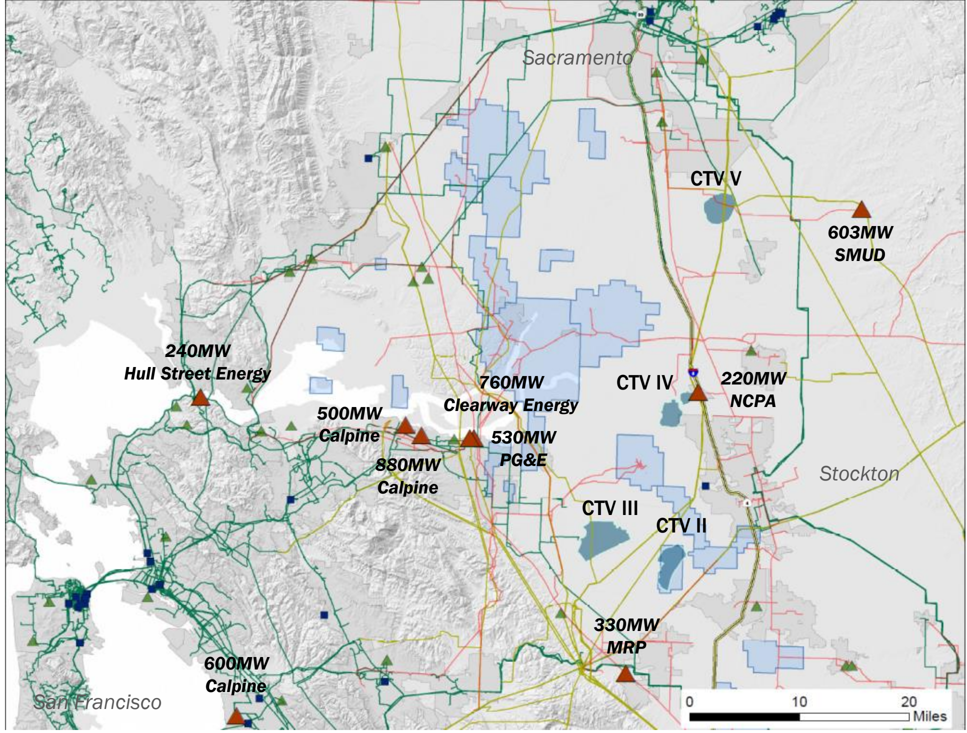
# Well Positioned to Decarbonize California's Largest Industries

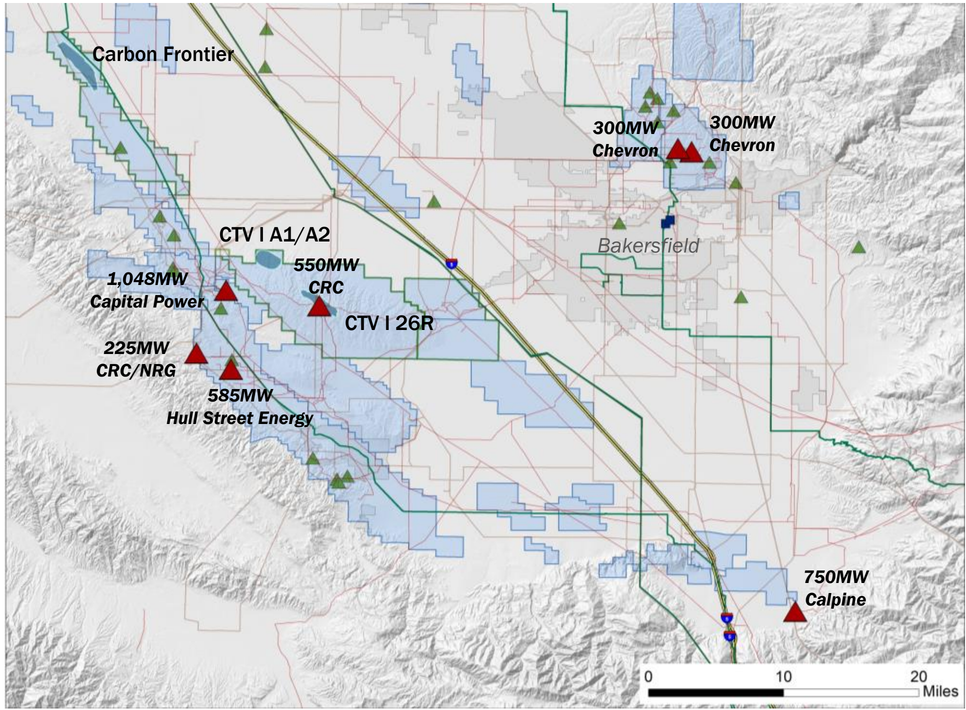
- CTV reservoirs are in proximity to the state's highest emitting industries
- Resource inventory and infrastructure in place to supply energy today
- Ability to provide power services with:
  - Accelerated time-to-market
  - Access to natural gas and interconnection
  - Proximity to fiber network
-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

## CALIFORNIA GHG EMISSIONS BY SECTOR[1]




See slide 25 for "Assumptions, Estimates and Endnotes".

# California's Premier Carbon Management Provider

- Received Kern County Board of Supervisors' approval of the conditional use permits for the CTV I CCS project
- Received CA's first EPA Class VI permits for CTV I – 26R; Approved California's first CCS project at Elk Hills Cryogenic Gas Plant
- Anticipating the receipt of Class VI draft permits for additional reservoirs in 2025[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 |
| | A1-A2 | 2026E | ~0.8 | ~0.4 | ~0.2 | ~8 |
| Carbon Frontier | | 2026E | ~3.3 | ~1.6 | ~0.8 | ~32 |
| CTV VI | | 2026E | ~3.4 | ~5.1 | ~2.5 | ~102 |
| *Coles Levee* | | *TBD* | *TBD* | *TBD* | *TBD* | *TBD* |
| **Central California** | | | **~9.0** | **~9.0** | **~4.5** | **~180** |
| | | | | | | |
| CTV II | | 2026E | ~1.0 | ~1.2 | ~0.6 | ~23 |
| CTV III | | 2026E | ~2.5 | ~3.6 | ~1.8 | ~71 |
| CTV IV | | 2026E | ~1.4 | ~1.7 | ~0.9 | ~34 |
| CTV V | | 2026E | ~0.7 | ~0.8 | ~0.4 | ~17 |
| **Northern California** | | | **~5.6** | **~7.3** | **~3.7** | **~145** |
| **Total - Combined** | | | **~14.6** | **~16.3** | **~8.2** | **~325** |

**Target Addressable Market by Region[3]**

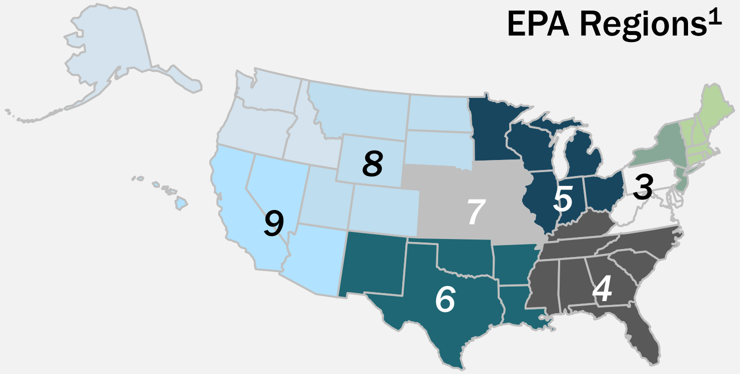
Annual Regional $CO_2$ Emissions (MMTPA)


CARBON TERRAVAULT

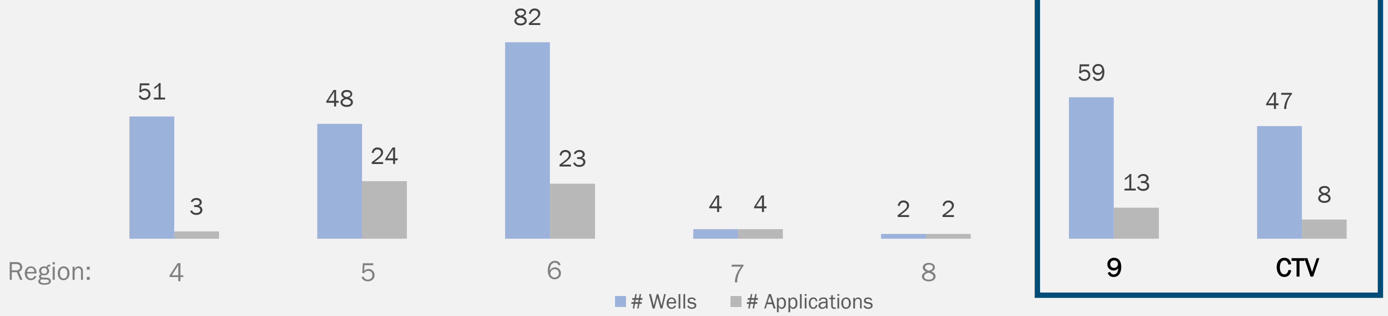
See slide 25 for "Assumptions, Estimates and Endnotes".

# Leading EPA Class VI Permitting Pipeline *(As of July 18, 2025)*

## EPA Regions[1]

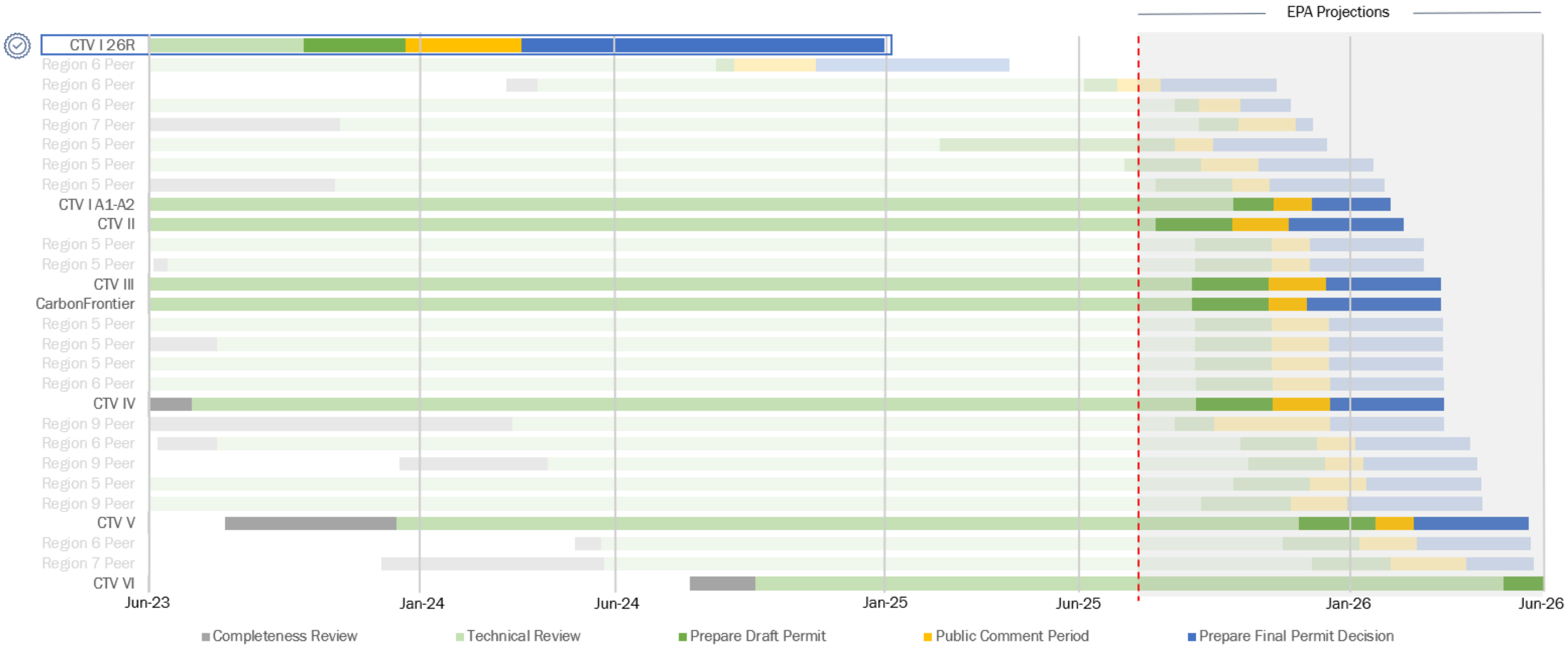



## EPA Class VI Projects Under Review[1]




## EPA Projected Permit Timeline[1]

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



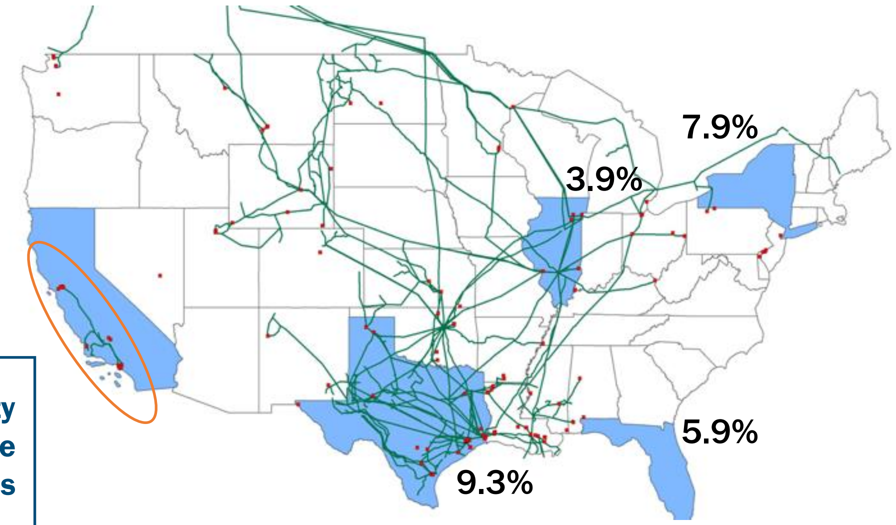

See slide 25 for "Assumptions, Estimates and Endnotes".

# Strong Commodity Price Realizations

- **Crude:** Crude indices experienced increased volatility during 2Q25 with prices slumping on 'Liberation Day' tariff announcements and OPEC returning offline production at a surprisingly increased pace, only to rally on Middle East military engagements. California realizations remained solid even with a continued (partial) outage at a major Bay Area refinery.
- **Natural Gas:** North American natural gas prices were slightly lower Q/Q while the California market labored under seasonally mild weather and a surplus of natural gas in storage.
- **NGLs:** Realizations for 2Q25 were seasonally lower Q/Q. California continues to carry a premium to the broader North American NGL marketplace. Our production is subject to virtually no impact related to US/Asian trade negotiations.

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

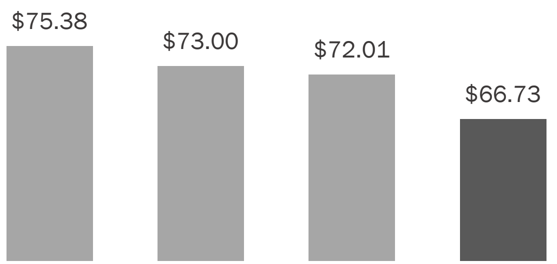
(amounts shown as % of U.S. domestic GDP)




**CRC's liquid commodity realizations are above domestic averages**

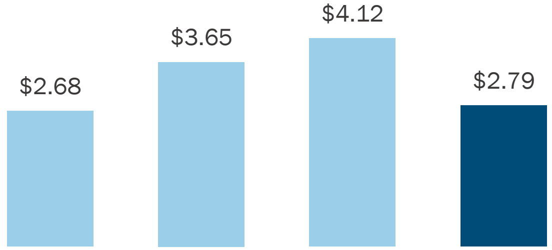
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 1Q25; EIA

**Oil w/ Hedges ($/BBL)**




**NGLs ($/BBL)**


**Natural Gas ($/MCF)**




| | 3Q24 | 4Q24 | 1Q25 | 2Q25 | 3Q24 | 4Q24 | 1Q25 | 2Q25 | 3Q24 | 4Q24 | 1Q25 | 2Q25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Average Benchmark Prices[1] | $78.54 | $73.97 | $74.92 | $66.76 | $78.54 | $73.97 | $74.92 | $66.76 | $2.16 | $2.79 | $3.65 | $3.44 |
| % of Benchmark[1] | 98% | 98% | 98% | 97% | 58% | 71% | 73% | 64% | 124% | 131% | 113% | 81% |
| Hedge Settlements | ($1.72) | $0.18 | ($1.56) | $1.66 | - | - | - | - | - | - | - | - |
| Average Realized Prices[2] | $75.38 | $73.00 | $72.01 | $66.73 | $45.77 | $52.62 | $54.64 | $42.41 | $2.68 | $3.65 | $4.12 | $2.79 |

See slide 25 for "Assumptions, Estimates and Endnotes".

# Hedge Portfolio (as of June 30, 2025)

| OIL | | 3Q25E | 4Q25E | 1Q26E | 2Q26E | 2H26E | 2027E | 2028E |
|---|---|---|---|---|---|---|---|---|
| **SOLD CALLS** | | | | | | | | |
| Brent | Barrels per Day | 30,000 | 29,000 | 35,000 | 35,000 | 35,000 | - | - |
| | Weighted-Average Price | $87.08 | $87.13 | $83.86 | $83.86 | $83.86 | - | - |
| **SWAPS** | | | | | | | | |
| Brent | Barrels per Day | 45,001 | 43,376 | 36,444 | 29,399 | 28,036 | 34,382 | 1,697 |
| | Weighted-Average Price | $70.63 | $69.86 | $68.98 | $68.03 | $67.25 | $64.63 | $65.00 |
| **PURCHASED PUTS[1]** | | | | | | | | |
| Brent | Barrels per Day | 30,000 | 29,000 | 35,000 | 35,000 | 35,000 | - | - |
| | Weighted-Average Price | $61.67 | $61.72 | $61.14 | $61.14 | $61.14 | - | - |
| **NATURAL GAS** | | **3Q25E** | **4Q25E** | **1Q26E** | **2Q26E** | **2H26E** | **2027E** | **2028E** |
| **SWAPS** | | | | | | | | |
| SoCal Border | MMBtu per Day | 25,750 | 22,408 | 20,350 | 13,250 | 10,329 | - | - |
| | Weighted-Average Price | $3.48 | $3.53 | $5.18 | $4.82 | $4.84 | - | - |
| NWPL Rockies[2] | MMBtu per Day | 51,750 | 51,750 | 51,750 | 51,750 | 51,750 | 33,616 | 1,576 |
| | Weighted-Average Price | $2.95 | $4.22 | $4.67 | $3.64 | $3.93 | $4.12 | $3.95 |
| **EST. HEDGE CONTRACT SETTLEMENTS[3]** | | **3Q25E** | **4Q25E** | **1Q26E** | **2Q26E** | **2H26E** | **2027E** | **2028E** |
| Combined Hedge Portfolio ($MM) | | $16 | $19 | $12 | $(0) | $7 | ($7) | $1 |

## 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

**~69% of remaining 2025E net oil production hedged** with an average **Brent floor price of ~$67** per barrel

## OPERATIONS

**~67% of remaining 2025E internal fuel consumption hedged** at an average **natural gas price of ~$3.56** per MMBtu

See slide 25 for "Assumptions, Estimates and Endnotes".

# Strong Balance Sheet, Ample Liquidity and Financial Flexibility

## 6/30/25 NET DEBT* SNAPSHOT

($MM)

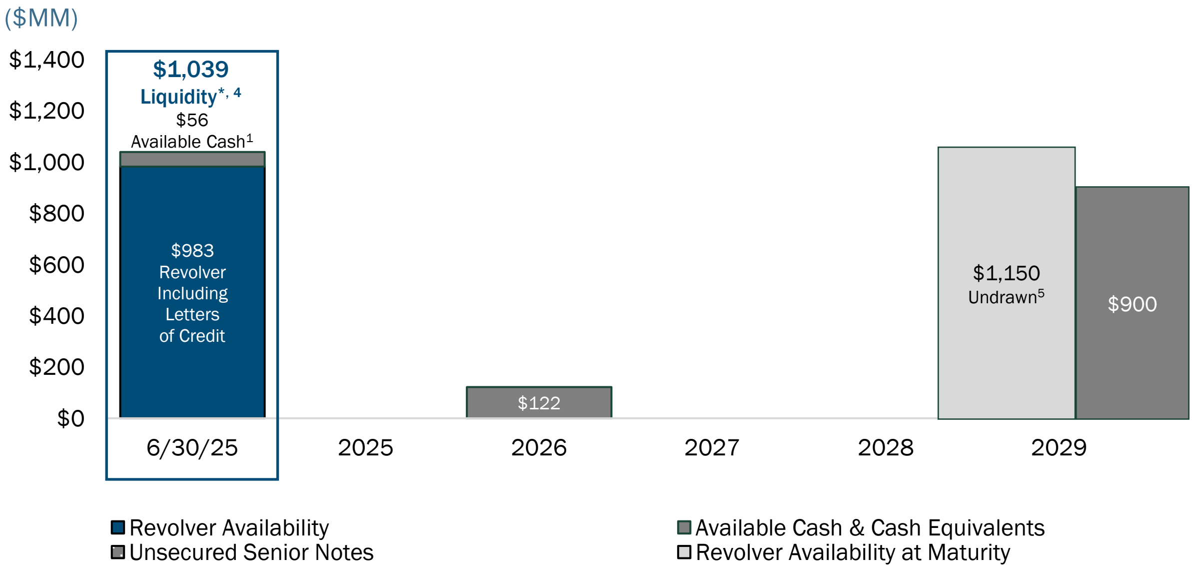
| | |
|---|---|
| Revolving Credit Facility (RCF) | $ - |
| 7.125% 2026 Senior Notes | 122 |
| 8.250% 2029 Senior Notes | 900 |
| **Face Value of Debt** | **$ 1,022** |
| Less Available Cash & Cash Equivalents[1] | (56) |
| **Net Debt*** | **$ 966** |

## MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)

| | |
|---|---|
| RCF Borrowing Base | $1,500 |
| 2Q25 Free Cash Flow* | $109 |
| 2Q25 Net Debt* / LTM EBITDAX*, 2 | 0.7x |
| LTM EBITDAX* / LTM Interest Expense*, 3 | 12.6x |

## MATURITY PROFILE




### RECENT CREDIT UPDATES

- Redeemed $123MM of the 2026 Senior Notes in February 2025, targeting to act on the balance in 2025
- Borrowing base reaffirmed at $1.5B in April

See slide 25 for "Assumptions, Estimates and Endnotes".

# Glossary

| Term | Definition |
|---|---|
| Bcf | Billion Cubic Feet |
| BMT | Billion Metric Tons |
| BTM | Behind-the-Meter |
| CARB | California Air Resources Board |
| CCS | Carbon Capture and Storage |
| CDMA | Carbon Dioxide Management Agreement |
| CEQA | California Environmental Quality Act |
| CGP | Cryogenic Gas Plant |
| CI | Carbon Intensity |
| CMB | Carbon Management Business |
| $CO_2$ | Carbon Dioxide |
| CTV | Carbon TerraVault *(a subsidiary of CRC)* |
| CUP | Conditional Use Permit |
| DAC | Direct Air Capture |
| D&C | Drilling and Completions |
| E&P | Exploration and Production |
| 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&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 |
| 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 |
| SFDR | Sustainable Finance Disclosure Regulation |
| SMOG | Standardized Measure of Discounted Future Net Cash Flows |
| SRP | Share Repurchase Program |
| SJV | San Joaquin Valley |
| TBA | To Be Announced |
| Tcf | Trillion Cubic Feet |
| WI | Working Interest |

# Assumptions, Estimates and Endnotes

Slide 2:
(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 4:
(1) All CRC's future quarterly dividends and share repurchases are subject to commodity prices, debt agreement covenants and Board of Directors approval. Excludes excise taxes and commissions paid on share repurchases.
(2) Source: FactSet. Represents current annual dividend policy of $1.55 per share divided by CRC's market capitalization as of August 1, 2025.

Slide 5:
(1) Includes gas processing costs.
(2) CMB expenses are included in other operating expenses, net in our condensed consolidated statement of operations.

Slide 6:
(1) NPV at 10% reflects the net present value of all synergies implemented to date, discounted at a 10% rate. The calculation assumes all realized synergies, except interest synergies, are sustainable over a 10-year period and excludes both costs to achieve the savings and taxes. Interest expense synergies are assumed to expire in 2029 on the expectation that the refinanced Aera-related indebtedness is repaid at maturity in 2029.

Slide 7:
(1) Source: CRC internal estimates. Project economics reflect available inventory supported by permits in hand.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 8:
(1) 2Q25E guidance assumes a 2Q25E Brent price of $63.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.11 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline.
(2) Other operating expenses net of other revenue is calculated as the difference between other revenue and other operating expenses, net and includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs. We have updated this caption for better alignment to our condensed consolidated statements of operations.
(3) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation
(4) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
(5) 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.

Slide 9:
(1) Free cash flow before net changes in operating assets and liabilities is calculated as net cash provided by operating activities before net changes in operating assets and liabilities* minus capital investments. Net cash provided by operating activities before net changes in operating assets and liabilities* is a non-GAAP number. Please see the Investor Relations page at www.crc.com for a reconciliation of net cash provided by operating activities before net changes in operating assets and liabilities to the nearest GAAP equivalent and other additional information.

Slide 11:
(1) Costs includes operating costs, CMB expenses which are included in other operating expenses, net, G&A expenses, electricity generation expenses, costs related to marketing of purchased commodities, transportation costs and taxes other than on income. Management's understanding and control of its cost structure is essential for profitability and efficiency. It informs resource and people allocation decisions, while identifying areas for cost reduction.
(2) Total year 2025E guidance assumes a 2025E Brent price of $68.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.65 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 12 for 2025E guidance.

Slide 12:
(1) Margin from purchased commodities is calculated as the difference between revenue from marketing of purchased commodities and costs related to marketing of purchased commodities, and excludes costs of transportation.
(2) Electricity margin is calculated as the difference between electricity sales and electricity generation expenses.
(3) Other operating expenses net of other revenue is calculated as the difference between other revenue and other operating expenses, net and includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.

Slide 15:
(1) Reserves estimated as of December 31, 2024 using SEC Prices of $80.42 per barrel for oil and $2.13 per MMbtu for natural gas.
(2) Calculated using annualized 4Q24 net production.
(3) CRC data from internal estimates. Peer data from Enverus as of July 2, 2025. Peers include BRY, CIVI, FANG, HPK, MGY, MTDR, PR, REI, REPX and SM.

# Assumptions, Estimates and Endnotes (Cont.)

**Slide 16:**

(1) Source: EPA, 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) See CRC’s 2Q22 earnings presentation for additional details on Brookfield's initial commitment of up to $500MM to invest in CCS projects that are jointly approved through the Carbon TerraVault JV.
(3) Source: Database of State Incentives for Renewables & Efficiency (DSIRE) from the N.C. Clean Energy Technology Center.
(4) Based on internal estimates of total resources located in California, and includes resources not owned by CRC.

**Slide 17:**

(1) Source: California Air Resources Board, "Current California GHG Emission Inventory Data 2000–2022," 2024.
(2) Source: California Energy Commission.

**Slide 18:**

(1) Source: EPA, 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.

**Slide 19:**

(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa. Based on EPA estimates and approvals. CTV I A1-A2 and CTV II are projected to receive a final permit decision in February 2026, CarbonFrontier, CTV III, and CTV IV are projected to receive a final permit decision in March 2026, CTV V is projected to receive a final permit decision in May 2026, and CTV VI is projected to receive a final permit decision in November 2026.

**Slide 20:**

(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 certain of our natural gas related to marketing activities.

**Slide 21:**

(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 2025E transportation guidance. See slide 12 for 2025E guidance.
(3) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of June 30, 2025.

**Slide 22:**

(1) Available cash and cash equivalents excludes $16MM of restricted cash.
(2) Net leverage is calculated as 2Q25 net debt of $966MM (excludes restricted cash of $16MM) divided by LTM adjusted EBITDAX of $1,370MM.
(3) Interest coverage is calculated as LTM adjusted EBITDAX of $1,370MM and LTM interest expense of $109MM.
(4) Liquidity on June 30, 2025 is calculated as $56MM of cash and cash equivalents (excluding $16MM of restricted cash) plus $1,150MM of borrowing capacity on CRC’s Revolving Credit Facility less $167MM in outstanding letters of credit.
(5) Undrawn Revolving Credit Facility as of June 30, 2025, excluding outstanding letters of credit.

# Forward – Looking / Cautionary Statements – Certain Terms

**Forward-Looking Statements:**

This document contains statements that CRC believes to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts are forward-looking statements, and include statements regarding CRC's future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives of management for the future. Words such as "expect," "could," "may," "anticipate," "intend," "plan," "ability," "believe," "seek," "see," "will," "would," "estimate," "forecast," "target," "guidance," "outlook," "opportunity" or "strategy" or similar expressions are generally intended to identify forward-looking statements. These forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

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