CALIFORNIA RESOURCES CORPORATION

A DIFFERENT KIND OF ENERGY COMPANY

First Quarter 2025 Results

May 7, 2025

1Q25 Key Takeaways — Execution, Execution, Execution

1. STRONG FINANCIAL & OPERATIONAL PERFORMANCE

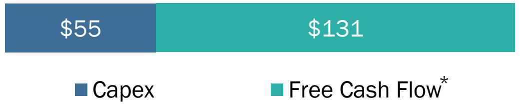
Generated **$328MM of Adj. EBITDAX*, exceeding** guidance

Delivered strong reservoir performance: **flat QoQ net production - above guidance midpoint**

7% QoQ decrease in non-energy operating costs[1], realized 74% of Aera merger-related **synergies**

$186MM

1Q25 OPERATING CASH FLOW



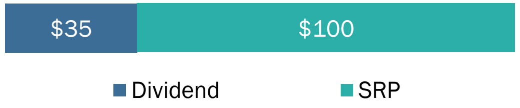
2. RECORD QUARTERLY SHAREHOLDER RETURNS

Returned $135MM or 103% of 1Q25 FCF* to shareholders[2]

Attractive fixed **dividend yield of ~4.3%** vs. market and peers[3]

$135MM

1Q25 TOTAL SHAREHOLDER RETURN[2]



3. BALANCE SHEET & HEDGE BOOK STRENGTH REDUCE 2025 RISK

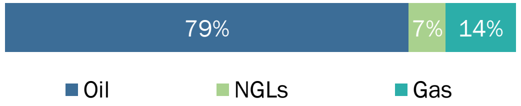
~70% of remaining 2025E net production hedged at a floor price of ~**$67/bbl Brent** drives cash flow stability

Integrated strategy provides **revenue diversification** (power and natural gas marketing with CMB in development)

Strengthened financial position – 0.7x 2025E Net Leverage*, [4]: redeemed $123MM of 2026 Senior Notes in February 2025, targeting to address the balance in 2025

141MBOE/D

1Q25 NET PRODUCTION



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

Robust 2025 Outlook, Strong Balance Sheet, Focus on Shareholder Returns

REAFFIRMING 2025E ADJ. EBITDAX* GUIDANCE[1]

DESPITE A ~16% DECREASE IN 2025 BRENT EXPECTATIONS

$1,100 - $1,200MM

~15%

2025E CONTROLLABLE COST STRUCTURE IMPROVEMENT VS PRO FORMA 2023 BASELINE[2]

TARGETING TO REALIZE $185MM OF THE $235MM OF AERA MERGER RELATED SYNERGIES BY YE25 AND THE REMAINDER IN EARLY 2026

ADVANCING CMB AND POWER PORTFOLIO

YE25 Targets

TARGETING FIRST CO_2 SEQUESTRATION FROM ELK HILLS CRYOGENIC GAS PLANT

EXPECTING A LONG TERM, THIRD PARTY, BEHIND THE METER PPA AT EHPP BY YE25

LINE OF SIGHT TO WELL PERMITTING PROGRESSION IN

2H25

EXPECTED TO INCREASE ACTIVITY IN 2026, IF CONDITIONS WARRANT

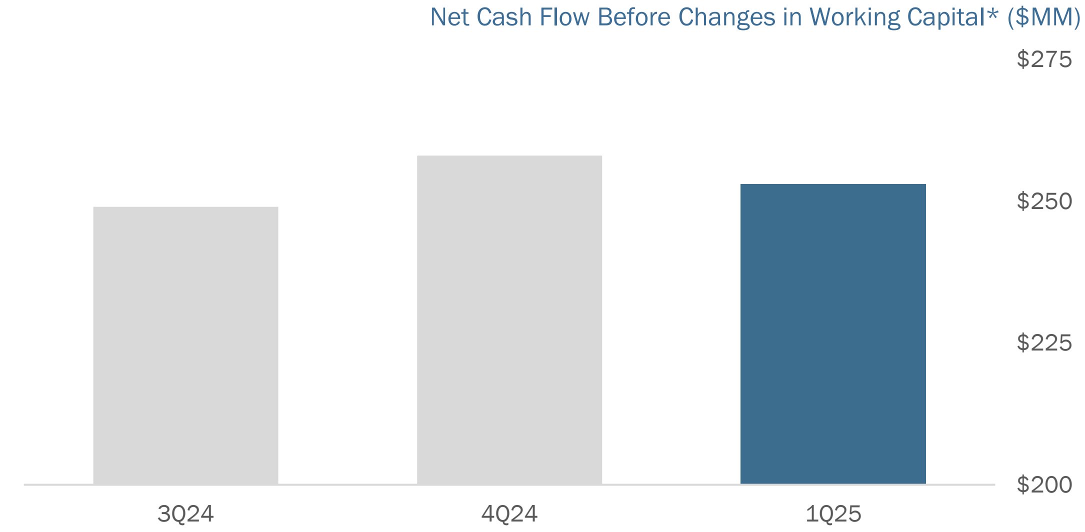
See slide 25 for “Assumptions, Estimates and Endnotes”.

Strong 1Q25
Execution, Execution, Execution

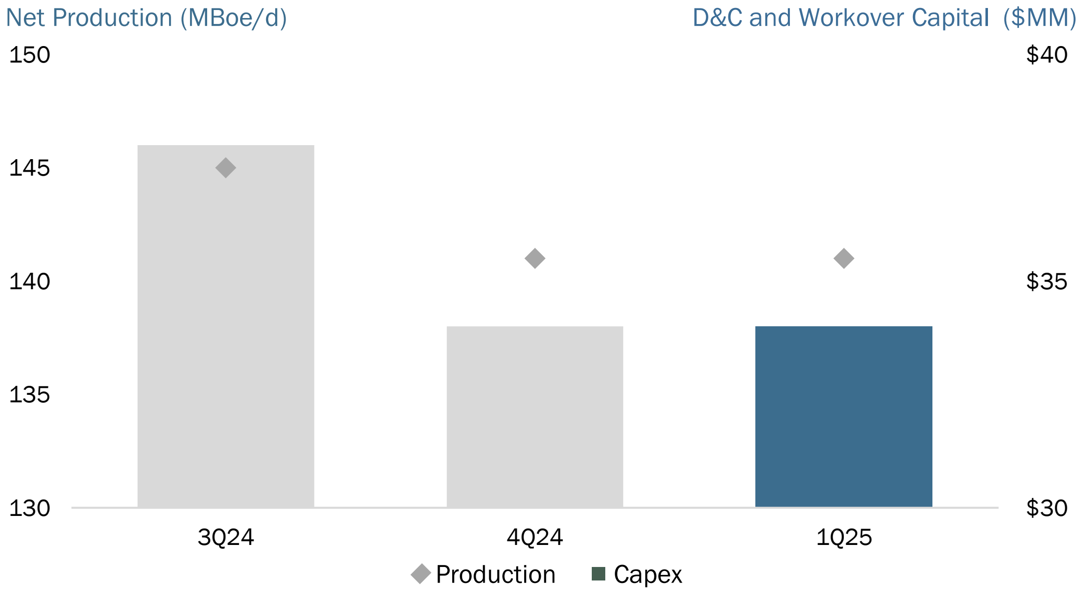
Demonstrating Strong 1Q25 Results

Commodity	1Q25E[1]	1Q25A
Brent ($/Bbl)	$76.54	$74.92
Brent realized price with hedge ($/Bbl)	N/A	$72.01
Oil without derivative settlements (% of Brent)	94% – 98%	98%
Operational and Financial		
Net Production (MBoe/d)	138 – 142	141
Net Oil Production (%)	79%	79%
Operating Costs ($MM)	$320 – $340	$316
G&A ($MM)	$80 – $84	$72
Adj. G&A* ($MM)	$75 – $80	$66
Taxes Other Than on Income ($MM)	$70 – $78	$70
Other Operating Revenue and Expenses, net[2] ($MM)	$10 – $30	($27)
Total Capital ($MM)	$60 – $70	$55
Adjusted EBITDAX* ($MM)	$275 - $295	$328
Other Items		
Margin from Purchased Commodities[3] ($MM)	$10 – $15	$14
Electricity Margin[4] ($MM)	$0 – $5	$12
Transportation Expense ($MM)	$18 – $22	$20
Total Return of Cash to Shareholders[5] ($MM)		
Shares Repurchased ($MM)		$100
Dividends Paid ($MM)		$35
Total ($MM)		$135

Stability of Cash Flows



Maintaining Capital Efficiency

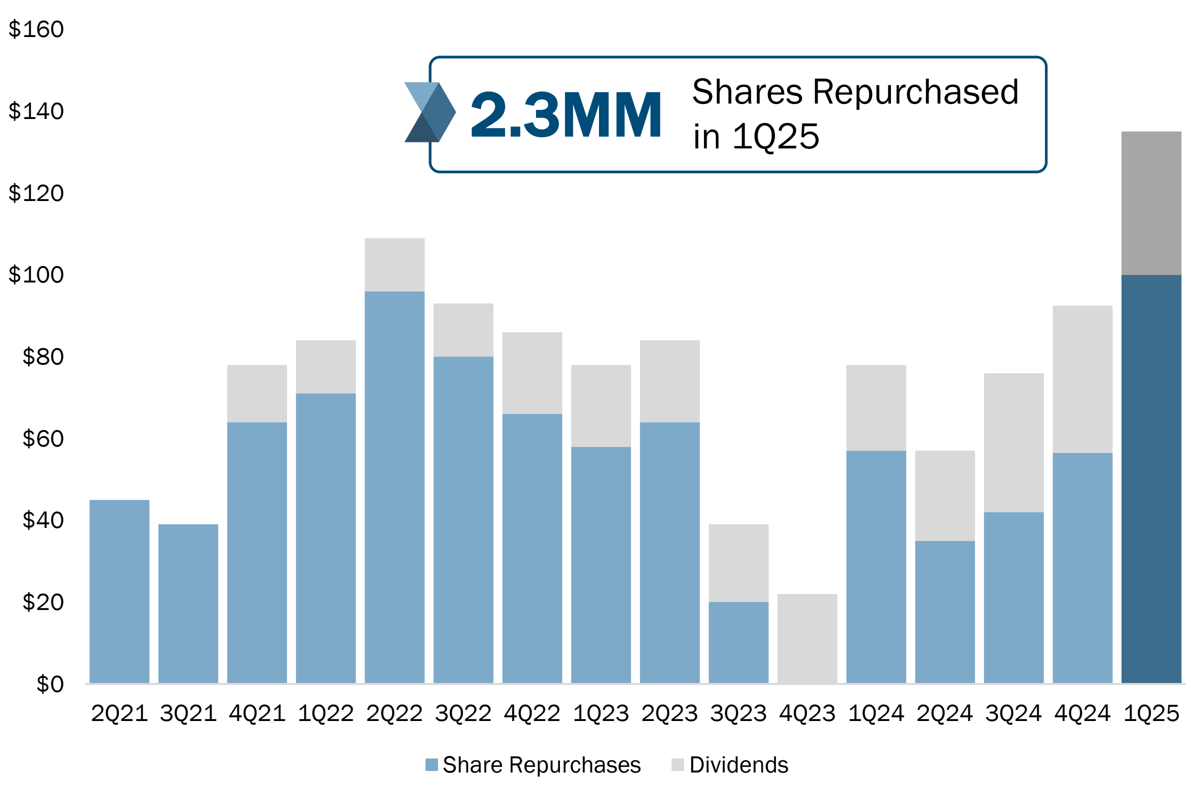


See slide 25 for “Assumptions, Estimates and Endnotes”.

Record Quarterly Returns to Shareholders

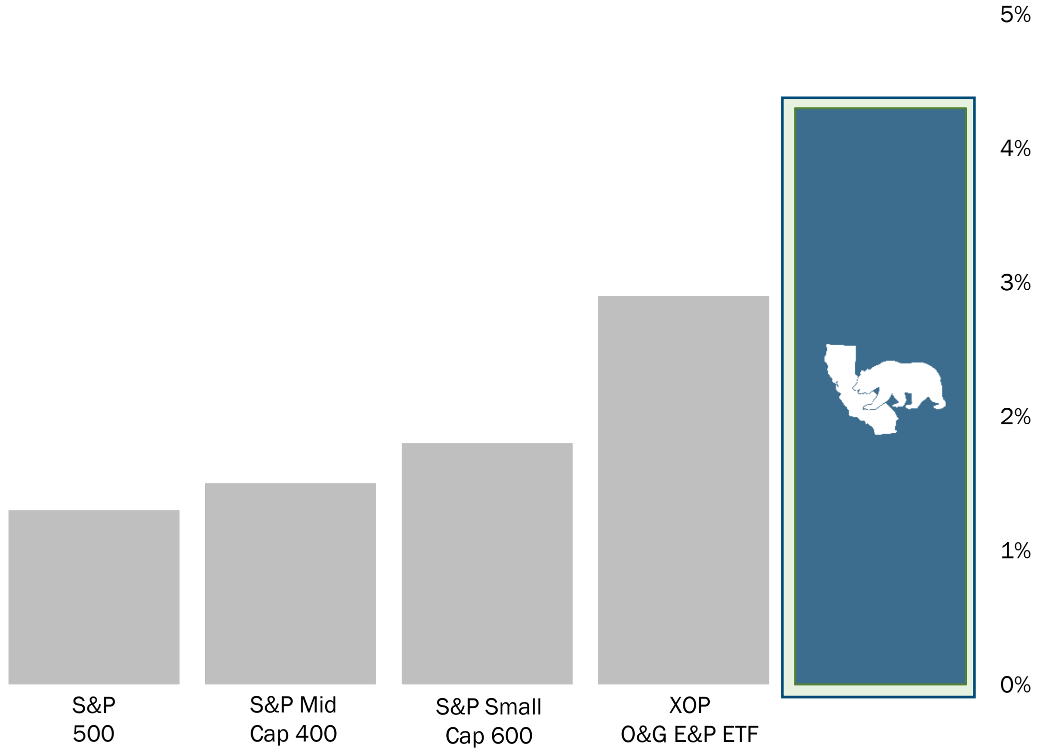
Consistent Track Record of Shareholder Returns[1]

Dividends & Share Repurchases ($MM)



Competitive Dividend Yield vs. Market[2]

Dividend Yield (%)



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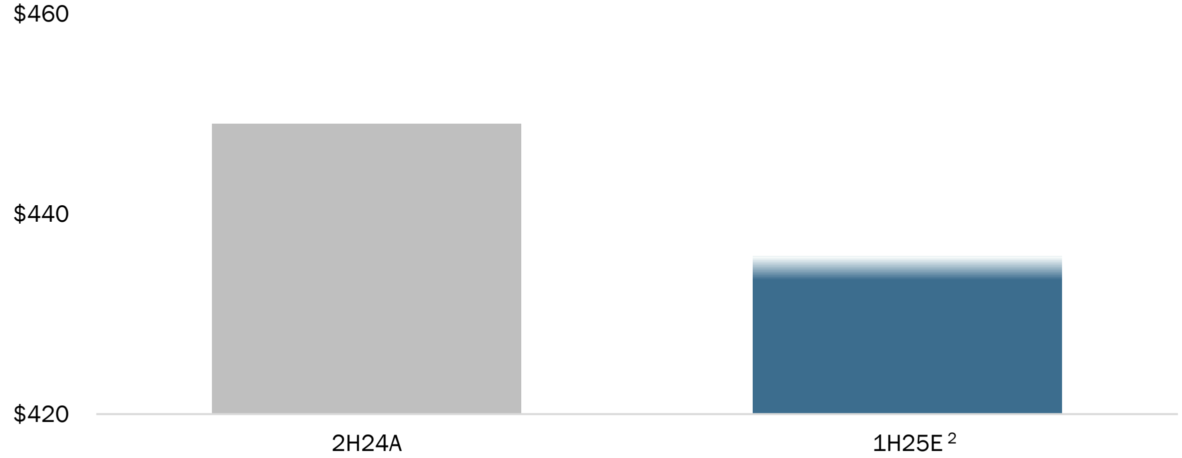
Enhancing Our Cost Structure

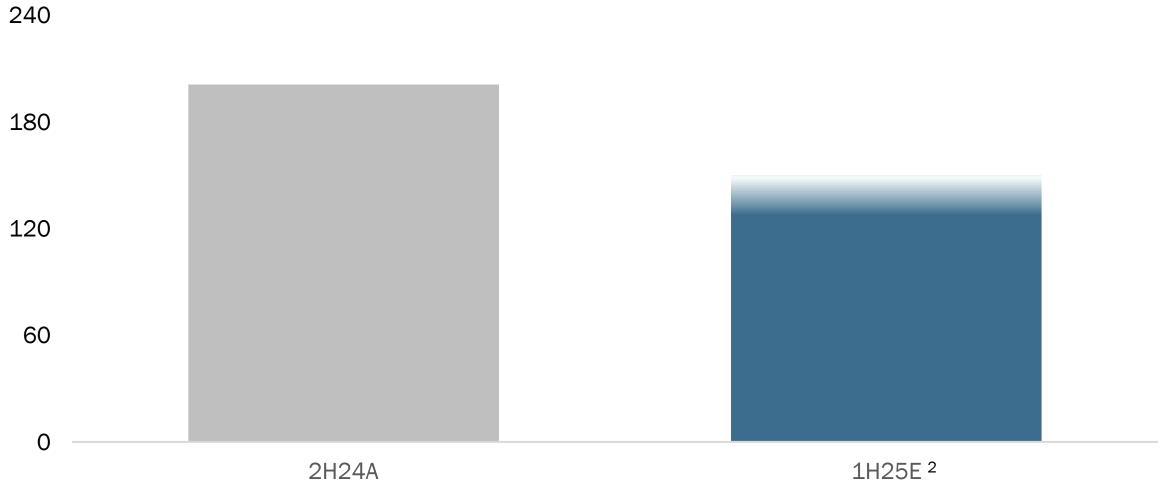
Targeting Lower Controllable Operating Costs

Non-Energy Operating Costs[1] ($MM)



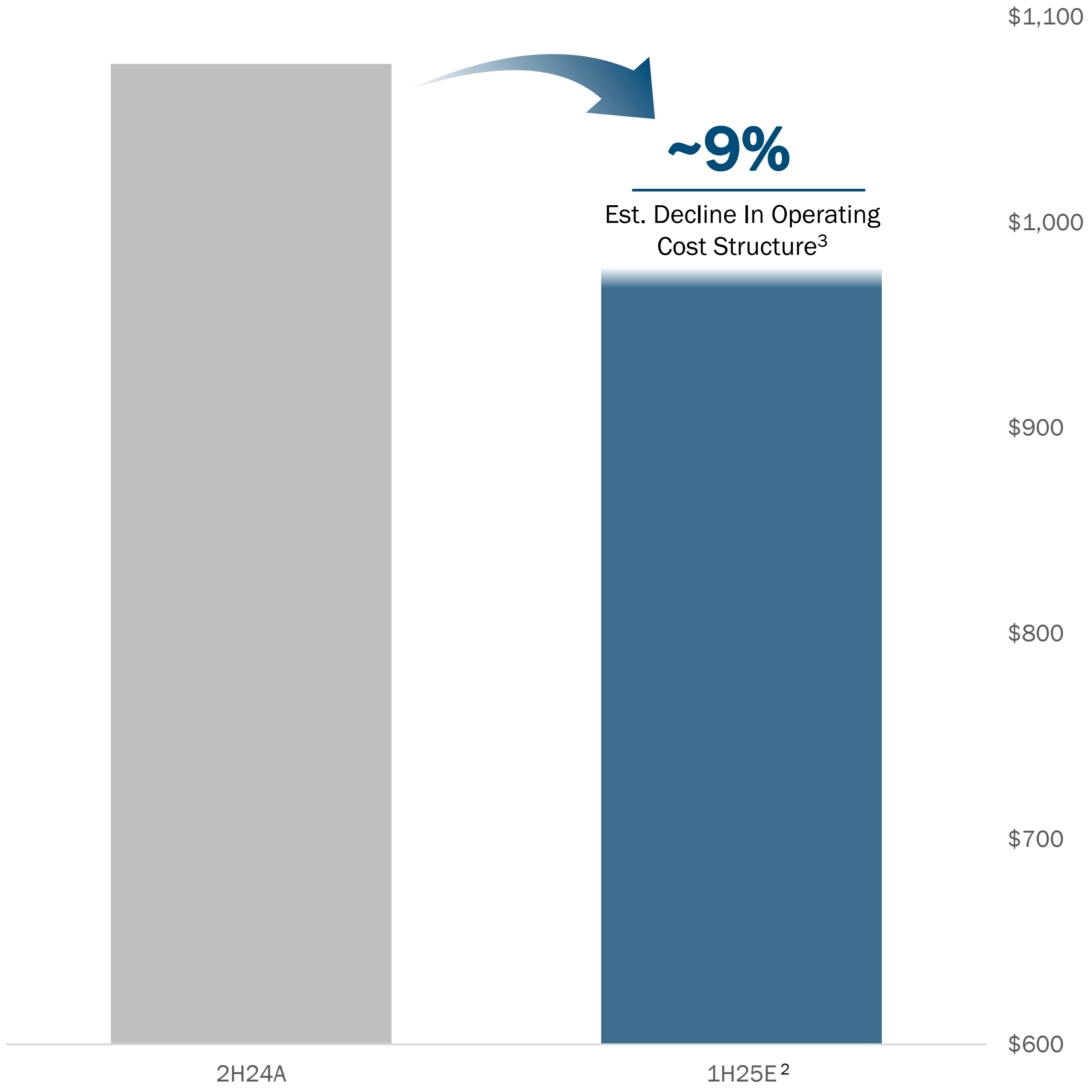
Expecting Reduction in G&A

G&A Expenses ($MM)



Estimating a Decrease in Operating Cost Structure[3]

($MM)



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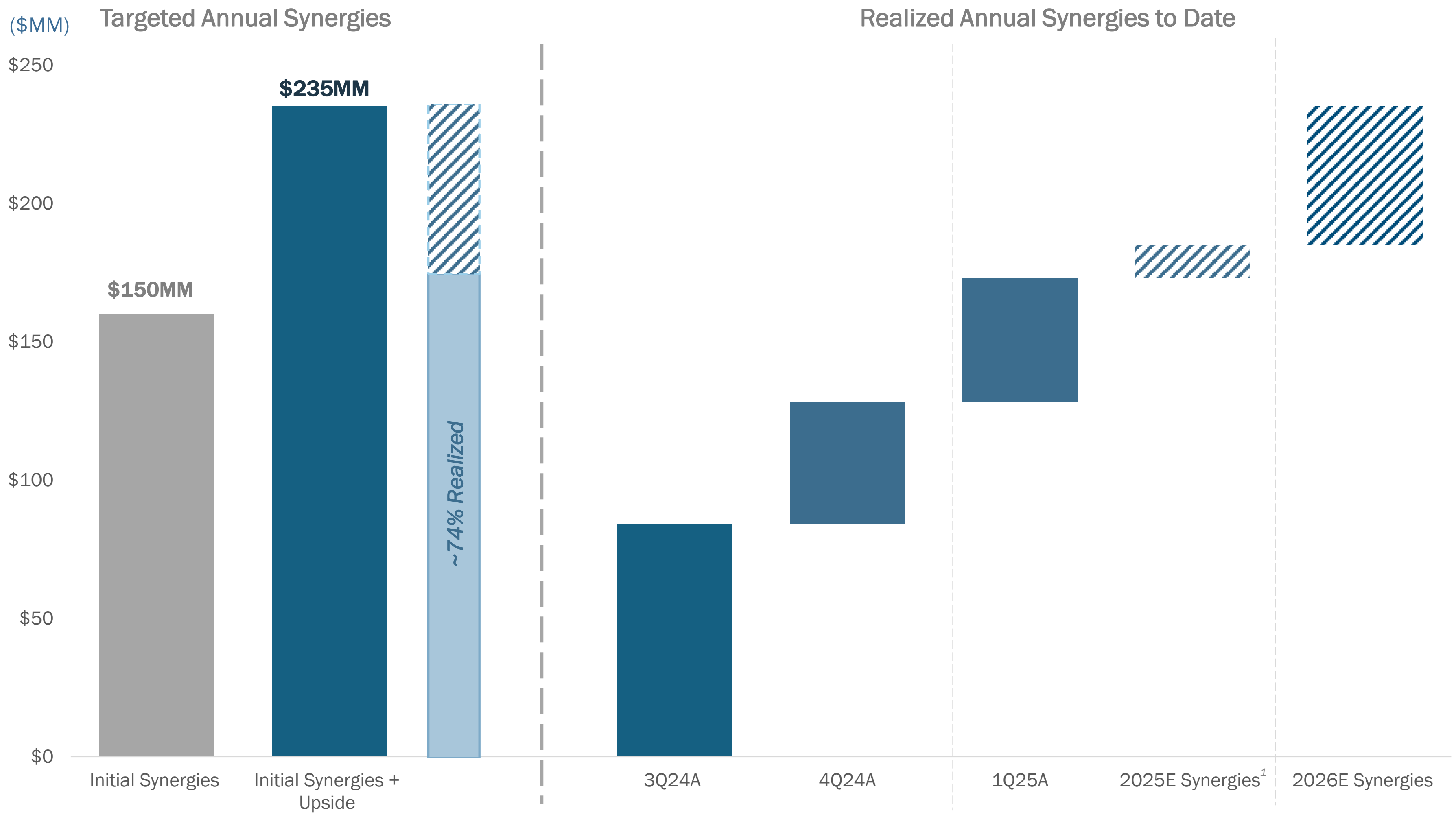
Executing on Our $235MM Total Synergies Target

Aera Merger Related Annual Synergies



Delivering on Our Targets

- $173MM or ~74% of total expected synergies realized to date
- Expecting to realize $185MM of synergies by the end of 2025
- Anticipating realization of remaining $50MM of synergies in early 2026
- Focusing on continuing to improve our operational processes

See slide 25 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

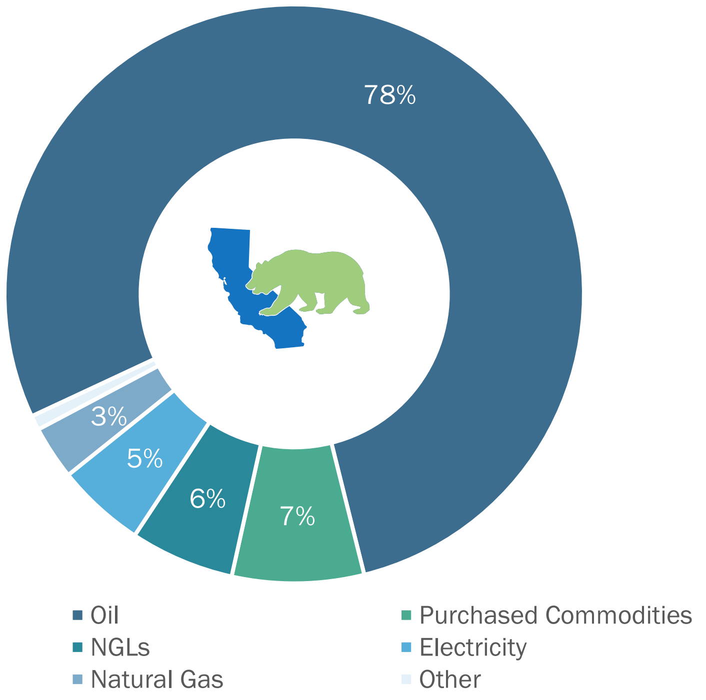
SUSTAINABLE SHAREHOLDER RETURNS STRATEGY

DISCIPLINED CAPITAL ALLOCATION

2Q25E and FY25E Guidance

Integrated Business Strategy and Strong Hedge Book Protect Cash Flows

2024A Revenue Sources Breakdown (%)

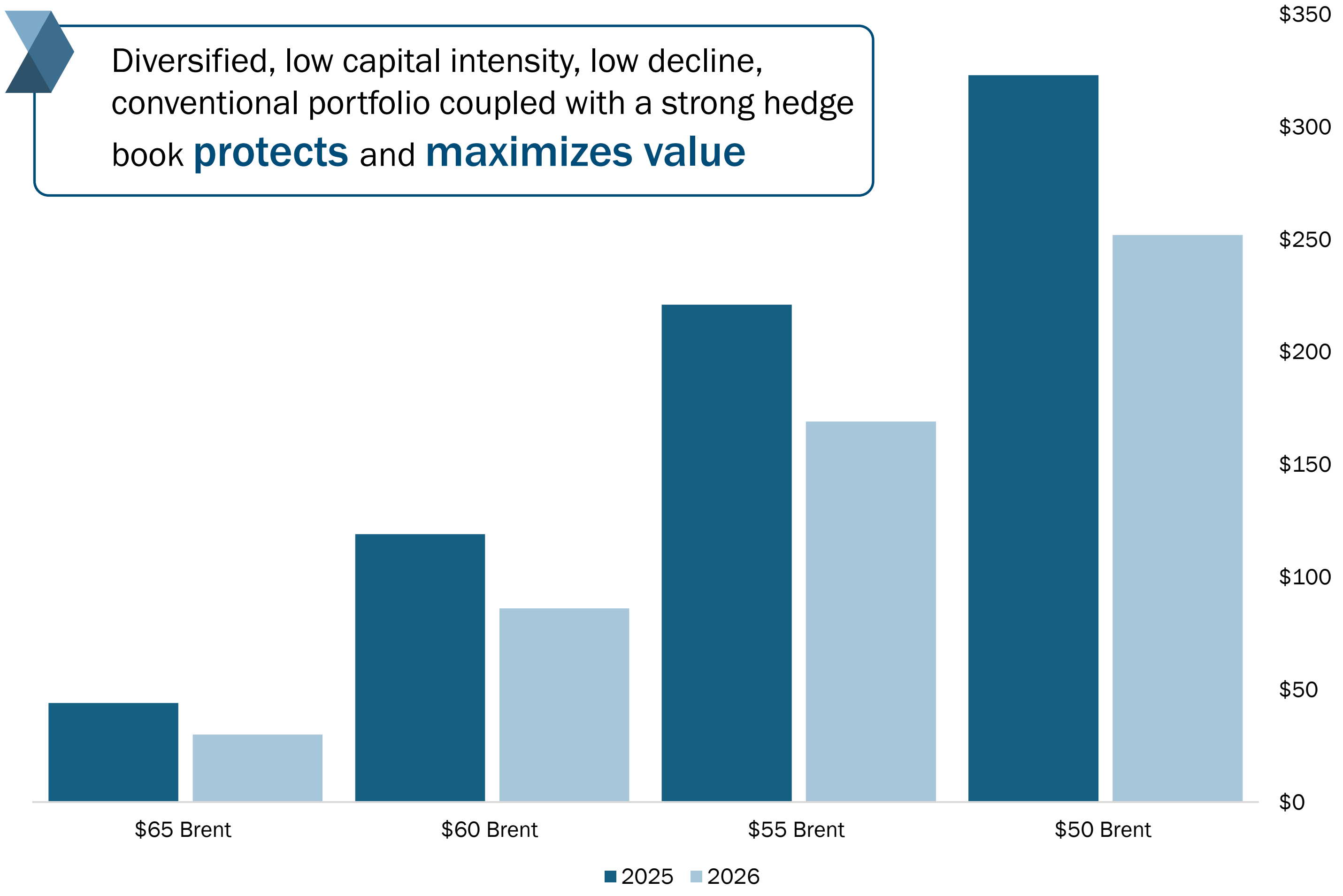


2025E Net Oil Production Hedged[2] (%)

CRC	~72%
Peers[3]	~25%

2025E & 2026E Oil Hedge Cash Settlements[1]

Diversified, low capital intensity, low decline, conventional portfolio coupled with a strong hedge book **protects** and **maximizes value**



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Lower Cost Structure & Integrated Strategy Provides Resilience in 2025

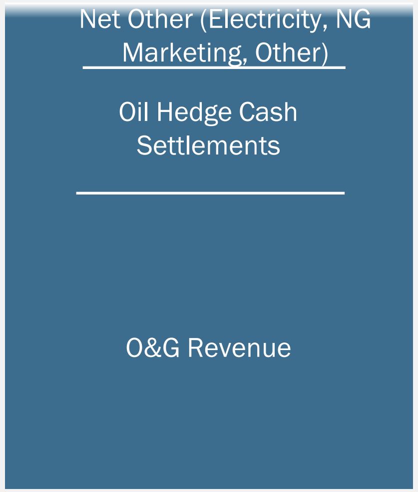
- **Conventional, low decline, low capital intensity asset base provides** ample run rate for CRC to efficiently deploy capital towards better return and future growth potential projects
- CRC **screens well vs. peers on 2025E leverage* and Brent breakeven** sensitivity analysis
- **Diversified revenue stream and hedge position defend near-term operating and capital return plans** while generating cash flow down to **~$34 Brent**

CRC Near Term O&G Project Economics[1]	Brent >25% IRR ($/Bbl)	WTI >25% IRR ($/Bbl)
Workovers	~$38	~$33
New Drills *(Average of sidetracks)*	~$52	~$47

2025E Brent Breakeven[2]

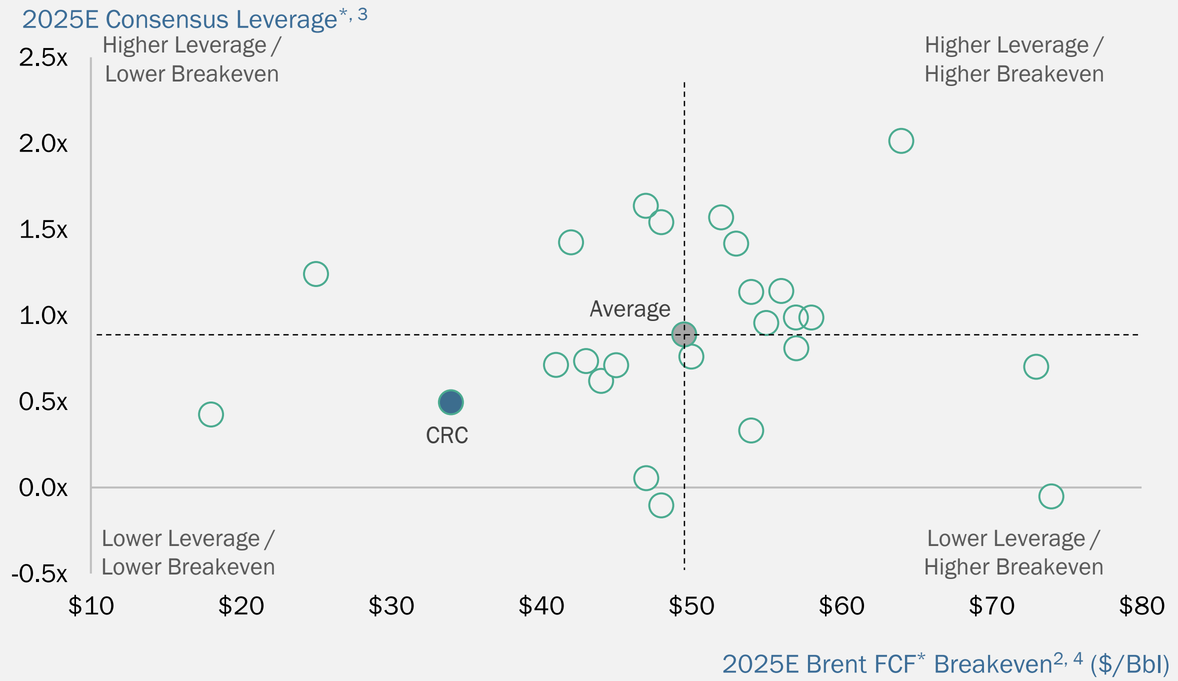
$33 - $35

($/Bbl)



2025E Revenue Sensitivity to Brent

2025E Leverage* / Breakeven – CRC Ranks Favorably Among Top Oily Peers



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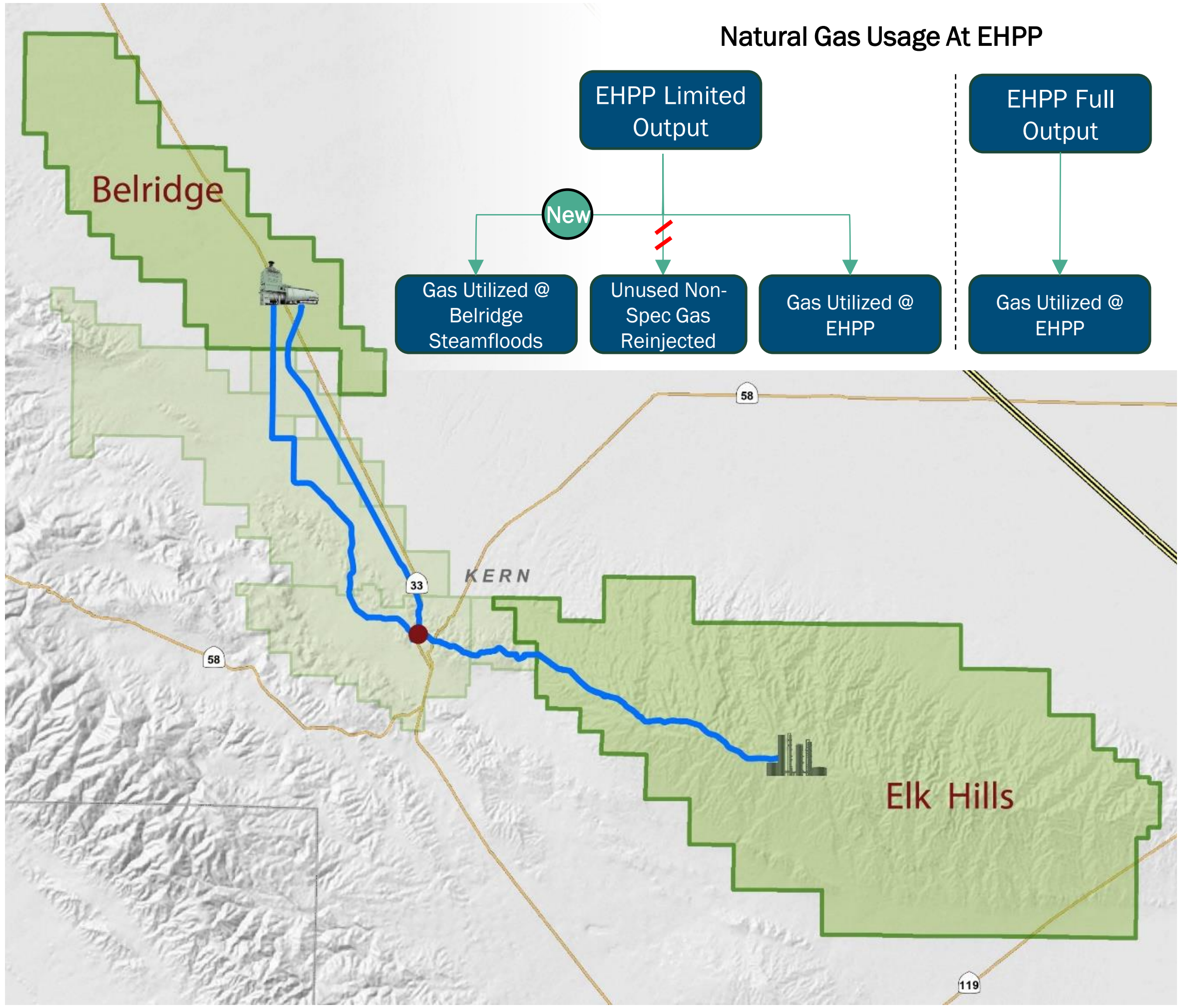
Enhancing Cash Flow Through Realized Portfolio Synergy – Natural Gas Optimization

Connected Elk Hills Produced Natural Gas to Belridge Steamfloods



- **Situation:** In periods of low electricity prices, CRC manages EHPP margin by reducing the power plant's electricity output. When EHPP uses less gas, the produced non-spec gas would be reinjected
- **Synergy**: By connecting CRC's Belridge field with Elk Hills field, CRC can now redirect unused non-spec gas for use in Belridge steamfloods instead of reinjecting it back into the reservoir
- **Savings:** When non-spec gas is consumed at Belridge:
    - Lower energy operating costs by replacing third party gas purchased at market prices with internal use gas
- **2Q25E Net Production/Costs Impact**:
    - ~10 MMcf/d (2MBoe/d) reduction in net gas production
    - Fully offset by cost savings at Belridge steamfloods
    - Internal use gas is not reported as sales volumes

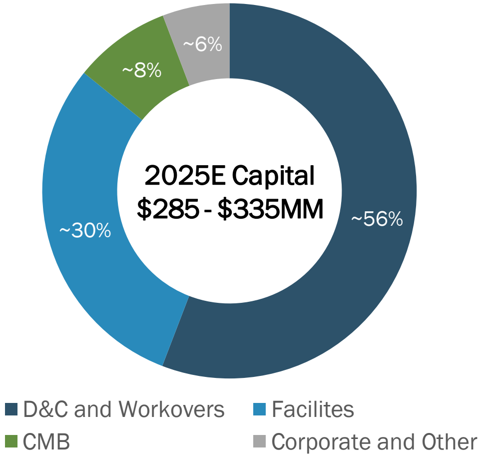
Source: CRC internal estimates.

2025E Guidance *(as of May 7, 2025)*

CRC Guidance	2Q25E Consolidated	Oil and Natural Gas	Carbon Management	2025E Consolidated	Oil and Natural Gas	Carbon Management
Net Production (MBoe/d) ~79% Oil	**133 – 137**			**132 – 138**		
Margin from Purchased Commodities[1] ($MM)	$20 – $25			$80 – $95		
Electricity Margin[2] ($MM)	$40 – $45			$175 – $190		
Operating Costs ($MM)	$295 – $315	$295 – $315		$1,230 – $1,300	$1,230 – $1,300	
G&A ($MM)	$76 – $80	$10 – $14	$2 – $4	$310 – $335	$40 – $50	$10 – $15
Adjusted G&A ($MM)*	*$69 – $74*	*$10 – $14*	*$2 – $4*	*$289 – $309*	*$40 – $50*	*$10 – $15*
Depreciation, Depletion and Amortization ($MM)	$124 – $128	$113 – $119		$500 – $515	$465 - $480	
Other Operating Revenue and Expenses, net[3] ($MM)	$5 – $20		$10 – $15	$35 – $85		$60 – $90
Transportation Expense ($MM)	$22 – $26	$6 – $10		$90 – $98	$28 – $32	
Taxes Other Than on Income ($MM)	$60 – $65	$50 – $55		$265 – $285	$220 – $230	
Interest and Debt Expense ($MM)	$26 – $30			$100 – $113		
Capital ($MM)	**$81 – $92**	$71 – $75	$5 – $10	**$285 – $335**	$250 – $280	$20 – $30
Adj. EBITDAX* ($MM)	**$275 – $290**	$290 - $320	($15) – ($20)	**$1,100 – $1,200**	$1,205 - $1,340	($80) – ($85)

Other Assumptions	2Q25E	2025E
Brent ($/Bbl)	$63.00	$63.00
NYMEX ($/mcf)	$4.11	$4.28
Oil – % of Brent	96% – 100%	96% – 100%
NGL – % of Brent	55% – 60%	60% – 68%
Natural Gas – % of NYMEX	50% – 60%	80% – 90%
Deferred Income Taxes	(68%) – (72%)	5% – 10%
Effective Tax Rate	29%	29%

Demonstrating **lower cost structure, improving margins and better capital efficiency**



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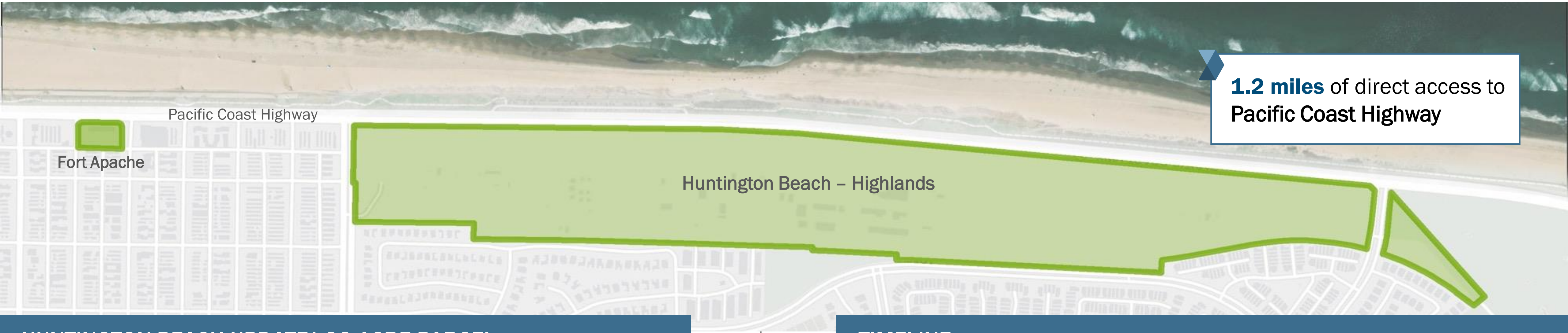
Appendix

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 mid-2026
- Once approved by the City Council, the project would be presented to the California Coastal Commission for final review and approval

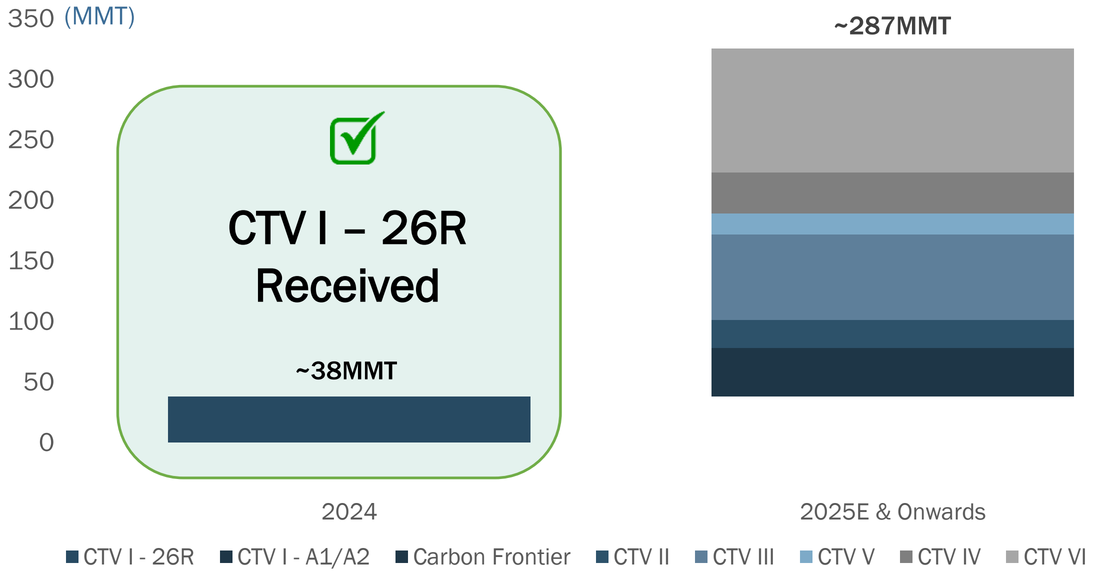
Source: CRC internal estimates. See www.crchbproperty.com for additional information.

Leading California's Decarbonization

EXPANDING OUR CO_2 PERMITTING LEADERSHIP

- Received CA's first EPA Class VI permits for CTV I – 26R
  - Permits became effective February 3, 2025
- 7 EPA Class VI permits in queue for ~287MMT of storage[1]
- Expecting to submit additional reservoirs to the EPA for Class VI permitting in 2025
- Identified up to 1BMT[2] of potential CO_2 storage in California

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)*[3]
- Approved California's first CCS project at cryogenic gas plant at Elk Hills
  - Ongoing engineering, equipment preparation and procurement with surface construction targeted to begin in 2Q25
  - Targeting first injection and initial cash flow by YE25[4]
- Attracting private and federal clean energy capital to California[5] through Carbon Management efforts
- Largest amount of potentially available and stackable incentives for CCS development in the country
- Expecting support for CO_2 pipeline transportation from California in 2025

CARBON TERRAVAULT

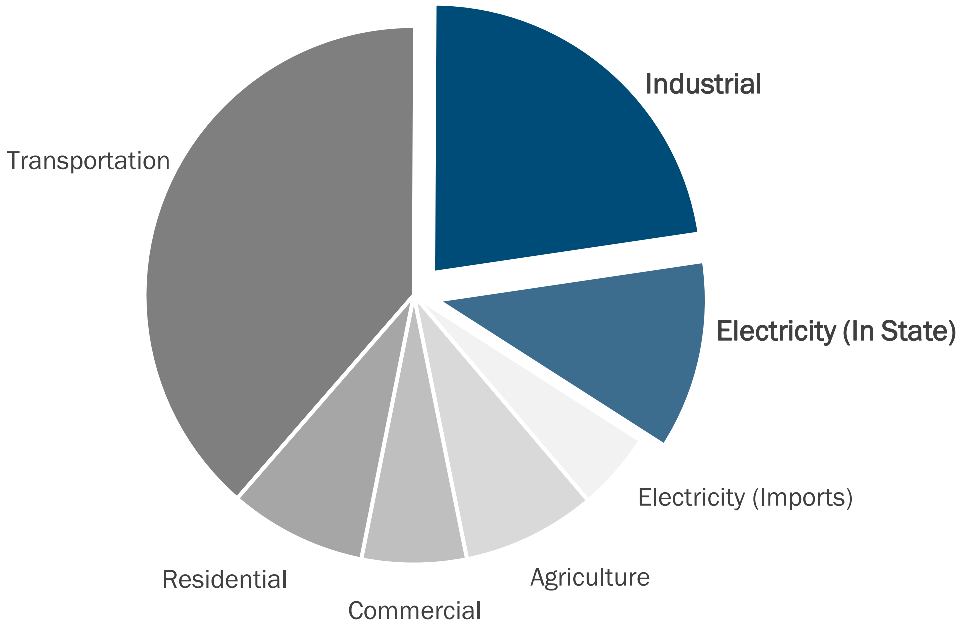
Positioned to Be California's Premier Carbon Management Provider

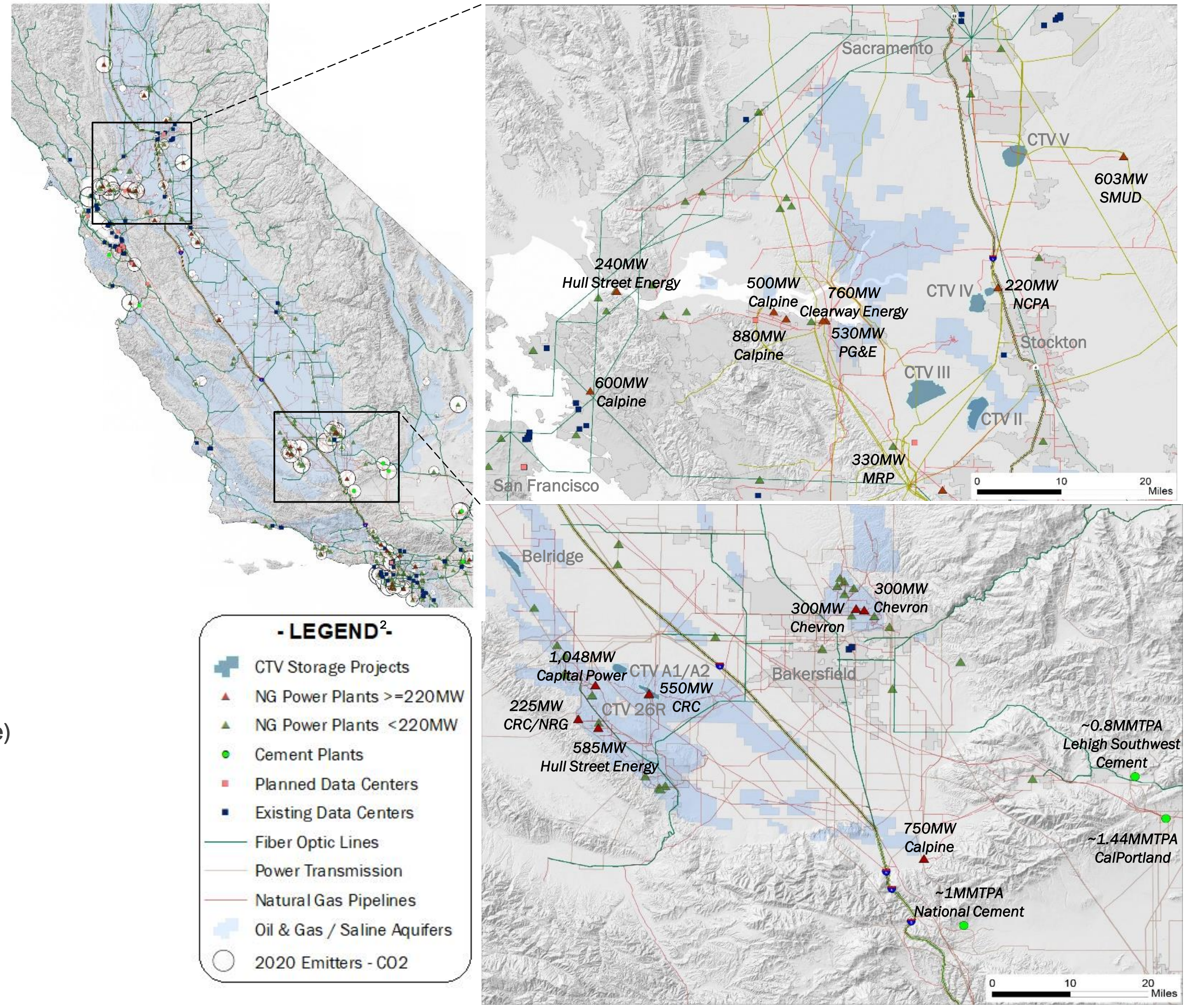
See slide 26 for "Assumptions, Estimates and Endnotes".

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 Basin

CALIFORNIA GHG EMISSIONS BY SECTOR[1]





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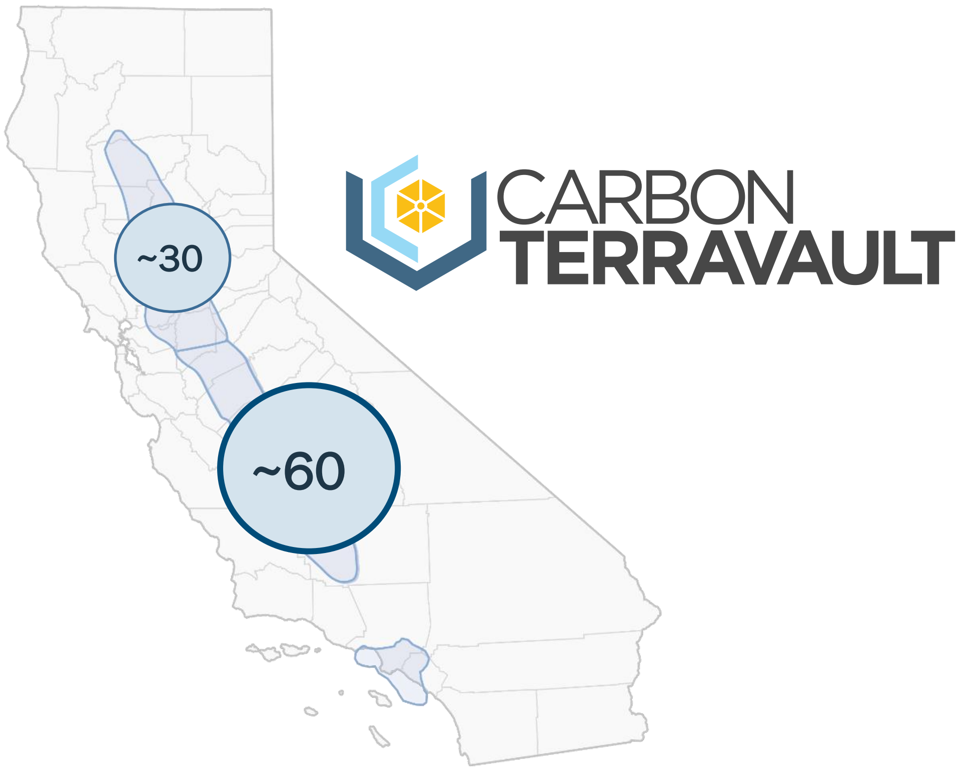
California's Premier Carbon Management Provider

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

Vault / Reservoir		Targeted Final EPA Class VI Permit Decision	Est. Annual Injection Rate[2] (MMTPA)			Permit Volumes[1] (MMT)
			EPA Class VI Permit	20 Years	40 Years	
CTV I	26R	Permit Received	~1.5[3]	~1.9	~1.0	~38
	A1-A2	2025E	~0.8	~0.4	~0.2	~8
Carbon Frontier		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		2025E	~0.7	~0.8	~0.4	~17
Northern California			**~5.6**	**~7.3**	**~3.7**	**~145**
Total - Combined			**~14.6**	**~16.3**	**~8.2**	**~325**

Target Addressable Market by Region[4]

Annual Regional CO_2 Emissions (MMTPA)



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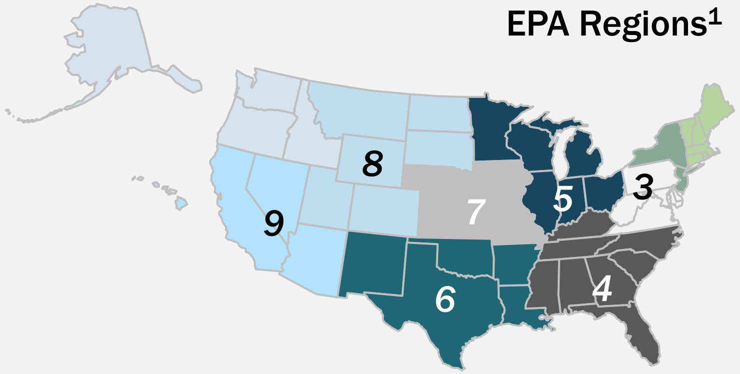
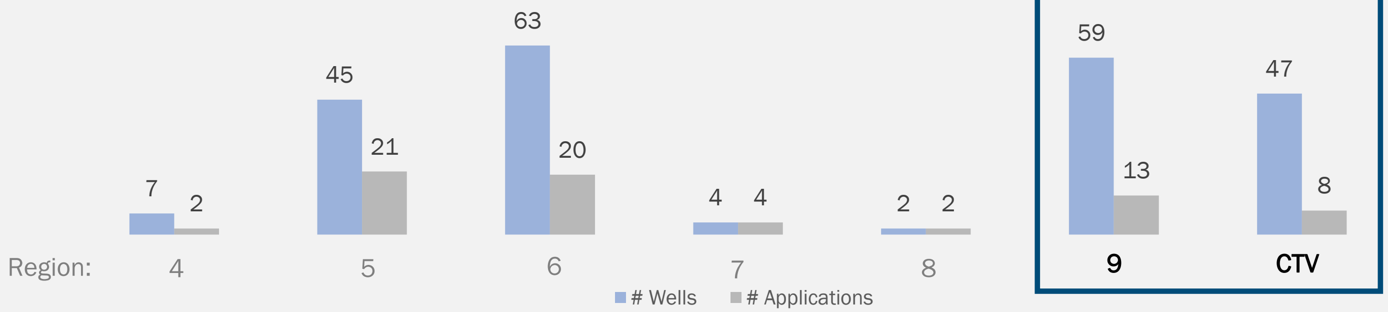
Leading EPA Class VI Permitting Pipeline *(As of April 25, 2025)*

EPA Regions[1]

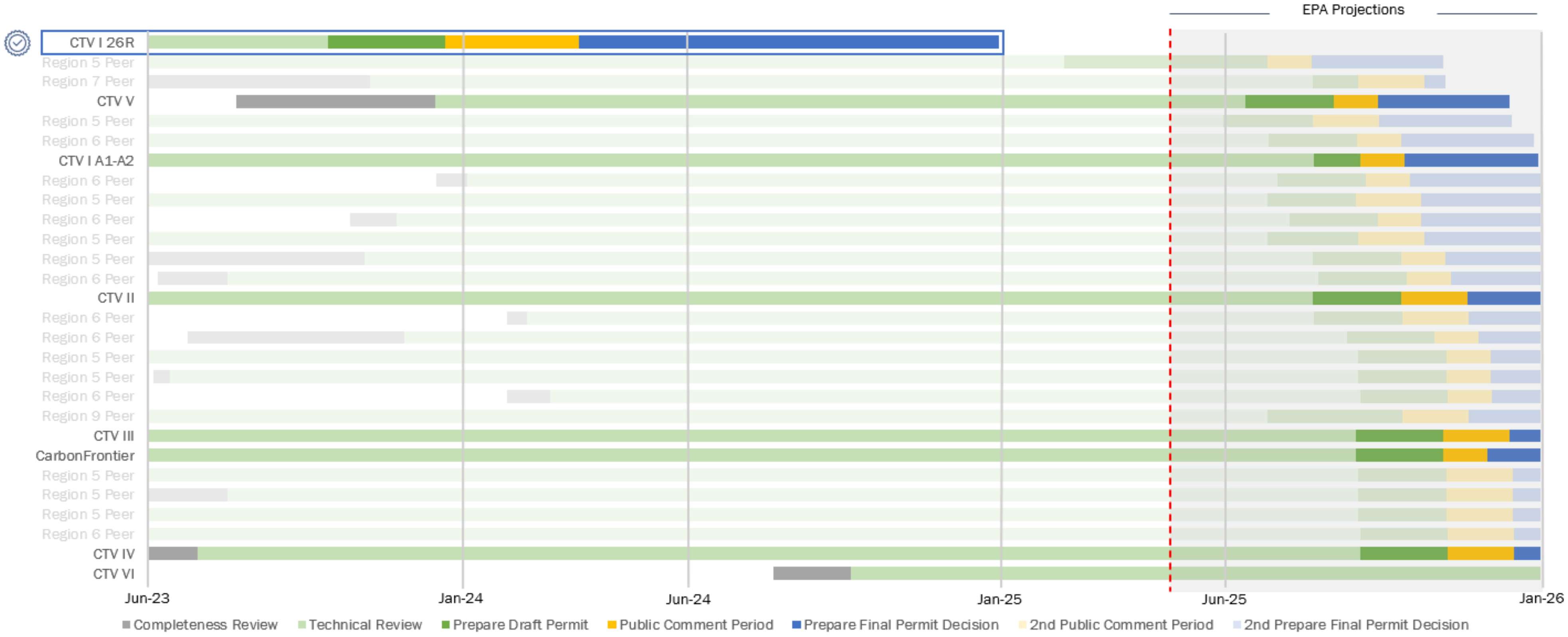


EPA Class VI Projects Under Review[1]



EPA Projected Permit Timeline[1]

Targeting **additional permitted CO_2** space in 2025



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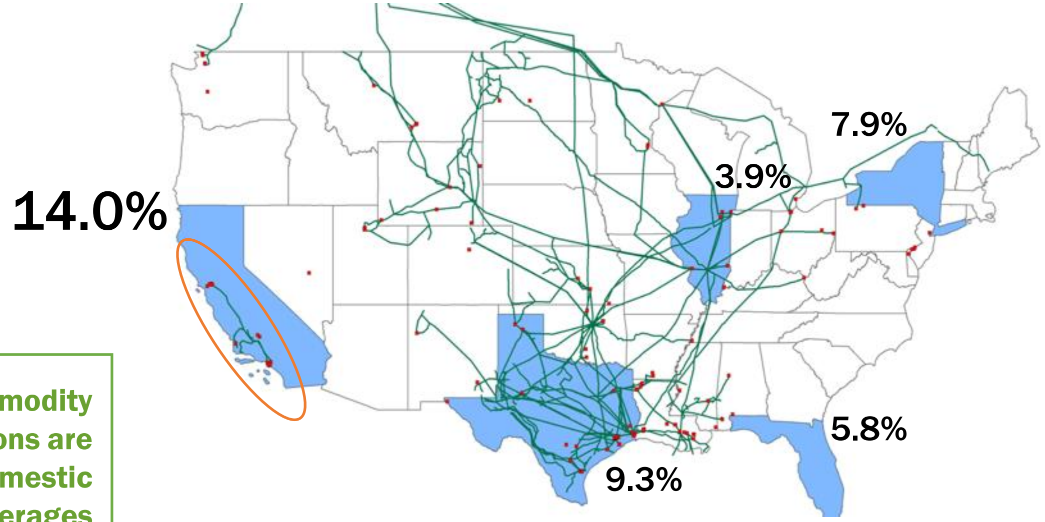
Strong Commodity Price Realizations

- **Crude:** Crude prices experienced limited volatility during 1Q25 with prices moving lower across the quarter. Price direction was influenced by anticipation of incremental OPEC+ barrels and concerns over global economic and trade conditions. California realizations remained solid even with an outage at a major refinery during the quarter.
- **Natural Gas:** While North American natural gas prices, in general, benefited from unseasonably cold weather, seasonal West Coast temperatures and surplus California storage inventories limited increases in local natural gas prices and realizations in 1Q25.
- **NGLs:** Realizations were strong in 1Q25 driven by demand for propane and butane from export and blending markets, respectively. California continues to carry a premium to the broader US NGL marketplace.

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

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



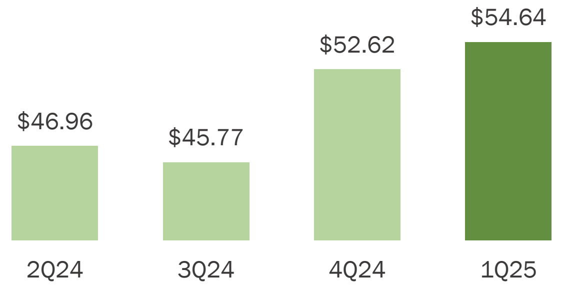
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 4Q24; EIA

CRC's commodity realizations are above domestic averages

Oil w/ Hedges ($/BBL)

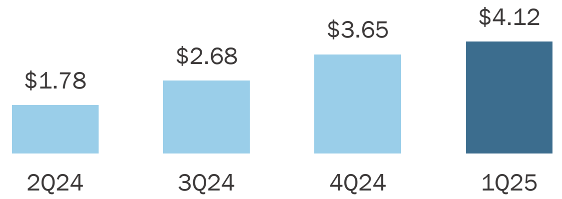
	2Q24	3Q24	4Q24	1Q25
Average Benchmark Prices[1]	$85.00	$78.54	$73.97	$74.92
% of Benchmark[1]	98%	98%	98%	98%
Hedge Settlements	($1.85)	($1.72)	$0.18	($1.56)
Average Realized Prices[2]	$81.29	$75.38	$73.00	$72.01

NGLs ($/BBL)



	2Q24	3Q24	4Q24	1Q25
Average Benchmark Prices[1]	$85.00	$78.54	$73.97	$74.92
% of Benchmark[1]	55%	58%	71%	73%
Hedge Settlements	-	-	-	-
Average Realized Prices[2]	$46.96	$45.77	$52.62	$54.64

Natural Gas ($/MCF)



	2Q24	3Q24	4Q24	1Q25
Average Benchmark Prices[1]	$1.89	$2.16	$2.79	$3.65
% of Benchmark[1]	94%	124%	131%	113%
Hedge Settlements	-	-	-	-
Average Realized Prices[2]	$1.78	$2.68	$3.65	$4.12

See slide 26 for "Assumptions, Estimates and Endnotes".

Hedge Portfolio (as of March 31, 2025)

OIL		2Q25E	3Q25E	4Q25E	1Q26E	2026E	2027E	2028E
SOLD CALLS								
Brent	Barrels per Day	30,000	30,000	29,000	15,000	15,000	-	-
	Weighted-Average Price	$87.08	$87.08	$87.13	$85.00	$85.00	-	-
SWAPS								
Brent	Barrels per Day	46,506	45,001	42,626	36,444	30,449	13,882	1,697
	Weighted-Average Price	$71.31	$70.63	$69.94	$68.98	$67.95	$65.53	$65.00
PURCHASED PUTS[1]								
Brent	Barrels per Day	30,000	30,000	29,000	15,000	15,000	-	-
	Weighted-Average Price	$61.67	$61.67	$61.72	$60.00	$60.00	-	-
NATURAL GAS		**2Q25E**	**3Q25E**	**4Q25E**	**1Q26E**	**2026E**	**2027E**	**2028E**
SWAPS								
SoCal Border	MMBtu per Day	29,074	25,750	22,408	2,675	660	-	-
	Weighted-Average Price	$3.44	$3.48	$3.53	$6.29	$6.29	-	-
NWPL Rockies	MMBtu per Day	51,750	51,750	51,750	49,425	44,618	12,616	1,576
	Weighted-Average Price	$2.95	$2.95	$4.22	$4.70	$4.01	$4.34	$3.95
EST. HEDGE CONTRACT SETTLEMENTS[2]		**2Q25E**	**3Q25E**	**4Q25E**	**1Q26E**	**2026E**	**2027E**	**2028E**
Combined Hedge Portfolio ($MM)		($20)	($5)	($2)	($2)	($16)	($16)	($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

~70% of remaining 2025E net oil production hedged with **Brent floor price of ~$67** per barrel

OPERATIONS

~70% of remaining 2025E internal fuel consumption hedged at an average **natural gas price of ~$3.41** per MMBtu

See slide 27 for "Assumptions, Estimates and Endnotes".

Strong Balance Sheet, Ample Liquidity and Financial Flexibility

3/31/25 NET DEBT* SNAPSHOT

($MM)

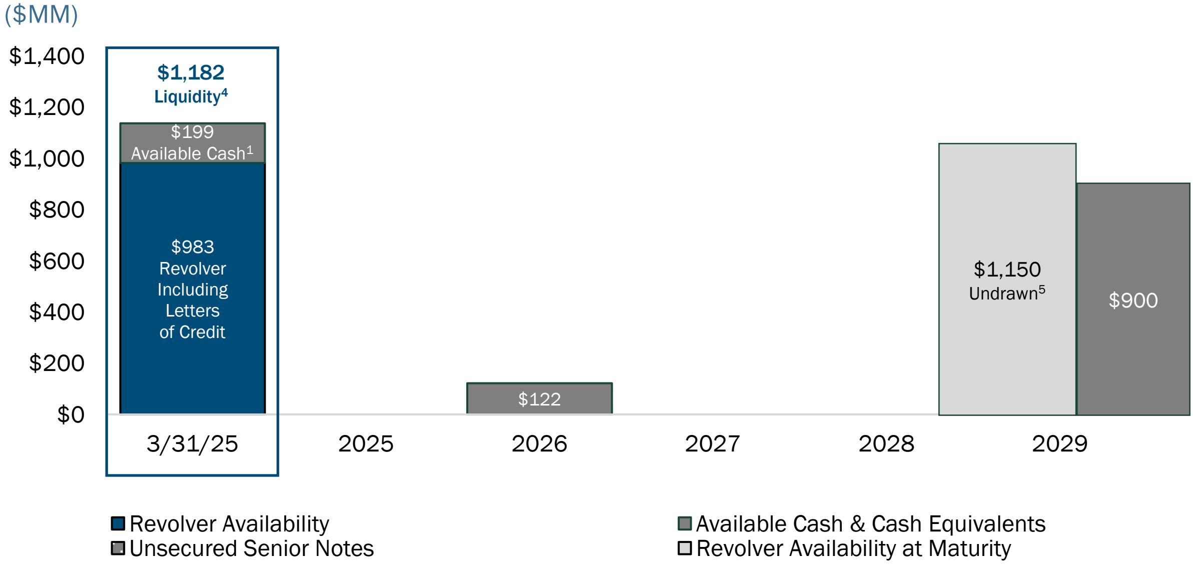
Revolving Credit Facility (RCF)	$	-
7.125% 2026 Senior Notes		122
8.250% 2029 Senior Notes		900
Face Value of Debt	**$**	**1,022**
Less Available Cash & Cash Equivalents[1]		(199)
Net Debt*	**$**	**823**

MULTIPLES DEMONSTRATE FLEXIBILITY

($MM)

RCF Borrowing Base	$1,500
1Q25 Free Cash Flow*	$131
1Q25 Net Debt* / 2025E EBITDAX*, [2]	0.7x
2025E EBITDAX* / 2025E Interest Expense*, [3]	10.8x

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 27 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
EHPP	Elk Hills Power Plant
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESG	Environmental, Social and Governance
FCF	Free Cash Flow
FEED	Front End Engineering and Design
FID	Final Investment Decision
FTM	Front-of-the-Meter
GHG	Greenhouse Gas
IRR	Internal Rate of Return

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

Assumptions, Estimates and Endnotes

Slide 2:

(1) Includes gas processing costs.

(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) Source: FactSet. As of May 2, 2025. Represents current annualized dividend policy of $1.55 per share divided by CRC's share price. Market includes S&P 500, S&P 400, S&P 600 and XOP ETF. Peers include AR, APA, BRY, BKV, CHRD, CIVI, CRK, CRGY, KOS, MGY, MTDR, MUR, PR, RRC, SOC, SM, TALO and VET.

(4) Net leverage is calculated as 1Q25 net debt of $823MM (excludes restricted cash of $15MM) divided by 2025E adjusted EBITDAX guidance midpoint. See slide 14 for 2025E guidance.

Slide 3:

(1) Total year 2025E guidance assumes a 2025E Brent price of $63.00 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $4.28 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 for 2025E guidance.

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

Slide 5:

(1) 1Q25E guidance assumes a 1Q25E Brent price of $76.54 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.38 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline.

(2) Other operating revenue and expenses, net is calculated as the difference between other revenue and other operating expenses, net. Includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.

(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 6:

(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. As of May 2, 2025. Represents current annualized dividend policy of $1.55 per share divided by CRC's share price of $36.22. Market includes S&P 500, S&P 400, S&P 600 and XOP ETF. Peers include AR, APA, BRY, BKV, CHRD, CIVI, CRK, CRGY, KOS, MGY, MTDR, MUR, PR, RRC, SOC, SM, TALO and VET.

Slide 7:

(1) Includes gas processing costs.

(2) 1H25E includes 1Q25 actual results and 2Q25E guidance midpoints. See slide 14 for 2Q25E guidance.

(3) Operating cost structure includes operating costs, CMB expenses, G&A expenses, transportation costs and taxes other than on income.

Slide 8:

(1) See slide 14 for 2025E guidance.

Slide 11:

(1) Source: CRC internal estimates. As of March 31, 2025.

(2) 2025E net oil production based on the 2025E guidance midpoints provided with 4Q24 earnings results on March 3, 2025.

(3) Source: Capital One Securities, "E&P Focus List and Relative Bias Index" April 30, 2025. Peers include APA, AR, BRY, CHRD, CIVI, CNX, COP, CRK, CTRA, DVN, EOG, EQT, EXE, FANG, GPOR, GRNT, HES, INR, MGY, MTDR, MUR, NOG, OVV, OXY, PR, RRC, SM, TXO and VTLE.

Assumptions, Estimates and Endnotes (Cont.)

Slide 12:

1. (1) Source: CRC internal estimates. Project economics reflect available inventory supported by permits in hand.
2. (2) CRC 2025E free cash flow breakeven, the price of oil at which CRC's total operating costs, total capital, interest and dividends are equal to its revenue, based on 2025E guidance midpoints and internal estimates. Hedge settlements as of March 31, 2025. See slide 14 for 2025E guidance.
3. (3) Source: FactSet consensus estimates. As of May 2, 2025.
4. (4) Source: Truist Securities, "Energy: Per Share Production Rate Key in Down Cycle" April 13, 2025 and assumes a +$5/bbl differential between Brent and WTI. Oily peers include APA, CHRD, CIVI, COP, CRC, CRGY, CTRA, CVX, DVN, EOG, FANG, INR, MGY, MNR, MTDR, MUR, NOG, OVV, OXY, PR, REI, REPX, SM and VTLE.

Slide 14:

(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 revenue and expenses, net is calculated as the difference between other revenue and other operating expenses, net. Includes exploration expense and CMB expenses. CMB expenses includes lease cost for sequestration easements, advocacy, and other startup related costs.

Slide 17:

(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) Source: CRC internal estimates.

(3) 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.

(4) Initial cash flow estimates include project assumptions described on slides 5 and 6 of CRC's January 2025 presentation.

(5) Source: Database of State Incentives for Renewables & Efficiency (DSIRE) from the N.C. Clean Energy Technology Center.

Slide 18:

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

(2) Source: California Energy Commission.

Slide 19:

(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 20:

(1) Source: EPA, www.epa.gov/uic/class-vi-wells-permitted-epa. Based on EPA estimates and approvals. CTV II is 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 and CTV VI is projected to receive a final permit decision in September 2026.

Slide 21:

(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.

Assumptions, Estimates and Endnotes (Cont.)

Slide 22:

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

(2) Represents estimated net cash settlement payments for derivative contracts and forward commodity prices as of March 31, 2025.

Slide 23:

(1) Available cash and cash equivalents excludes $15MM of restricted cash.

(2) Net leverage is calculated as 1Q25 net debt of $823MM (excludes restricted cash of $15MM) divided by 2025E adjusted EBITDAX guidance midpoint. See slide 14 for 2025E guidance.

(3) Interest coverage is calculated as 2025E adjusted EBITDAX guidance midpoint divided by interest and debt expense guidance midpoint. See slide 14 for 2025E guidance.

(4) Liquidity on March 31, 2025 is calculated as $199MM of cash and cash equivalents (excluding $15MM 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 March 31, 2025, excluding outstanding letters of credit.

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