Third Quarter 2026 Results

November 2, 2026



Strengthening California's Leading Energy Infrastructure Platform

Enhancing Our California Core

- Strong reservoir performance driving ~2% sequential net production growth
- Announced an agreement to divest Uinta Basin assets
- Closed all-cash acquisition of Crimson which includes key rights-of-way that help build a foundation for a potential statewide CO_2 pipeline system[1]

Expanding Our Leading Carbon Management Business

- Signed MOU[2] with Bloom Energy for development of 1GW or more of clean power and storage of up to 3MMTPA of CO_2 emissions
- Submitted new EPA Class VI permit application for ~57MMT of CO_2 emissions bringing total submitted EPA Class VI permit volumes to ~409MMT[3]

Commitment to Shareholder Returns

- $66MM returned to shareholders in 3Q26 including $30MM in share repurchases and $36MM in dividends; ~45% of quarterly free cash flow*, [4]
- ~4% increase in quarterly dividend to $0.42 per share; ~3.0% annual dividend yield vs. peer average of ~1.8%[4, 5]

3Q26 Results Highlights

152MBoe/d
Total Net Production
~80% Oil

$158MM
Total Capital
$155MM E&P

$341MM
Adj. EBITDAX*

$300MM
Cash Flow Before W/C*

BLOOM
1GW or More and
3MMTPA MOU[2]

~57MMT
New EPA Class VI
Permit Submitted[3]

$66MM
Total Shareholder
Returns[4]

~4%
Quarterly Dividend
Increase[4]

Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities".
See slide 24 for "Assumptions, Estimates and Endnotes".

California Focused

Closed Crimson Acquisition

Accretive	Attractively Priced	Industrial Logic
4.4x EV/27E Adj. EBITDA*, 1	~$63MM Cash[2]	Strong Asset Fit

- ~2,000-mile Crimson diversified midstream system and storage to link Central California production to highest-value markets and other growth opportunities
- Deal includes: SoCal Pipeline Network, IVEC Line, San Pablo Bay Pipeline, KLM Pipeline and other strategic assets
- Transaction includes any proceeds from pending rate cases
- Acquisition includes land rights that help build a foundation for the long-term development of a potential CO_2 pipeline system[3]
- Targeting the re-opening of San Pablo Bay Pipeline in 1Q27

CALIFORNIA RESOURCES × Crimson Midstream, LLC

Announced the Divestiture of Non-Core Uinta Basin[4]

Strategic Sale	Attractively Priced	CRC Focus
Unconventional Asset	~$90MM Cash[5]	California

- Accretive sale to cost structure and capital: Capital reallocation toward shareholder returns and other corporate purposes
- ~0.5% estimated improvement to corporate Brent-linked oil realizations
- Initial purchase price to be adjusted based on an economic effective date of July 1, 2026 (other than for certain items) and other transaction and closing costs[5]
- Closing expected by year-end 2026, subject to customary closing conditions

Unlocking Capital

Net Mineral Acres: ~100,000 acres
1H26 Oil Realization: ~79% of WTI
Net Revenue Interest: ~61%
1H26 Operating Cost/Boe: ~$26/Boe
Total ARO Liability: ~$32MM



Reallocated Uinta 2026E D&C Capital[6]

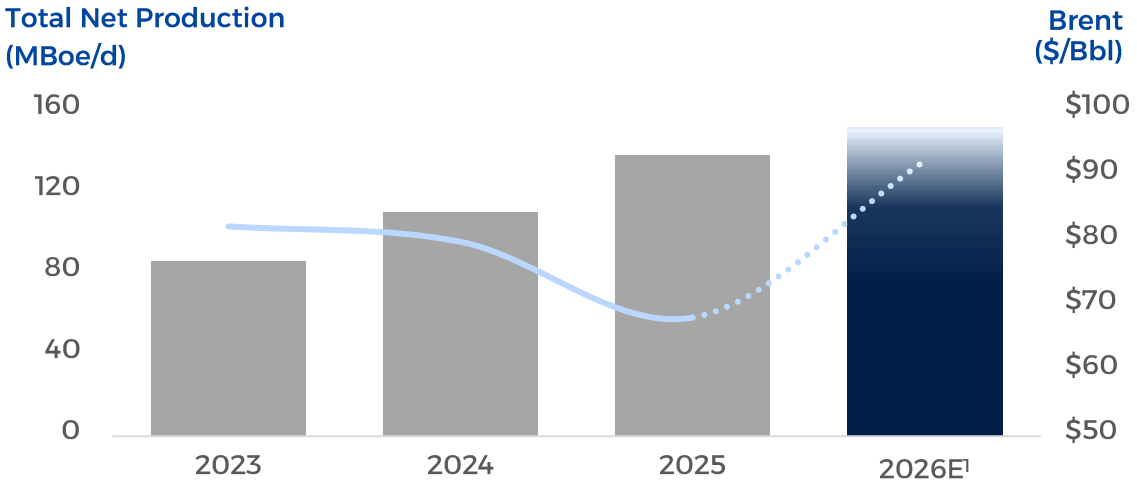
Initial Purchase Price[5]

Potential Unlocked Funds

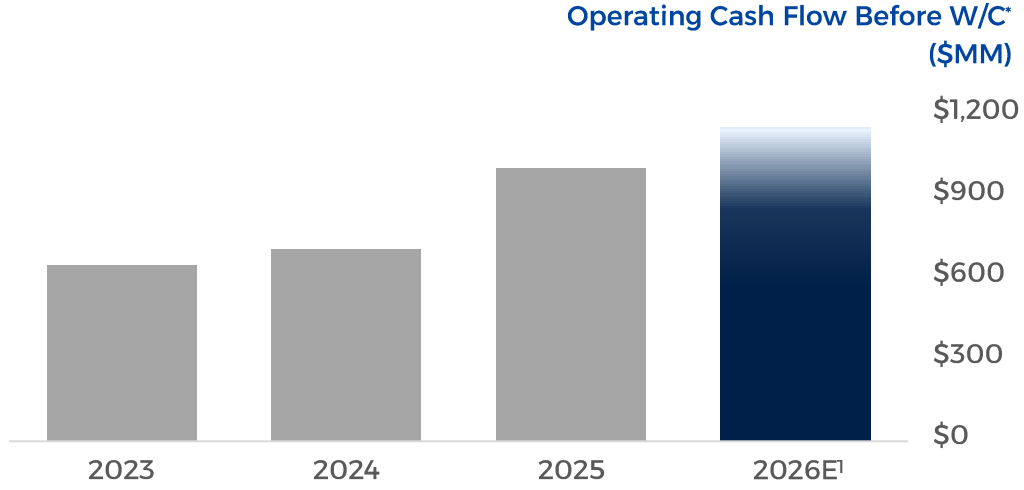
See slide 24 for "Assumptions, Estimates and Endnotes".

Building Momentum Through Year-End 2026

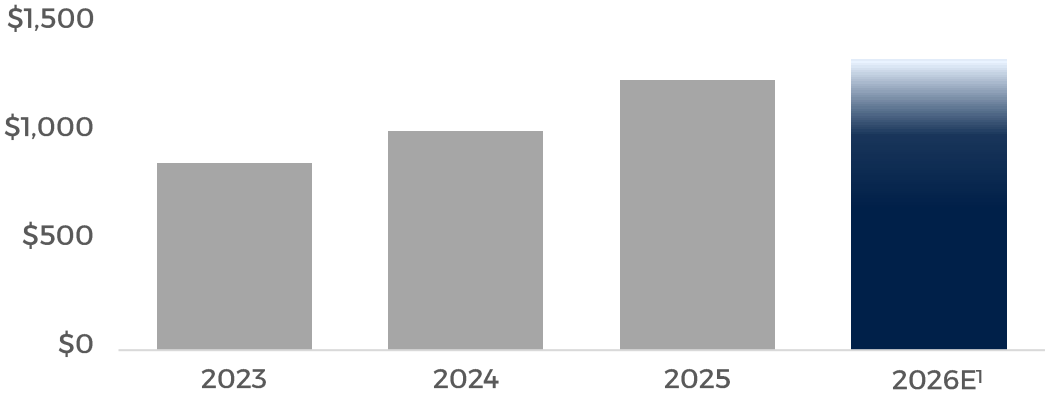
Added Production in Lower Price Environments



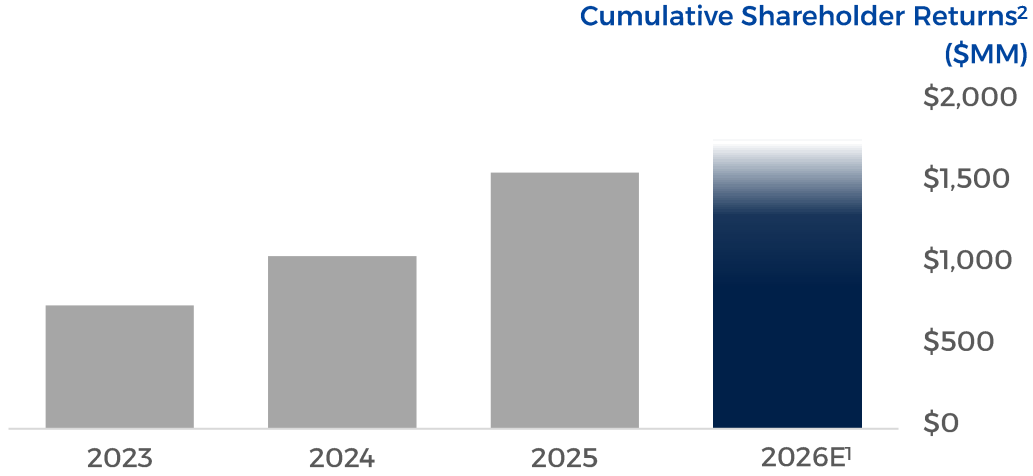
Robust Cash Flow Growth



Driving a ~15% Earnings CAGR



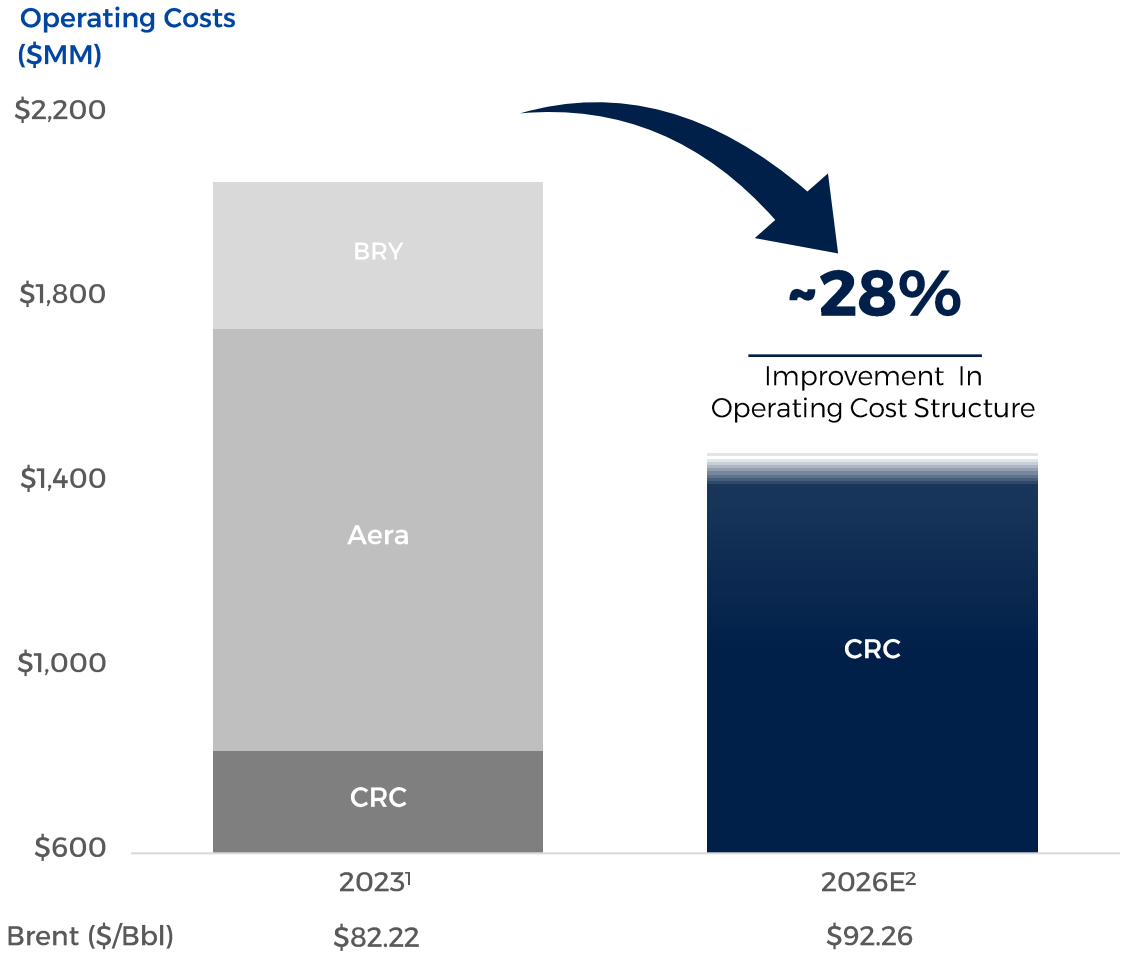
Commitment to Shareholder Returns

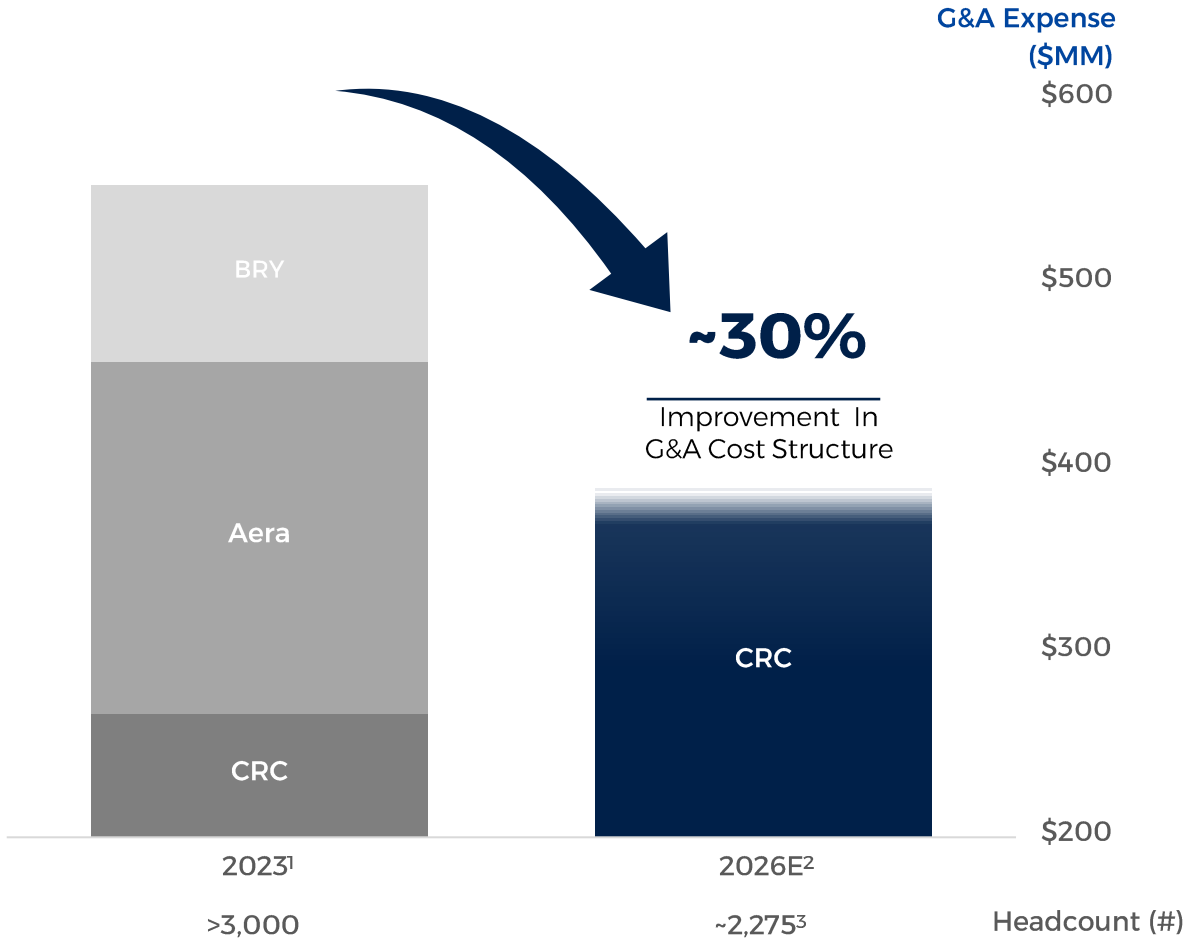


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Significant Improvement Since 2023

Reduced Operating Costs and G&A Expense by >$740MM Since 2023 Through Timely M&A Activity[1]

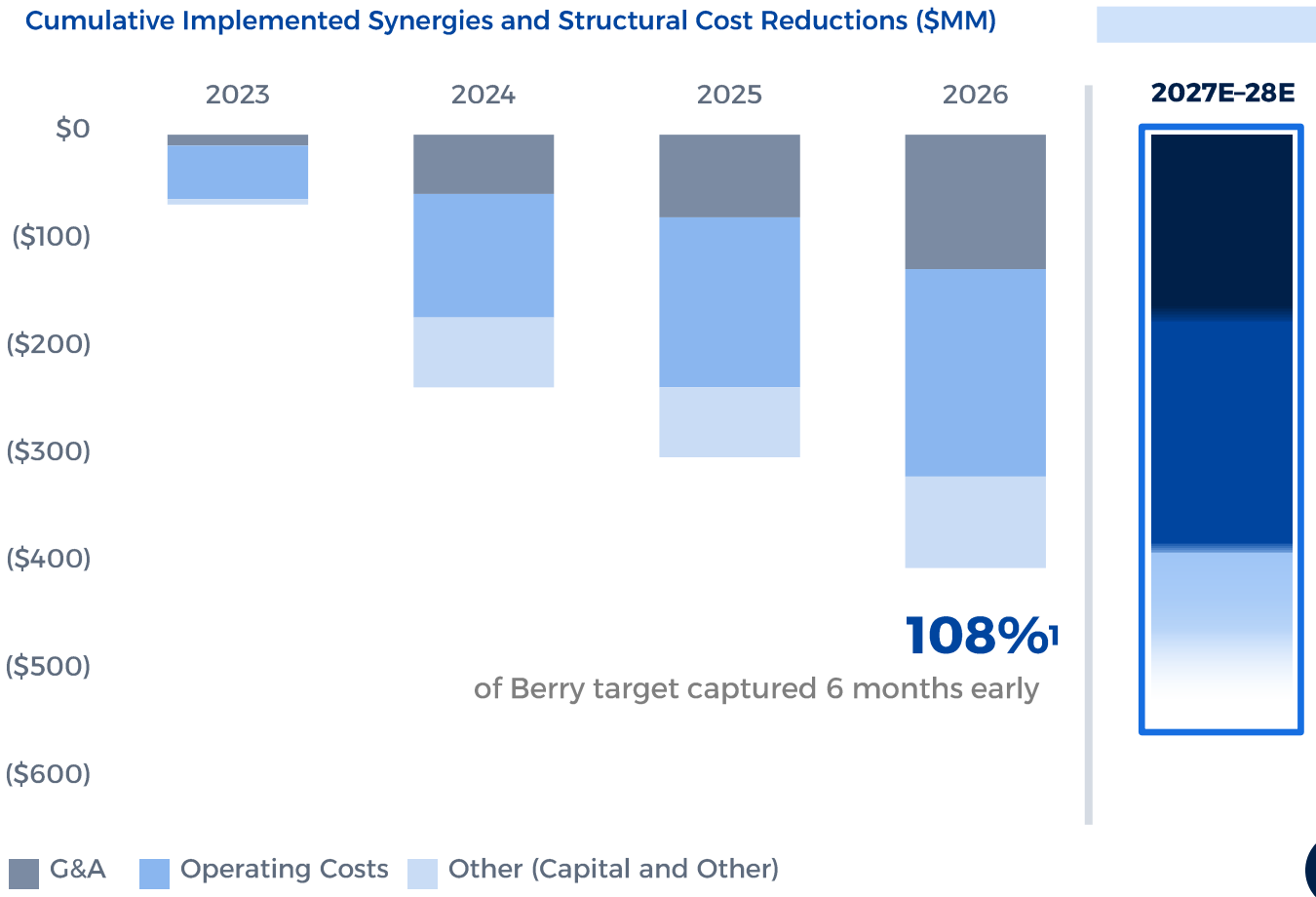




See slide 24 for "Assumptions, Estimates and Endnotes".

Unlocking the Value of Our Assets: The Next Chapter of CRC

From Integration Synergies to Organic Efficiencies



The Next Phase: Organic Cost Reductions

Lower controllable cost structure while maintaining safe, reliable operations and our ability to grow

Streamline Our Foundation
Standardize core systems and connect enterprise data

Simplify How We Work
Align how work gets done across the business, removing duplication remaining after the mergers

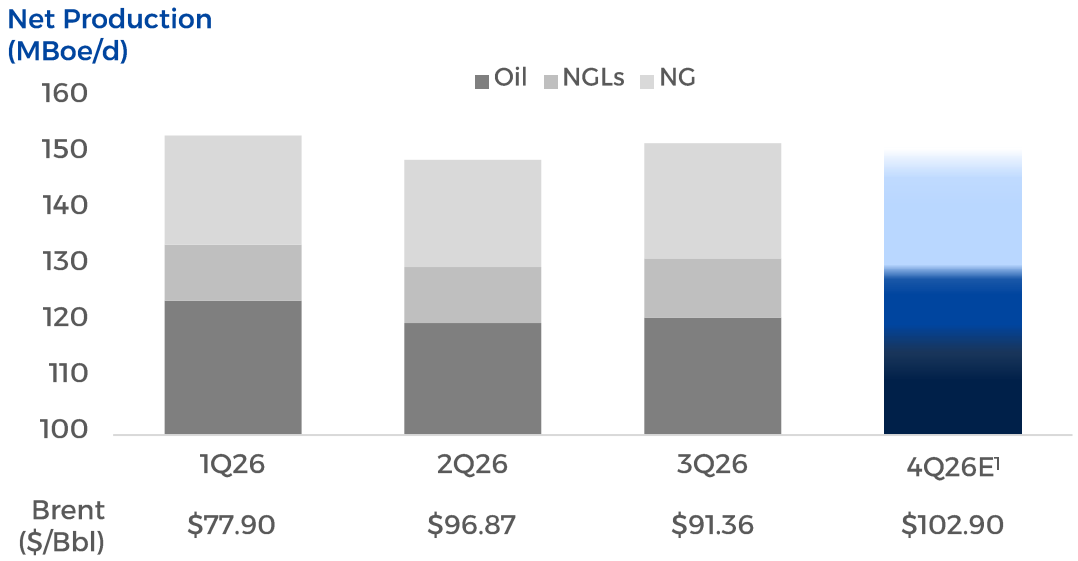
Apply AI and Digital Tools
Move faster, reduce manual work, and improve productivity

Cost reduction targets to be shared with our 2027 plan

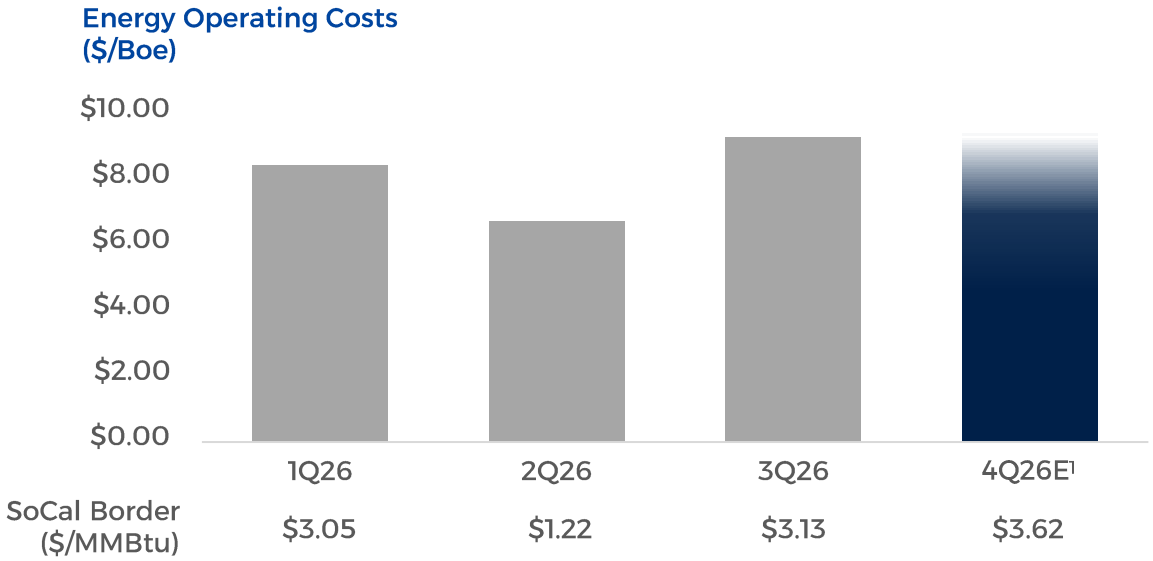
M&A Driven (2023–26) → **Organically Driven (2027–28)**

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

Strong Production Performance



Energy Costs Dependent on Fuel Prices



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

3Q26 Commentary

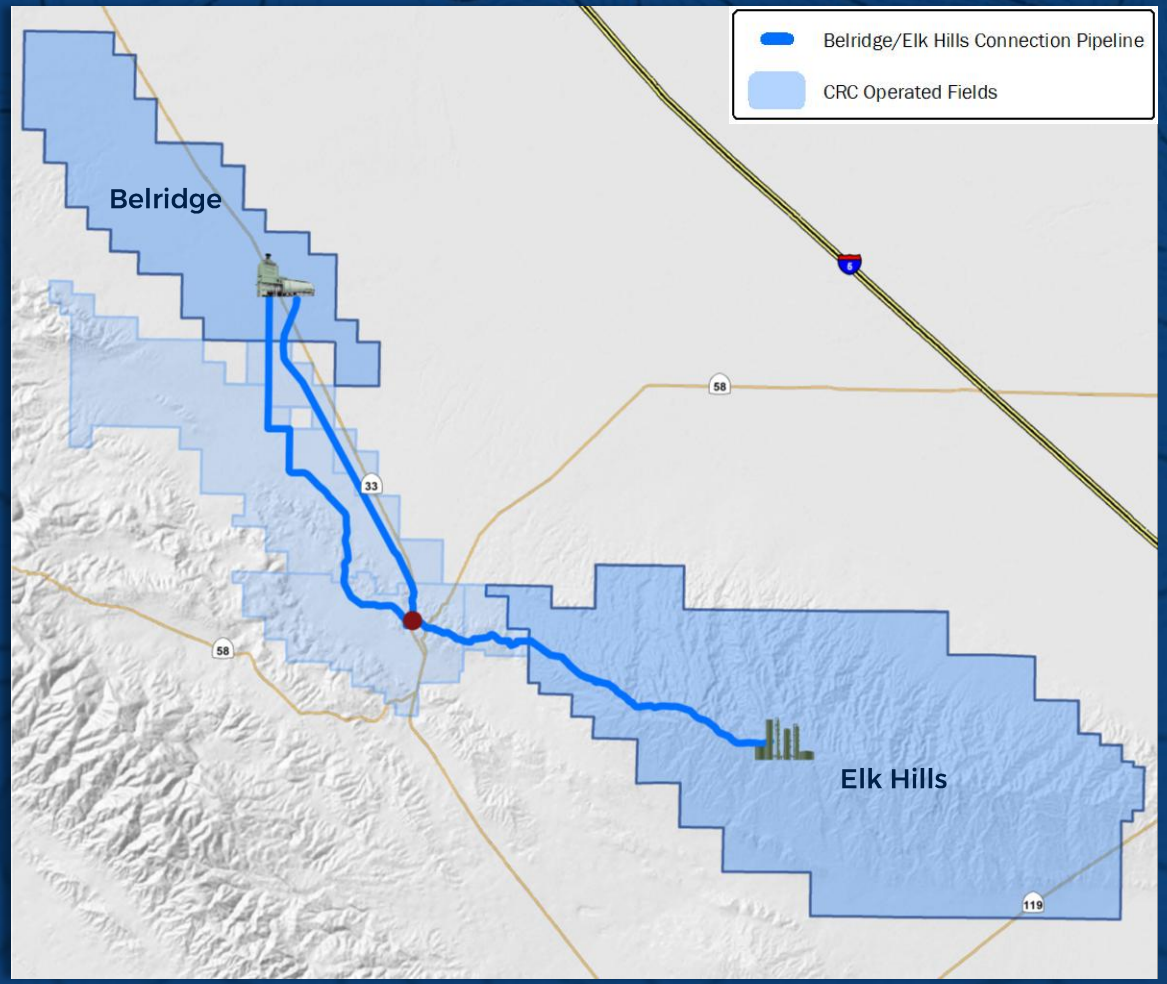
- **Net oil production** rose sequentially by ~1% to 121 MBo/d, primarily related to sale of crude oil inventory, and drilling and workover activity
- First CCS project enabled **stronger than previously anticipated NGL yields** and added ~1 MBoe/d in 3Q26
- **Stronger electricity prices** drove higher EHPP utilization and higher natural gas sales
- **Uinta net production** contributed ~4 MBoe/d to 3Q26 results

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- **Higher-than-anticipated natural gas prices** drove an increase in energy operating costs for internal field operations
- **All-time high diesel cracks** led to high energy operating costs for drilling rig operations
- **Disciplined hedge strategy** mitigates fuel energy volatility with ~58% of 4Q26E natural gas consumption at an average price of $4.23/MMBtu; ~58% of 2027E natural gas consumption hedged at an average price of $3.98/MMBtu[2]

Benefits of Our Integrated Strategy in Action

Connection Between Belridge and Elk Hills Fields Supports Natural Gas Optimization

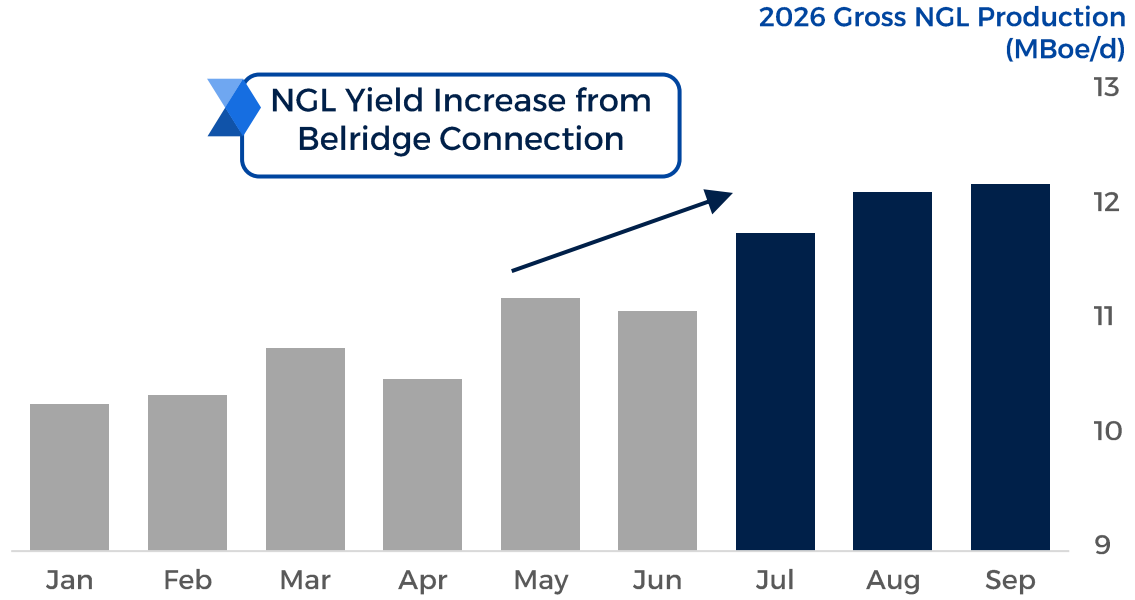


See slide 25 for "Assumptions, Estimates and Endnotes".

First CCS Project Drives Incremental NGL Yields

~6MMcf/d	~1MBoe/d	~$20MM[1]
Incremental Net Gas Production	Increase in Net NGLs Production	Est. Annual Revenue Benefit

- First CCS project cleans inlet gas to CRC's Elk Hills cryogenic gas plant, supporting incremental gas processing capacity and subsequently increased NGL yields
- Connection from Belridge production field to Elk Hills cryogenic gas plant supplies additional natural gas for processing
- Established infrastructure to support natural gas development and future infrastructure integration opportunities in the area

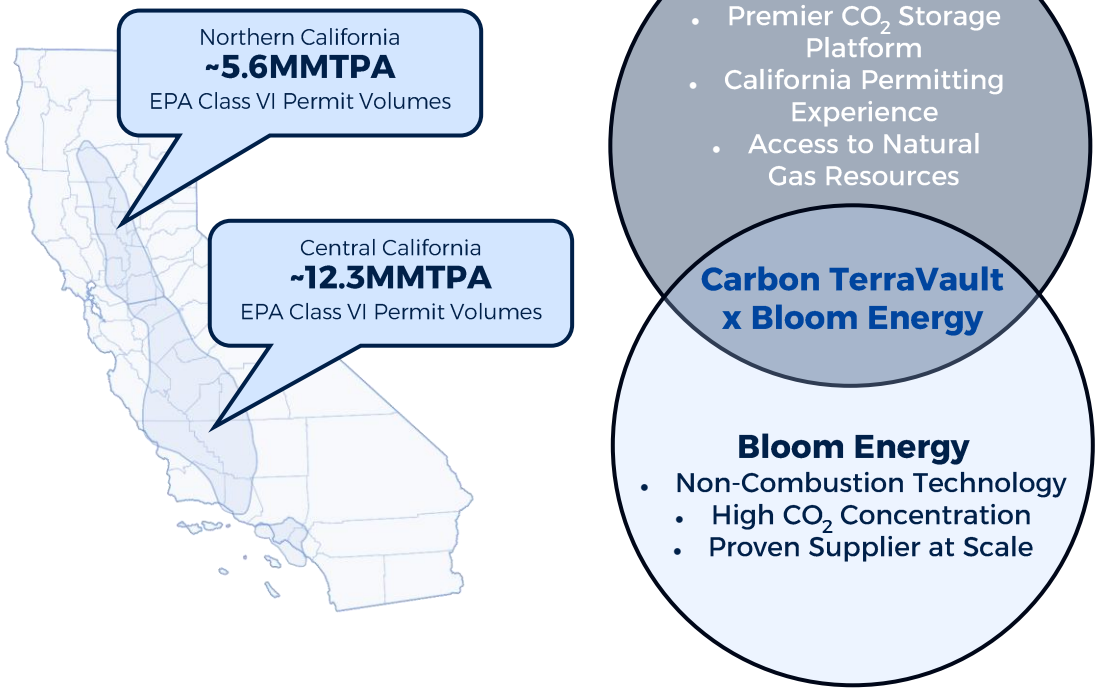


Bloom MOU[1] to Advance Clean Power Solutions in California

CARBON TERRAVAULT x Bloom energy

Developing Potential	Power Generation of	Up to
FTM & BTM	**1GW**	**3MMTPA**
Clean Power Solutions in CA	or More	of CO_2 Emissions

CTV EPA Class VI Permit Volumes[2] (MMTPA)



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

Collaboration with Leading Clean Power Producer

CTV and Bloom Energy to jointly evaluate and target the potential development of solid-oxide fuel cell power generation paired with CCS across California

- Identifying and developing new commercial pathways with potential power offtake customers
- Initially contemplating FTM and BTM power opportunities:
  1. **FTM Clean Energy Projects** – targeting multiple projects with potential connection to CTV's vast California storage portfolio and utility offtake
  2. **BTM Clean Energy Opportunities** – additional contemplated projects across CRC's Central Valley footprint, designed for industries seeking on-site, clean and reliable power

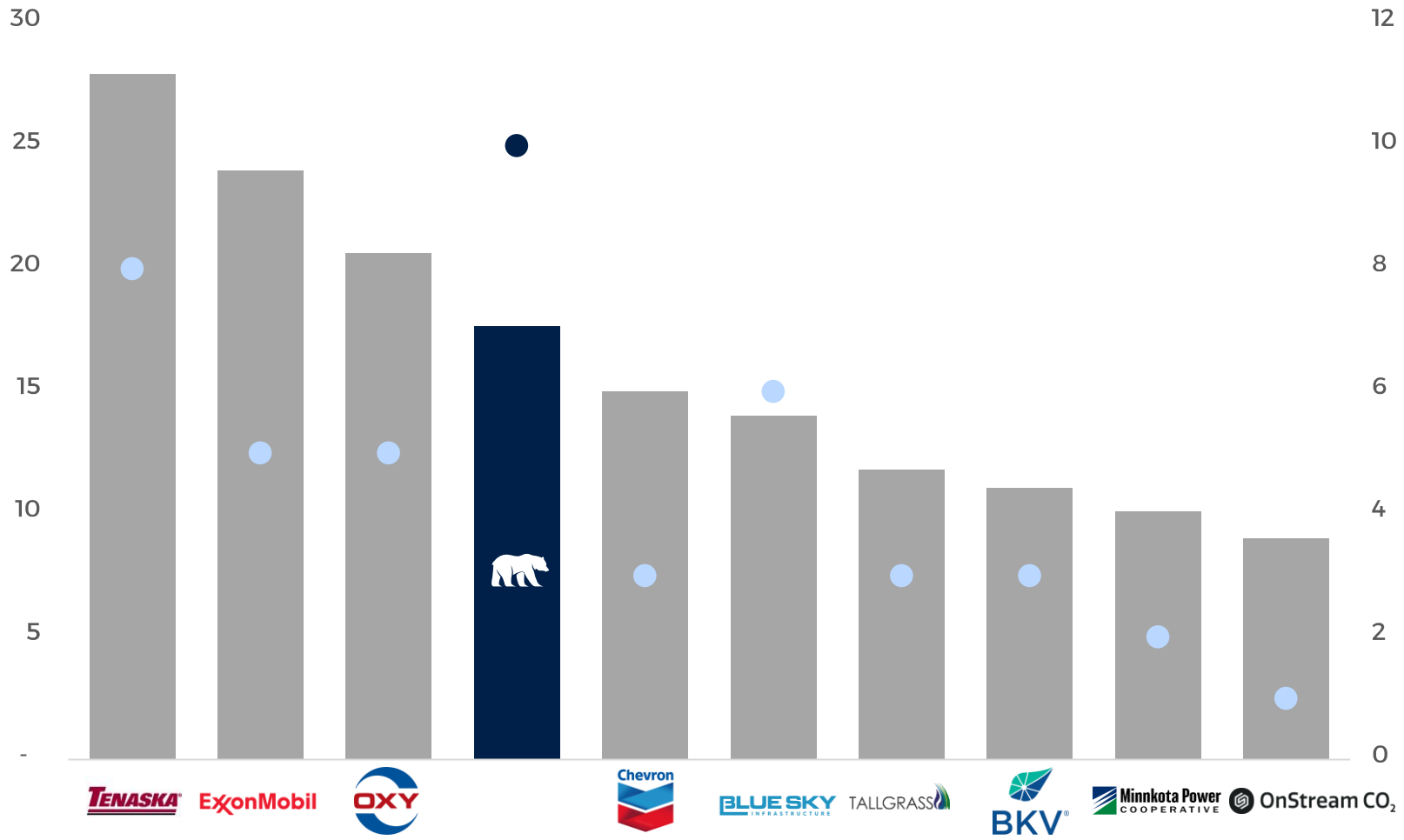
MOU[1] leverages the combined strengths of both companies to develop baseload clean power solutions in California

- **CRC's proven track record of developing projects** from permitting to execution
- **CTV's leading CCS storage platform** in California
- **Bloom's clean, non-combustion fuel cells** with a **high-concentration CO_2 stream** improving the efficiency of CCS

CTV: 4th Largest Carbon Management Platform in the U.S.[1]

Total Reservoir Injection Capacity Submitted for Permits (MMTPA)

Total CO_2 Storage Projects (#)



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

California's Leading CO_2 Storage Portfolio

36%

EPA Class VI Wells (US)[2]

Largest individual share of wells under EPA lead agency review

CTV | Others

88%

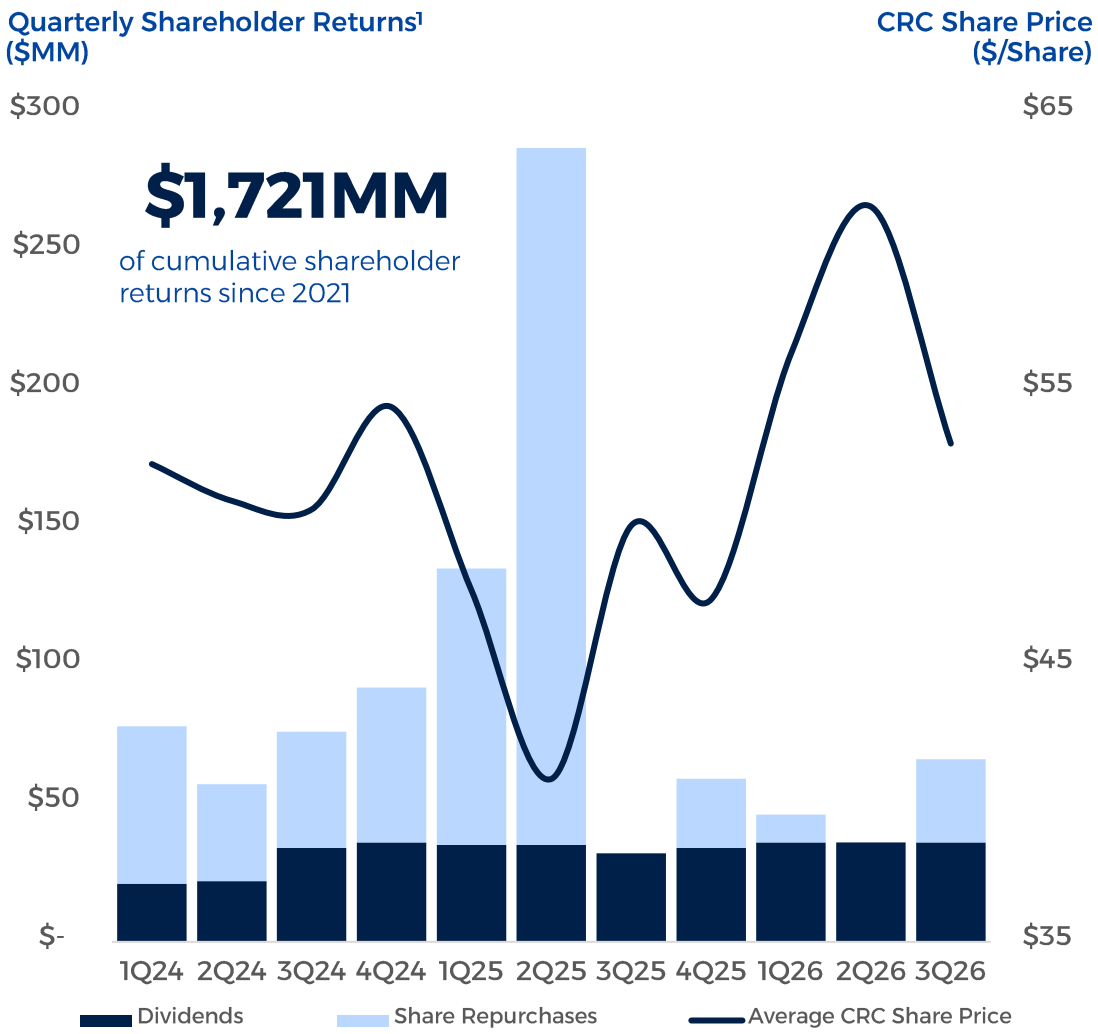
California Class VI Wells[2]

Dominant share of the emerging California CCS market

CTV | Others

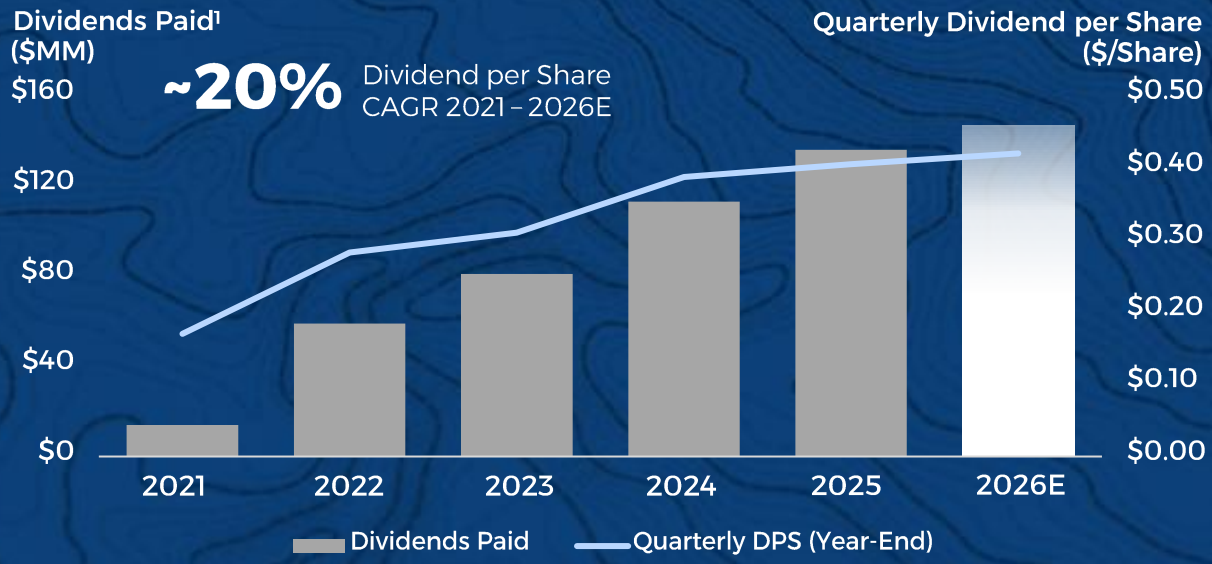
- California's first CCS project operational
- Submitted a new EPA Class VI permit (CTV VIII) for ~57MMT[2] of storage
- Anticipating the receipt of one or more additional draft EPA Class VI permits by year-end 2026[2]

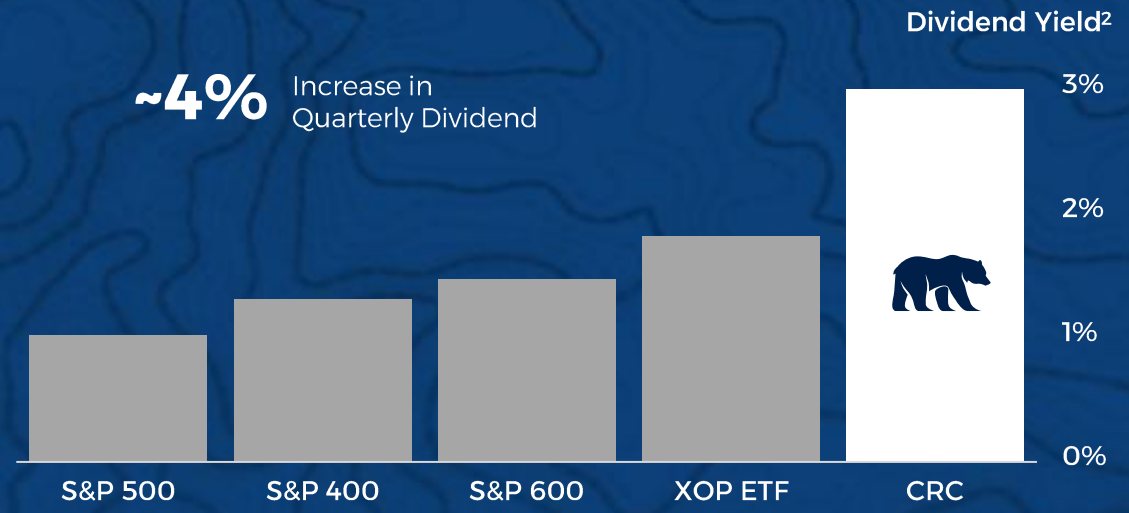
Opportunistic Share Repurchases Create Value



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

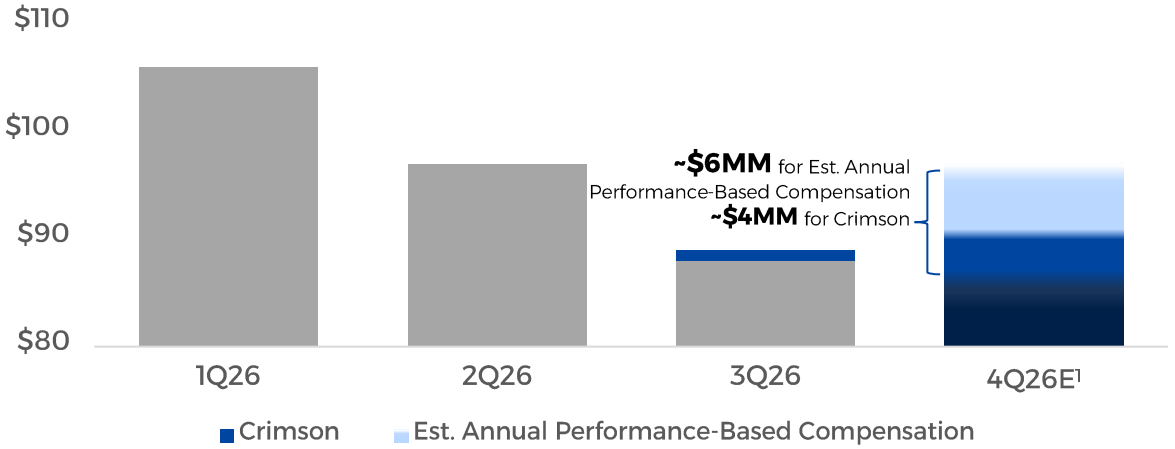
Commitment to Long-Term Dividend Growth



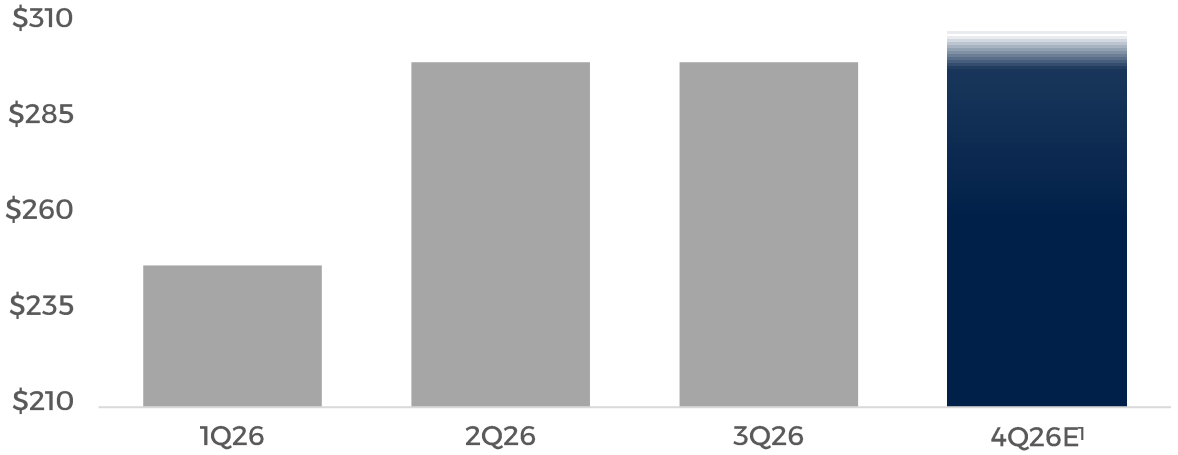


Improving the Core Cost Structure to Grow Long-Term Cash Flow

G&A Expense ($MM)



Operating Cash Flow Before WC Changes* ($MM)



Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities".
See slide 25 for "Assumptions, Estimates and Endnotes".

3Q26 Results

Commodity	3Q26A
Oil Realizations (% of Brent)	~91%
NGL Realizations (% of Brent)	~53%
Natural Gas Realizations (% of NYMEX)	~119%
Operational and Financial	
Net Production (MBoe/d)	152
Net Oil Production (MBo/d)	121
Operating Costs ($MM)	$386
G&A Expenses ($MM)	$89
Adj. G&A Expenses* ($MM)	$79
Taxes Other Than on Income ($MM)	$81
Transportation Costs ($MM)	$31
Other Operating Expenses Net of Other Revenue*, 2	$35
Total Capital ($MM)	$158
Adj. EBITDAX* ($MM)	$341
Operating Cash Flow Before WC Changes*	$300
Free Cash Flow Before WC Changes*	$142
Other Items	
Margin from Purchased Commodities*, 3	$15
Electricity Revenue Net of Electricity Generation Expenses*, 4	$35
Total Return of Cash to Shareholders[5] ($MM)	
Share Repurchases ($MM)	$30
Dividends Paid ($MM)	$36
Total Shareholder Returns ($MM)	$66

California's Leading Energy Infrastructure Platform

- 4th Largest Economy in the World and 2nd Largest Consumer of Energy in the U.S.[1]
- Historical Increase in Reliance on Energy Imports, While Local Production has Declined
- Unique Supply and Demand Dynamics Drive Premium Energy Price Environment

CRC's California Energy Portfolio

~23 Years[2] 2P Reserve Life Index	**~147MBoe/d**[3] 2026E CA Net Production (~80% Oil)	**~1.9MM** Mineral Acres
~400Mbo/d Crude Oil Transportation Capacity	**~350MMcf/d** Natural Gas Transportation Capacity	**>5MMBbls** Total Liquids Storage Capacity
Nearly **~1GW** Power Generation Capacity	Up to **~18MMTPA**[4] EPA Class VI CO_2 Permit Volumes Submitted	Active **CCS Project** Operating CA's First CCS Project

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

Integrated Assets Across the Energy Value Chain





Guidance & Capital Structure

4Q26 Outlook *(inclusive of Uinta)*

CRC Guidance (as of November 2, 2026)	**4Q26E Consolidated**	**Oil and Natural Gas**	**Carbon Management**
Net Production (MBoe/d) ~79% Oil	150 – 152		
Margin from Purchased Commodities*, [1] ($MM)	$11 – $15		
Electricity Revenue Net of Electricity Generation Expenses ($MM) [2]	$5 – $11		
Operating Costs ($MM)	$370 – $390	$370 – $390	
G&A ($MM)	$95 – $99	$12 – $16	$0 – $2
Adjusted G&A ($MM)*	*$83 – $93*	*$12 – $16*	*$0 – $2*
Depreciation, Depletion and Amortization ($MM)	$128 – $140	$120 – $130	
Other Operating Expenses Net of Other Revenue*, [3] ($MM)	$20 – $30		$4 – $12
Transportation Expense ($MM)	$30 – $35	$20 – $24	
Taxes Other Than on Income ($MM)	$68 – $78	$60 – $66	
Interest and Debt Expense, Net ($MM)	$28 – $32		
Capital ($MM)	$110 – $130	$110 – $125	$0 – $2
Adj. EBITDAX* ($MM)	$340 – $380		

Other Assumptions	**4Q26E**
Brent ($/Bbl)	$102.90
NYMEX ($/Mcf)	$3.25
Oil – % of Brent	91% – 93%
NGL – % of Brent	55% – 62%
Natural Gas – % of NYMEX	110% – 116%
Current Income Tax Provision[4] ($ MM)	($2) – $2
Effective Tax Rate	27% – 31%

4Q26 Commentary

~1MBoe/d

Est. QoQ impact due to PSC effects

~$10MM

Est. impact to G&A due to annual performance-based compensation and Crimson

~$8MM

Of capital to support 2027 development readiness

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

Early 2027 Thoughts

Annual Cadence

~6 Rigs

$450 - $475MM

2027E D&C and Workover Capital*

Entry to Exit

Flat

Gross Production

- Targeting restart of the SPBP in 1Q27
- Expect return to normalized oil realization levels

Strong Balance Sheet and Financial Flexibility

Recent Highlights

- S&P upgraded corporate rating to BB-
- Borrowing base reaffirmed at $1.5B in October 2026
- Extended maturity of revolving credit facility to March 2030

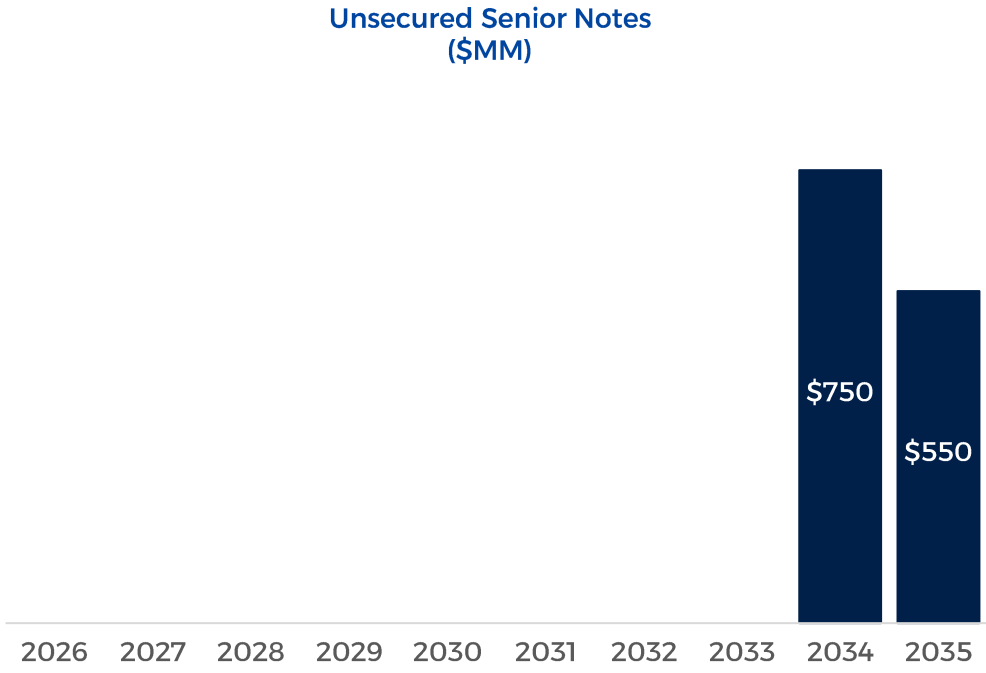
Liquidity Snapshot

Net Debt* as of September 30, 2026		**($MM)**
Revolving Credit Facility (RCF)	$	–
7.000% 2034 Senior Notes		750
7.250% 2035 Senior Notes		550
Face Value of Total Debt	**$**	**1,300**
Less: Available Cash & Cash Equivalents[1]		(35)
Net Debt*	**$**	**1,265**
Liquidity*, [2]	**$**	**1,315**
3Q26 Net Leverage*, [3]		**1.0x**
3Q26 Interest Coverage*, [4]		**11.0x**

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

Long-Dated Debt Maturities Support Strategic Growth

No Debt Maturities Until 2034





Appendix

Sustainability is Embedded in Our Operations

Near-Term Ambition

≥20% by 2035

from 2020 Baseline

Reduction in Average Carbon Intensity of Oil & Gas Operations

Long-Term Goal

≥80% by 2045

from 2020 Baseline

Reduction in Scope 1 & 2 Emissions

Responsible Net Zero

Goal to Reduce Absolute Scope 1 & 2 Emissions, and Neutralize Remaining Emissions[1]

2025 Sustainability Update

Climate

~25%

Reduction in Scope 1 and 2 emissions vs 2020 baseline[2]

Stewardship

"Grade A"

MiQ certification rating for the majority of operations[3]

Carbon

~409MMT

CO_2 emission permit volumes submitted to the EPA[4]

Water

~4.6B Gal

Treated, reclaimed water delivered to California; ~3x internal consumption

Community

>$2.0MM

Charitable donations to support local communities

Governance

~30%

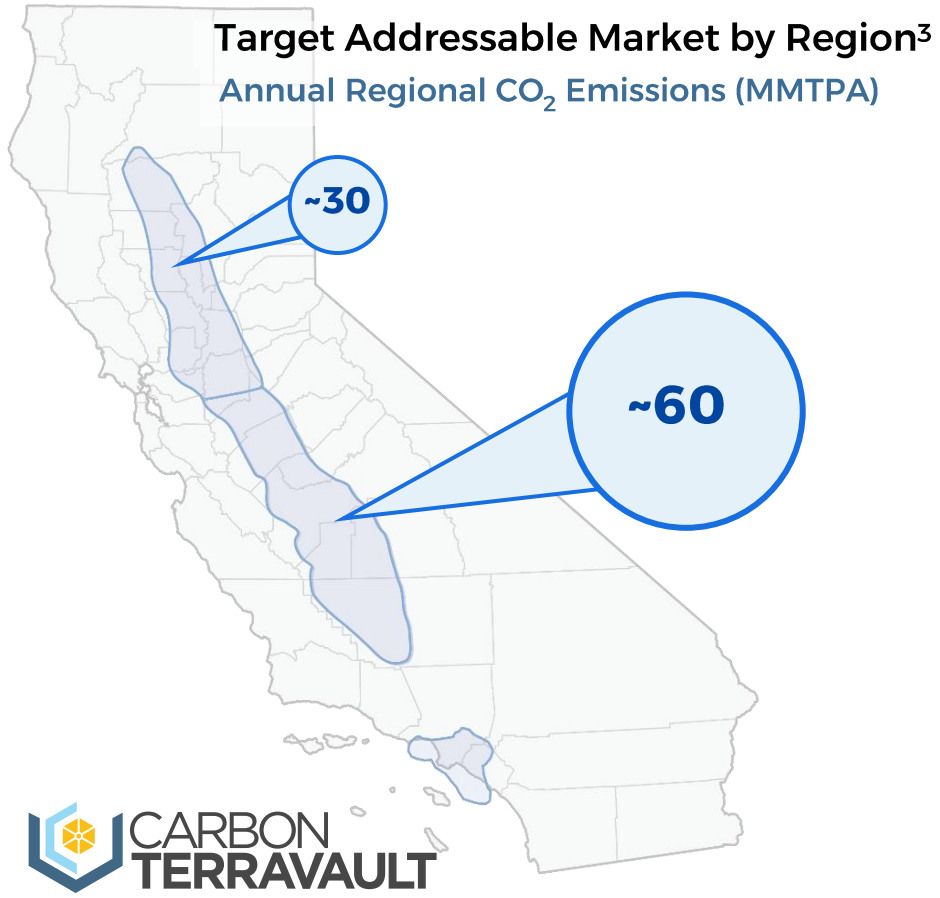
Executive compensation tied to ESG-related goals

See slide 27 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 one or more Class VI draft permits for additional reservoirs in 2026[1]

Vault / Reservoir	Targeted EPA Class VI Permit Decision[1]		Est. Annual Injection Rate[1] (MMTPA)			Permit Volumes[1] (MMT)
	Draft Permit	Final Permit	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	2026	~0.8	~0.4	~0.2	~8
Carbon Frontier	2026	2027	~3.3	~1.6	~0.8	~32
CTV VI	2027	2027	~3.4	~5.1	~2.5	~102
CTV VII	-	-	~1.4	~1.4	~0.7	~27
CTV VIII[NEW]	-	-	~1.9	~2.9	~1.4	~57
Central California			~12.3	~13.3	~6.6	~264
CTV II	2027	2027	~1.0	~1.2	~0.6	~23
CTV III	2026	2027	~2.5	~3.6	~1.8	~71
CTV IV	2027	2027	~1.4	~1.7	~0.9	~34
CTV V	2027	2027	~0.7	~0.8	~0.4	~17
Northern California			~5.6	~7.3	~3.7	~145
Total - Combined			~17.9	~20.6	~10.3	~409



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

Production Sharing Contracts (PSC) at Higher Prices

CRC sees a difference of **~4.1 MBO/D** in net oil production **between $50/Bbl and $110/Bbl[1]**

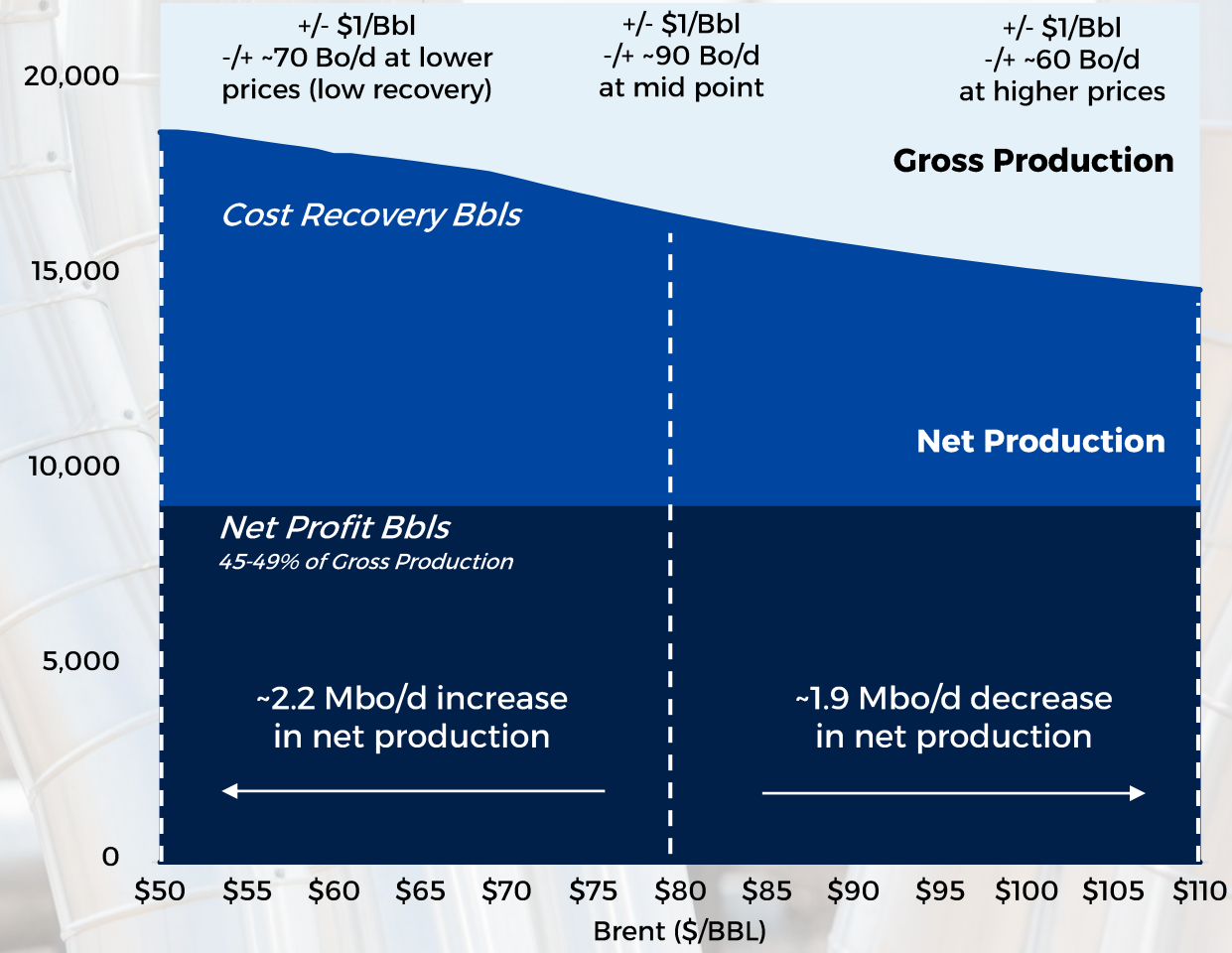
Approximately 12% of CRC's gross oil production is subject to PSC Mechanics:

- 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 "profit barrels" are recovered

Effect of Oil Price on Net Production[1]

Wilmington Field Production (Bo/d)



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

Hedge Portfolio *(as of September 30, 2026)*

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[1]

OPERATIONS

~58% of remaining 2026E internal fuel consumption hedged at an average natural gas price of ~$4.23/MMBtu[1]

Oil Production	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Calls (Short) – Brent	Bbl/d	36,000	1,250	5,250	500	2,862	35,434
	$/Bbl	$83.51	$70.47	$72.07	$69.30	$69.79	$84.29
Swaps (Short) – Brent	Bbl/d	41,703	80,811	65,014	68,047	64,761	7,285
	$/Bbl	$67.98	$66.04	$65.54	$65.57	$65.56	$66.98
Puts (Long)[2] – Brent	Bbl/d	36,000	1,250	5,250	500	2,862	53,734
	$/Bbl	$61.11	$60.00	$61.90	$60.00	$60.00	$60.89

Natural Gas Consumption	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Swap (Long) – SoCal Border	MMBtu/d	9,908	14,044	-	-	-	-
	$/MMBtu	$4.84	$4.77	-	-	-	-
Swap (Long) – NWPL Rockies[3]	MMBtu/d	91,750	94,336	94,170	92,000	91,326	62,725
	$/MMBtu	$4.17	$4.18	$3.78	$3.88	$3.95	$3.59

Combined Portfolio	Units	4Q26E	1Q27E	2Q27E	3Q27E	4Q27E	2028E
Est. Hedge Contract Settlements[4]	$MM	($159)	($179)	($142)	($117)	($93)	($68)

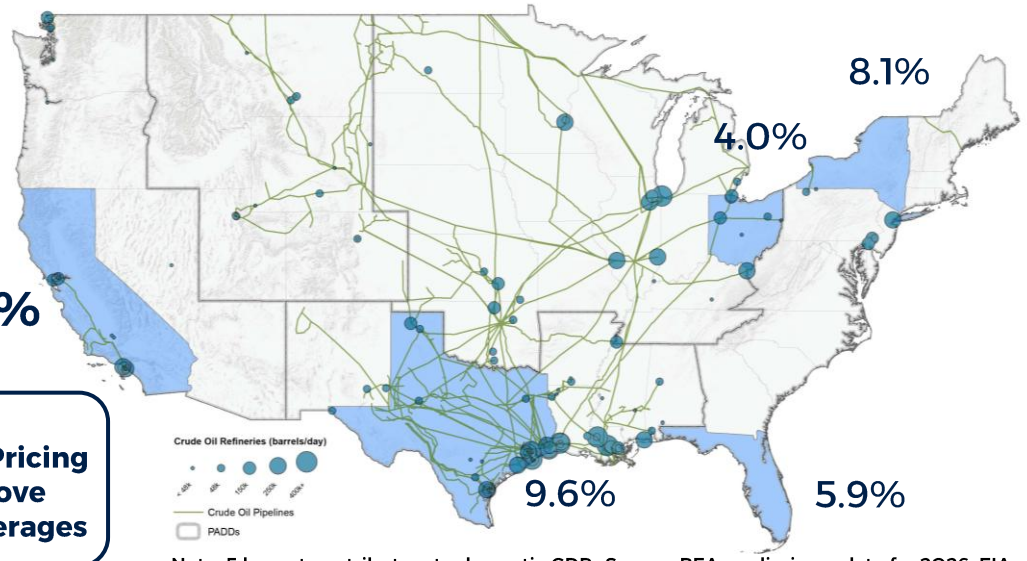
See slide 27 for "Assumptions, Estimates and Endnotes".

Commodity Price Realizations

- **Crude:** 3Q26 Brent crude oil prices were volatile as a result of the conflict in the Middle East, the conflict between Russia and Ukraine, and shifting expectations for cessation of hostilities or further escalation in each. California price realizations are expected to have troughed as alternative pathways to market are being actioned.
- **NGLs:** 3Q26 natural gas liquids prices pulled back slightly Q/Q on slightly higher realizations, while Y/Y, liquids prices have increased but have failed to keep pace with crude oil prices. California NGLs maintain a meaningful premium to the broader North American market.
- **Natural Gas:** Broadly, 3Q26 natural gas prices remained rangebound. California natural gas prices increased Q/Q as transportation alternatives out of key North American production basins came online requiring California to compete for out-of-state supplies. Market area storage remains elevated.

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

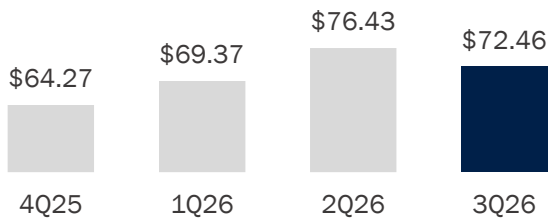
(amounts shown as % of U.S. domestic GDP)



California Commodity Pricing Generally Above Domestic Averages

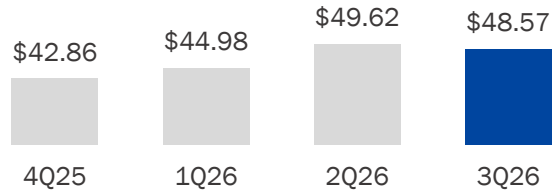
Note: 5 largest contributors to domestic GDP. Source: BEA, preliminary data for 2Q26; EIA

Oil w/ Hedges ($/BBL)



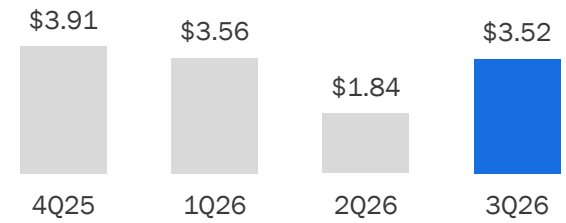
	4Q25	1Q26	2Q26	3Q26
Average Benchmark Prices[1]	$63.08	$77.90	$96.87	$91.36
% of Benchmark[1]	97%	96%	95%	91%
Hedge Settlements	$3.13	($5.16)	($15.12)	($10.96)
Average Realized Prices[2]	$64.27	$69.37	$76.43	$72.46

NGLs ($/BBL)



	4Q25	1Q26	2Q26	3Q26
	$63.08	$77.90	$96.87	$91.36
	68%	58%	51%	53%
	-	-	-	-
	$42.86	$44.98	$49.62	$48.57

Natural Gas ($/MCF)



	4Q25	1Q26	2Q26	3Q26
	$3.55	$5.04	$2.90	$2.96
	110%	71%	63%	119%
	-	-	-	-
	$3.91	$3.56	$1.84	$3.52

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
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) Development of a CO_2 pipeline system is subject to further acquisition of all necessary land rights, permitting, engineering, construction and significant capital expenditures over a multi-year period. No assurance can be given that any such development will occur.
2) MOUs are non-binding agreements. The projects and transactions described in an MOU are subject to certain conditions precedent, typically including the negotiation of definitive documents, a final investment decision by the parties and receipt of EPA Class VI permits and other regulatory approvals.
3) 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.
4) 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.
5) Source: FactSet as of October 30, 2026. Peers include APA, BKV, CHRD, CRK, CRGY, GPOR, KOS, MGY, MTDR, MUR, NOG, RRC, SOC, SM, TALO and VET.

Slide 3:

1) Estimated 2027 adjusted EBITDA is based on CRC's projections for Crimson and: (i) assumes the acquired pipeline systems continue to operate at current levels (except for the San Pablo Bay pipeline where an increase in throughput is projected for 2027), (ii) assumes transportation rates consistent with existing tariffs (including contemplated increases, a portion of which are interim until rate case settlement), (iii) includes payments made by CRC as a shipper on certain of the acquired pipelines, and (iv) does not include any material capital expenditures for that period. CRC has not included a reconciliation of this non-GAAP measure to its nearest GAAP equivalent because it cannot do so without unreasonable effort and any attempt to do so would be inherently imprecise.
2) Initial purchase price excludes $7 million of preliminary purchase price adjustments. The final purchase price remains subject to certain adjustments.
3) Development of a CO_2 pipeline system is subject to further acquisition of all necessary land rights, permitting, engineering, construction and significant capital expenditures over a multi-year period. No assurance can be given that any such development will occur.
4) The transaction has an effective date of July 1, 2026, is subject to receipt of certain third-party consents and customary closing conditions, and is expected to close by year-end 2026. Following the closing of the transaction, CRC expects to provide additional financial and operating guidance.
5) Before transaction costs and customary purchase price adjustments. CRC bears the following post-effective date cost of approximately $4MM in drilling and completions capital, and other customary purchase price adjustments.
6) Reallocated capital represents $46MM of 2026 budgeted capital reduced by $11MM in actual amounts spent.

Slide 4:

1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 for 4Q26E guidance.
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.

Slide 5:

1) 2023 information represents the combined costs for legacy CRC, legacy BRY and legacy Aera, and excludes presentation adjustments, transaction adjustments and financing adjustments. Operating costs for Aera have been restated using CRC's accounting classification.
2) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 for 4Q26E guidance.
3) Includes approximately 600 employees in the C&J Well Services business.

Assumptions, Estimates and Endnotes

Slide 6:
1) Information relative to the midpoint of the Berry merger synergy target of $90MM - $100MM.

Slide 7:
1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 for 4Q26E guidance.
2) Subject to commodity prices and market factors.

Slide 8:
1) Estimate assumes a Brent price of $93.28 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.05 per Mcf.

Slide 9:
1) MOUs are non-binding agreements. The projects and transactions described in an MOU are subject to certain conditions precedent, typically including the negotiation of definitive documents, a final investment decision by the parties and receipt of EPA Class VI permits and other regulatory approvals.
2) 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.

Slide 10:
1) Source: Enverus (October 2026) and internal estimates.
2) Source: EPA as of October 23, 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.

Slide 11:
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 October 30, 2026. Represents CRC's current annual dividend policy of $1.68 per share divided by CRC's share price as of October 30, 2026.

Slide 12:
1) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 for 4Q26E guidance.
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 revenue net of electricity generation expenses 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.

Assumptions, Estimates and Endnotes

Slide 13:

1) Source: EIA, total energy consumption estimates 2024.
2) Data reflect reserves and annual production volumes as of December 31, 2025 using SEC Prices of $69.38 per barrel for oil and $3.39 per MMBtu for natural gas. 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. Information includes Uinta assets that were owned as of year-end 2025 and that CRC expects to divest by year-end 2026.
    - 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).
    - 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.
3) Total year 2026E estimates assume a 4Q26E Brent price of $102.90 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.25 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 15 for 4Q26E guidance.
4) 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.

Slide 15:

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 revenue net of electricity generation expenses 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.
4) Current income tax composition is subject to variability and depends on a number of factors, including but not limited to, final taxable income determinations, the availability and utilization of net operating loss carryforwards (NOLs), applicable tax credits, and other differences between book and taxable income. Accordingly, the current provision may vary from period to period and should not be viewed as indicative of future tax obligations.

Assumptions, Estimates and Endnotes

Slide 16:

1) Available cash and cash equivalents excludes $13MM of restricted cash.
2) Liquidity on September 30, 2026 is calculated as $35MM of cash and cash equivalents (excluding $13MM of restricted cash) plus $1,460MM of borrowing capacity on CRC's revolving credit facility less $180MM in outstanding letters of credit.
3) Net leverage is calculated as 3Q26 net debt of $1,265MM (excluding restricted cash of $13MM) divided by LTM adjusted EBITDAX of $1,234MM.
4) Interest coverage is calculated as LTM adjusted EBITDAX of $1,234MM divided by LTM interest expense of $112MM.

Slide 18:

1) Planned use of either carbon offsets generated and claimed internally or carbon offsets purchased and claimed through the third-party carbon market (including California's Cap-and-Invest Program) for Scope 1 GHG emissions, and use of contractual instruments such as renewable energy certificates or carbon offsets for Scope 2 GHG emissions.
2) Excludes sustainability metrics related to Berry which merged with CRC on December 18, 2025, unless otherwise expressly noted.
3) MiQ certification covers production operations in the San Joaquin, Ventura and Los Angeles basins.
4) 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.

Slide 19:

1) Source: EPA as of October 23, 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 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) Net Production from Wilmington field only. Includes the effects of a development program in the Los Angeles basin.

Slide 21:

1) Subject to commodity prices and market factors.
2) Purchased and sold puts with the same strike price have been netted together.
3) NWPL volumes require transportation to where the gas is consumed. These costs are reflected in our 4Q26E transportation guidance. See slide 15 for 4Q26E guidance.
4) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of September 30, 2026.

Slide 22:

1) Benchmark prices are based on Brent for oil and NGLs, and NYMEX average monthly settled price for natural gas.
2) Average realized prices include hedges on oil and natural gas.

Forward-Looking / Cautionary Statements – Certain Terms

Forward-Looking Statements:

Information set forth in this communication, including financial estimates and statements as to the effects of the Berry Merger and the Crimson acquisition, constitute "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and other securities laws. All statements other than historical facts are forward-looking statements, and include statements regarding the benefits of the Berry Merger and the Crimson acquisition, CRC's future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives and intentions of management for the future. Words such as "expect," "could," "may," "anticipate," "intend," "plan," "ability," "believe," "seek," "see," "will," "would," "estimate," "forecast," "target," "guidance," "outlook," "opportunity" or "strategy" or similar expressions are generally intended to identify forward-looking statements. These forward-looking statements are based upon the current beliefs and expectations of the management of CRC and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, projected in, or implied by, such statements.

Although CRC believes the expectations and forecasts reflected in its forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond its control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause CRC's actual results to be materially different than those expressed in its forward-looking statements are described in its most recent Annual Report on Form 10-K and its other periodic filings with the SEC. These factors include, but are not limited to: fluctuations in commodity prices; production levels and/or pricing by OPEC, OPEC+ or U.S. producers; government policy, war and political conditions and events; changes in price realizations; integration efforts and projected synergies and other benefits in connection with the Berry Merger, Crimson acquisition and other acquisitions; divestitures and joint ventures, including the Uinta divestiture; regulatory actions and changes that affect the oil and gas industry generally and CRC in particular; the efforts of activists to delay or prevent oil and gas activities or the development of CRC's carbon management segment; changes in business strategy and the ability and financial resources to execute its capital plan in a timely manner; lower-than-expected production; changes to estimates of reserves and related future cash flows; the recoverability of resources and unexpected geologic conditions; general economic conditions and trends; results from operations and competition in the industries in which it operates; CRC's ability to realize the anticipated benefits from prior or future efforts to reduce costs and improve capital efficiencies; environmental risks and liability; the benefits contemplated by its energy transition strategies and initiatives; CRC's ability to successfully identify, develop and finance carbon capture, transportation and storage projects, power projects and other renewable energy efforts, including those contemplated by the Bloom MOU; changes in transportation costs and CRC's ability to develop midstream opportunities; delays from government approvals and otherwise that could affect the timing of projects; future dividends and share repurchases and de-leveraging efforts; and natural disasters, accidents, mechanical failures, power outages, labor difficulties, cybersecurity breaches or attacks or other catastrophic events.

CRC cautions you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the date hereof, and CRC is under no obligation, and expressly disclaims any obligation to update, alter or otherwise revise any forward-looking statements, whether as a result of new information, future events or otherwise. This communication may also contain information from third-party sources. This data may involve a number of assumptions and limitations, and CRC has not independently verified them and does not warrant the accuracy or completeness of such third-party information.

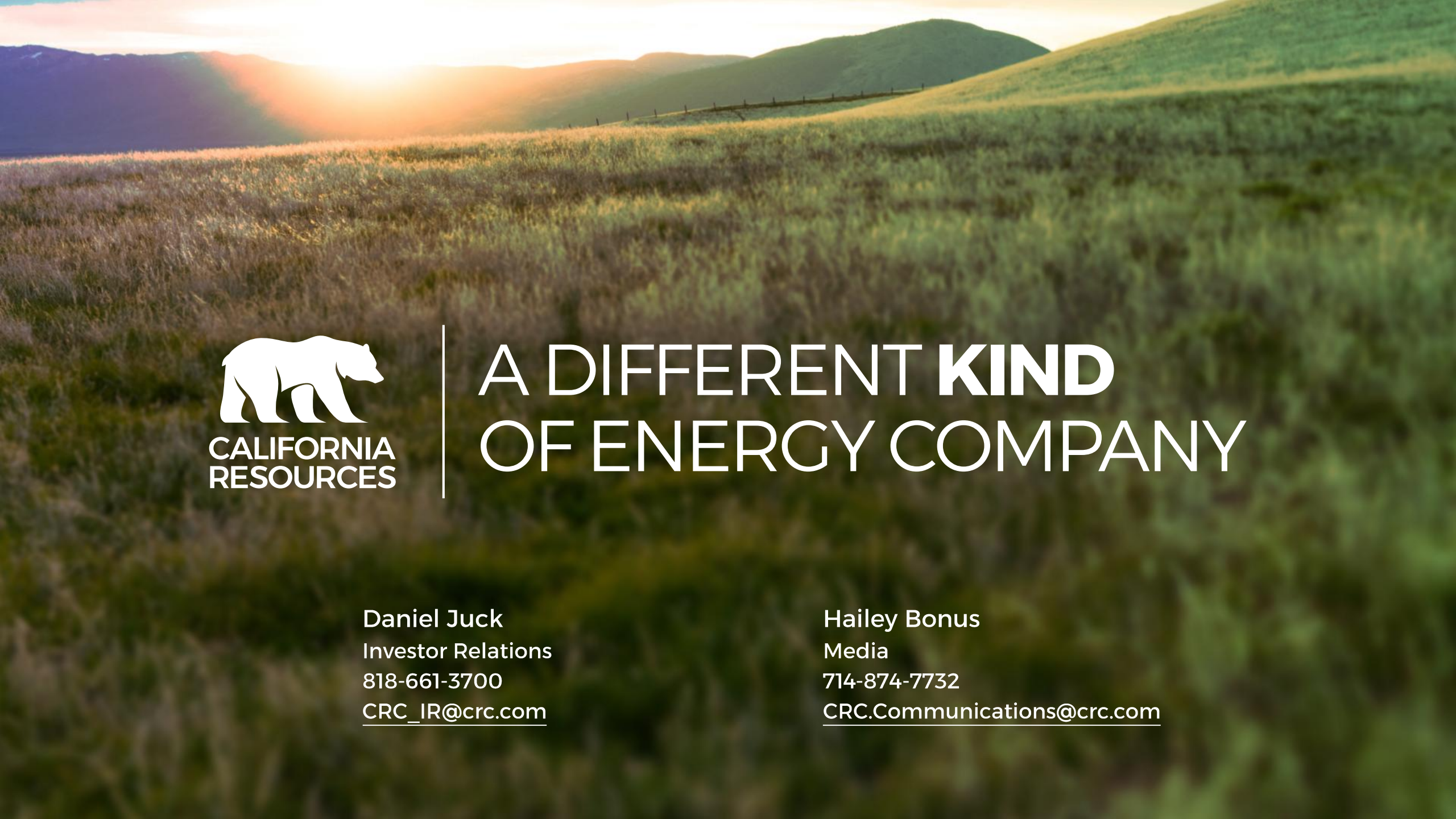
Forward-Looking / Cautionary Statements – Certain Terms

Non-GAAP Financial Measures:

This presentation contains certain financial measures that are not prepared in accordance with generally accepted accounting principles ("GAAP"). These measures are identified with an "*" and include but are not limited to Adjusted EBITDAX, Drilling, Completion and Workover Capital, Reserve Replacement Ratio, per Bbl Brent O&G Only Breakeven Price, Operating Cash Flow Before WC Changes, Adjusted G&A Expense, Other Operating Expenses Net of Other Revenue, Margin from Purchased Commodities, Electricity Revenue Net of Electricity Generation Expenses, PV-10, Net Debt, Liquidity, Free Cash Flow, Free Cash Flow Before WC Changes, Net Leverage and Interest Coverage. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Additionally, this presentation includes forward-looking non-GAAP financial measures, including adjusted EBITDAX. CRC is unable to provide a reconciliation of such forward-looking non-GAAP measures to the most directly comparable forward-looking GAAP financial measures because certain information needed to reconcile these measures is dependent on future events, many of which are outside of CRC's control and cannot be reasonably predicted at this time. These items include, but are not limited to, changes in working capital, the timing and amount of capital accruals, and other non-cash or unusual items. Accordingly, a quantitative reconciliation is not available without unreasonable efforts.

Industry and Market Data:

This presentation has been prepared by CRC and includes market data and other statistical information from sources it believes to be reliable, including independent industry publications, governmental publications or other published independent sources. Some data is also based on our good faith estimates, which are derived from CRC's review of internal sources as well as the independent sources described above. Although CRC believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy and completeness. CRC owns or has rights to various trademarks, service marks and trade names that it uses in connection with the operation of its business. This presentation also contains trademarks, service marks and trade names of third parties, which are the property of their respective owners. CRC's use or display of third parties' trademarks, service marks, trade names or products in this presentation is not intended to, and does not imply, a relationship with CRC or an endorsement or sponsorship by or of CRC.



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