First Quarter 2026 Results

May 5, 2026

Executing on Multiple Value Drivers

Accelerating Shareholder Value

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

Improving Operating Efficiencies

- Lowering 2026E facilities capital by $10MM driven by operating efficiencies[1]
- Increasing Berry merger synergy target by ~12%

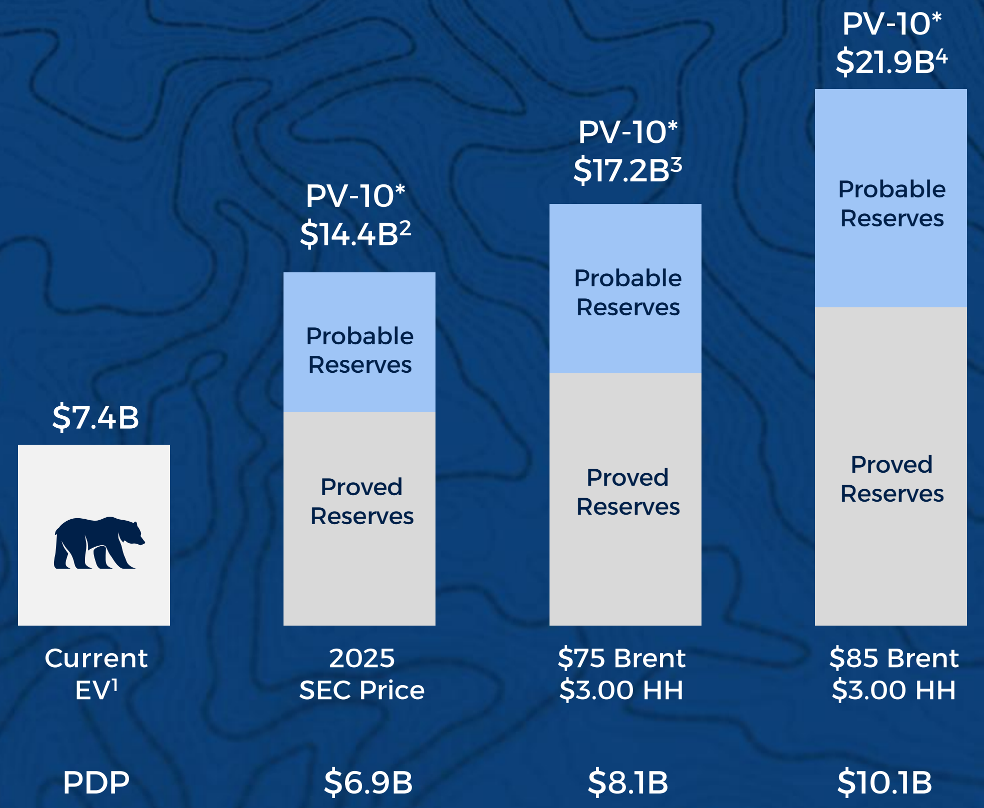
Raising 2026E Outlook

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

See slide 23 for “Assumptions, Estimates and Endnotes”.

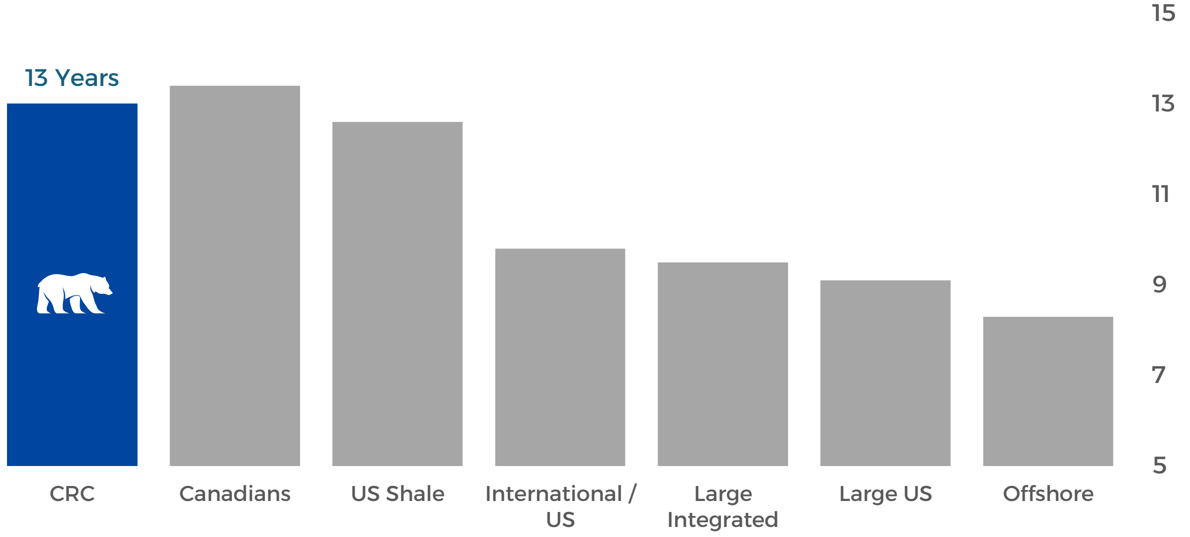
Significant Value From World-Class Conventional Reservoirs

Material Upside From Long Duration Assets



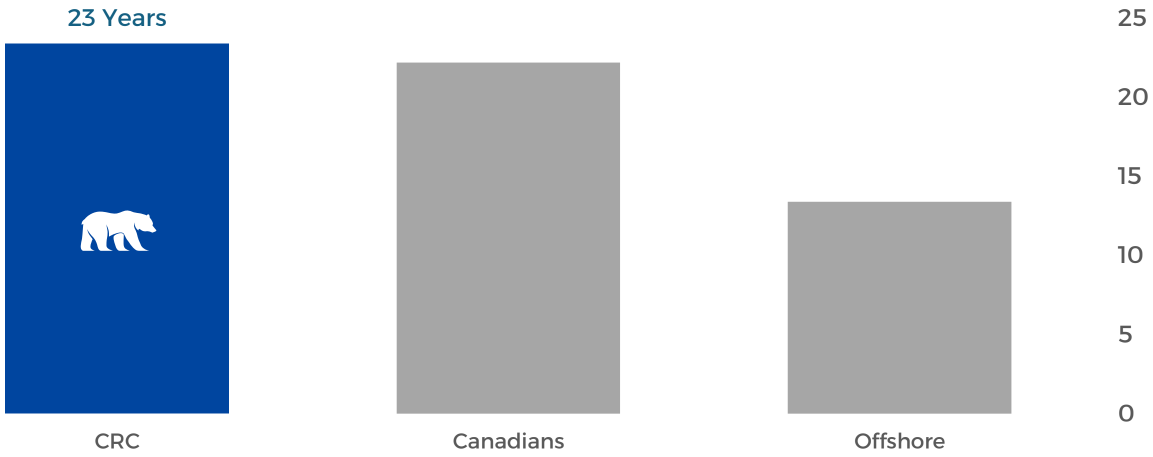
Long Proved Reserves Base

Proved Reserves / Annual Production (Years)[5]



Multi-Decade Conventional Runway

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



See slides 23 and 24 for "Assumptions, Estimates and Endnotes".

Delivering Through 1Q26 Macro Uncertainty – Returning To Growth

STRONG FINANCIAL AND OPERATING RESULTS

BENEFITTED FROM BRENT-LINKED PRODUCTION

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

Delivered
$304MM
Adj. EBITDAX*

IMPROVED CAPITAL STRUCTURE

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

Maintained
<1.1x
Net Leverage*

CONTINUED SHAREHOLDER RETURNS FOCUS

Attractive ~2.4% Dividend Yield[1]
Opportunistic and Disciplined Share Repurchases

Returned
$46MM
Dividends and SRP[2]

HIGHLIGHTS

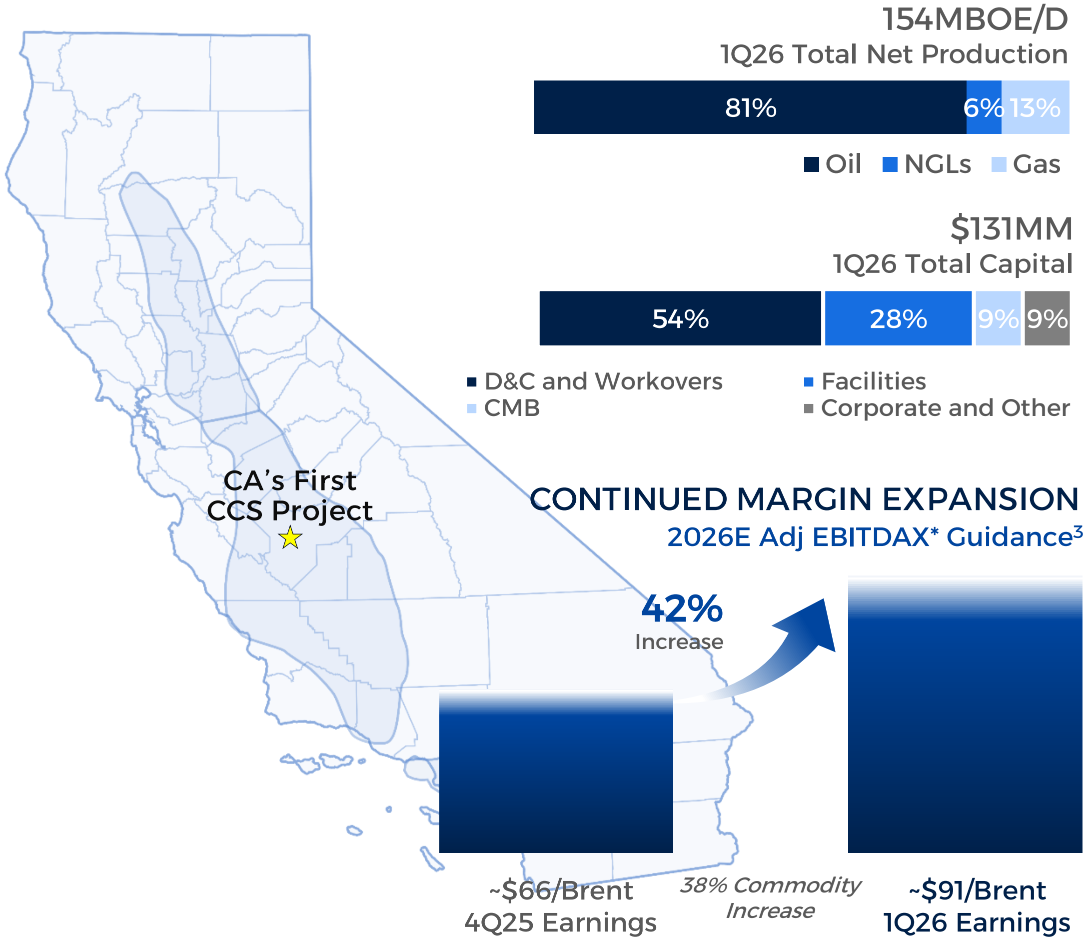
Increasing 2H26E Activity by
3 Drilling Rigs
2 Rigs in CA + 1 in UT
Targeting ~1% Entry to Exit Growth

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

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

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

California's Premier Energy Platform



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

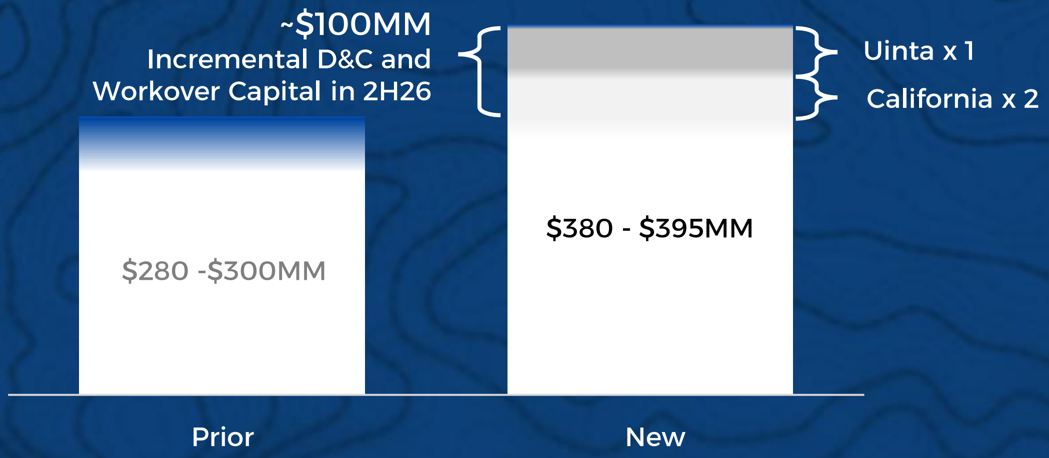
Bringing Value Forward

Targeting Return to Growth Production Profile By YE26

Gross Production (MBoe/d)

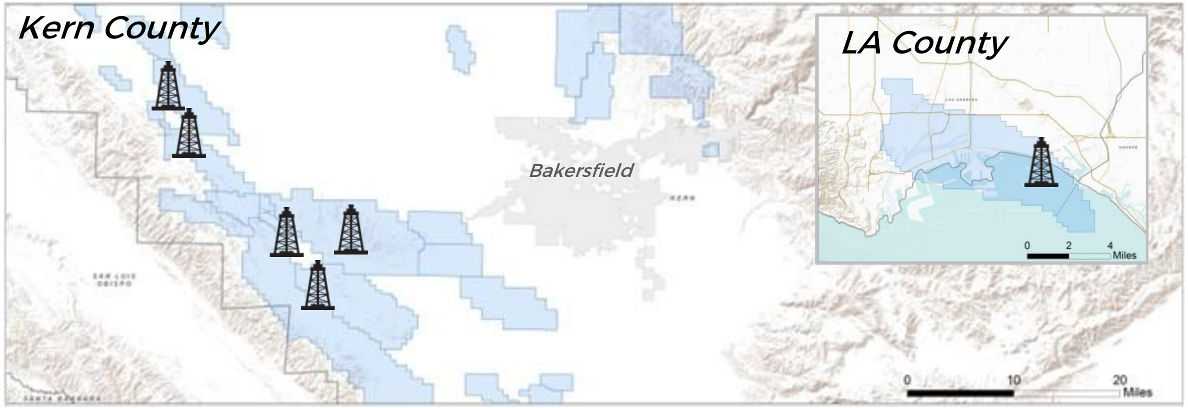
Efficient Capital Allocation In Line with Expectations

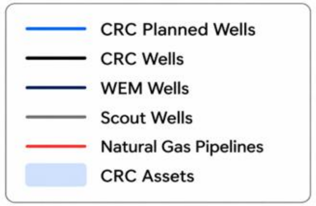
2026E D&C and Workover Capital ($MM)[1]



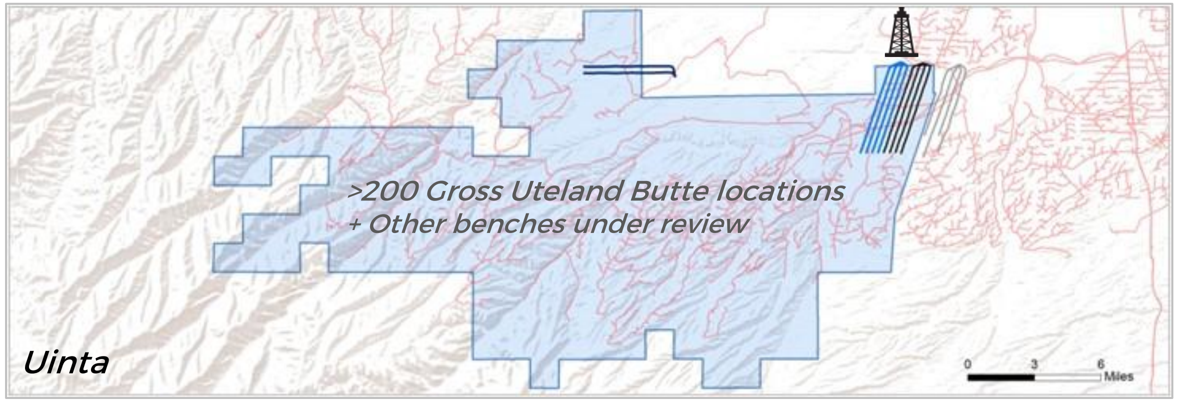
Portfolio Approach

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





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



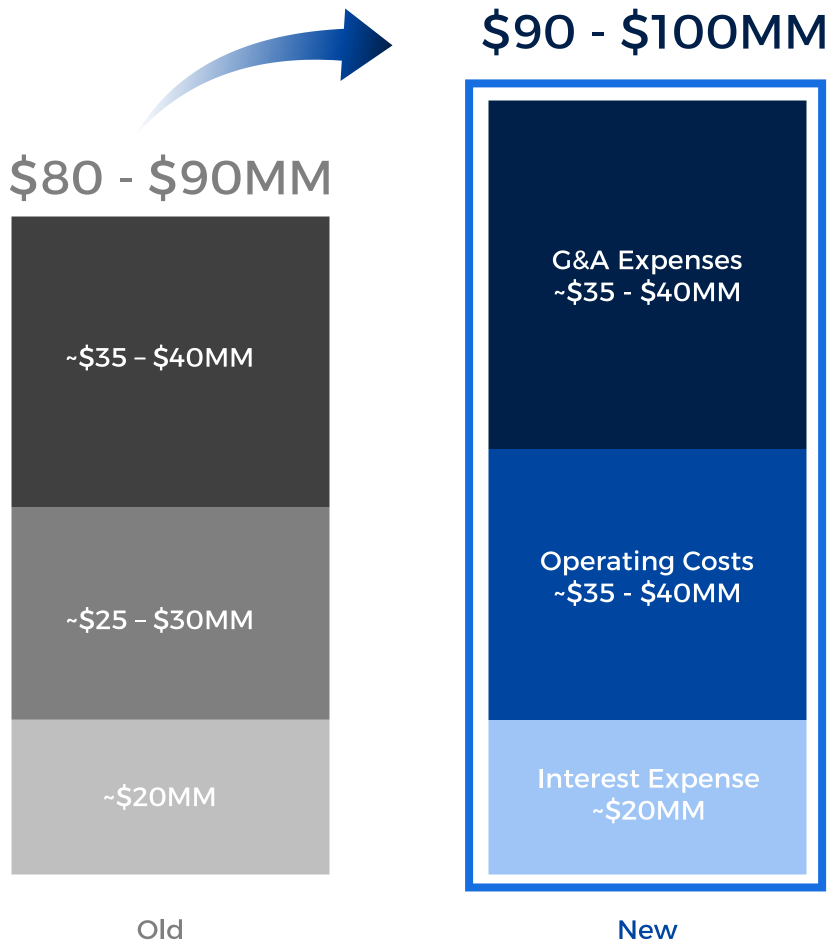
See slide 24 for "Assumptions, Estimates and Endnotes".

Continued Structural Cost Reductions Drive Margin Expansion

With >80% of Synergies Implemented to Date

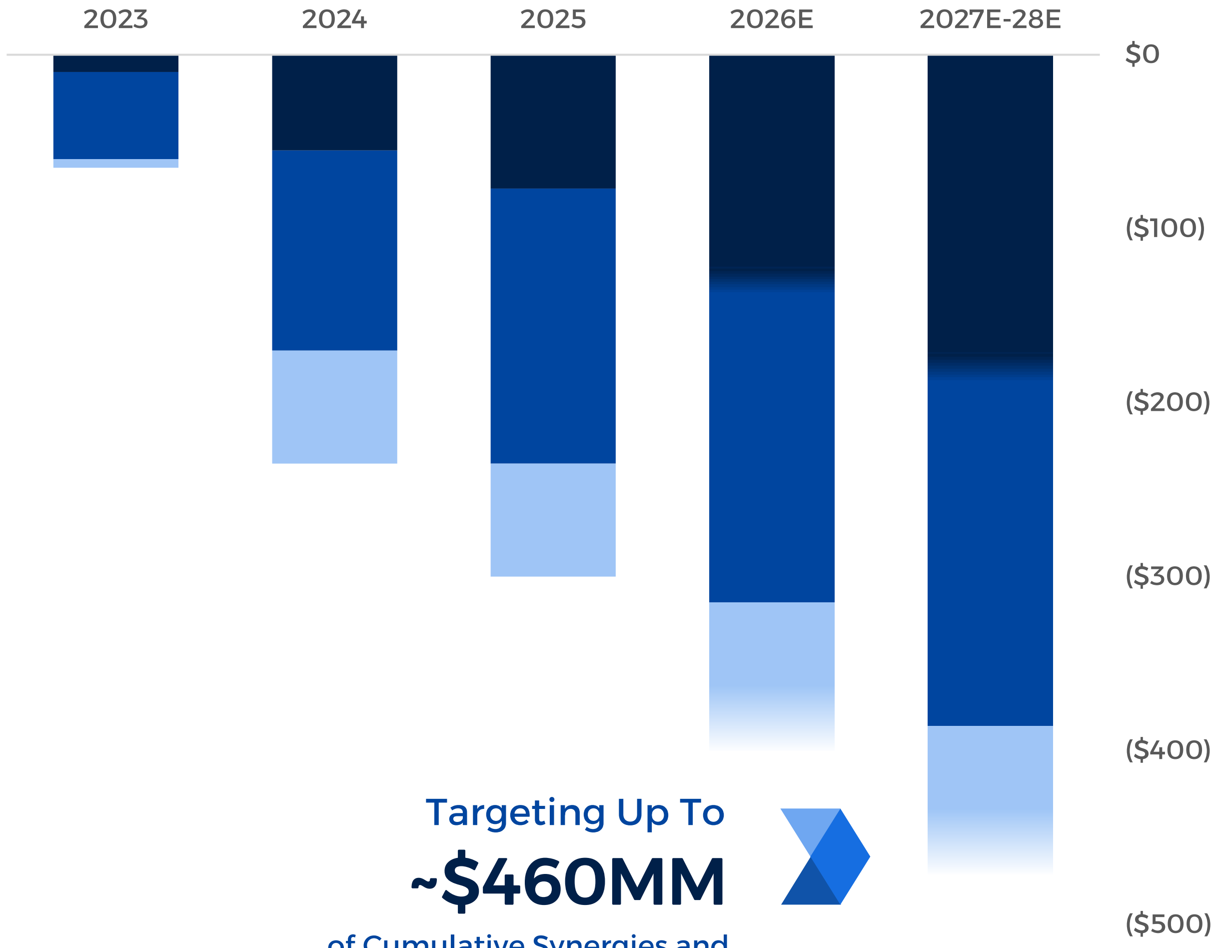
12% Increase in Targeted Synergies

2026 Estimated Berry-Related Synergies ($MM)



Benefits of a Leaner CRC

Targeted Cumulative Synergies and Structural Cost Reductions ($MM)



Targeting Up To

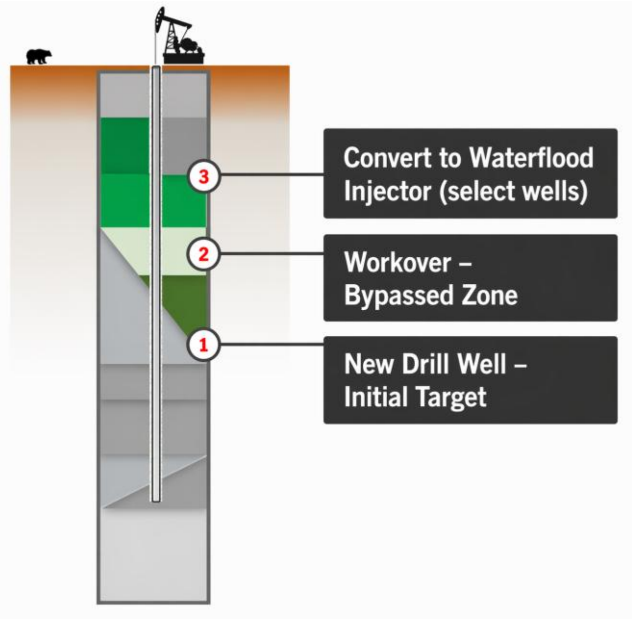
~$460MM

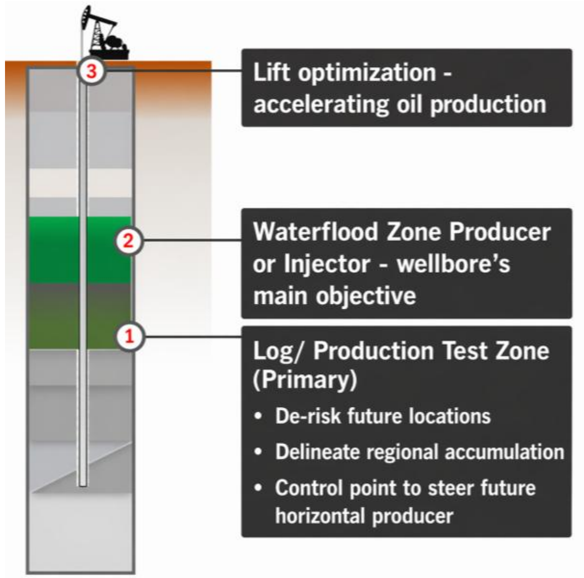
of Cumulative Synergies and Cost Reductions Through 2028

Low-Decline Assets - Quick Returns

2026E Key Operational Updates

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





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

Program Built for Value Creation

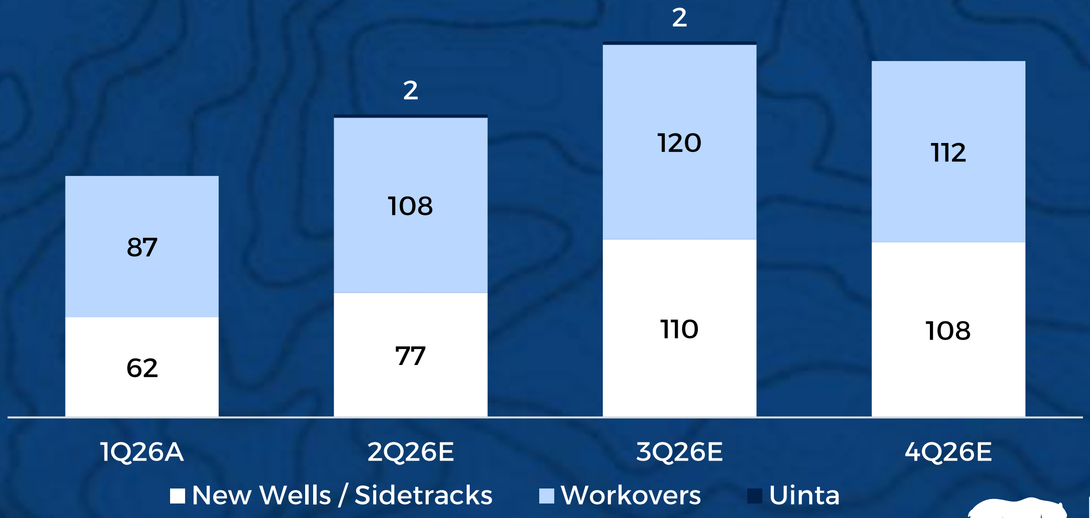
Updated 2026E O&G Program Economics[1,2]

~4.5x	~69%
MOIC[3]	IRR

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

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

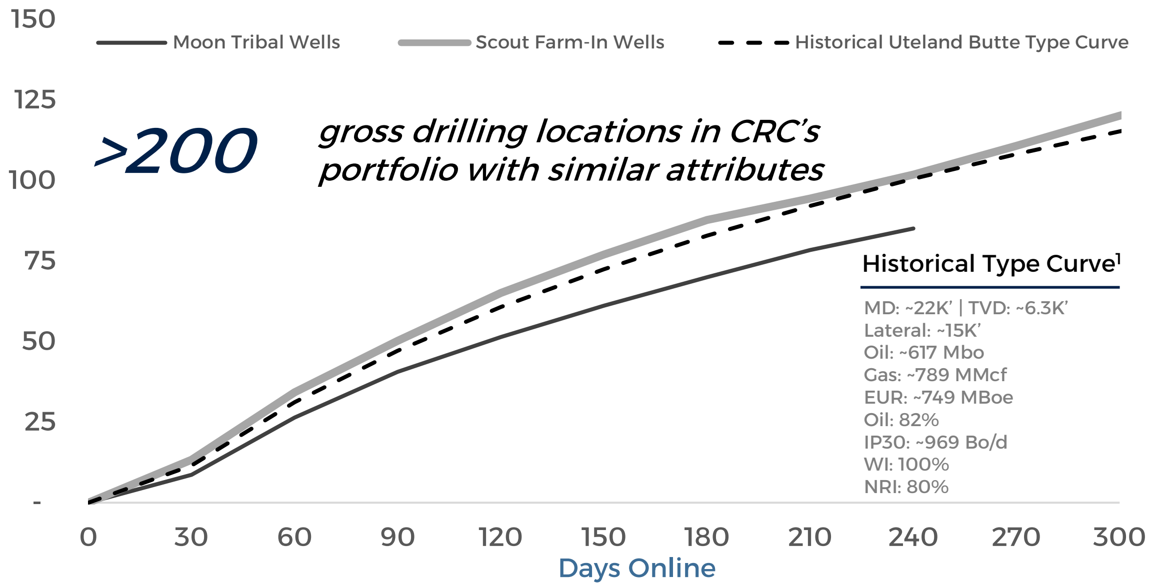
Planned Quarterly Wells



Uinta: Highly Contiguous Asset with Abundant Stacked Pay Opportunities

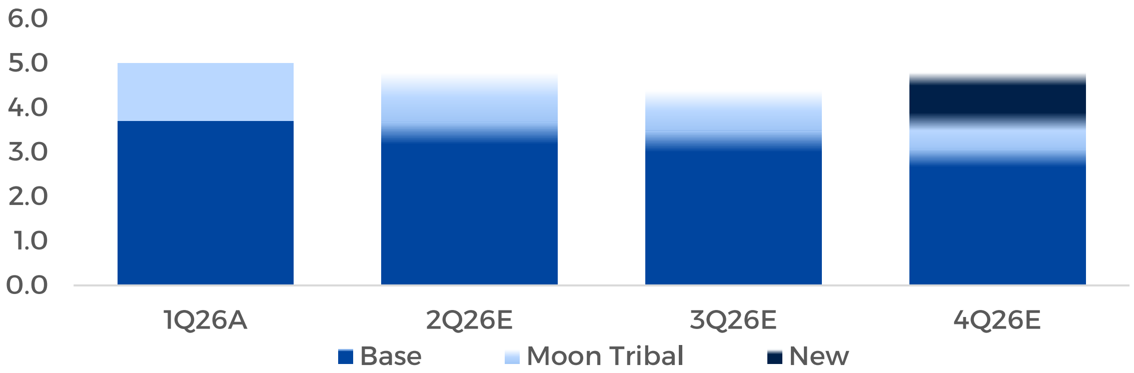
Nearby Type Curves Demonstrate Upside

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

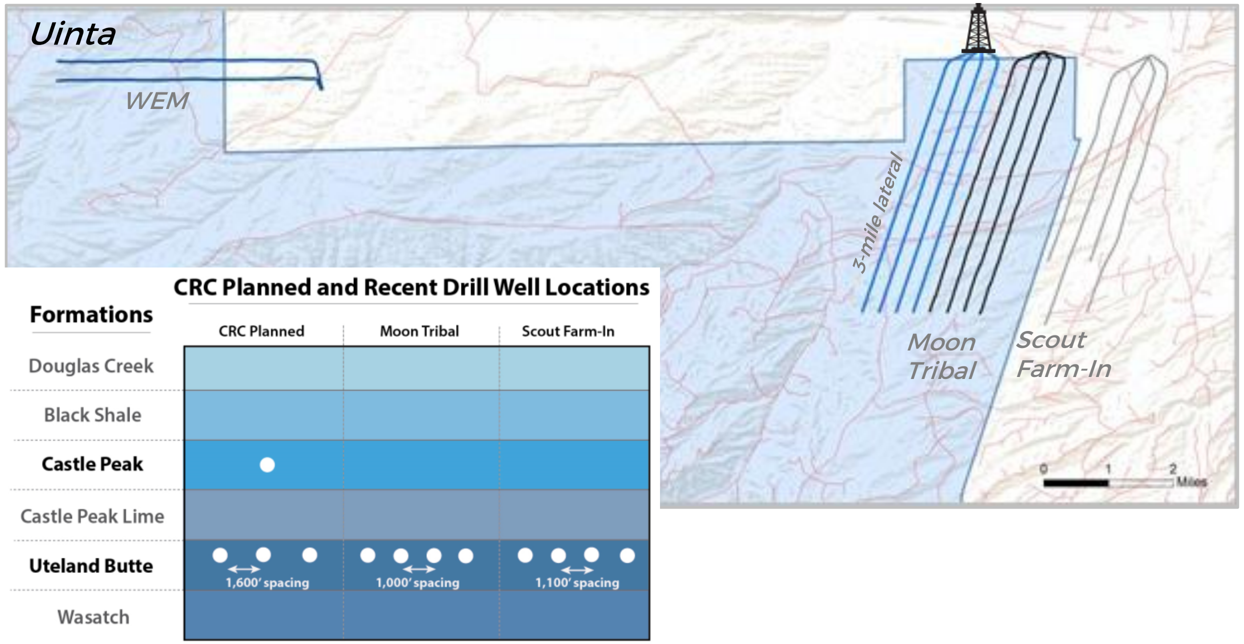


Accelerating Production

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



De-Risking Acreage

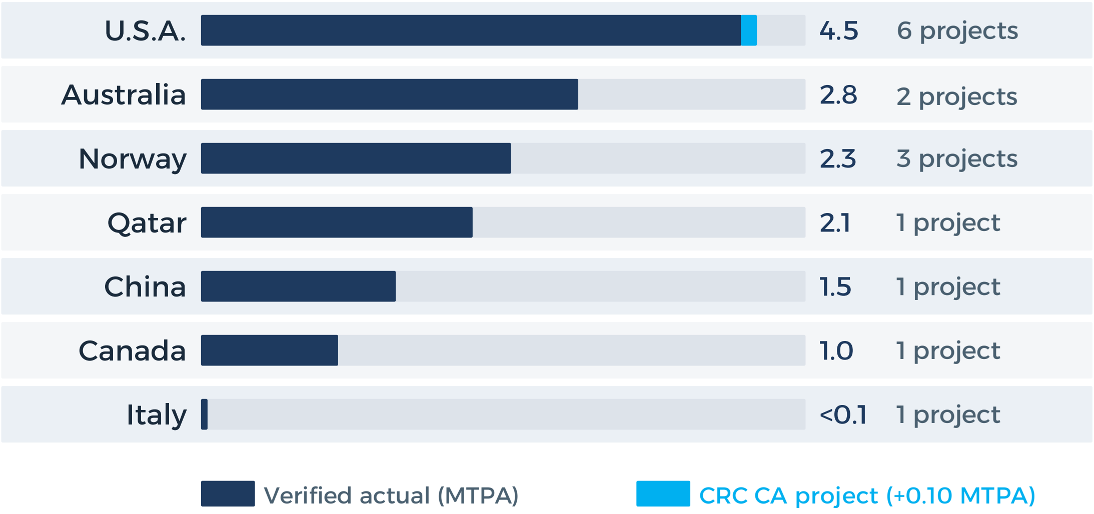


- Offset well production has substantially de-risked performance of CRC future wells
- Moon Tribal wells provided completion optimization learnings that are expected to lower future costs and improve productivity performance
- Allocating ~$46MM to D&C a new 4-well pad: 3 wells targeting Uteland Butte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

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

Next to Join the Ranks of Global CCS Leaders[1]

A Differentiated Position in Global CCS



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

Once the Elk Hills Project is Operational, CRC will be...

1. **1 of only 2 U.S. oil & gas companies to be storing CO_2**
   underground through EPA Class VI geologic sequestration wells

2. **1 of only 6 true commercial-scale CCS sequestration projects in the US**
   to be permanently injecting and storing CO_2 in dedicated geologic formations (EPA class VI)

3. **1 of 15 commercial-scale CCS projects globally**
   to be actively injecting and storing CO_2 (Non-EOR, Non-Acid Gas Injection)

4. **California's first and only commercial-scale CCS project**
   once operational and injecting CO_2 in the state

EPA CO_2 Sample Collection

CO_2 Line to Injection Pad

Capture Equipment

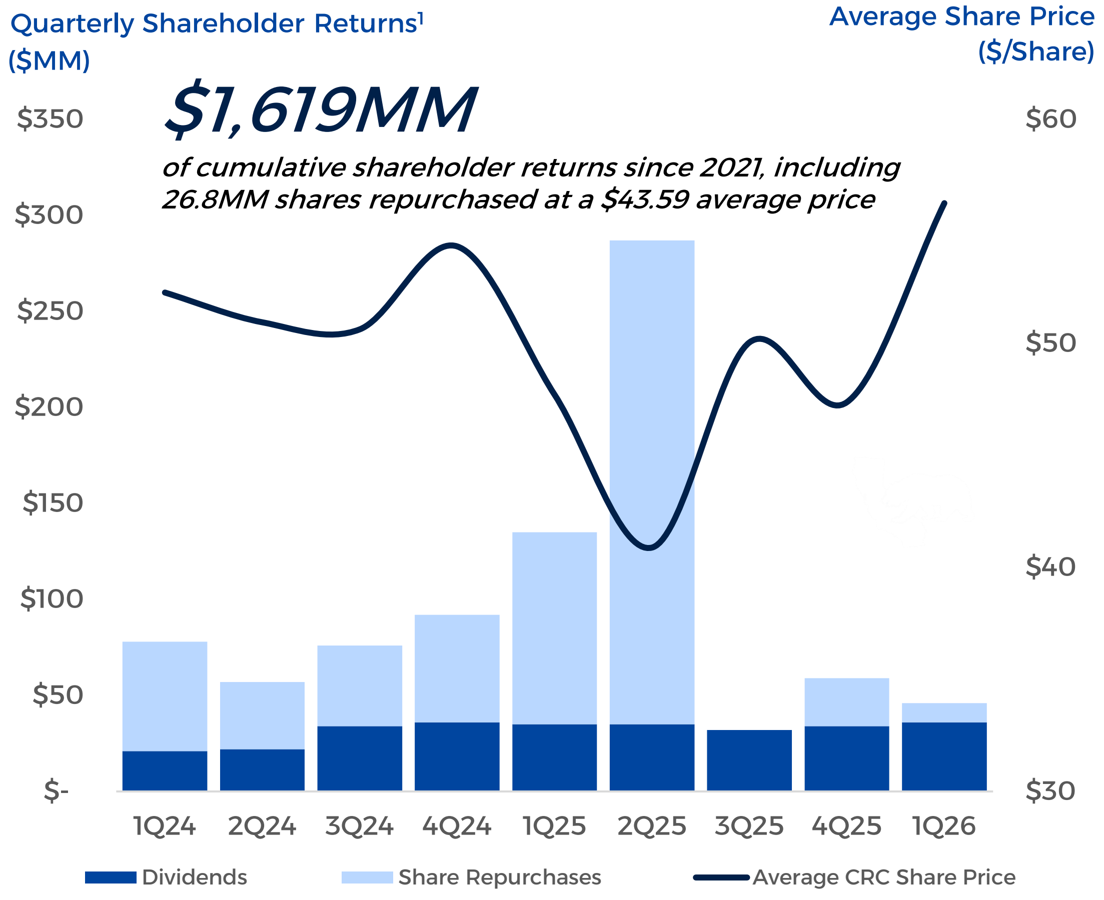
Poised to Join an Elite Sequestration Peer Group

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

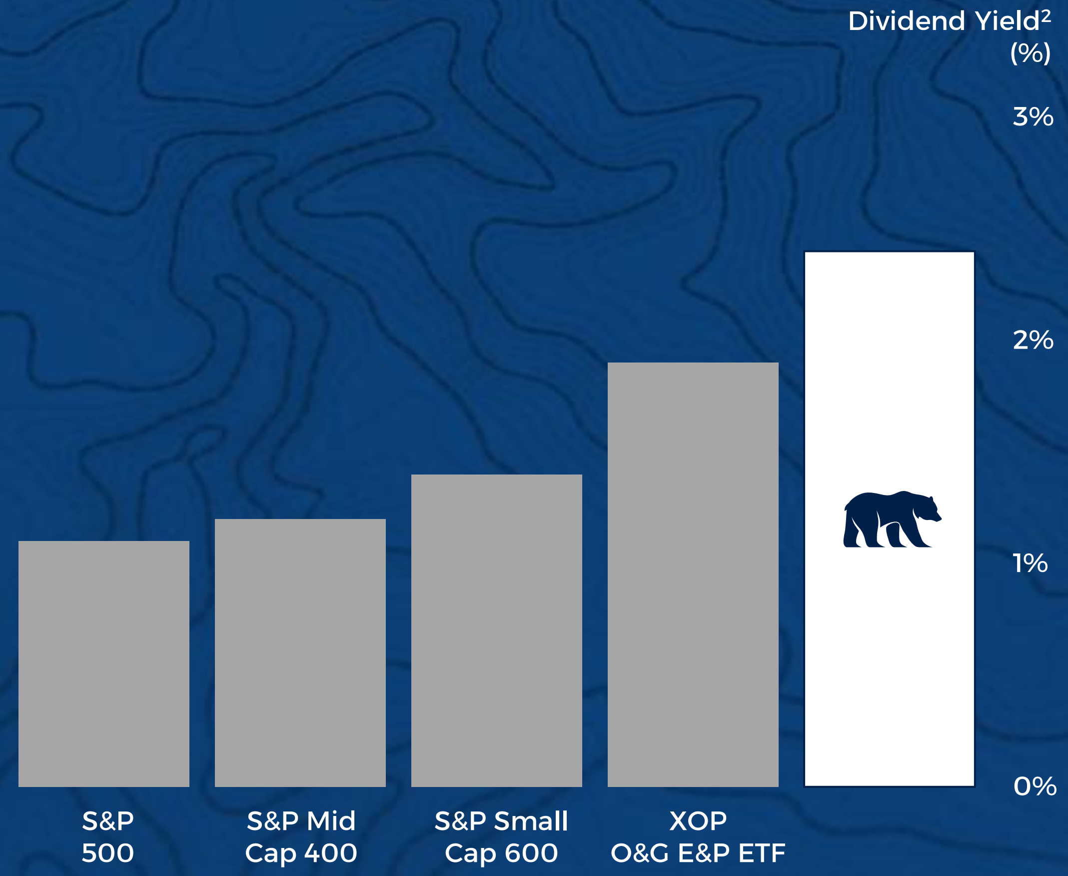
CRC Elk Hills, California	Chevron Gorgon, Australia	ExxonMobil Strathcona, Canada
Shell Quest, Canada	Equinor Snøhvit, Norway	Santos Moomba, Australia

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

Opportunistic Share Repurchases Create Observable Value



Attractive Fixed Dividend vs Market



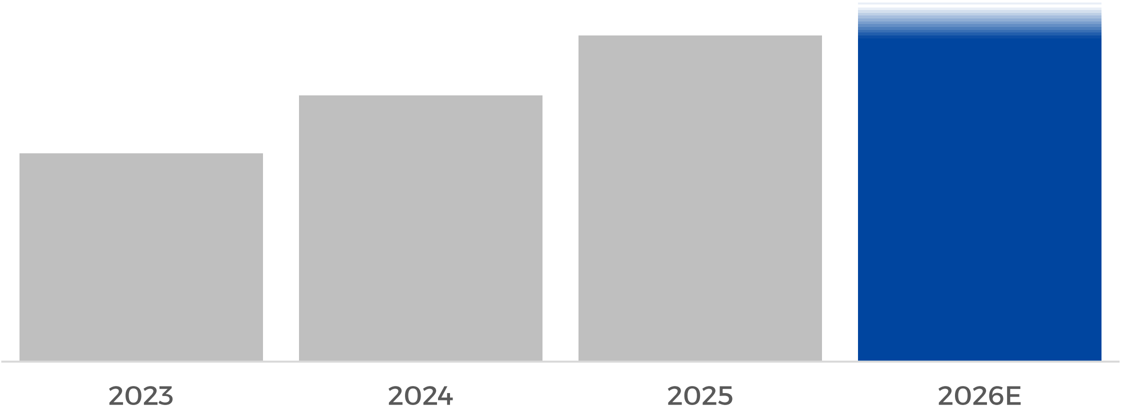
See slide 24 for "Assumptions, Estimates and Endnotes".

A Different Kind of Energy Company

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

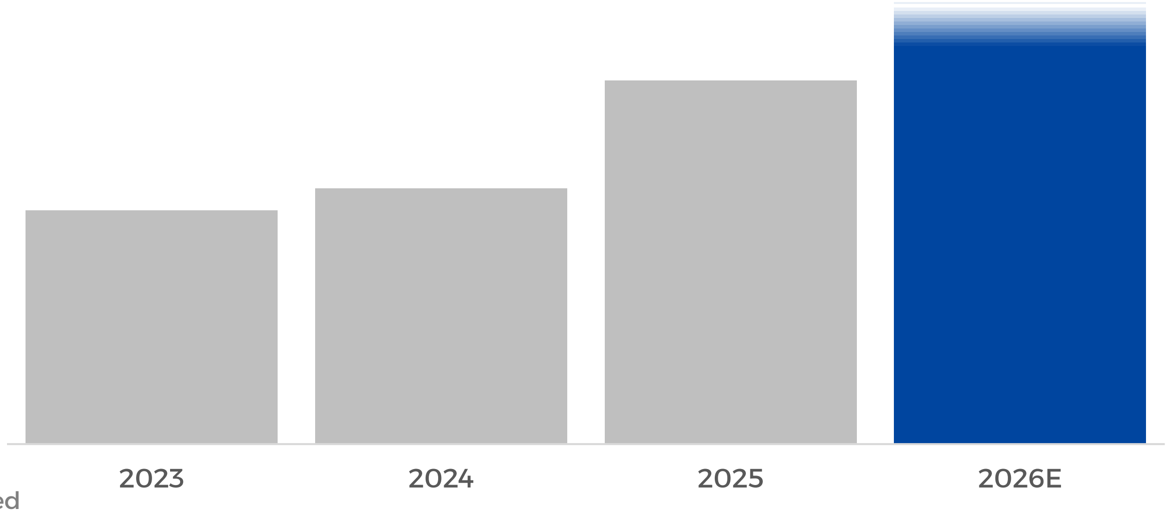
Gaining Scale

Gross Production (MBoe/d)[1]



Growing Cash Flow

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



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

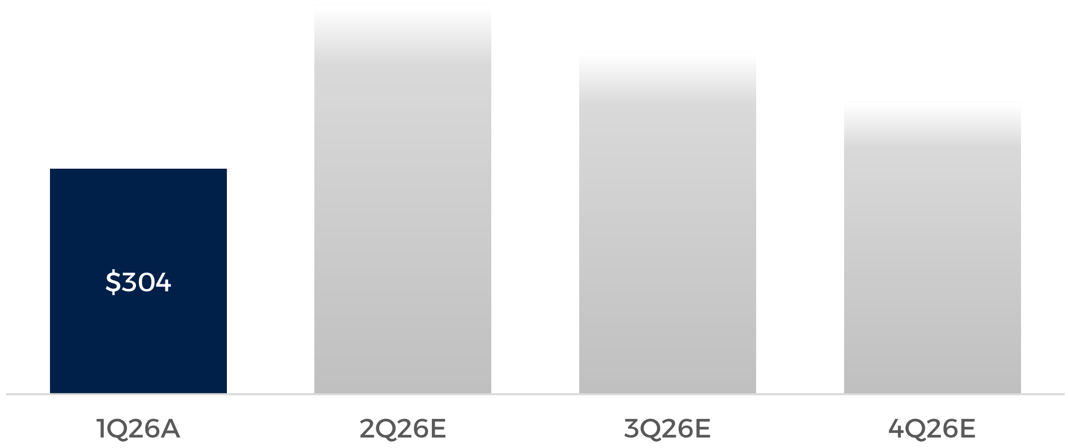
Note: "Before WC Changes" means "Before Net Changes in Operating Assets and Liabilities".
See slide 24 for "Assumptions, Estimates and Endnotes".

Results, Guidance & Capital Structure

Solid Year Ahead

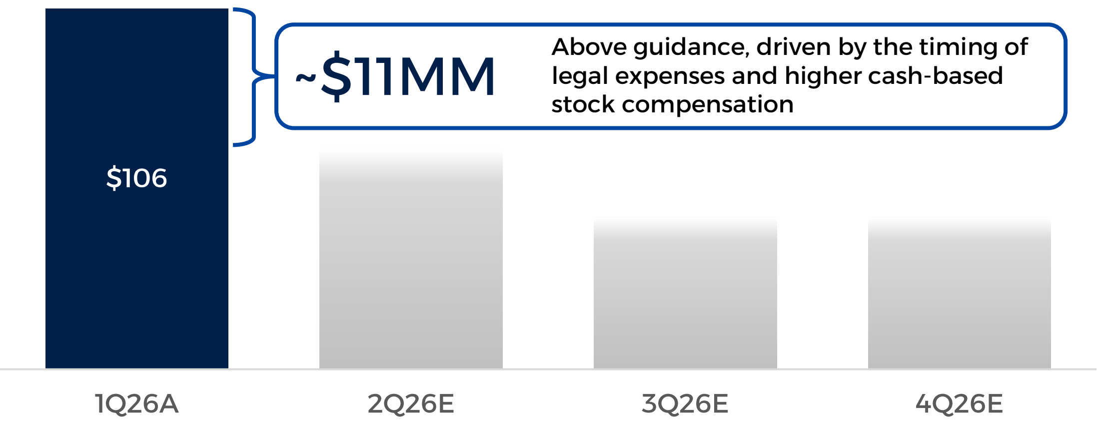
Improved 2026E Outlook Despite 1Q Noise

Adj. EBITDAX* ($MM)[1]



G&A Run Rate On Track by 2Q26

G&A Expenses ($MM)[1]



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

Strong 1Q26 Results

Commodity	1Q26A
Brent ($/Bbl)	$77.90
Oil Realized Price without Hedges ($/Bbl)	$74.53
Oil Realizations without Hedges (% of Brent)	96%
Oil Realized Price with Hedges ($/Bbl)	$69.37
Oil Realization with Hedges (% of Brent)	89%
Operational and Financial	
Net Production (MBoe/d)	154
Net Oil Production (% of Total)	81%
Operating Costs ($MM)	$365
G&A Expenses ($MM)	$106
Adj. G&A Expenses* ($MM)	$99
Taxes Other Than on Income ($MM)	$67
Other Operating Expenses Net of Other Revenue*,2	$44
Total Capital ($MM)	$131
Adj. EBITDAX* ($MM)	$304
Operating Cash Flow Before WC Changes*	$247
Free Cash Flow Before WC Changes*	$116
Other Items	
Margin from Purchased Commodities*, 3	$18
Electricity Revenue Net of Electricity Generation Expenses*, 4	$6
Transportation Costs ($MM)	$26
Total Return of Cash to Shareholders[5] ($MM)	
Share Repurchases ($MM)	$10
Dividends Paid ($MM)	$36
Total Shareholder Returns ($MM)	$46

Improved 2026E Outlook

CRC Guidance *(as of March 31, 2026)*	2Q26E Consolidated	Oil and Natural Gas	Carbon Management	2026E Consolidated	Oil and Natural Gas	Carbon Management
Net Production (MBoe/d) ~81% Oil	148 – 150			149 – 155		
Margin from Purchased Commodities*[1] ($MM)	$10 - $15			$50 - $65		
Electricity Revenue Net of Electricity Generation Expenses ($MM)[2]	($6) – ($2)			$25 - $45		
Operating Costs ($MM)	$335 - $355	$335 - $355		$1,415 - $1,485	$1,415 - $1,485	
G&A ($MM)	$90 - $100	$13 - $17	$2 - $4	$360 – $380	$50 - $60	$6 - $12
Adjusted G&A ($MM)*	*$85 - $95*	*$13- $17*	*$2- $4*	*$325 - $340*	*$50 - $60*	*$6 - $12*
Depreciation, Depletion and Amortization ($MM)	$145 - $157	$140 - $150		$595 - $615	$575 - $590	
Other Operating Expenses Net of Other Revenue*[3] ($MM)	$10 - $20		$2 - $10	$75 - $85		$20 - $30
Transportation Expense ($MM)	$25 - $30	$19 - $24		$105 - $115	$65 - $70	
Taxes Other Than on Income ($MM)	$60 - $70	$55 - $60		$270 - $280	$238 - $243	
Interest and Debt Expense, Net ($MM)	$30 - $35			$120 - $130		
Capital ($MM)	$120 - $140	$115 - $130	$2 - $5	$520 - $560	$500 - $525	$12 - $20
Adj. EBITDAX* ($MM)	$370 - $410			$1,400 - $1,500		

Other Assumptions	2Q26E	2026E
Brent ($/Bbl)	$105.36	$90.58
NYMEX ($/Mcf)	$2.77	$3.61
Oil – % of Brent	94% - 97%	94% - 98%
NGL – % of Brent	44% - 50%	50% - 55%
Natural Gas – % of NYMEX	38% - 44%	67% - 72%
Current Income Tax Provision[4] ($ MM)	$2 - $4	$5 - $8
Effective Tax Rate	6% - 9%	12% - 16%

2Q26 Commentary

~4.0MBoe/d

Impact due to PSC effects, EHPP downtime and NGL stacking

1x1 Operations

at EHPP in 2Q26 driven by weaker expected power prices

42% Rise in 2026E Adj. EBITDAX* Guide

2026E Capital
$520 - $560MM

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

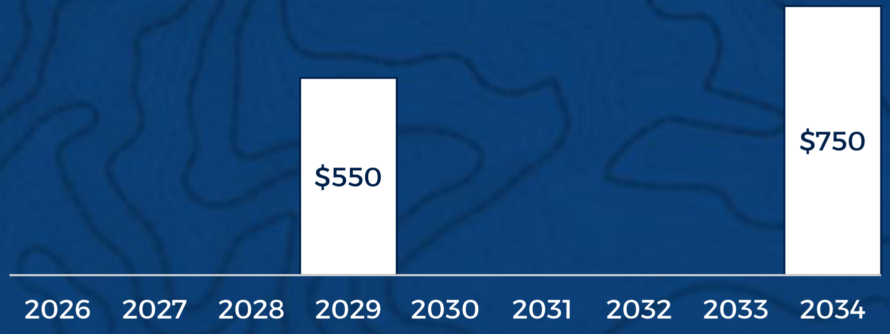
Capital Structure Provides Flexibility

1Q26 Highlights

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

Long Dated Debt Maturity Profile

Unsecured Senior Notes ($MM)



Strong Balance Sheet and Ample Liquidity

Ample Liquidity

Net Debt* Snapshot as of March 31, 2026		($MM)
Revolving Credit Facility (RCF)	$	25
8.250% 2029 Senior Notes		550
7.000% 2034 Senior Notes		750
Face Value of Debt	$	1,325
Less Available Cash & Cash Equivalents[1]		(25)
Net Debt*	$	1,300
Liquidity*[2]	$	1,276

Strong Coverage Ratios

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

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

Appendix

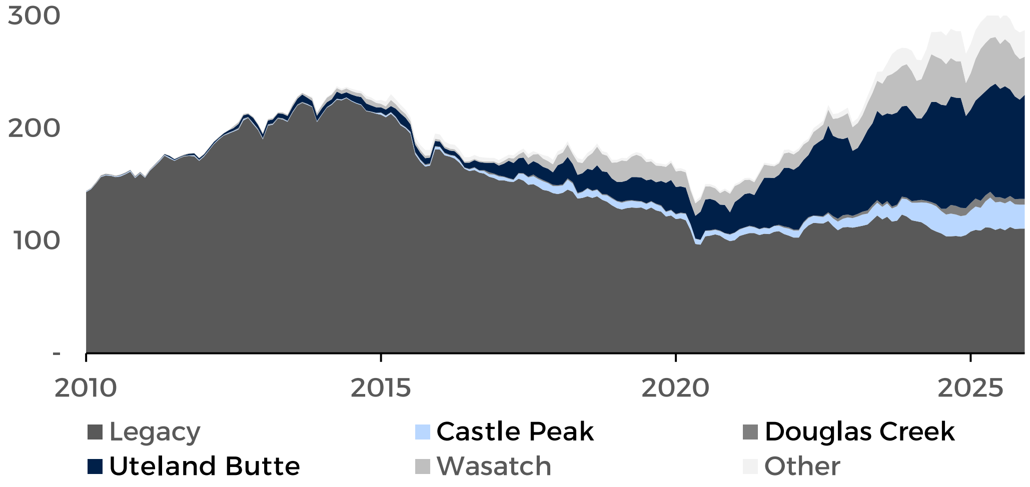
Top-Quartile Well Performance Puts Uinta on the Map

Uinta Basin Performance Rivals Permian & Bakken

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

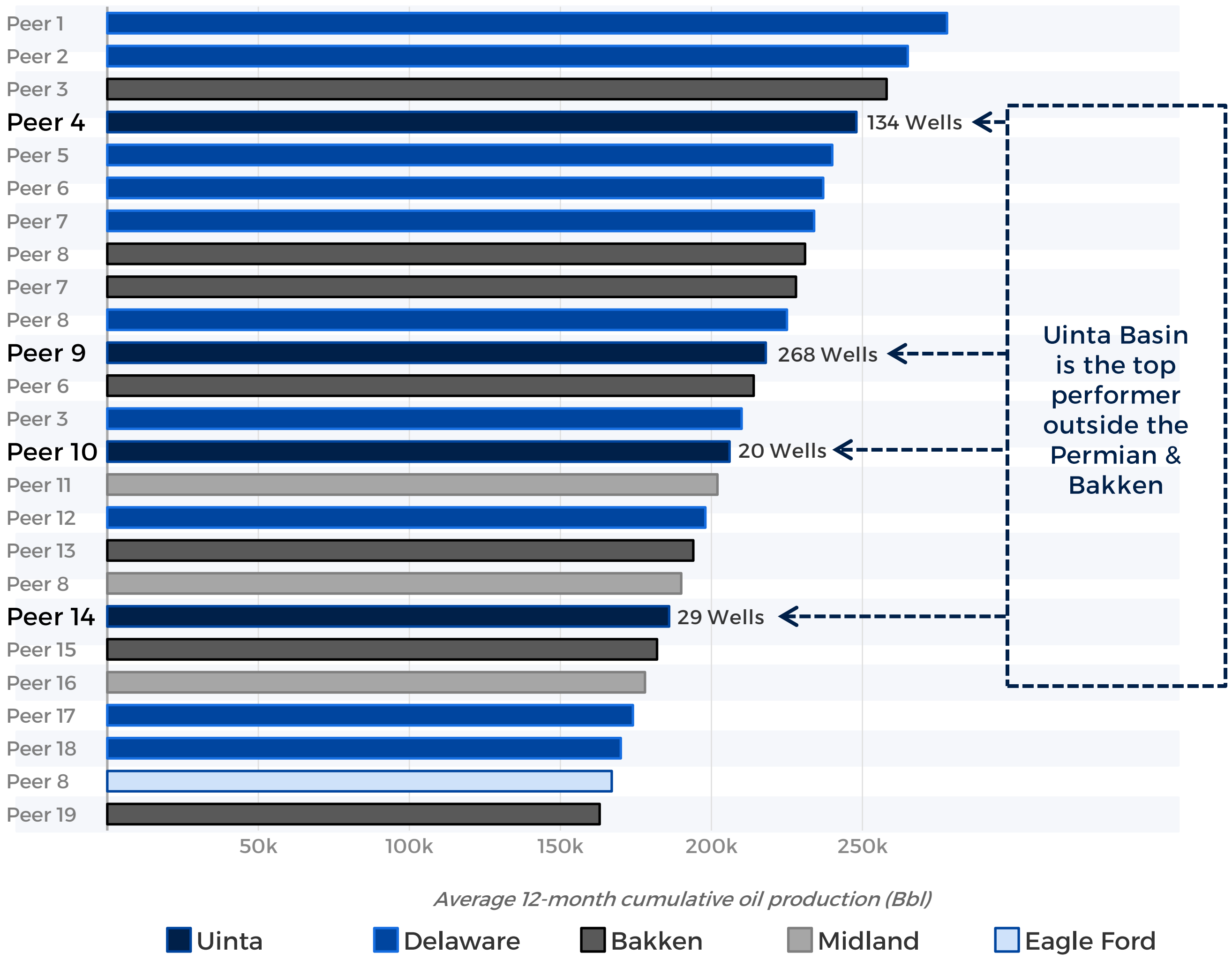
Since YE2020, 2x Rise in Basin Production

Uinta Basin Gross Production (MBoe/d)[1]



Recent Wells are Competitive on First 12-Month Oil Rates

Top 25 Lower 48 Operators Ranked by 2019+ Well Performance[2]



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

Production Sharing Contracts (PSC) at Higher Prices

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

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

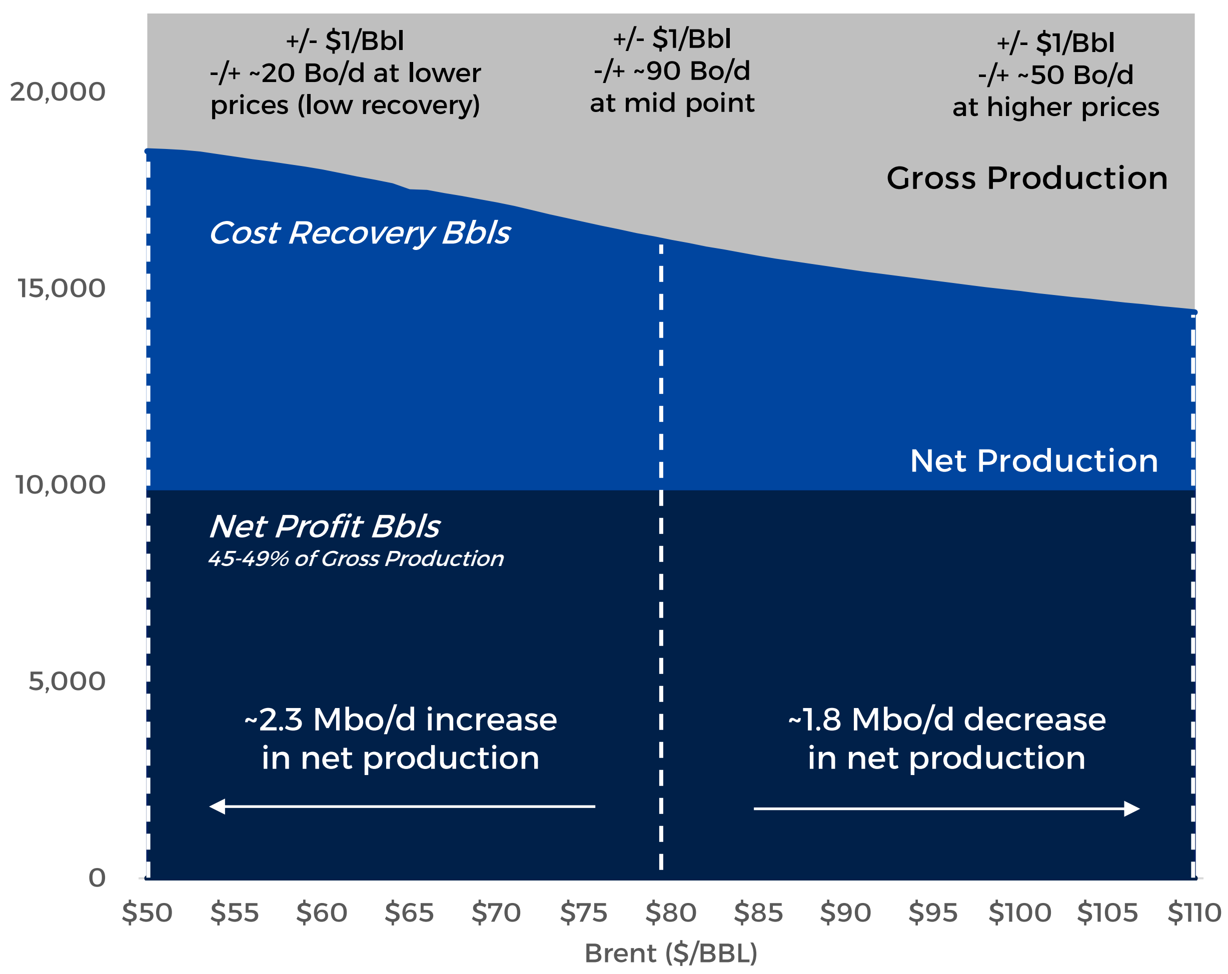
- CRC pays its partners' share of operating and capital cost
- CRC recovers partners' share of operating and capital costs through production sharing, where CRC's cost recovery is reported as revenue
- CRC receives ~45-49% of the gross production as "Profit Barrels" after cost recovery
- CRC's net share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

As prices rise, fewer barrels are assigned as cost recovery

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

Effect Of Oil Price On Net Production[2]

Wilmington Field Production (Bo/d)



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

Power-to-CCS Expansion

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

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

Regulatory momentum supports Power-to-CCS optionality

CA's first CO_2 injection expected in Spring 2026, subject to EPA approval

Current Market Dynamics

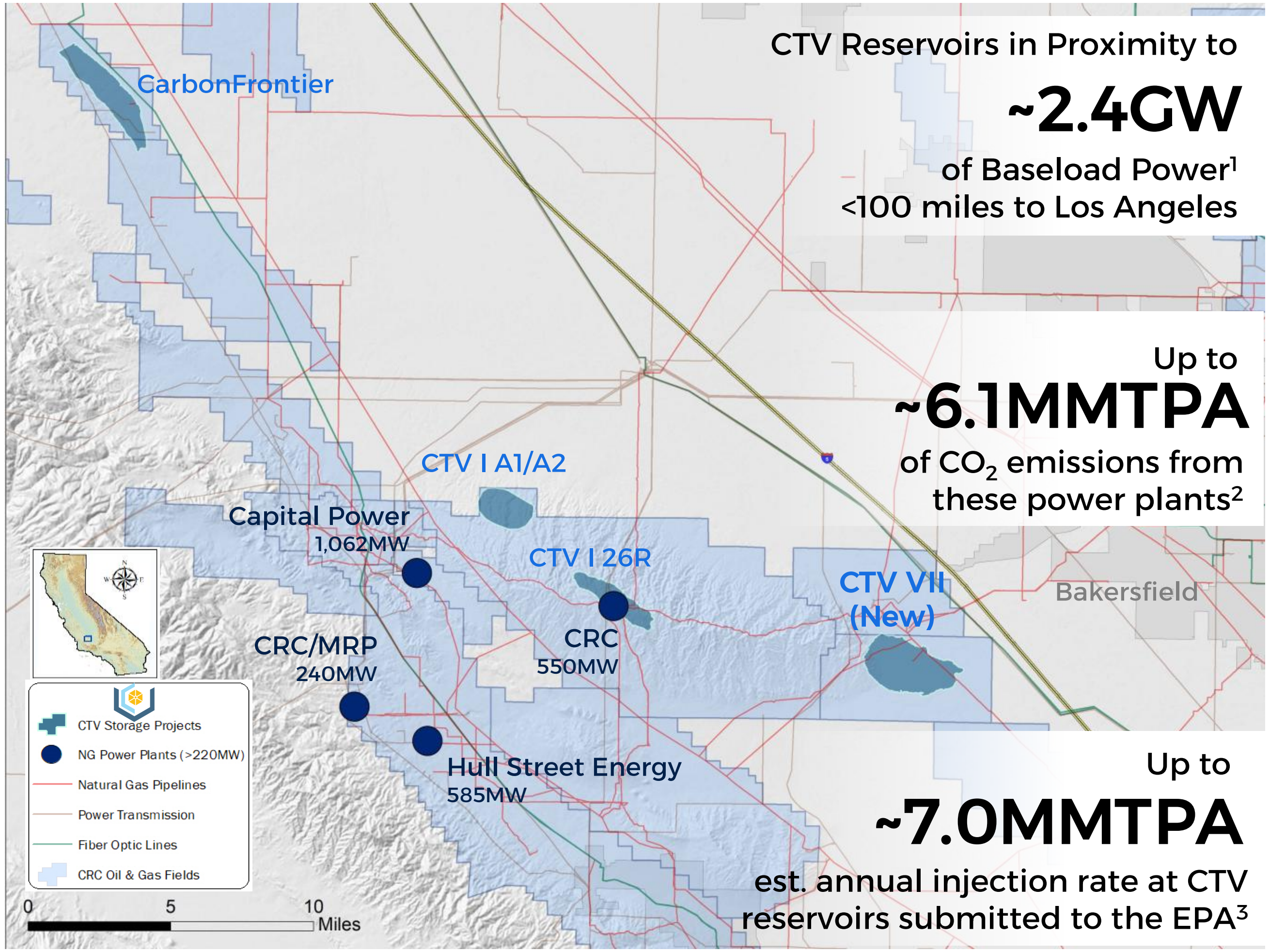
Opportunity	Customers	Clean Premium
1 FTM Utility Sale	Utilities	✓
2 FTM Sale	Existing Data Centers, Industrials	✓
3 BTM Industry Sale	New Data Centers, Industrials	✓

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

Kern County CCS Opportunity

- Natural gas pipeline connectivity
- Power interconnect
- Water availability and supply
- Proximity to major fiber networks
- Access to premier CO_2 storage reservoirs
- Possible CO_2 pipeline connectivity

Powered Land



CTV Reservoirs in Proximity to **~2.4GW** of Baseload Power[1] <100 miles to Los Angeles

Up to **~6.1MMTPA** of CO_2 emissions from these power plants[2]

Up to **~7.0MMTPA** est. annual injection rate at CTV reservoirs submitted to the EPA[3]

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

OIL		2Q26E	3Q26E	4Q26E	2027E	2028E
SOLD CALLS						
Brent	Barrels per Day	36,000	36,000	36,000	2,465	17,534
	Weighted-Average Price	$83.51	$83.51	$83.51	$71.06	$81.28
SWAPS						
Brent	Barrels per Day	44,487	42,869	41,703	69,610	7,285
	Weighted-Average Price	$68.52	$68.20	$67.98	$65.69	$66.98
PURCHASED PUTS[1]						
Brent	Barrels per Day	36,000	36,000	36,000	2,465	17,534
	Weighted-Average Price	$61.11	$61.11	$61.11	$61.01	$62.74
NATURAL GAS		**2Q26E**	**3Q26E**	**4Q26E**	**2027E**	**2028E**
SWAPS						
SoCal Border	MMBtu per Day	13,250	10,750	9,908	3,463	-
	Weighted-Average Price	$4.82	$4.83	$4.84	$4.77	$-
NWPL Rockies[2]	MMBtu per Day	91,750	91,750	91,750	88,254	11,475
	Weighted-Average Price	$3.77	$3.76	$4.17	$4.00	$3.51
EST. HEDGE CONTRACT SETTLEMENTS[3]		**2Q26E**	**3Q26E**	**4Q26E**	**2027E**	**2028E**
Combined Hedge Portfolio ($MM)		($252)	($157)	($89)	($359)	($21)

STRATEGY

CRC's hedging strategy is designed to meet our business objectives should market prices decline and participate in upside should market prices increase

EXECUTION

~65% of remaining 2026E net oil production hedged at an average Brent floor price of ~$65/Bbl[4]

OPERATIONS

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

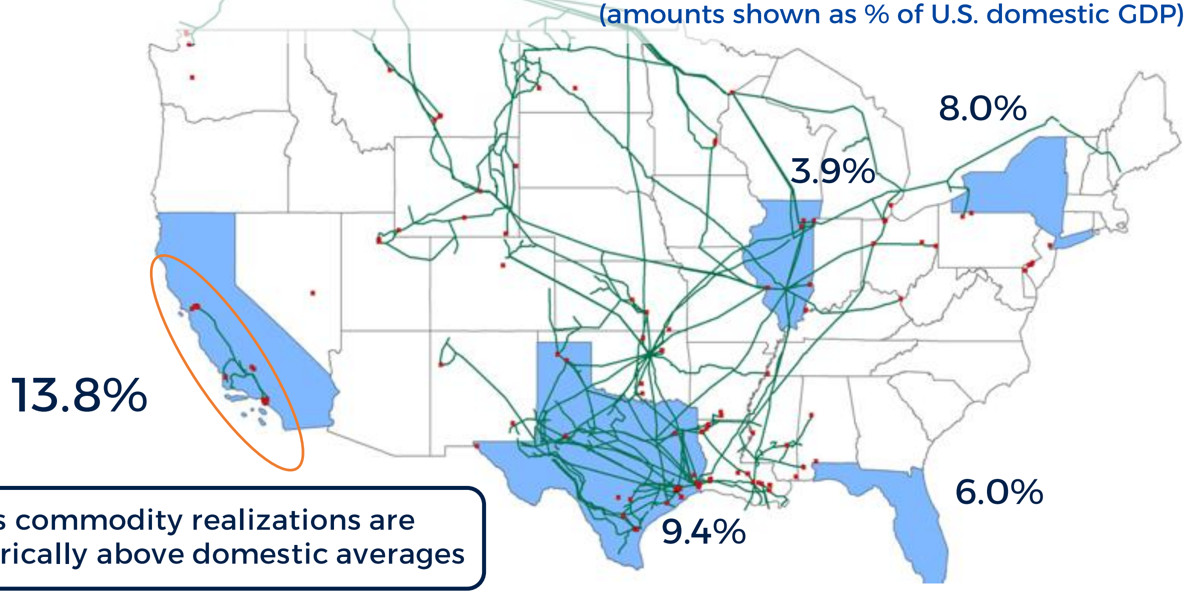
See slide 26 for "Assumptions, Estimates and Endnotes".

Strong Commodity Price Realizations

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

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

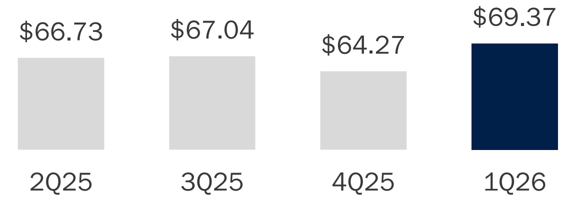
(amounts shown as % of U.S. domestic GDP)



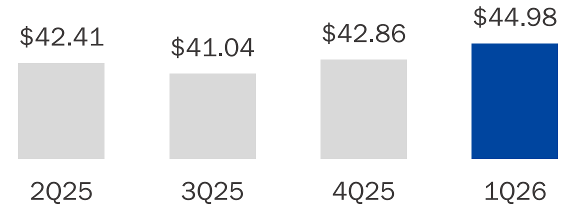
CRC's commodity realizations are historically above domestic averages

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

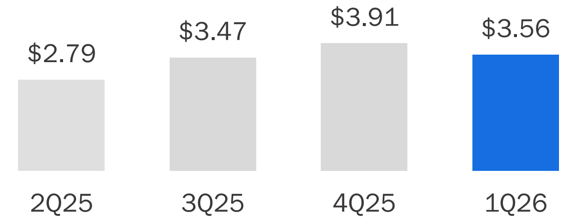
Oil w/ Hedges ($/BBL)



NGLs ($/BBL)



Natural Gas ($/MCF)



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

See slide 26 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) Total year 2026E guidance assumes a 2026E Brent price of $90.58 per barrel of oil, NGL realizations consistent with prior years and an average daily NYMEX gas price of $3.61 per mcf. Generally, CRC's share of production under PSCs decreases when commodity prices rise and increases when prices decline. See slide 14 for 2026E guidance.

Slide 3:

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

1) Enterprise value calculated using net debt of $1,300MM (as of March 31, 2026) plus market capitalization (as of May 1, 2026) using 88.8MM shares outstanding.
2) PV-10 of proved reserves ($8.7B) and probable reserves ($5.7B) as of December 31, 2025 were calculated using SEC prices (after adjustments for price realizations) of $69.38 per barrel of oil and $3.39 per MMBtu of natural gas.
3) PV-10 of proved reserves ($10.3B) and probable reserves ($6.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of $75.00 per barrel of oil and $3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.
4) PV-10 of proved reserves ($13.0B) and probable reserves ($8.9B) as of December 31, 2025 were calculated using assumed prices (after adjustments for price realizations) of $85.00 per barrel of oil and $3.00 per MMBtu of natural gas and held flat. PV-10 using assumed prices was prepared on the same basis as the PV-10 using SEC prices. Investors should be careful to consider strip prices as an addition to, and not as a substitute for, SEC prices (as defined below), when considering our reserves.

Assumptions, Estimates and Endnotes

Slide 3 (Cont.):

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

Slide 4:

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

Slide 5:

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

Slide 7:

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

Slide 8:

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

Slide 9:

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

Slide 10:

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

Slide 11:

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

Assumptions, Estimates and Endnotes

Slide 13:

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

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 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.
5) Corporate and other includes corporate, C&J Well Services and exploration capital.

Slide 15:

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

Slide 17:

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

Slide 18:

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

Assumptions, Estimates and Endnotes

Slide 19:
1) Source: Company reports.
2) Based on signed memoranda of understanding (MOUs) and existing CRC power assets.
3) Includes EPA Class VI permit estimated annual CO2 injection rates for CTV I 26R, CTV I A1-A2, CarbonFrontier and CTV VII.

Slide 20:
1) Purchased and sold puts with the same strike price have been netted together.
2) NPWL volumes require transportation to where the gas is consumed. These costs are reflected in our 2026E transportation guidance. See slide 14 for 2026E guidance.
3) Represents estimated net cash settlement payments inclusive of premiums for derivative contracts and forward commodity prices as of April 29, 2026.
4) Subject to commodity prices and market factors.

Slide 21:
1) 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.

Forward-Looking / Cautionary Statements – Certain Terms

Forward-Looking Statements:

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

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

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