



**CALIFORNIA
RESOURCES**

2025

**ANNUAL
REPORT**

FINANCIAL & OPERATIONAL HIGHLIGHTS

FINANCIAL HIGHLIGHTS

2025

2024

2023

Dollar amounts in millions, except share and per-share amounts, as of and for the years ended December 31

Total Operating Revenues	\$ 3,669	\$ 3,198	\$ 2,801
Net Income	\$ 363	\$ 376	\$ 564
Adjusted Net Income ^(a)	\$ 359	\$ 317	\$ 372
Net Income per Share – Diluted	\$ 4.15	\$ 4.62	\$ 7.78
Adjusted Net Income per Share – Diluted ^(a)	\$ 4.11	\$ 3.89	\$ 5.13
Net Cash Provided by Operating Activities	\$ 865	\$ 610	\$ 653
Capital Investments	\$ 322	\$ 255	\$ 185
Free Cash Flow ^(a)	\$ 543	\$ 355	\$ 468
Net Cash Provided by (Used in) Financing Activities	\$ (380)	\$ 343	\$ (289)
Total Assets	\$ 7,403	\$ 7,135	\$ 3,998
Long-Term Debt, Net	\$ 1,283	\$ 1,132	\$ 540
Stockholders' Equity	\$ 3,674	\$ 3,538	\$ 2,219
Weighted-Average Shares Outstanding - Diluted	87.4	81.4	72.5
Year-End Shares	88.8	91.1	68.7

OPERATIONAL HIGHLIGHTS

2025

2024

2023

Average Daily Net Production:

Oil (MMbbl/d)	109	80	52
NGLs (MMbbl/d)	10	10	11
Natural Gas (MMcf/d)	114	117	135
Total (MBoe/d) ^(b)	138	110	86

Average Realized Prices:

Oil with hedge (\$/Bbl)	\$ 67.51	\$ 75.66	\$ 65.97
Oil without hedge (\$/Bbl)	\$ 66.52	\$ 76.92	\$ 80.41
NGLs (\$/Bbl)	\$ 45.30	\$ 48.93	\$ 48.94
Natural Gas (\$/Mcf)	\$ 3.57	\$ 2.99	\$ 8.59

Proved Reserves:

Oil (MMBbl)	541	443	256
NGLs (MMBbl)	37	34	35
Natural Gas (Bcf)	455	409	518
Total (MMBoe) ^(b)	654	545	377

Standardized Measure of Discounted Future Net Cash Flows (in billions)

PV-10 of Cash Flows (in billions) ^(a)	\$ 6.7	\$ 6.7	\$ 4.1
	\$ 8.7	\$ 8.9	\$ 5.5

Net Mineral Acreage (in thousands):

Developed	802	757	684
Undeveloped	1,184	1,106	1,008
Total	1,986	1,863	1,692

Closing Share Price

	\$ 44.71	\$ 51.89	\$ 54.68
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(a) See www.crc.com, Investor Relations for a discussion of these performance and non-GAAP measures, including a reconciliation to the most closely related GAAP measure or information on the related calculations.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

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

2025 CEO Annual Report Letter

Fellow Shareholders,

California Resources Corporation delivered an exceptional year in 2025.

We generated strong financial results, achieved production growth for the third consecutive year, and returned substantial capital to shareholders – all while operating in one of the most demanding regulatory environments in the United States. We did so profitably and with a focus on sustainability, as reflected by MiQ methane performance certifications for production assets across the Los Angeles, Ventura, and San Joaquin basins. This underscores that strong operational performance and responsible development go hand in hand.

Importantly, California's regulatory environment now recognizes the importance of local production in delivering energy affordability and reliability. The passage of Senate Bill 237 and resolution of litigation regarding Kern County's environmental impact report provided permitting clarity in Kern County, and CRC has begun receiving new drilling permits to support its planned 2026 drilling program. This clarity enables CRC to allocate and invest capital with confidence in 2026 and beyond.

As the energy landscape continues to evolve, CRC is anchored by long-duration, low-decline conventional reservoirs that provide stable production, modest reinvestment requirements, and durable free cash flow across commodity cycles. In a period defined by price volatility, disciplined capital markets, and growing energy demand in California, our intentionally integrated strategy builds on this resilient foundation. By pairing our core operations with disciplined expansion in carbon management and power, we are positioned to support the state's long-term energy needs while advancing its decarbonization objectives.

2025: Disciplined Execution, Scale, and Returns

In 2025, CRC delivered another year of disciplined execution across the portfolio. Our teams improved reservoir performance, reduced corporate base decline rates, enhanced capital efficiency and, combined with the benefit of well-timed strategic mergers, enabled approximately 25% year-over-year production growth. This performance reflects both the quality of our long-life conventional asset base and the depth of our operational capability.

We also demonstrated that scale and integration are repeatable sources of value creation. Following the Aera transaction, we delivered \$235 million of merger-related synergies through disciplined cost rationalization and operational efficiencies while maintaining safe operations and production stability. In December, we completed the merger with Berry Corporation, extending the life of our conventional inventory and further expanding our footprint in California. Integration is underway using the same proven playbook, with execution focused on cost structure, operational alignment, and long-term value creation.

The financial impact of strong execution in 2025 is evident in our results. Despite a 14% decline in Brent, CRC generated record adjusted EBITDAX² and free cash flow² in 2025, while strengthening the balance sheet and maintaining ample liquidity¹. Furthermore, we returned more than 90% of free cash flow² to shareholders through a combination of dividends and share repurchases, demonstrating our continued focus on delivering meaningful value in a previously permitting constrained environment. More broadly, since mid-2021, CRC has returned nearly \$1.6 billion to shareholders, repurchasing approximately 26.8 million shares over that period. Throughout our history, our capital allocation philosophy has remained consistent: drive long-term per-share value through disciplined execution and integration.

Carbon TerraVault and Power: From Concept to Execution

CRC's long-life asset base and subsurface expertise also provide a natural foundation for carbon management and power. In 2025, Carbon TerraVault reached a significant milestone: we advanced California's first carbon capture and storage project from permitting to construction, and completed pre-operational activities at our Elk Hills Cryogenic Gas Plant. This positions the project for first carbon dioxide (CO₂) injection in the spring of 2026, subject to final regulatory approvals.

The commencement of CO₂ injection at the CTV I storage reservoir places CRC among a small group of operators globally that have developed CCS projects from concept to operation. This milestone reflects years of deliberate actions across permitting, engineering and stakeholder education. Our approach has been consistent throughout – regulatory clarity first, followed by technical readiness and commercial alignment – leveraging existing infrastructure and subsurface expertise while maintaining a disciplined, milestone-based approach to capital deployment.

Looking ahead, we see growing demand for reliable, decarbonized power solutions in California as electricity needs expand across industrial, infrastructure, and data-driven applications. CRC is uniquely positioned at the intersection of long-duration subsurface assets, existing infrastructure, and power capabilities. Our focus now is on progressing our portfolio of projects where commercial contracts, strong counterparties and compelling economics converge.

Looking Forward

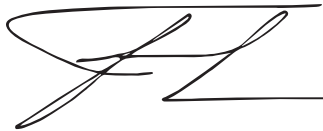
As we enter 2026, our priorities are clear:

- Generate durable free cash flow through disciplined operations and capital allocation
- Complete integration activities and progress planned synergies using a proven framework
- Advance Carbon TerraVault into operations, including commencement of CO₂ injection at the CTV I storage reservoir
- Progress high-return opportunities across the portfolio based on returns and execution readiness
- Maintain balance sheet strength while supporting continued shareholder returns

CRC is not built to chase cycles. It is built to perform through them – anchored by long-duration assets, a multi-decade inventory of low-decline development opportunities, disciplined capital allocation, and an integrated strategy that generates cash today while extending relevance and value over time. That performance is enabled by our people – their expertise, discipline, and commitment to safe, responsible operations – and is what makes CRC a ***Different Kind of Energy Company***.

I want to thank our employees for their professionalism and execution, our communities and partners for their continued engagement, and our shareholders for their confidence and support.

Sincerely,



Francisco Leon
President and Chief Executive Officer
California Resources Corporation

¹ Represents the achievement of record annual adjusted EBITDAX, annual free cash flow and annual total shareholder returns which includes share repurchases and dividends paid since October 2020 in 2025.

² Represents a non-GAAP measure. 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. Free cash flow is equal to net cash provided (used) by operating activities less capital investments.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2025

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number 001-36478

California Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

46-5670947

(I.R.S. Employer
Identification No.)

1 World Trade Center, Suite 1500

Long Beach, California 90831

(Address of principal executive offices) (Zip Code)

(888) 848-4754

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	CRC	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or such shorter period as the registrant was required to submit such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer Accelerated Filer Non-Accelerated Filer
Smaller Reporting Company Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2025: \$3,803,313,982.

At January 31, 2026, there were 88,597,474 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2025 with the Securities and Exchange Commission in connection with the registrant's 2025 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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GLOSSARY AND SELECTED ABBREVIATIONS

The following are abbreviations and definitions of certain terms used within this Form 10-K:

- **AB** - Assembly Bill
- **ABR** - Alternate base rate.
- **Aera** - Aera Energy LLC.
- **Aera Merger** - The transactions contemplated by the definitive agreement and plan of merger entered into on February 7, 2024 to obtain all the ownership interests in Aera in an all-stock transaction.
- **ASC** - Accounting Standards Codification.
- **ARO** - Asset retirement obligation.
- **Bbl** - Barrel.
- **Bbl/d** - Barrels per day.
- **Bcf** - Billion cubic feet.
- **Bcfe** - Billion cubic feet of natural gas equivalent using the ratio of one barrel of oil, condensate, or NGLs converted to six thousand cubic feet of natural gas.
- **Berry** - Berry Corporation (bry).
- **Berry Merger** - The transactions contemplated by the definitive agreement and plan of merger entered into on September 14, 2025 to combine with Berry in an all-stock transaction.
- **Boe** - We convert natural gas volumes to crude oil equivalents using a ratio of six thousand cubic feet (Mcf) to one barrel of crude oil equivalent based on energy content. This is a widely used conversion method in the oil and natural gas industry.
- **Boeld** - Barrel of oil equivalent per day.
- **Brookfield** - BGTF Sierra Aggregator LLC.
- **Btu** - British thermal unit.
- **CalGEM** - California Geologic Energy Management Division.
- **CAISO** - California Independent System Operator.
- **Carbon TerraVault JV** - A joint venture between our wholly-owned subsidiary Carbon TerraVault I, LLC with Brookfield for the further development of a carbon management business in California.
- **CCS** - Carbon capture and storage.
- **CDMA** - Carbon Dioxide Management Agreement.
- **CEQA** - California Environmental Quality Act.
- **CO₂** - Carbon dioxide.
- **DAC** - Direct air capture.
- **DD&A** - Depletion, depreciation, and amortization.
- **EOR** - Enhanced oil recovery.
- **EPA** - United States Environmental Protection Agency.
- **ESG** - Environmental, social and governance.
- **E&P** - Exploration and production.
- **GAAP** - United States Generally Accepted Accounting Principles.
- **G&A** - General and administrative expenses.
- **GHG** - Greenhouse gases.
- **JV** - Joint venture.
- **KMTPA** - Thousand metric tons per annum.
- **LCFS** - Low Carbon Fuel Standard.
- **MBbl** - One thousand barrels of crude oil, condensate or NGLs.
- **MBbl/d** - One thousand barrels per day.
- **MBoeld** - One thousand barrels of oil equivalent per day.
- **MBwid** - One thousand barrels of water per day
- **Mcf** - One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six thousand cubic feet of natural gas.

- **MHp** - One thousand horsepower.
- **MMBbl** - One million barrels of crude oil, condensate or NGLs.
- **MMBoe** - One million barrels of oil equivalent.
- **MMBtu** - One million British thermal units.
- **MMcfd** - One million cubic feet of natural gas per day.
- **MMT** - Million metric tons.
- **MMTPA** - Million metric tons per annum.
- **MW** - Megawatts of power.
- **NGLs** - Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as purity products such as ethane, propane, isobutane and normal butane, and natural gasoline.
- **NYMEX** - The New York Mercantile Exchange.
- **OCTG** - Oil country tubular goods.
- **Oil spill prevention rate** - Calculated as total Boe less net barrels lost divided by total Boe.
- **OPEC** - Organization of the Petroleum Exporting Countries.
- **OPEC+** - OPEC together with Russia and certain other producing countries.
- **PHMSA** - Pipeline and Hazardous Materials Safety Administration.
- **Proved developed reserves** - Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- **Proved reserves** - The estimated quantities of natural gas, NGLs, and oil that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic conditions, operating methods and government regulations.
- **Proved undeveloped reserves** - Proved reserves that are expected to be recovered from new wells on undrilled acreage that are reasonably certain of production when drilled or from existing wells where a relatively major expenditure is required for recompletion.
- **PSCs** - Production-sharing contracts.
- **PV-10** - Non-GAAP financial measure and represents the year-end present value of estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.
- **Responsible Net Zero** - Refers to our net zero emissions goal adopted by our Board of Directors in May 2025 consisting of achieving at least an 80% reduction of absolute Scope 1 and 2 GHG emissions and neutralizing the remaining Scope 1 and 2 emissions to achieve Net Zero by 2045.
- **SB** - Senate Bill
- **Scope 1 emissions** - Our direct emissions.
- **Scope 2 emissions** - Indirect emissions from energy that we use (e.g., electricity, heat, steam, cooling) that is produced by others.
- **Scope 3 emissions** - Indirect emissions from upstream and downstream processing and use of our products.
- **SDWA** - Safe Drinking Water Act.
- **SEC** - United States Securities and Exchange Commission.
- **SEC Prices** - The unweighted arithmetic average of the first day-of-the-month price for each month within the year used to determine estimated volumes and cash flows for our proved reserves.
- **SOFR** - Secured overnight financing rate as administered by the Federal Reserve Bank of New York.
- **Standardized measure** - The year-end present value of after-tax estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. Standardized measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions.

- **TRIR** - Total Recordable Incident Rate calculated as recordable incidents per 200,000 hours for all workers (employees and contractors).
- **Working interest** - The right granted to a lessee of a property to explore for and to produce and own oil, natural gas or other minerals in-place. A working interest owner bears the cost of development and operations of the property.
- **WTI** - West Texas Intermediate.

PART I

ITEMS 1 & 2 BUSINESS AND PROPERTIES

Business

We are an independent energy and carbon management company advancing the energy transition. We are committed to environmental stewardship while safely providing local, responsibly sourced energy. We are also focused on maximizing the value of our land, mineral ownership, and energy expertise for decarbonization by developing carbon capture and storage (CCS) and other emissions reducing projects.

Our business is organized into two reporting segments: oil and natural gas and carbon management. Our oil and natural gas segment explores for, develops and produces crude oil and condensate, natural gas liquids and natural gas in major producing basins located in California and Utah. As of December 31, 2025, our proved reserves totaled an estimated 654 MMBoe, of which 541 MMBbl were crude oil and condensate reserves, 37 MMBbl were NGL reserves and 455 Bcf, or 76 MMBoe, were natural gas reserves. As of December 31, 2025, we held approximately 2 million net mineral acres. Our operated asset base spans 68 distinct fields with approximately 22,000 net operated wells. We had average net production of approximately 138 MBoe/d (79% oil) for the year ended December 31, 2025.

Our carbon management segment, which we refer to as Carbon TerraVault, is focused on building, installing, operating and maintaining CO₂ capture equipment, transportation assets and underground storage facilities. Our carbon management segment also owns an investment in the Carbon TerraVault JV. For more information on our segments, refer to *Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations, Segment Results of Oil and Natural Gas Operations and Results of our Carbon Management Segment, and Part II, Item 8 – Financial Statements and Supplementary Data, Note 16 Segment Information.*

Berry Merger

On September 14, 2025, we entered into an agreement to combine with Berry in an all-stock transaction. Berry was an independent energy company that owned oil-weighted, mostly conventional oil and natural gas fields in California and oil and natural gas fields in Utah that have the potential for unconventional development. The Berry fields in California are adjacent to or within the areas in which we operate. Through the Berry Merger, we added 56 MMBoe of proved developed reserves as well as C&J Well Services, one of the largest upstream well servicing and abandonment services businesses in California.

The Berry Merger closed on December 18, 2025 and we issued 5,572,115 shares of our common stock, which represented 0.0718 shares of our common stock for each outstanding share of Berry stock as of December 17, 2025. Immediately following the closing of the Berry Merger, the former Berry stockholders owned approximately 6% of CRC. In connection with the closing, Berry’s outstanding debt was repaid and the underlying credit agreements were terminated. We repaid a significant portion of this indebtedness with proceeds from the issuance of our 2034 Senior Notes, which closed in October 2025. For more information on the Berry Merger, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations.*

Except when the context otherwise requires or where otherwise indicated, all references to “CRC,” the “Company,” “we,” “us” and “our” refer to California Resources Corporation and its consolidated subsidiaries as of the date presented.

Business Strategy

- **Focus on integrating merger assets to capture synergies and continue reducing costs across our combined business.** We are focused on reducing costs and improving operating efficiencies as a result of the Berry Merger. We are targeting annual run-rate synergies in the range of \$80 million to \$90 million within twelve months of the closing of the Berry Merger. We expect these synergies will come primarily from lower operating costs, general and administrative expenses and financing costs for the combined companies. In addition, we are pursuing other cost reduction efforts as part of our normal business processes.
- **Maintain high standards of operational performance that create sustainable cash flows.** We seek to maintain the highest standards of safety and operational integrity in the management of our assets, with the objective of sustaining long-term value and reliable cash flow generation. We believe that the strength and quality of our underlying assets, together with disciplined operational practices, position us to deliver durable financial results. For the year ended December 31, 2025, we generated \$363 million of net income and \$865 million of net cash provided by operating activities. We intend to continue prioritizing operational improvements in a safe, compliant, and environmentally responsible manner, recognizing that consistent execution is fundamental to financial performance.
- **Focus on core E&P assets and pursue new opportunities.** We are the largest operator in California and currently operate all of our core oil and gas fields. We intend to leverage this position and prioritize our strongest assets to simplify our operational structure and lower costs. We may have the opportunity to acquire additional producing assets at attractive valuations and could pursue other acquisitions that meet our financial, operational and regulatory criteria. In addition, we expect that the resumption of new well permitting in early 2026 will enhance our ability to develop our core assets in Kern County, which we believe will further strengthen our cash flows and position as the largest operator in California. Finally, we will continue to review non-core assets for potential divestment or alternative development opportunities where such actions are consistent with our strategic and capital allocation objectives.
- **Maintain a disciplined and flexible capital program.** We intend to maintain a disciplined and flexible capital program, allocating capital amongst our assets to maximize value in light of evolving regulatory and market conditions. Following the resumption of permitting for new wells in January of this year, we expanded our drilling program to include new well development in Kern County. We plan to pursue the development of new wells with attractive return profiles and payback periods of approximately three years across our portfolio. We expect to fund our capital program primarily from operating cash flows and maintain a flexible approach to adapt to fluctuations in commodity prices, permitting activity and broader regulatory developments.
- **Preserve balance sheet strength and increase shareholder returns over time.** We maintain a strong balance sheet and low leverage and continue to prioritize balance sheet protection. As of December 31, 2025, we had \$1,401 million of liquidity, consisting of \$1,284 million available for borrowing under the Revolving Credit Facility (after taking into account \$176 million of outstanding letters of credit) and \$117 million in available cash on hand. We had \$1,300 million of long-term indebtedness as of the same date. By maintaining low leverage and ample liquidity, we believe we will be able to ensure a strong financial foundation that we expect will allow us to grow shareholder returns over time.
- **Advance our carbon management solutions to lead the energy transition in California.** We are focused on maximizing the value of our land, mineral and technical resources for decarbonization by developing CCS and other emissions reducing projects. In early 2026, we expect to capture emissions at our cryogenic gas plant at Elk Hills field for permanent sequestration. We are well positioned to provide industrial scale projects to help California meet its decarbonization goals and leverage our Carbon TerraVault JV with Brookfield to reduce our capital investments to develop these projects.

- **Maintain our commitment to safety and environmental stewardship.** Our commitment to health, safety and the environment (HSE) defines how we operate our business. We prepare our workforce to work safely through comprehensive training, safe work practices, technology and rigorous maintenance and asset integrity programs. In addition, we intend to continue efforts to reduce CO₂ and methane emissions in our operations, proactively manage our idle wells and reduce our consumption of freshwater in our operations. We previously received MiQ's certification of methane emissions for certain fields and expect to continue to seek third party certifications of our results and disclosure practices. Our commitment to these efforts is reflected in our management compensation metrics that include safety and environmental targets.
- **Proactively engage with our legislators, regulators and the communities in which we operate.** We seek to communicate effectively with legislators, regulators and state and local government and community leaders to ensure they understand the potential impacts of new legislation and regulations on our business and the state's energy affordability, reliability and transition objectives. We strive to produce energy in a safe and responsible manner to help support and enhance the quality of life in the communities in which we operate.

Oil and Natural Gas Segment

The following table highlights key information about our oil and natural gas segment as of and for the year ended December 31, 2025:

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Uinta Basin	Other Basins	Total Operations
Mineral Acreage						
Net mineral acreage (thousands)	1,304	36	418	98	130	1,986
Average net mineral acreage held in fee (%)	88 %	58 %	47%	— %	89%	75 %
Number of producing fields we operate						
	38	4	20	4	2	68
Average drilling rigs						
	2	—	—	—	—	2
Net wells drilled and completed						
	43.0	—	—	—	—	43.0
Proved reserves						
Oil (MMBbl)	426	64	—	26	25	541
NGLs (MMBbl)	35	—	—	1	1	37
Natural gas (Bcf)	407	4	8	30	6	455
Total (MMBoe)	<u>529</u>	<u>65</u>	<u>1</u>	<u>32</u>	<u>27</u>	<u>654</u>
Oil percentage of proved reserves	81 %	98%	— %	81 %	93 %	83 %
Production^(a)						
Total net production (MMBoe)	40	6	1	—	3	50
Average daily net production (MBoe/d)	110	17	2	—	9	138

(a) Our production includes oil, natural gas and NGL sales from fields added in the Berry Merger, which closed on December 18, 2025.

For a discussion of the regulatory issues affecting the development of our oil and natural gas properties, see *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Basins in Which We Operate

San Joaquin Basin

Commercial petroleum development in the San Joaquin basin began in the 1800s. This resource rich basin in California contains multiple stacked formations throughout its areal extent, and we believe that this basin provides appealing opportunities for re-development of existing wells, as well as new discoveries and unconventional play potential. The geology of the San Joaquin basin continues to yield stratigraphic and structural trap discoveries.

The California oil fields added through the Berry Merger are located in the San Joaquin basin, including extensions of our existing Midway-Sunset, South Belridge and McKittrick fields, as well as additions adjacent to existing operations in Poso Creek and Round Mountain. Our largest fields in the San Joaquin basin include the Belridge and Elk Hills fields.

Belridge field: We operate and hold substantially all of the working, surface and mineral interests in the Belridge field, which consists of the North Belridge and South Belridge fields. The Belridge field consists of waterflood and steamflood operations. For the steamflood operations, we utilize natural gas that is both purchased from third parties and produced from our other fields. Our operations at Belridge include a central control facility with remote automation control on over 95% of the producing wells.

Elk Hills field: We operate and hold substantially all the working, surface and mineral interests in the Elk Hills field. Infrastructure includes efficient natural gas processing facilities, including a cryogenic gas plant, with a combined gas processing capacity of 330 MMcf/d, and a 550 MW cogeneration power plant that generates electricity to power our oil and gas operations at Elk Hills and other nearby producing fields. Our operations at Elk Hills also include a central control facility and remote automation control on over 95% of the producing wells.

Midway-Sunset field: We are a major operator and hold a significant portion of the working, surface and mineral interests in the Midway-Sunset field. The Midway-Sunset field consists of steamflood operations, in which we utilize natural gas that is both purchased from third parties and produced from our other fields.

We believe our extensive 3D seismic library, which covers over 900,000 acres in the San Joaquin basin, or over 60% of our gross mineral acreage in this basin, gives us a competitive advantage in field development.

Los Angeles Basin

This basin is a northwest-trending plain about 50 miles long and 20 miles wide located in California. Most of the significant discoveries in the Los Angeles basin date back to the 1920s. The Los Angeles basin has one of the highest concentrations per acre of crude oil in the world. We have significant operations in the Wilmington field, which is a large active oil field in this basin.

Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover certain capital and operating costs that we incur, (ii) for our share of contractually defined base production where applicable, and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming

comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented 3% of our total production for the year ended December 31, 2025.

Sacramento Basin

California's Sacramento basin is a deep, thick sequence of sedimentary deposits of natural gas within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918.

Uinta Basin

The Uinta basin consists mostly of mature light oil and natural gas fields covering more than 15,000 square miles with significant undeveloped resources. Exploration efforts immediately after the Second World War led to the first commercial oil discoveries in the Uinta basin. The application of improved hydraulic stimulation techniques in the mid-2000s greatly increased production from the Uinta basin.

We obtained approximately 100,000 net mineral acres in the Uinta basin in connection with the Berry Merger. We have an average working interest greater than 95% in these assets, and operations in the Brundage Canyon, Ashley Forest, Lake Canyon and Antelope Creek areas. A majority of our Utah acreage is on tribal lands and substantially all of it is held by production. The Uinta basin assets include both conventional and unconventional reserves. In addition to vertical well development, Berry completed four horizontal wells in 2025 and we are considering additional unconventional development.

We also have extensive gas infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. We have natural gas gathering systems consisting of approximately 500 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. We also own a natural gas processing plant in the Brundage Canyon area located in Duchesne County, Utah with processing capacity of approximately 25 mmcf/d.

Other Basins

We have oil and natural gas operations in other basins in California, including the Ventura and Salinas basins. We also have mineral interests in undeveloped acreage throughout California, including the Santa Maria basin which is located in San Luis Obispo County and Santa Barbara County.

Mineral Acreage

The following table summarizes our gross and net developed and undeveloped mineral acreage as of December 31, 2025.

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Uinta Basin	Other Basins	Total
	(in thousands)					
Developed ^(a)						
Gross ^(b)	544	21	241	47	14	867
Net ^(c)	498	16	230	45	13	802
Undeveloped ^(d)						
Gross ^(b)	938	22	222	62	143	1,387
Net ^(c)	806	20	188	53	117	1,184
Total						
Gross ^(b)	1,482	43	463	109	157	2,254
Net ^(c)	1,304	36	418	98	130	1,986

(a) Mineral acres spaced or assigned to productive wells.

- (b) Total number of mineral acres in which interests are owned.
- (c) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under our PSCs.
- (d) Mineral acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the mineral acreage contains proved reserves.

At December 31, 2025, 75% of our total net mineral interest position was held in fee and the remainder was leased. Of our leased acreage, approximately 77% is held by production and the remainder is subject to lease expiration if initial wells are not drilled within a specified period of time. The primary terms of our leases range from one to twenty years. The terms of these leases are typically extended upon achieving commercial production for so long as such production is maintained. Work programs are designed to ensure that the economic potential of any leased property is evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for retaining the lease. In cases where we determine we want to take the additional time required to fully evaluate undeveloped acreage, we have generally been successful in obtaining extensions.

If we are not able to establish production or otherwise extend lease terms, approximately 6,000 net mineral acres will expire in 2026, 7,000 net mineral acres will expire in 2027 and 11,000 net mineral acres will expire in 2028. These leases represent 2% of our total net undeveloped acreage and 1% of our total net acreage as of December 31, 2025 and these expirations, should they occur, would not have a material adverse effect on us. Historically, we have not dedicated any significant portion of our capital program to prevent lease expirations and do not expect to do so in the future.

Title to Properties

As is customary in the oil and natural gas industry for acquired properties, we initially conduct a high-level review of the title to our properties at the time of acquisition. Individual properties may be subject to ordinary course burdens that we believe do not materially interfere with the use or affect the value of such properties. Burdens on properties may include customary royalty or net profits interests, liens incident to operating agreements and tax obligations or duties under applicable laws, or development and abandonment obligations, among other items. Prior to the commencement of drilling operations on those properties, we typically conduct a more thorough title examination and may perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. For additional information on properties that secure our debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt*.

Production, Price and Cost History

The following table sets forth information regarding our production volumes, average realized and benchmark prices and operating costs per Boe (presented before and after hedges) for the periods presented. See *Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations* for more information on our production and commodity prices. The Berry Merger and Aera Merger affect comparability of our production results between periods. For more information on the Berry Merger and the Aera Merger, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations*.

	Year Ended December 31,		
	2025	2024	2023
Average daily net production			
Oil (MBbl/d)	109	80	52
NGLs (MBbl/d)	10	10	11
Natural gas (MMcf/d)	114	117	135
Total daily net production (MBoe/d)	138	110	86
Total production (MMBoe)	50	40	31
Average realized prices			
Oil with derivative settlements (\$/Bbl) \$	67.51	\$ 75.66	\$ 65.97
Oil without derivative settlements (\$/Bbl) \$	66.52	\$ 76.92	\$ 80.41
NGLs (\$/Bbl) \$	45.30	\$ 48.93	\$ 48.94
Natural gas (\$/Mcf) \$	3.57	\$ 2.99	\$ 8.59
Average benchmark prices			
Brent oil (\$/Bbl) \$	68.22	\$ 79.84	\$ 82.22
WTI oil (\$/Bbl) \$	64.81	\$ 75.72	\$ 77.62
NYMEX gas (\$/MMBtu) \$	3.43	\$ 2.27	\$ 2.74
Operating costs per Boe			
Operating costs \$	25.42	\$ 24.51	\$ 26.24
Operating costs, after hedges on purchased natural gas \$	25.94	\$ 25.31	\$ 26.24

Oil, natural gas and NGL production for our two largest fields for the years ended December 31, 2025 and 2024 are presented in the table below:

	Belridge		Elk Hills	
	2025	2024	2025	2024
Average daily net production				
Oil (MBbl/d)	32	34	14	14
NGLs (MBbl/d)	—	—	7	7
Natural gas (MMcf/d)	—	—	56	59
Total daily net production (MBoe/d)	32	34	30	31

Oil, natural gas and NGL production for our two largest fields for the year ended December 31, 2023 is presented in the table below:

	<u>Elk Hills</u>	<u>Wilmington</u>
	<u>2023</u>	<u>2023</u>
Average daily net production		
Oil (MBbl/d)	16	16
NGLs (MBbl/d)	8	—
Natural gas (MMcf/d)	68	—
Total daily net production (MBoe/d)	<u>35</u>	<u>16</u>

Our operating costs include (1) variable costs that fluctuate with production levels and (2) fixed costs that typically do not vary with changes in production levels or well counts, especially in the short term. The substantial majority of our near-term fixed costs become variable over the longer term because we manage them based on the field's stage of life and operating characteristics. For example, portions of labor and material costs, energy, workovers and maintenance expenditures correlate to well count, production and activity levels. Portions of these same costs can be relatively fixed over the near term; however, they are managed down as fields mature in a manner that correlates to production and commodity price levels. A certain amount of costs for facilities, surface support, surveillance and related maintenance can be regarded as fixed in the early phases of a program. However, as the production from a certain area matures, well count increases and daily per well production drops, such support costs can be reduced and consolidated over a larger number of wells, reducing costs per operating well. Further, many of our other costs, such as property taxes and oilfield services, are variable and will respond to activity levels and tend to correlate with commodity prices. We can quickly scale our operating costs in response to prevailing market conditions. We believe that a significant portion of our operating costs is variable over the lifecycle of our fields.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in operating costs on our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

The following table presents our operating costs after adjustment for excess costs attributable to PSCs for the periods presented:

	<u>Year ended December 31,</u>					
	<u>2025</u>		<u>2024</u>		<u>2023</u>	
	(in millions)	(\$ per Boe)	(in millions)	(\$ per Boe)	(in millions)	(\$ per Boe)
Operating costs	\$ 1,280	\$ 25.42	\$ 983	\$ 24.51	\$ 822	\$ 26.24
Excess costs attributable to PSCs	\$ (47)	(0.92)	(67)	(1.67)	(71)	\$ (2.25)
Operating costs, excluding effects of PSCs ^(a)	<u>\$ 1,233</u>	<u>\$ 24.50</u>	<u>\$ 916</u>	<u>\$ 22.84</u>	<u>\$ 751</u>	<u>\$ 23.99</u>

(a) Operating costs, excluding effects of PSCs is a non-GAAP measure. As described above, the reporting of our PSCs creates a difference between reported operating costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel operating costs. These amounts represent our operating costs after adjusting for this difference.

Estimated Proved Reserves and Future Net Cash Flows

The following tables summarize our estimated proved oil (including condensate), NGLs and natural gas reserves and PV-10 as of December 31, 2025. Our estimated volumes and cash flows were calculated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Prices), unless prices were defined by contractual arrangements. For oil volumes, the average Brent spot price of \$69.38 per barrel and WTI price of \$65.34 per barrel were adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of \$3.39 per MMBtu was adjusted for energy content, transportation fees and market differentials. All prices are held constant throughout the lives of the properties. The average realized prices for estimating our proved reserves as of December 31, 2025 were \$67.21 per barrel for oil, \$45.81 per barrel for NGLs and \$3.44 per Mcf for natural gas.

Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. Refer to *Part II, Item 8 – Financial Statements, Supplemental Oil and Gas Information* for additional information on our proved reserves.

	As of December 31, 2025					
	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Uinta Basin	Other Basins	Total
Proved developed reserves						
Oil (MMBbl)	363	63	—	5	21	452
NGLs (MMBbl)	29	—	—	—	1	30
Natural Gas (Bcf)	324	4	8	9	6	351
Total (MMBoe) ^(a)	446	64	1	7	23	541
Proved undeveloped reserves						
Oil (MMBbl)	63	1	—	21	4	89
NGLs (MMBbl)	6	—	—	1	—	7
Natural Gas (Bcf)	83	—	—	21	—	104
Total (MMBoe)	83	1	—	25	4	113
Total proved reserves						
Oil (MMBbl)	426	64	—	26	25	541
NGLs (MMBbl)	35	—	—	1	1	37
Natural Gas (Bcf)	407	4	8	30	6	455
Total (MMBoe)	529	65	1	32	27	654

(a) As of December 31, 2025, approximately 10% of proved developed oil reserves, 6% of proved developed NGLs reserves, 7% of proved developed natural gas reserves and, overall, 10% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

Changes to Proved Reserves

We added 93 MMBoe of proved reserves through the Berry Merger in 2025, including locations in the San Joaquin and Uinta basins. The components of the changes to our proved reserves during the year ended December 31, 2025 were as follows:

	San Joaquin Basin	Los Angeles Basin ^(a)	Sacramento Basin	Uinta Basin	Other Basins	Total
			(MMBoe)			
Balance at December 31, 2024 . . .	441	78	3	—	23	545
Revisions related to price	(11)	(13)	(2)	—	1	(25)
Revisions related to performance	49	6	1	—	5	61
Extensions and discoveries	3	—	—	—	—	3
Improved recovery	26	—	—	—	1	27
Acquisitions and divestitures	61	—	—	32	—	93
Production	(40)	(6)	(1)	—	(3)	(50)
Balance at December 31, 2025 . . .	<u>529</u>	<u>65</u>	<u>1</u>	<u>32</u>	<u>27</u>	<u>654</u>

(a) Includes proved reserves related to PSCs of 51 MMBoe and 62 MMBoe at December 31, 2025 and 2024, respectively.

Revisions related to price – We had net negative price-related revisions of 25 MMBoe. Included in these revisions are negative price-related revisions of 37 MMBoe, which were partially offset by 23 MMBoe of positive revisions. These negative revisions are primarily a result of lower average realized SEC Prices in 2025 as compared to 2024, including lower natural gas realizations in certain areas. These negative revisions were partially offset by positive revisions primarily from lower operating costs related to steamflood management.

Also included in the net negative price-related revisions are negative revisions of 12 MMBoe offset by 1 MMBoe of positive revisions, which were due the extension of the cap-and-invest program. The majority of these revisions were located in the San Joaquin basin. See *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Revisions related to performance – We had 61 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 80 MMBoe and negative performance-related revisions of 19 MMBoe. Our positive performance-related revisions primarily related to additional drilling activity in the San Joaquin basin, maintaining higher than forecasted base production, and extension of field life through steam management. Our negative performance-related revisions primarily were due to lower overall expected recovery from certain projects in the San Joaquin basin.

Extensions and discoveries – We added 3 MMBoe related to drilling in the San Joaquin basin.

Improved recovery – We added 27 MMBoe related to increased drilling activity associated with steamfloods in the San Joaquin basin.

Acquisitions and divestitures – We added 93 MMBoe related to the Berry Merger in the San Joaquin and Uinta basins.

Changes to Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2025 were as follows:

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Uinta Basin	Other Basins	Total
	(MMBoe)					
Balance at December 31,						
2024	38	—	—	—	1	39
Revisions related to price	(1)	—	—	—	—	(1)
Revisions related to performance	13	1	—	—	2	16
Improved recovery	26	—	—	—	1	27
Acquisition	12	—	—	25	—	37
Transfers to proved developed reserves	(5)	—	—	—	—	(5)
Balance at December 31,						
2025	83	1	—	25	4	113

Revisions related to price – We had 1 MMBoe of net negative price-related revisions primarily resulting from lower average realized SEC Prices in 2025 as compared to 2024, including lower natural gas realizations in certain areas. Our negative price revisions of 2 MMBoe were partially offset by 1 MMBoe of positive revisions from lower operating costs.

Revisions related to performance – We had 16 MMBoe of net positive performance-related revisions primarily in the San Joaquin basin. Positive performance-revisions of 26 MMBoe were partially offset by 10 MMBoe negative revisions related to well performance and proved undeveloped reserves which were removed from our five year development plan in 2025.

Improved recovery – We added 27 MMBoe related to new projects associated with steamfloods in the San Joaquin basin.

Acquisition – We added 37 MMBoe in connection with the Berry Merger in the San Joaquin and Uinta basins.

Transfers to proved developed reserves – We converted 5 MMBoe of proved undeveloped reserves to proved developed reserves in the San Joaquin basin. This resulted in a conversion rate of 13% of our beginning-of-year proved undeveloped reserves, with an investment of \$45 million in drilling and completion capital.

PV-10 and Standardized Measure

PV-10 of cash flows is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC Prices. Calculation of PV-10 does not give effect to derivative transactions. Our PV-10 is computed on the same basis as our standardized measure of future net cash flows, the most comparable measure under GAAP, but does not include the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

As of December 31, 2025

	(in millions)	
Standardized measure of discounted future net cash flows	\$	6,666
Present value of future income taxes discounted at 10%		2,051
PV-10 of cash flows	\$	<u>8,717</u>

Reserves Evaluation and Review Process

Our estimates of proved reserves and related discounted future net cash flows as of December 31, 2025 were made by our technical personnel, comprised of reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management’s funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Operating and capital costs are forecast using the current cost environment applied to expectations of future operating and development activities related to the proved reserves. See *Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Estimates* for further discussion of uncertainties inherent in the reserve estimates.

Proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods, for which the incremental cost of any additional required investment is relatively minor. Proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Our Director of Reserves is the technical person who is primarily responsible for overseeing the preparation of our reserves estimates in compliance with the SEC rules and regulations. He has over 16 years of experience in the upstream oil and gas industry, with projects ranging from appraisal of primary production reservoirs to enhanced oil recovery methods. He holds a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, to review and approve our oil and natural gas reserves for 2025. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Netherland, Sewell & Associates, Inc. (NSAI) was engaged to provide an independent audit of our reserves estimates for our fields located in California. For the year ended December 31, 2025, NSAI audited 81% of our total proved reserves.

DeGolyer and MacNaughton was engaged to provide an independent audit of our reserves estimates for the Uinta basin. For the year ended December 31, 2025, DeGolyer and MacNaughton audited 5% of our total proved reserves in the Uinta basin.

Our independent reserve engineers examined the assumptions underlying our reserves estimates, adequacy and quality of our work product and estimates of future production rates. They also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, they developed their own independent estimates of reserves for those fields that they audited. When compared on a field-by-field basis, some of our estimates were greater and some were

less than the estimates of our independent reserve engineers. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our estimates and those of our independent reserve engineers are to be expected. The aggregate difference between our estimates and those of the independent reserve engineers was less than 10%, which was within the Society of Petroleum Engineers (SPE) acceptable tolerance.

In the conduct of the reserves audits, our independent reserve engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if anything came to the attention of our independent auditors that brought into question the validity or sufficiency of any such information or data, they would not rely on such information or data until they had resolved their questions relating thereto or had independently verified such information or data. Our independent reserve engineers determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC as well as the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. Our independent reserve engineers each issued an unqualified audit opinion on the applicable portions of our proved reserves as of December 31, 2025, which are attached as Exhibit 99.1 and Exhibit 99.2 to this Form 10-K and incorporated herein by reference.

NSAI qualifications – The primary technical engineer responsible for our audit is a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 6 years of prior industry experience. The primary geologist for our audit is a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 12 years of prior industry experience.

DeGolyer and MacNaughton – The primary technical engineer responsible for our audit is a Licensed Professional Engineer in the State of Texas, has Master of Science and Doctor of Philosophy degrees in Petroleum Engineering and has more than 10 years of experience in oil and gas reservoir studies and reserves evaluation.

Drilling Statistics

The following table sets forth information on our net exploration and development wells drilled and completed during the periods indicated, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. We refer to gross wells as the total number of wells in which interests are owned, including outside operated wells. Net wells represent wells reduced to our fractional interest. For information on our 2026 capital program, see *Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations, Uses of Cash* and for information on the California regulatory environment and our ability to obtain permits, see *Regulation of the Industries in Which We Operate*.

	<u>San Joaquin Basin</u>	<u>Los Angeles Basin</u>	<u>Sacramento Basin</u>	<u>Uinta Basin</u>	<u>Other Basins</u>	<u>Total Net Wells</u>
2025						
Productive						
Exploratory	—	—	—	—	—	—
Development	43.0	—	—	—	—	43.0
Dry						
Exploratory	—	—	—	—	—	—
Development	—	—	—	—	—	—
2024						
Productive						
Exploratory	—	—	—	—	—	—
Development	8.0	—	—	—	—	8.0
Dry						
Exploratory	—	—	—	—	—	—
Development	—	—	—	—	—	—
2023						
Productive						
Exploratory	—	—	—	—	—	—
Development	4.0	26.5	—	—	—	30.5
Dry						
Exploratory	—	—	—	—	—	—
Development	—	—	—	—	—	—

The following table sets forth information on our exploratory and development wells where drilling was either in progress or pending completion as of December 31, 2025.

	<u>San Joaquin Basin</u>	<u>Los Angeles Basin</u>	<u>Sacramento Basin</u>	<u>Uinta Basin</u>	<u>Other Basins</u>	<u>Total Net Wells</u>
Gross	9.0	—	—	—	—	9.0
Net	9.0	—	—	—	—	9.0

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce at a reasonable rate of return. Our average working interest in our producing wells was 98% as of December 31, 2025. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and mechanically capable of production) as of December 31, 2025, excluding wells that have been idle for more than five years:

	As of December 31, 2025			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross^(a)	Net^(b)	Gross^(a)	Net^(b)
San Joaquin Basin	18,455	18,077	81	81
Los Angeles Basin	1,689	1,598	—	—
Sacramento Basin	6	1	672	623
Uinta Basin	1,200	1,170	168	168
Other Basins	687	687	4	4
Total	22,037	21,533	925	876
Multiple completion wells included in the total above	326	324	20	17

(a) The total number of wells in which interests are owned.
(b) Net wells include wells reduced to our fractional interest.

Exploration Inventory

We maintain a portfolio of exploration prospects in the San Joaquin basin, supported by an extensive library of 3D and 2D seismic data used to identify, evaluate and refine exploration opportunities. From time to time, we select exploration projects for investment when our business outlook and the prospect's potential to advance our strategic objectives justify the associated risks.

Marketing Arrangements

Sales of our oil, natural gas and NGLs we produce are shown in the table below for the years ended December 31, 2025, 2024 and 2023. For more information on our revenues, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Revenue*.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Oil	\$2,647	\$2,255	\$1,534
NGLs	164	186	198
Natural gas	99	96	423
Oil, natural gas and NGL sales	\$2,910	\$2,537	\$2,155

Oil

We sell nearly all of our crude oil produced in California to local California refiners. A majority of our crude oil production is connected to third-party pipelines and California refining markets via our gathering systems. The majority of our production from our Uinta assets is sold to the Salt Lake City market, with some sold to the Gulf Coast market. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements.

In 2025, the marketing arrangements for the majority of our production no longer rely on local postings but are instead based directly on Brent prices subject to applicable adjustments. International waterborne-based Brent prices are relevant because there is limited crude pipeline infrastructure available to transport crude overland from other parts of the United States into California. We believe

that these limitations will continue to contribute to higher realizations in California than most other U.S. oil markets for comparable grades. The prices received for our Utah production have typically been based on local postings that are tied to WTI prices.

We have entered into derivative contracts to provide price protection for sales of produced oil. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our Brent-based derivative contracts.

Natural Gas

We sell all of our natural gas not used in our operations into the California and Utah markets. A majority of these sales are made at index-based prices tied to SoCal Border pricing which can differ from NYMEX pricing. SoCal Border pricing reflects local market fundamentals, such as storage capacity and the availability of transportation capacity between the market and producing areas. Transportation capacity availability, transportation pricing, and gas processing prices in other areas may influence California prices because California imports nearly 95% of its natural gas from other states and Canada. We deliver our natural gas to customers using firm capacity contracts that have variable pricing on actual volumes shipped. Currently, we have sufficient capacity to ship our production volumes and we believe that we have the ability to enter into additional capacity agreements as needed.

In addition to selling natural gas, we also use natural gas in steam generation for our steamfloods and for power generation. We have entered into derivative contracts to provide price protection for the purchase of natural gas used in our steamflood operations. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our natural gas derivative contracts.

NGLs

NGL prices vary by liquid type and realizations are closely correlated to the different commodity prices to which they relate. Prices can also fluctuate due to the demand for certain chemical products (for which NGLs are used as feedstock) and due to infrastructure constraints and seasonality. Finally, our results are also affected by the performance of our natural gas-processing plants. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the remaining products as NGLs. The efficiency with which we extract liquids from the wet gas stream affects our production volumes and operating results. Our natural gas-processing plants also facilitate access to third-party delivery points near the Elk Hills field.

We currently have a pipeline transportation contract to ship approximately 6,000 barrels per day of NGLs through March 2026. Our contract to transport NGLs requires us to cash settle any shortfall between the contractual throughput minimums and volumes actually shipped. We expect to continue to meet all our throughput minimums under this contract.

Delivery Commitments

We have commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2025, we had delivery commitments as shown in the table below.

	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>
Oil (MMBbl)	38	21	3	—	—
NGL (MMBbl)	1	—	—	—	—
Natural gas (Bcf)	12	—	—	—	—

We expect to fulfill our delivery commitments predominantly from producing our proved developed reserves and to a lesser extent from third party volumes acquired in connection with our marketing activities. We typically enter into index-based contracts with prices set at the time of delivery.

Our Principal Customers

We primarily sell crude oil, natural gas and NGLs to California refineries, marketers and other purchasers that have access to transportation and storage facilities.

In October 2025, Phillips 66 closed its Wilmington refinery in Los Angeles, California. In April 2025, Valero notified the California Energy Commission of its intent to idle, restructure, or cease refining operations at its Benicia refinery in the San Francisco Bay Area by the end of April 2026. In January 2026, Valero confirmed its plans to cease refining operations at Benicia and presently does not expect any changes to the previously announced timeline. We have historically sold a portion of our crude oil to these refineries.

Following the closure of the Phillips 66 refinery, and assuming Valero's Benicia refinery ceases operations, six major petroleum refineries will remain in California, each with a refining capacity exceeding 75,000 barrels per day. Five of these refineries currently purchase California crude oil. If Valero's Benicia refinery ceases operations, California would have approximately 1.1 million barrels per day of refining capacity available to process California crude oil, which is approximately four times the volume of crude oil produced in the state. However, the ability of producers to access the entirety of this refining capacity would be limited by available pipeline transportation and in-take constraints at individual refineries. Based on currently available refining capacity and our flexibility in marketing our crude oil production, we do not expect that a cessation of operations at these refineries, including the Valero Benicia refinery, would have a material adverse effect on our ability to market our crude oil.

In December 2025, crude oil shipments on the San Pablo Bay Pipeline – the primary inland pipeline carrying crude from California fields to Bay Area refiners – were effectively suspended after refinery demand declined and producers ceased nominations, reducing volumes to zero. The closure of this pipeline effectively eliminated our access to Bay Area refineries and we modified our marketing, transportation and shipping arrangements to reach alternative markets in Southern California. As a result, we expect to experience higher transportation costs as well as greater reliance on southbound transportation capacity. These effects are likely to continue for as long as the suspension of pipeline flow persists, and could persist should the pipeline be permanently idled. In addition, any significant increase in in-state crude oil production, including from offshore platforms, could further stress available transportation capacity and negatively impact price realizations. At this time, we cannot predict whether or when crude shipments on the San Pablo Bay Pipeline will resume.

The loss of refineries in the Bay Area and related pipeline transportation capacity and any additional closures in the future could increase our transportation costs and negatively impact realizations and materially adversely affect our business, financial condition, results of operations or cash flow.

Our ability to sell our products can be affected by a variety of factors that are beyond our control. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of our Business, Summary of Significant Accounting Policies and Other* for more information on our customers.

Competition

Our competitors are primarily other exploration and production companies that produce oil, natural gas and NGLs. We compete locally against independent producers and a major international oil company which operate in California. We also compete with foreign oil and gas companies since

California imports over 75% of the oil it consumes and nearly 95% of its natural gas needs. We believe that our proximity to the California refineries gives us a competitive advantage over importers due to lower transportation costs. Further, California refineries are generally designed to process crude with characteristics similar to those of our production. However, efforts to construct new interstate pipelines to transport refined products or to increase waterborne imports of refined products, if successful, could alter local supply dynamics and affect competitive conditions in our market. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines.

In Utah, we compete locally against independent producers that operate in the area. Additionally, we compete to transport our oil to refineries within Utah. Competition for pipeline and transportation capacity, including access to interstate pipelines and rail facilities, may affect realized pricing and basis differentials.

We compete for third-party services in California and Utah to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. The regulatory environment in California could negatively impact the number of oil field service providers, drilling and workover rigs, pipe and other oil field equipment in the state. We have not experienced shortages or delays in the delivery of materials or services from our vendors in either California or Utah.

Carbon Management Segment

Our carbon management segment, which we refer to as Carbon TerraVault, pursues the development of carbon capture and sequestration projects. We expect that our Carbon TerraVault CCS projects will inject CO₂ captured from industrial, power, agriculture and other emissions sources into subsurface reservoirs and permanently store CO₂ deep underground. We also expect to invest in projects that rely on CCS technology in connection with reducing our own emissions, including a project at our cryogenic gas processing plant discussed below. In addition, we may participate in the development of projects that are the source of these CO₂ emissions.

CCS Permitting

In December 2024, the EPA issued Class VI permits, the first permits issued in California, for underground injection and storage of CO₂ into the 26R reservoir which is located at our Elk Hills field. The permits became effective on February 6, 2025. The 26R reservoir is part of our Carbon TerraVault JV as discussed further below.

We have submitted permit applications with the EPA for another permanent sequestration project at our Elk Hills field, four permanent sequestration projects in the Sacramento basin and two permanent sequestration projects in Central California that are under review by the EPA. We acquired one permit application with the EPA for sequestration projects in the Belridge field as part of the Aera Merger.

The timing, review and approval of our permit applications by the EPA are uncertain and we can give no assurances that these permit applications will be reviewed and approved in a timely manner or at all.

CCS Projects

We recently completed construction of carbon capture equipment at our cryogenic gas processing facility at the Elk Hills field and are currently commissioning the facility. This project which will remove CO₂ from inlet gas for injection into the nearby 26R storage reservoir (owned by the Carbon TerraVault JV) in spring 2026, subject to EPA approval. We expect this project will increase operational efficiency of the cryogenic gas processing plant, improve propane recovery from inlet gas, and reduce the carbon intensity of the electricity generated at our Elk Hills power plant.

We expect that the size and scope of projects providing for the capture of emissions will continue to grow as we develop our carbon management segment. We expect to minimize the amount of capital we spend on these projects through partnerships and joint ventures, including the Carbon TerraVault JV. For more information about the risks involved in our carbon management segment, see *Part I, Item 1A – Risk Factors*.

Carbon TerraVault JV

In August 2022, we entered into a joint venture with Brookfield. We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Our initial contribution included rights to inject CO₂ into the 26R reservoir in our Elk Hills field for permanent CO₂ storage. Brookfield has contributed \$92 million to date. The remaining amount of Brookfield's initial investment is based on the permitted storage capacity, subject to certain contractual adjustments. This remaining amount will be contributed to the joint venture upon entering into contracts for the injection of specified volumes with respect to the 26R reservoir. The parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met.

Both Brookfield and CRC have granted the other party a right to participate in projects that involve the capture, transportation and storage of CO₂ in California. These projects may be developed throughout the Carbon TerraVault JV or other joint ventures. This right expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the investment committee of the Carbon TerraVault JV for storage projects representing in excess of 5 million metric tons per annum (MMTPA) in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of \$500 million (unless Brookfield elects to increase its commitment). The non-presenting party has the option to accept, decline or defer its decision to participate. If the decision is deferred, then the presenting party may continue to pursue development; however during this time and prior to a final investment decision, the non-presenting party may elect to participate provided they pay their share of the project development costs incurred up to that point. The joint venture does not have a definitive term and terminates upon either party holding all of the ownership interests in the joint venture.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our Carbon TerraVault JV.

Competition

We compete with other potential storage providers to acquire and develop storage reservoirs and enter into agreements with existing and future emission sources.

Responsible Net Zero Goal

In May 2025, our Board of Directors adopted the following net zero emissions goal (Responsible Net Zero):

Our goal is to achieve at least an 80% reduction of absolute Scope 1 and 2 greenhouse gas emissions and neutralize the remaining Scope 1 and 2 emissions to achieve Net Zero by 2045. Our near-term ambition is to achieve a 20% reduction in the average carbon intensity of all CRC oil and gas production by 2035, thereby reducing our customers' Scope 3 emissions. We are committed to responsibly producing energy in a manner consistent with the UN's Sustainable Development Goals.

Our Responsible Net Zero goal is based on the following considerations:

- We use 2020 total Scope 1 and 2 GHG emissions (including those of Aera) as our baseline to measure progress towards our Responsible Net Zero goal. Our emissions are based on calculations reported to the California Air Resources Board (CARB).

- The term “neutralize” as it relates to Scope 1 GHG emissions refers to the 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-Trade Program). For Scope 2 GHG emissions, the term “neutralize” refers to the use of contractual instruments such as renewable energy certificates or carbon offsets.
- The term “carbon offsets” refers to greenhouse gas emission reductions arising from third-party certified projects that remove, reduce, or avoid GHG emissions from the atmosphere.
- References to UN Sustainable Development Goals (UN SDGs) refer primarily to goals regarding income inequality, biodiversity, corruption, Scope 1 and 2 GHG emissions carbon intensity, fair labor and gender treatment. Operating a business consistent with UN SDGs is inherently a subjective determination regarding which UN SDGs to prioritize, how to weigh such matters against commercial considerations and to what extent a business activity promotes or is consistent with a given UN SDG.
- Future acquisitions and divestitures, as well as changes to methodology in accounting for carbon emissions or adjustments to historical carbon calculations as well as the use of third-party data or validation processes, could cause us to change our Responsible Net Zero goal.
- Assumptions, estimates, goals and similar statements and concepts regarding our Responsible Net Zero goal contain or assume forward looking statements within the meaning of federal securities laws and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. For a discussion of these risks and uncertainties, please refer to the *Risk Factors* and *Forward-Looking Statements* described in our Annual Report on our most recent Form 10-K and any subsequently filed Quarterly Reports on Form 10-Q and Current Reports on Form 8-K filed with the United States Securities and Exchange Commission.

Our Responsible Net Zero goal replaces our previously adopted Full Scope Net Zero goal. This change was primarily driven by the impact of the Aera Merger, which nearly doubled the size of our asset base and impacted the overall carbon intensity of our operations. The continuing lack of regulatory clarity around the measurement of Scope 3 GHG emissions (including the impact of carbon capture and sequestration in such calculations) also contributed to this change.

Infrastructure

Our infrastructure includes the plants and facilities shown in the table below.

Description	Quantity	Unit	Capacity			
			San Joaquin Basin	Uinta Basins	Other Basins	Total
Gas Processing Plants	6	MMcf/d	335	25	10	370
Power Plants ^(a)	11	MW	855	—	—	855
Steam Generators/Plants	221	MBbl/d	681	—	—	681
Compressors	1,372	MHp	356	—	31	387
Water Management Systems		MBw/d	3,922	—	420	4,342
Water Softeners	137	MBw/d	400	—	—	400
Tank Storage		MBbls	3,202	660	163	4,025
Oil and NGL Storage		MBbls	799	4	46	849
Carbon capture equipment	1	KMTPA	100	—	—	100
Pipelines		Miles				>12,000

(a) Includes 120 MW attributable to our 50% interest in the Midway Sunset Power Plant. Does not include the Long Beach Unit Power Plant described below or microturbines that generate limited power.

Power Generation Assets

We own and/or operate power generation facilities with a combined 855 MW of capacity. A material portion of the electrical output of these facilities is used in our oil and natural gas operations at nearby fields. Generating capacity that is not used in our operations is offered into the California Independent System Operator (CAISO) wholesale power market. We enter into resource adequacy capacity contracts with load-serving entities which are tasked with ensuring there is sufficient available generating capacity to support their forecasted customer energy demand. Our contracts for resource adequacy are at market prices and generally for a term that does not exceed twelve months. The actual electrical output of our power generating facilities varies over time based on operating conditions, pricing and other conditions. Our significant power generating facilities are described below.

San Joaquin Basin

Elk Hills Power Plant – We own a 550 MW combined-cycle cogeneration power plant, located adjacent to the Elk Hills natural gas processing facility. The plant runs at varying levels based on power pricing and other market conditions.

The Elk Hills power plant supplies electricity to Elk Hills field and the power needs of the field remain relatively constant throughout the year. Because the output of the plant varies, we expect approximately 25% to 60% of the electricity generated in 2026 will be used in our oil and natural gas operations. The remaining facility capacity is available to the resource adequacy market and is offered to the CAISO wholesale market.

Midway Sunset Cogeneration Facilities

- We own a 50% interest in a 240 MW cogeneration power plant located in the Midway Sunset field in Kern County and the remaining 50% is held by San Joaquin Energy Company, a subsidiary of NRG Energy, Inc. Our investment in this joint venture is accounted for using the equity method of accounting as discussed in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions*. The electricity generated by this plant is sold to CAISO and the facility also participates in the resource adequacy capacity market.
- Following the Berry Merger, we own three natural gas burning cogeneration plants, each located in the Midway Sunset field in Kern County, that produce electricity and steam. These include a 36 MW facility, an 18 MW facility, and a 5 MW facility. We use a portion of the electricity generated by these cogeneration facilities to support our oil and natural gas operations in the area. Excess electricity is either sold to a California public utility under a power purchase agreement that expires in November 2026 or offered to the CAISO and the resource adequacy capacity market.

Belridge Power Plant – We own a 62 MW cogeneration power plant located in the Belridge field in Kern County, California. The electricity generated by this plant is used in our operations.

Los Angeles Basin

Long Beach Unit Power Plant – We operate a 48 MW power generating facility that is owned by the Long Beach Unit in the Wilmington field. The electricity generated by this plant is used in our operations.

In addition, we own and/or operate a number of smaller gas-fired power plants that are primarily used to generate power for our oil and natural gas operations.

Other Infrastructure Assets

Gas processing infrastructure used in our oil and gas segment includes the Elk Hills cryogenic gas plant with a capacity of 200 MMcf/d of inlet gas and one low temperature separation plant used as a backup facility. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to various North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our natural gas processing facilities for NGL sales to third parties. We own, control and operate water management and steam-generation infrastructure. We soften and self-supply water to generate steam, reducing our operating costs. This is integral to our oil and natural gas operations in the San Joaquin basin. Our tank storage capacity throughout California gives us flexibility for a period of time to store crude oil and NGLs, allowing us to continue production and avoid or delay any field shutdowns in the event of temporary power, pipeline or other shutdowns. Our pipelines are dedicated almost entirely to collecting our oil and natural gas production and are in close proximity to field-specific facilities such as tank farms or central processing sites. Our oil pipelines connect to multiple third-party transportation pipelines. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems.

We also own a natural gas processing plant in the Brundage Canyon area located in Duchesne County, Utah with capacity of approximately 25 MMcf/d. We have natural gas gathering systems consisting of approximately 500 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. We also have extensive gas infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. This facility takes delivery from gathering and compression facilities we operate.

Human Capital Management

We had approximately 2,500 employees as of December 31, 2025, as compared to approximately 1,550 as of December 31, 2024, all of whom were located in the United States. The significant growth in headcount of approximately 990 employees relates to the Berry Merger that closed in December 2025. Approximately 640 of these employees are employed by our subsidiary C&J Well Services. Approximately 250 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third-party contractors throughout our operations.

Development

We provide various employee development opportunities to enhance leadership growth and expand career opportunities. Our employees undergo mandatory annual training on our policies including health and safety, business ethics, harassment, IT security and others. In addition to training, our employees receive regular performance and career development discussions from their direct managers. We utilize an annual performance review process for all employees.

Culture and Engagement

Our goal is to foster an open and welcoming culture and we are committed to advancing a workplace culture that is hospitable to all backgrounds and perspectives. We believe this encourages workforce engagement and leads to more thoughtful and innovative business decisions.

Safety and Environmental Stewardship

Our unwavering commitment to health, safety and the environment defines how we operate our business. We prepare our workforce to work safely through comprehensive training, safe work practices, technology and rigorous maintenance and asset integrity programs. Each year, we set

thresholds for TRIR and gross barrels spilled as quantitative metrics that directly impact incentive compensation for all of our employees. We registered a workforce TRIR of 0.40 and recorded 1,124 gross barrels of production fluids spilled in 2025, excluding Berry operations. We have achieved exemplary safety performance over the last several years by promoting a culture of safety where all employees, contractors and vendors are empowered with Stop Work Authority to cease any activity – without repercussions – to prevent a safety or environmental accident.

Engagement and Retention

We survey our employees annually to ensure employee sentiment is collected and heard each year allowing us to assess engagement levels and drivers to determine areas of improvement to enhance engagement and retention. The results of the engagement surveys are reviewed by senior management and our Board of Directors. Senior leadership also hosts regular townhalls so employees can engage with them through question-and-answer sessions.

Reorganization

In February 2026, we undertook a reduction in force following the Berry Merger that resulted in a reduction of our headcount and we expect to recognize a charge of approximately \$22 million in other operating expenses, net on our condensed consolidated statement of operations for the three months ended March 31, 2026, which primarily includes severance.

Seasonality

Certain of our operating costs and the prices for our products fluctuate throughout the year. For example, prices for natural gas (that we both market to third parties and purchase for use in our operations) tend to be higher in the winter and summer months. However, seasonality overall does not have a material effect on our earnings during the year.

Our operations have been, and in the future could be, impacted by winter weather conditions, especially in Utah, and by electrical storms and high temperatures in the spring and summer, as well as by wildfires and rain.

Regulation of the Industries in Which We Operate

Our operations are subject to a wide range of federal, state and local laws and regulations. Those that specifically relate to oil and natural gas exploration and production and carbon sequestration, utilization and storage are described in this section. CalGEM is the primary regulator of the oil and natural gas production industry in California and the California State Lands Commission provides additional administration of the state's surface and mineral interests. With respect to our assets in Utah, we operate under leases regulated by federal agencies, including the Bureau of Land Management (BLM), as well as on lands regulated by the Utah Division of Oil, Gas and Mining.

Regulation of Exploration and Production Activities

Well Permitting

During 2025, we continued to experience delays from CalGEM in obtaining new well, sidetrack, deepening and workover permits. These delays resulted from a combination of more stringent environmental review requirements, limited agency resources and policy directives outside of our control. During 2025, we (including our Berry subsidiary) received permits for 506 workovers, six deepenings and 346 sidetracks, and no permits for new oil and gas wells.

CalGEM resumed issuing permits for new oil and gas wells beginning in January 2026 following the enactment of Senate Bill 237. As of January 31, 2026, we had received 16 permits for new oil and gas

wells and expect to receive additional permits during the course of the year. We also expect the issuance of workover, deepening and sidetrack permits to increase throughout 2026.

We currently hold sufficient permits to undertake a majority of our 2026 capital program. Now that CalGEM has resumed issuing permits through the Kern County EIR process, we expect to obtain additional new well permits for the remainder of our 2026 capital program on a timely basis. See *Liquidity and Capital Resources* for more information. For more information on our permitting risks, see *Part 1, Item IA – Risk Factors – Risks Related to Regulation and Government Action, We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.*

Kern County EIR Litigation

Since June 2022, our oil and gas drilling activities have been significantly impaired as a result of litigation by certain environmental activists. This litigation primarily challenged Kern County's adoption of an ordinance that provided for the countywide development of oil and natural gas wells on the grounds that the Environmental Impact Report (EIR) prepared by the county for the project failed to satisfy the requirements of CEQA. The litigation resulted in numerous court rulings, orders and appeals. Following the enactment of SB 237 as described below, the trial court issued an order on the merits of the case that lifted the stay that had effectively prevented the issuance of new well drilling permits in Kern County. The deadline for appeals passed on February 2, 2026, with no appeal filed. Developments in the enactment of SB 237 or in the permitting process more broadly that are adverse to Kern County could further adversely affect our business, results of operations and financial condition.

Regulatory Activity

In recent years, the California Legislature and Governor have significantly expanded the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities through legislation and policy pronouncements. CalGEM's responsibilities now include public health and safety and the reduction or mitigation of greenhouse gas emissions while meeting the state's energy needs. The scope and limits of this expanded authority, and the manner in which it may be exercised, remain subject to interpretation and legal challenge, creating uncertainty regarding certain aspects of oil and natural gas operations in California. For example, CalGEM published a rulemaking, effective in 2024, prohibiting well stimulation treatment in connection with oil production. Prior to the rulemaking, CalGEM denied certain well stimulation treatment permits in Kern County (as part of the well stimulation treatment permitting phase out). The legality and validity of CalGEM's denial of such permits is subject to challenge, with litigation pending at this time. Along with other plaintiffs, we are seeking declaratory and other relief.

CalGEM is also required to study and prioritize idle wells with emissions, evaluate abandonment and restoration costs, and review and adjust bonding requirements. CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general, including by imposing setback distances, limiting well stimulation, completion or injection activities, or banning certain operations outright. Other local governments have also sought to ban natural gas or the transportation of natural gas through their cities.

Senate Bill 237 (Oil and Gas Permitting)

Senate Bill 237 (SB 237), enacted in September 2025, implements a number of changes to help facilitate new and continued oil and gas production in Kern County. Among other provisions, SB 237

deems Kern County's Second Supplemental EIR (SSEIR) sufficient for full compliance with the requirements of the California Environmental Quality Act (CEQA). Projects that satisfy the SSEIR, certified pursuant to the Kern County Oil and Gas Ordinance, are deemed sufficient and no further environmental review or additional mitigation measures are required. The provisions of SB 237 became effective as of January 1, 2026, and allow for the issuance of up to 2,000 new drill wells per year for up to ten years in Kern County. We believe that the adoption of SB 237 will support operational continuity and investment planning by California's oil and gas industry and, due to the increased clarity around permitting standards, will help enhance long-term development opportunities in Kern County, benefiting our asset base located in the region.

Assembly Bill 1207 (Cap-and-Invest Extension)

Assembly Bill 1207 (AB 1207), enacted in September 2025, extends California's greenhouse gas cap-and-invest program through 2045, providing long-term policy certainty for covered entities under the Program. The legislation also establishes emission reduction initiatives, enhanced reporting requirements and a Climate Mitigation Fund to support consumer rebates and investments to reduce household energy costs.

Senate Bill 614 (Carbon Dioxide Pipeline Regulation)

Senate Bill 614 (SB 614), enacted in October 2025, revises the definition of "pipeline" for purposes of the Elder California Pipeline Safety Act of 1981 to include intrastate pipelines used for the transportation of carbon dioxide (CO₂). The law requires the Office of the State Fire Marshal to adopt implementing regulations regarding the safe transportation of CO₂ in pipelines by July 1, 2026, establishing a pathway to lifting the current moratorium on the construction and operation of new CO₂ pipeline operations in the state. The legislation mandates stringent design, routing, and disclosure standards consistent with or exceeding a proposed revision to federal requirements under the Pipeline and Hazardous Materials Safety Administration that was subsequently withdrawn prior to federal enactment (Draft PHMSA Regulations). Under SB 614, CO₂ pipelines within a single facility and for which construction was permitted before July 1, 2025, shall not be required to subsequently comply with those regulations that pertain to design and construction if the pipeline is constructed to meet the standards of the Draft PHMSA Regulations. The CO₂ pipelines comprising our Carbon Terra Vault I (CTV I) project at our Elk Hills field were permitted prior to July 1, 2025, and have been constructed to meet the standards of the Draft PHMSA Regulations. Upon implementation, SB 614 is expected to help enable the development of carbon-capture and storage projects that rely upon capture of carbon dioxide from an emission source that is remote from the facility into which the emissions will be sequestered.

Pipeline Transportation

Federal and state pipeline regulations have also been revised by both CalGEM and the Office of the State Fire Marshal over recent years, including requirements relating to integrity management, risk assessments, and spill prevention, amongst others. Additionally, PHMSA has, from time to time, issued new regulations expanding or otherwise revising pipeline integrity requirements. For example, in January 2025, PHMSA released a final rule enhancing requirements for detecting and repairing leaks on new and existing natural gas distribution, gas transmission and gas gathering pipelines. However, the current administration withdrew the final rule and, accordingly, it has not been codified. Prior to that, in September 2023, PHMSA published a proposed rule that would enhance the safety requirements for gas distribution pipelines and would require updates to distribution integrity management programs, emergency response plans, operations and maintenance manuals, and other safety practices. The Federal Register indicates that PHMSA is analyzing comments to the proposed rule through December 2026.

Waste Emissions Charge

In May 2025, following a joint resolution of disapproval under the Congressional Review Act, the EPA issued a final rule to remove the Waste Emission Charge (WEC) regulations, originally adopted under the Inflation Reduction Act, from the Code of Federal Regulations. As a result, the fees associated with methane emissions from certain oil and gas facilities that would have been due to the EPA in September 2025 were not collected. Although the underlying statute still requires a methane charge, An Act to Provide for Reconciliation Pursuant to Title II of H. Con. Res. 14th and commonly referred to as the One Big Beautiful Bill Act, postponed implementation from 2024 to 2034.

Water Injection

Our operations in the Wilmington Oil Field use injection wells to reinject produced water under approved waterflooding plans. CalGEM has issued a directive to reduce the injection well pressure in a gradual manner in accordance with a five-year injection reduction work plan. The first phase of reduction commenced July 1, 2024, and a second reduction began in January 2025. The next phase of reduction continues to be on hold while we evaluate the impact of the previously implemented reductions together with CalGEM. We currently estimate a negligible impact on production and reserves under the existing work plan. However, material changes to the existing plan could require revisions to these estimates.

Activism

Opposition toward oil and gas drilling and development activity has been growing over time. Companies in the oil and gas industry are often the target of efforts to delay or prevent oil and gas development by non-governmental organizations and individuals. This opposition also extends to our carbon management segment as certain activists oppose carbon capture and sequestration efforts by the oil and gas industry. These activists use a variety of tactics that primarily rely on allegations regarding safety, environmental compliance and business practices. At both the state and federal level, these tactics include seeking changes to laws, pressuring governmental agencies to promulgate regulations or engage in rulemaking, or pursuing litigation.

For example, in November 2024, environmental groups collectively filed CEQA litigation against Kern County alleging CEQA violations in connection with the County's approval of conditional use permits for our CTV I project at our Elk Hills Field. At this time, we cannot predict the outcome of this challenge with any certainty. Such lawsuits have the potential to delay timely construction of our CCS projects and commencement of operations and could otherwise have a material adverse effect on our business, results of operations and financial condition. Please see *Regulation of Carbon Capture, Sequestration and Storage – CCS Project Permitting* below for additional information.

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and the National Environmental Policy Act (NEPA), among others. California imposes additional laws that are analogous to, and often more stringent than comparable federal laws.

These laws and regulations, among other things:

- establish air, soil and water quality standards and require monitoring, reporting and attainment plans that may include mitigation measures or restrictions on development or operations in certain regions, including the San Joaquin Valley;
- require permits, approvals and mitigation measures before drilling, workover, production, underground injection, waste disposal or facility construction activities may commence;
- require the installation and operation of safety systems and pollution control equipment, including leak detection, monitoring, inspection, maintenance and repair programs;
- restrict the use of water, land, habitat and other natural resources and impose conservation, reclamation, energy efficiency or renewable energy requirements;
- regulate the generation, handling, storage, transportation and disposal of solid and hazardous wastes, including requirements related to well plugging and abandonment and facility decommissioning;
- limit or prohibit operations in certain protected areas or require habitat conservation or land dedication;
- impose liabilities, including strict or joint and several liability, for unauthorized releases or discharges of regulated materials;
- impose taxes, fees or other charges related to environmental compliance;
- require environmental analyses, recordkeeping and reporting; and
- may expose us to administrative proceedings, civil litigation or enforcement actions by governmental authorities or third parties.

Compliance with these requirements can restrict operations or increase costs. For example, California continues to regulate underground injection activities under the Safe Drinking Water Act, including through ongoing coordination among CalGEM, the State Water Resources Control Board and the U.S. Environmental Protection Agency (EPA) regarding aquifer exemptions and well integrity. While a significant number of aquifer exemption applications have been approved, certain applications remain subject to additional technical review, and permitting timelines and conditions may continue to evolve. These processes have resulted, and could continue to result, in permit delays, operational restrictions or additional compliance costs.

At the federal level, the scope and application of NEPA requirements remain uncertain. Following the change in presidential administration, the Council on Environmental Quality (CEQ) rescinded all of its regulations implementing NEPA and withdrew its interim guidance on the consideration of greenhouse gas emissions and climate change under NEPA. In September 2025, the CEQ issued new guidance to federal agencies implementing NEPA, encouraging agencies to limit their NEPA reviews, rely more heavily on sponsor-prepared documents, and streamline the NEPA process. Subsequently, several agencies have made significant changes to their NEPA rules and procedures. As a result of these changes, the standards and procedures governing environmental review of federal actions, including oil and natural gas activities on federal lands, remain in flux and may result in delays or additional analysis requirements.

There is also uncertainty regarding the availability and timing of certain federal funding programs. In early 2025, the federal government temporarily paused and subsequently resumed disbursement of certain grants and loans appropriated under the Inflation Reduction Act and the Infrastructure Investment and Jobs Act while undertaking a broader review of federal spending processes. Although these actions did not alter statutory tax credit provisions, any future disruption, delay or withdrawal of federal funding could adversely affect the development, timing or economics of projects in which we or our counterparties participate.

California continues to implement policies addressing water scarcity and drought conditions that may restrict groundwater extraction or increase water costs. Water management, including our ability

to recycle, reuse and dispose of produced water, and to access third-party water supplies on commercially reasonable terms and in compliance with applicable laws and permits, is critical to our operations. We treat and reuse water produced in our operations for pressure management, waterflooding, steamflooding and drilling activities, and we also supply reclaimed produced water to certain agricultural users. We additionally rely on water from local and regional suppliers, including for power generation and steam operations. While our operations have not to date been materially impacted by restrictions on third-party water supplies, future limitations or increased costs could adversely affect our operations.

Federal, state and local agencies may assert overlapping jurisdiction in these areas, and certain laws and regulations may apply retroactively. These regimes may impose liability on us for past conditions or activities, including those attributable to prior owners or operators, regardless of fault or the legality of the original conduct.

Regulation of Carbon Capture, Sequestration and Storage

Unitization Senate Bill No. 905

Senate Bill No. 905 (SB 905), enacted on September 16, 2022, contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Senate Bill No. 905 also provides for a unified permitting process to simplify the permitting process for CCS projects, although this will be optional for project applicants. Additionally, the law contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California. The California Air Resources Board has been tasked with developing this proposed framework and this work is still pending at this time. We believe that our Carbon TerraVault projects will continue to be developed on a timeline consistent with our initial expectations as these initial projects are not reliant on the unitization or permitting regulations being developed under Senate Bill No. 905.

Pipelines and Senate Bill No. 614

Our CO₂ pipelines comprising our CTV I project are subject to Senate Bill No. 614, discussed in more detail above.

CCS Project Permitting

On October 21, 2024, the Kern County Board of Supervisors approved the issuance of the conditional use permits and certified the EIR for our first CCS project, Carbon TerraVault I (CTV I). On November 22, 2024, a group of non-governmental organizations filed suit against the County of Kern and its Board of Supervisors, challenging the certification of the EIR alleging non-compliance with CEQA. In addition to challenging the EIR, the Petitioners stated their intention to seek injunctive relief for a stay of the project, but to date have not yet sought such relief. This litigation is ongoing, and we cannot predict the outcome of this litigation with certainty.

The EPA issued Class VI underground injection control (UIC) permits for the construction and operation of four CO₂ injection wells at the site of the CTV I 26R underground CO₂ storage reservoir at our Elk Hills Field. The EPA's permits became effective February 3, 2025.

Construction and testing of our first two Class VI wells is complete, and final modifications and testing are being conducted at our Elk Hills Field. We anticipate the first CO₂ injection at these sites in spring 2026.

As of February 28, 2026, we have eight Class VI UIC project applications related to our carbon management segment pending with the EPA in different stages of the permitting process.

We expect a final decision on Class VI UIC permits for our CTV I A1-A2 CO₂ storage reservoir at Elk Hills and our Class VI permits for CTV II (Union Island) and CTV III (Victoria Island) in 2026. We cannot provide assurances as to the actual timing of EPA's approval of the Class VI UIC permits, or that those permits will not be challenged, and cannot guarantee how these matters could ultimately delay or otherwise adversely impact our ability to timely execute our CCS projects.

Federal Tax Credits

The Inflation Reduction Act enhanced existing credits for the capture and sequestration of carbon dioxide (45Q credit) by increasing the size of the maximum credit to \$85 per metric ton of qualified carbon dioxide when such carbon dioxide is captured from industrial and power generation facilities and to \$180 per metric ton of carbon dioxide when a direct air capture facility is utilized to capture such carbon dioxide, and, in each case, when such captured carbon dioxide is disposed of by the taxpayer in secure geological storage. The Inflation Reduction Act also extended the date for when qualifying facilities must begin construction to before January 1, 2033. Further, a direct pay option for the 45Q credit (for a limited five-year period) was added for new projects placed in service after December 31, 2022, and the Inflation Reduction Act provides an option to monetize the 45Q credit through a sale of the 45Q credit to an unrelated taxpayer for tax years beginning after December 31, 2022. These additional energy-related tax incentives enhance the economics for development of CCS projects in California. The accessibility of direct pay, tax equity financing, and the credit transfers market for 45Q credits provided under the Inflation Reduction Act is still developing, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45Q credit exist. The One Big Beautiful Bill Act enacted on July 4, 2025, amended section 45Q to restrict certain ownership and debt sources from specified foreign entities.

The current administration recently signed several Executive Orders reversing, revoking or rescinding many climate-related actions and has expressed a desire to make modifications to the Inflation Reduction Act. The enactment of any legislation that reduces or eliminates 45Q credits could have an adverse effect on the development of our carbon management business and its prospects. For more information, see *Part 1, Item IA – Risk Factors – Risks Related to Carbon TerraVault and Our Carbon Management Segment, Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may not currently be sufficient for our Carbon TerraVault business and other CCS projects to be economical, may not be fully realized, or could be changed or terminated.*

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track, mitigate and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy or feedstocks. While in office, President Biden issued several executive orders on climate change. However, upon the first days in office, the current administration signed several Executive Orders reversing, revoking or rescinding many climate-related actions and it remains to be seen how such Executive Orders may impact our business and what may result from any litigation, administrative or legislative actions relating to such Executive Orders.

Separately, California has adopted stringent laws and regulations to reduce GHG emissions and may continue to adopt more. The current state laws and regulations:

- established a “cap-and-invest” program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually through 2045 (the year that the state’s “cap-and-trade” program currently expires);
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of natural gas, propane and liquid transportation fuels sold for use in California;

- established a low carbon fuel standard (LCFS) and associated tradable credits that require a progressively lower carbon intensity of the state’s fuel supply than baseline gasoline and diesel fuels, and provide a mechanism to generate LCFS credits through innovative crude oil production methods such as those employing solar or wind energy or carbon capture and sequestration;
- mandated that California derive 60% of its electricity for retail customers from renewable resources by 2030;
- established a policy to derive all of California’s retail electricity from renewable or “zero-carbon” resources by 2045, subject to required evaluation of the feasibility by state agencies;
- imposed state goals to double the energy efficiency of buildings by 2030 and to reduce emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030; and
- mandated that all new single family and low-rise multifamily housing construction in California include rooftop solar systems or direct connection to a state-approved community solar system.

In November 2024, CARB finalized amendments to the LCFS Regulation which included increasing 2030 carbon intensity (CI) targets from 20% to 30% and extending CI reductions to 90% by 2045. Additional updates include additional funding of zero-emission vehicle charging and hydrogen fueling infrastructure, amongst other matters. The final rulemaking package was enacted in June 2025.

California’s cap-and-invest program is a market-based emissions reduction program to limit GHG emissions. AB 1207, further discussed above, extends the cap-and-invest program through 2045. The program applies to major GHG-emitting sources such as electricity generation and industrial facilities, with set carbon benchmarks that gradually decrease each year. Covered emitters must either reduce their emissions below this benchmark or purchase allowances at auction, incentivizing investment in lower-emissions technologies. However, unlike the LCFS, CARB’s CCS protocol has not yet been incorporated into the cap-and-invest program. The timing for the adoption of a protocol is unclear. Until CARB adopts a CCS protocol for cap-and-invest, the program does not have a mechanism for GHG emissions sequestered using CCS to be incorporated into the program and may be treated no different than unabated emissions. If CARB fails to adopt a CCS protocol for cap-and-invest, this could result in certain projects becoming less or non-economical, which in turn could limit our ability to successfully pursue certain CCS projects in the future. We are exploring alternative approaches to account for carbon capture under the California cap-and-invest program, but we cannot guarantee that CARB will accept these alternative approaches or that we will be able to pursue them in a timely manner to support our carbon capture projects.

In addition, the current Governor of California and certain municipalities in California have announced their commitment to adhere to GHG reductions called for in the Paris Agreement through executive orders, pledges, resolutions and memoranda of understanding or other agreements with various other countries, U.S. states, Canadian provinces and municipalities. In furtherance of this commitment, in September 2022, the Governor of California signed Assembly Bill No. 1279 into law, which codifies a previously issued executive order by the Governor’s Office requiring the state to achieve carbon neutrality by 2045. In addition, the Governor of California previously issued an executive order directing several agencies to take further actions with respect to reducing emissions of GHGs. The Governor has also directed state agencies to implement other measures to mitigate climate change and strengthen biodiversity, such as via the conservation of 30% of state lands and waters by 2030. For more information, see *Part I, Item 1A – Risk Factors, Risks Related to Regulation and Government Action, Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material adverse effect on our business, and financial condition and results of operations.*

The EPA and the CARB have also expanded direct regulation of methane as a contributor to GHG emissions. For example, in December 2023, the EPA finalized more stringent methane rules for new,

modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources, known as OOOOc. However, the rule is currently being challenged and, in December 2025, the EPA finalized a rule extending various compliance deadlines pursuant to OOOOb and OOOOc. Additionally, following the change in administration, further proposals have been made to repeal or otherwise modify these requirements, including the EPA's GHG "Endangerment Finding," which underpins the majority of EPA's GHG regulations. We cannot predict whether such efforts will ultimately be successful.

Regulation of Transportation, Marketing and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the U.S. are set by the market and are not presently regulated.

Federal and state laws regulate transportation rates for, and marketing and sale of, petroleum products and electricity with respect to certain of our operations and those of certain of our customers, suppliers and counterparties. Such regulations also govern:

- interstate and intrastate pipeline transportation rates for oil, natural gas and NGLs in regulated pipeline systems;
- prevention of market manipulation in the oil, natural gas, NGL and power markets;
- market transparency rules with respect to natural gas and power markets;
- the physical and futures energy commodities market, including financial derivative and hedging activity; and
- prevention of discrimination in natural gas gathering operations in favor of producers or sources of supply.

The federal and state agencies overseeing these regulations have substantial rate-setting and enforcement authority, and violation of the foregoing regulations could expose us to litigation with government authorities, counterparties, special interest groups and others.

International treaties and regulations also affect the marketing or sale of our products. In addition, mandates or subsidies have been adopted or proposed by the state and certain local governments to require or promote renewable energy or electrification of transportation, appliances and equipment, or prohibit or restrict the use of petroleum products, by our customers or the public.

Available Information

We make available, free of charge on our website www.crc.com, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Definitive Proxy Statements and amendments to those reports filed or furnished, if any, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Unless otherwise provided herein, information contained on our website is not part of this report. The SEC maintains an internet site, <http://www.sec.gov>, that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

In addition to its reports filed or furnished with the SEC, the Company publicly discloses material information from time to time in its press releases, at annual meetings of Shareholders, in publicly accessible conferences and investor presentations, and through its website (principally in its Investor Relations page). References to the Company's website in this Form 10-K are provided as a convenience and do not constitute, and should not be deemed, an incorporation by reference of the information contained on, or available through, the website, and such information should not be considered part of this Form 10-K.

ITEM 1A RISK FACTORS

Described below are certain risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flow. These risks are not the only risks we face. Our business could also be affected materially and adversely by other risks and uncertainties that are not currently known to us or that we currently deem to be insignificant.

Summary:

Risks Related to Our Oil and Gas Business

- Prices for our products are volatile and a substantial decline in prices over an extended period could have a material adverse effect on our financial condition, results of operations, cash flow and ability to invest in our assets.
- Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this geographic area, including drought, earthquake and wildfire risks.
- Drilling for and producing oil and natural gas carries significant operational risks and uncertainty. We may not drill wells at the times we schedule, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.
- Our business involves substantial capital investments, and we may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production.
- Reductions in California refining and pipeline capacity could adversely affect our ability to market our production and our realized prices.
- We may be negatively impacted by inflation, including through increased operating, capital and financing costs.
- We are subject to economic downturns and the effects of public health events which may materially and adversely affect the demand and the market price for our products.
- The other risk factors described under Risks Related to Our Oil and Gas Business below.

Risks Related to Carbon TerraVault and Our Carbon Management Segment

- We may not be able to grow our Carbon TerraVault business and develop large scale CCS projects.
- Our ability to achieve our emissions goals, including our Responsible Net Zero objective, and other carbon management objectives is subject to significant risks and uncertainties.
- Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may be insufficient, unavailable, delayed, reduced or terminated.
- Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties that could adversely affect our ability to implement our carbon management strategy.

Risk Factors Related to Our Business Generally

- Increasing activism against the industries in which we operate, including the oil and gas industry and our involvement in carbon capture, storage, utilization and sequestration, presents risks to our business.
- Changes in expectations as to ESG matters may adversely impact our business, regulation and access to capital.
- Mergers, acquisitions and dispositions, including continued integration of the Berry Merger completed in December 2025, involve substantial risks.
- The other risks described under Risks Related to Our Business Generally described below.

Risks Related to Regulation and Government Action

- We may face material delays related to our ability to timely obtain permits necessary for our operations, or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.

- Our operations in Utah are subject to additional regulatory, permitting and legal risks, including risks associated with federal and tribal lands.
- We may face increased local restrictions on oil and gas exploration and production operations or even be prohibited from operating in certain areas as a result of recently enacted California legislation.
- Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, results of operations and financial condition.
- Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.
- Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation much of which is still being developed. Failure to comply with these regulations and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, results of operations and financial condition.
- The other risks described under Risks Related to Regulation and Government Action below.

Risks Related to Our Indebtedness

- We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.
- Our existing and future indebtedness may adversely affect our business, financial condition and financial flexibility.
- The other risks described under Risks Related to Our Indebtedness below.

Risks Related to Our Common Stock

- Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.
- The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.
- The other risks described under Risks Related to Our Common Stock below.

Risks Related to Our Oil and Gas Business

Prices for our products are volatile and a substantial decline in prices over an extended period could have a material adverse effect on our financial condition, results of operations, cash flow and ability to invest in our assets.

Our financial condition, results of operations, cash flow and ability to invest in our assets are highly dependent on oil, natural gas and NGL prices. Prices for these products are volatile and are subject to fluctuations in response to factors beyond our control, including changes in global and regional supply and demand, inventory levels, geopolitical events (including conflicts in Ukraine and Israel and the geopolitical uncertainty in the Middle East and Venezuela), actions by OPEC and other significant producers, economic conditions, public health events, government regulation and policies relating to energy and climate change, weather conditions, natural disasters, transportation and storage constraints, and market speculation. Sustained periods of lower commodity prices could materially and adversely affect our business by reducing our cash flows, limiting our ability to fund capital expenditures, decreasing the value of our proved reserves, reducing our borrowing capacity under our Revolving Credit Facility, limiting our access to capital markets, and impairing our ability to service our indebtedness or comply with financial covenants. While we use commodity price hedging

arrangements to manage a portion of our exposure to price volatility, our hedging program does not provide protection for all of our production, may limit our ability to benefit from price increases, and exposes us to counterparty risk. We may be unable to enter into additional hedging arrangements on acceptable terms or at all.

Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this geographic area, including drought, earthquake and wildfire risks.

Our operations are highly concentrated in California. As a result, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. Changes in state or regional laws and regulations affecting our operations, local price fluctuations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. Our operations are also exposed to natural disasters and related events common to California, such as wildfires, mudslides, high winds, earthquakes and extreme weather events, and the potential increase to the frequency of drought and flooding. Further, our operations may be exposed to power outages, mechanical failures, industrial accidents or labor difficulties. Certain of our operations depend on a limited number of specialized vendors and service providers in California, and the exit or reduced availability of key suppliers could increase costs, disrupt operations or delay planned activities. Any one of these events has the potential to cause producing wells to be shut in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, prevent development of lease inventory before expiration and limit access to markets for our products.

Drilling for and producing oil and natural gas carries significant operational risks and uncertainty. We may not drill wells at the times we schedule, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.

The development of oil and natural gas properties is subject to numerous operational risks, including the risks of permitting or construction delays, equipment failures, accidents, environmental hazards, unusual or unexpected geologic conditions, adverse weather conditions, title or surface access disputes, cost over-runs, and disappointing drilling results or reservoir performance. Development activities also depend in part on our analysis of geophysical, geologic, engineering, production and other technical data and processes, including the interpretation of 3D seismic data. This analysis is often inconclusive or subject to varying interpretations. Any of the foregoing operational risks could cause actual results to differ materially from the expected payback or cause a well or project to become uneconomic or less profitable than forecast.

If future drilling activities do not generate sufficient production and reserves, we may be forced to curtail drilling or development of our assets. We make assumptions about the consistency and accuracy of data when we identify locations for new wells or opportunities for workovers, sidetracks and deepenings, and these assumptions may prove inaccurate. We cannot guarantee that well locations will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations or from our other drilling activities. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented 2% of our total net undeveloped acreage at December 31, 2025.

Our business involves substantial capital investments, and we may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production.

We intend to fund our 2026 capital program using cash flow from operations. Accordingly, a reduction in operating cash flow could require us to reduce, defer or reprioritize capital investments. In general, the ability to execute our capital plan depends on a number of factors, including production

levels and commodity prices, regulatory and third-party approvals, our ability to timely drill, complete and stimulate wells, our ability to secure equipment, services and personnel, and our ability to fund capital expenditures.

Access to future capital may be limited by our lenders, capital markets constraints, activist funds or investors, or poor stock price performance. As a result, we may be unable to deploy capital in the manner planned, which could negatively impact our production, development activities and ability to pursue acquisitions or partnerships.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Over time, a sustained decline in our production and reserves could reduce our cash flows, liquidity and ability to satisfy our debt obligations and the value of our reserves.

Reductions in California refining and pipeline capacity could adversely affect our ability to market our production and our realized prices.

We sell nearly all of our crude oil production into California markets. In recent periods, certain California refineries and interconnected pipelines have announced closures or reductions in operations, and additional reductions in refining capacity may occur in the future. Decreases in in-state refining capacity or in the availability of related pipeline throughput may disrupt our ability to efficiently transport and market our crude oil, increase competition among producers for access to remaining refining outlets and reduce the number of available purchasers for our products. For example, the recent shutdown of the San Pablo Bay Pipeline eliminated pipeline access to Bay Area refineries and has prompted us to modify our marketing, transportation and shipping arrangements to reach alternative markets. See *Part I, Item 1 and 2 – Business and Properties, Oil and Natural Gas Segment, Marketing Arrangements, Our Principal Customers*. While we seek to manage these risks through marketing arrangements and operational flexibility, reduced refining capacity or related pipeline takeaway could adversely affect our ability to efficiently deliver our production to market, negatively impact pricing dynamics for our crude oil and result in lower realized prices or wider differentials in future periods. Any such impacts could have a material adverse effect on our results of operations and cash flows.

We may be negatively impacted by inflation, including through increased operating, capital and financing costs.

Increases in inflation may have an adverse effect on us. Operating and capital costs in the oil and natural gas industry are heavily influenced by commodity prices, including the prices we pay for electricity, natural gas and steel-based materials used in our operations. For example, we use natural gas and electricity extensively in our operations, including gas to generate steam for steam floods and electricity to power field operations. If we are unable to generate sufficient electricity for use in our operations, we may need to purchase electricity from third parties. Increases in the volumes or prices of commodities used in our operations could cause increases in our operating expenses. We attempt to manage our exposure to commodity price increases through hedging and longer-term fixed price contracts. However, these measures do not fully protect us from inflationary pressures and may not be available on acceptable terms or at all. Inflation could also result in higher interest rates, which could increase our future financing costs.

We are subject to economic downturns and the effects of public health events which may materially and adversely affect the demand and the market price for our products.

The marketing of our oil, natural gas and NGLs depends on the existence of adequate markets for our products. Imbalances between supply and demand, including as a result of economic downturns or

public health events, could cause significant market volatility and adversely affect commodity prices. The extent and duration of public health events, governmental responses and resulting economic impacts are hard to predict. This uncertainty could force us to reduce operating expenses or capital expenditures, which could negatively affect future production and our reserves. We may experience labor shortages if our employees are unwilling or unable to come to work because of illness, quarantines, government actions or other restrictions in connection with a pandemic. If our suppliers cannot deliver the materials, supplies and services we need, we may need to suspend operations. In addition, we are exposed to changes in commodity prices which have been and will likely remain volatile. We cannot predict the duration and extent of a pandemic's adverse impact on our operating results.

A public health event that adversely affects global economic conditions could also heighten or exacerbate many of the other risks described in the *Risk Factors* herein.

The conflicts in Ukraine and Israel and the geopolitical uncertainty in the Middle East and Venezuela have caused price volatility and geopolitical instability which impact our business.

Conflicts and geopolitical tensions have contributed to volatility in the prices of oil, natural gas and NGLs in recent periods. The extent and duration of military actions, sanctions, retaliatory measures and resulting market disruptions are uncertain and could continue to have a substantial impact on the global economy and our business. In addition, any easing, suspension or removal of sanctions on Venezuelan oil production or exports could increase global supply and exert downward pressure on oil prices, which could adversely affect our results of operations and cash flows. In addition, disruptions to global shipping routes, energy infrastructure or transportation corridors, including in or near the Middle East, could further constrain supply, increase costs or contribute to additional price volatility.

Actions by OPEC+ and other producing countries, including decisions to implement, extend, unwind or reinstate production limits, may significantly affect global oil supply and prices. Actual production levels and spare capacity are difficult to assess, and increased production by OPEC+ members or other producing countries could contribute to price declines. These geopolitical developments may also heighten or exacerbate other risks described in this “*Risk Factors*” section.

Some of our competitors have greater resources than us and we may not be able to successfully compete in acquiring and developing new properties.

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods and services and hiring and retaining employees needed to operate and manage our business and marketing oil, natural gas or NGLs. Competitors include a multinational oil company, independent production companies and individual producers and operators. In California, our competitors are few, which may limit available acquisition opportunities. Some of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address such competitive factors more effectively than we can or withstand industry downturns more easily than we can.

Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.

We enter into hedges to mitigate our economic exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our Revolving Credit Facility also includes a covenant that would require us to enter into hedges if the ratio of our indebtedness to Consolidated EBITDAX (as defined in the Revolving Credit Facility) exceeds certain levels. These hedges expose us to the risk of financial losses depending on commodity price movements and may prevent us from realizing the full benefits of price increases. Our ability to realize the benefits of our

hedges also depends in part upon the counterparties to these contracts honoring their financial obligations. If any of our counterparties are unable to perform their obligations in the future, we could be exposed to increased cash flow volatility that could affect our liquidity. In addition, our level of hedging activity may be impacted by financial regulations that could increase our costs of hedging and/or limit the number of hedging counterparties available to us.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may differ materially from our estimates.

Estimating proved reserves and related future net cash flows involves significant judgment and uncertainty, and our assumptions may ultimately prove to be inaccurate. In addition, reserve estimates may change over time as additional data becomes available through development and appraisal activities.

Our ability to maintain or increase our reserves, other than through acquisitions, depends on our ability to drill new wells, which may be limited by permitting constraints. See *Risks Related to Regulation and Government Action – We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory and legal developments.*

To the extent we are able to drill new wells, our ability to maintain or increase reserves depends on the success of improved recovery, extension and discovery projects, which are influenced by reservoir characteristics, technology improvements, commodity prices and operating costs. Many of these factors are outside management's control and will affect whether the historical sources of proved reserves additions continue to provide reserves at similar levels.

Lower commodity prices may reduce the quantity of our proved reserves, particularly those expected to be produced in later years, and may cause certain proved undeveloped reserves to become uneconomic or fail to meet SEC development timing requirements, including the five-year rule. In addition, our reserves information represents estimates prepared by internal engineers. Although a substantial portion of our proved reserve estimates are audited by independent petroleum engineers, we cannot guarantee that the estimates are accurate.

Reserves estimation is a partially subjective process that depends on numerous variables and assumptions, including geology, regulatory approvals, capital availability, development effectiveness and commodity prices, many of which are outside of our control. Actual developments that differ from our expectations could cause us to make significant negative revisions to our reserves which could materially adversely affect our business.

From time to time we may engage in step-out drilling, or drilling in new or emerging plays, which involves heightened uncertainty and may reduce the value of undeveloped acreage if unsuccessful.

The risk profile for step-out drilling or drilling in new or emerging plays is higher than for other locations because we have less geologic and production data and drilling history. The economic success of such drilling depends on numerous variables, including commodity prices, capital availability, drilling results, regulatory approvals, costs and transportation capacity. We may not find commercial amounts of oil or natural gas or actual costs may be higher than initially expected. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. In either case, the value of our undeveloped acreage may decline and could be impaired.

Risks Related to Carbon TerraVault and Our Carbon Management Segment

We may not be able to grow our Carbon TerraVault business and develop large scale CCS projects.

We are developing a carbon management business in California that relies on CCS projects, an emerging sector with limited large-scale precedent in the state. These projects are in the early-stages of development and therefore face significant operational, technological and regulatory risks, and our ability to successfully develop these projects depends on a number of factors beyond our control, including the following:

- Obtaining Class VI permits for carbon dioxide injection and storage from the EPA is a multi-year process, and the time to obtain permits may vary with the complexity and type of storage reservoir. The analysis of the suitability of a reservoir for carbon sequestration is complex and our permit applications are subject to extensive review by the EPA. There can be no assurances that the EPA will release Class VI permits to us when we expect, if at all, and our efforts to obtain Class VI permits could be subject to legal challenges.
- Because large-scale CCS projects represent an emerging sector, there are limited precedents to assess the economic feasibility or commercial terms of such projects. In addition, any of the operational, regulatory or financial risks described herein could cause actual results to differ materially from expected payback or cause a project to become uneconomic or less profitable than forecast.
- CCS projects may require significant capital investments by us, our joint venture partners and third parties, and sufficient capital or financing may not be available on reasonable terms or at all. In some cases, these projects involve the production of hydrogen, ammonia or other products and markets for some of these products are still emerging.
- CCS projects may require long-term agreements with emitters and other third parties, and we may be unable to secure such agreements on acceptable terms or at all.
- The development and operation of production facilities for hydrogen, ammonia and other products and associated sequestration facilities are highly complex. There can be no assurances that we or our partners will be able to successfully develop, maintain and operate these production and sequestration facilities.
- The performance of certain of our carbon and power-related projects depends in part on the reliable operation of associated power generation facilities, and reduced availability or unplanned outages could adversely affect project economics and expected returns.
- Certain of our CCS projects rely on pore space we do not own, and we may be unable to obtain necessary rights from landowners on acceptable terms or at all.
- Complex recordkeeping and GHG emissions/sequestration accounting may be required in connection with one or more of our projects, which may increase the costs of such operations. Different methodologies may be required for various regulatory and non-regulatory accounts regarding GHG emissions/sequestration at one or more of our projects, including but not limited to compliance with the EPA's Mandatory Greenhouse Gas Reporting Program.
- Carbon capture may be viewed as a pathway to the continued use of fossil fuels and there may be organized opposition (including lawsuits) to CCS projects from environmental groups, local residents and legislators.
- Other regulatory uncertainties described herein.

There can be no assurances that we will successfully develop our CCS projects, including our cryogenic gas plant CCS project or CalCapture, and a failure to do so could have an adverse effect on our carbon management business and its prospects. We do not expect the failure of a single CCS project to create an impact on our overall financial condition or operations. However, as the scale of our CCS projects grows, so will their impact on our overall financial condition and operations. Moreover, our failure to successfully develop our CCS projects would adversely affect our ability to

claim emissions reductions related to our sequestration activities and our ability to meet our carbon management goals, which in turn could have an adverse effect on our business and reputation.

Our ability to achieve our emissions goals, including our Responsible Net Zero objective, and other carbon management objectives is subject to significant risks and uncertainties.

We have adopted various sustainability-related targets and objectives, including our Responsible Net Zero objective, and our efforts to establish, pursue and report on these targets expose us to operational, reputational, financial, legal and other risks. Our Responsible Net Zero objective considers Scope 1 and Scope 2 emissions, reflecting an approach that prioritizes operational emissions reductions and carbon management solutions while recognizing the ongoing role of responsibly produced energy and the practical, regulatory and technological constraints associated with achieving absolute net zero emissions.

Our ability to advance our Responsible Net Zero objective depends in significant part on the successful development of our Carbon TerraVault business and related carbon capture and sequestration projects, as well as continued operational improvements. These efforts are subject to substantial regulatory, technical and commercial uncertainty, including risks related to permitting, financing, third-party participation and evolving regulatory frameworks. If we are unable to successfully develop these projects or achieve anticipated operational improvements, our ability to advance our Responsible Net Zero objective could be materially and adversely affected.

In addition, emissions accounting standards, regulatory requirements and climate science continue to evolve. Changes in applicable laws, regulations, guidance or methodologies could affect our ability to claim emissions reductions, accurately report progress or achieve our stated objectives on the timelines contemplated, if at all.

Our adoption of a Responsible Net Zero objective may increase scrutiny from investors, regulators and other stakeholders, some of whom may have differing views regarding the appropriate scope, pace or methods for achieving emissions reductions. A failure or perceived failure to pursue or accurately describe progress toward our Responsible Net Zero objective, or to align related disclosures with evolving regulatory or market expectations, could expose us to regulatory enforcement actions, litigation, reputational harm, increased costs or reduced access to capital.

Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may be insufficient, unavailable, delayed, reduced or terminated.

Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives established under federal and state laws, regulations and governmental programs to be economically viable. Governmental incentives are important to the expected economics of our carbon management business and related projects, including the Section 45Q carbon sequestration credit expanded under the Inflation Reduction Act, the One Big Beautiful Bill Act and LCFS credits under California law. The availability and value of these incentives depend on satisfaction of detailed statutory and regulatory requirements, some of which remain subject to evolving guidance, interpretation, audit and enforcement by the U.S. Department of the Treasury, the Internal Revenue Service, the California Air Resources Board and other federal and California state governmental authorities.

In addition to tax incentives, certain CCS projects may rely on federal grants, loans or other funding programs authorized under the Inflation Reduction Act or the Infrastructure Investment and Jobs Act. Such programs are subject to agency discretion, eligibility criteria, administrative review, funding availability and the risk of delay, modification, reprioritization or cancellation. Changes in federal administration priorities, executive orders, agency rulemaking, enforcement practices or congressional

action have and could further modify, delay, limit, condition or repeal grants, funding programs or tax incentives applicable to our carbon management business. For example, the current administration has taken steps to reduce the availability of federal grants for CCS projects, including canceling grants that had been previously awarded.

If incentives such as the Section 45Q credit, LCFS credit or other applicable federal or state programs are eliminated, reduced, delayed, materially restricted or made subject to more burdensome compliance requirements, our Carbon TerraVault projects may become uneconomic or no longer feasible. In addition, the ability to monetize tax credits, including through direct pay, tax equity financing or credit transfers, is uncertain and depends on evolving federal rules, market liquidity, counterparties, pricing dynamics and compliance risk. We cannot assure that we or our partners will be able to efficiently monetize such incentives on acceptable terms or at all.

Many incentives applicable to CCS projects require long-term secure geological storage of captured CO₂ and ongoing compliance with monitoring, reporting and verification requirements. Failure to satisfy these requirements could result in the recapture of tax credits or other incentives, indemnification obligations to partners or counterparties, penalties, increased regulatory scrutiny or other liabilities. Any of the foregoing risks could materially and adversely affect our carbon management business, financial condition, results of operations and prospects.

Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties that could adversely affect our ability to implement our carbon management strategy.

In August 2022, we entered into the Carbon TerraVault JV with Brookfield to pursue the development of a carbon management segment in California. The management and financing of the joint venture are subject to inherent uncertainties, which could delay or prevent CCS projects, require us to seek alternative sources of capital or otherwise affect our carbon management strategy.

Brookfield has committed an initial \$500 million to invest in CCS projects that are jointly approved through Carbon TerraVault JV. The remaining amount of Brookfield's initial investment will depend on the amount of storage capacity that is permitted subject to certain contractual adjustments. Future storage projects for Brookfield's initial commitment are subject to approval of the joint venture, including Brookfield. There can be no assurances that any of these funding milestones will be achieved so that Brookfield will fund the rest of its commitment. In addition, the parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met. The exercise of Brookfield's put right could materially and adversely affect our carbon management business, financial condition, results of operations and prospects.

Although we own a 51% interest in the Carbon TerraVault JV, we share decision making authority with Brookfield on matters that most significantly impact the economic performance of the joint venture. Any failure to reach a decision with Brookfield could potentially prevent or delay our pursuit of CCS projects or cause such projects to be cancelled. Moreover, if Brookfield does not approve a proposed CCS project that we want to pursue, we will have to seek alternative sources of capital to fund the project and there can be no assurances that such sources of capital will be available.

Risk Factors Related to Our Business Generally

Increasing activism against the industries in which we operate, including the oil and gas industry and our involvement in carbon capture, storage, utilization and sequestration, presents risks to our business.

Opposition toward oil and gas drilling and development activity has increased over time, and companies in the oil and gas industry are often the target of efforts by non-governmental organizations

and individuals to delay or prevent oil and gas development, including through allegations regarding safety, environmental impacts or compliance and business practices. These efforts include seeking changes to laws, pressuring governmental agencies to engage in rulemaking or pursuing litigation.

This opposition also extends to our carbon management segment as certain activists oppose carbon capture and sequestration efforts by the oil and gas companies. For example, on November 22, 2024, a group of non-governmental organizations filed a Petition for Writ of Mandate and Complaint for Injunctive Relief against Kern County and its Board of Supervisors (CTV I Complaint) in Kern County for our CTV I project. This litigation is ongoing. See *Regulation of Carbon Capture, Sequestration and Storage – CCS Project Permitting*. Such lawsuits could delay construction or commencement of operations and have a material and adverse effect on our carbon management business and its prospects.

Heightened concerns by certain parties around climate change and GHG emissions have increased pressure on lawmakers, regulators and others to take action, particularly in California, regardless of the merit of these allegations. We may need to incur significant costs associated with responding to these initiatives and such actions may have a material adverse effect on our financial results. Complying with any resulting additional legal or regulatory requirements that are substantial or prevent or interfere with our activities could have a material adverse effect on our business, financial condition and results of operations.

Changes in expectations as to ESG matters may adversely impact our business, reputation and access to capital.

We face increased attention and evolving expectations from investors, regulators and other stakeholders regarding ESG matters, including climate change, environmental and social impacts and voluntary or mandatory ESG disclosures. Increased demand for alternative forms of energy may increase costs, reduce demand for our products and contribute to increased investigations and litigation, any of which could adversely affect our business. Increased attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us. In some cases, liability or regulatory action may be pursued without regard to our causation of, or contribution to, the asserted harm. While we may participate in various ESG frameworks and certification programs, we cannot guarantee that such participation or certification will achieve intended outcomes or improve perceptions of our products or business.

Our ESG disclosures may be based on expectations, assumptions or hypothetical scenarios that are uncertain, subject to change and difficult to verify over long time horizons. Such expectations, assumptions or hypothetical scenarios are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established approach to identifying, measuring and reporting on many ESG matters. Additionally, while we may also announce various ESG targets, such targets are often aspirational and may be subject to change depending on changed circumstances, methodologies, business forecasts or other factors. We may not be able to meet or make progress against such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs, inaccurate forecasts or technical difficulties. To the extent we do meet such targets, they may ultimately be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or heightened scrutiny of their methodologies. Some of these arrangements may receive scrutiny from certain constituencies who criticize the methodology of offsets or do not believe offsets should be utilized to neutralize GHG emissions. Also, despite these aspirational goals, we may receive pressure from investors, lenders or

other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to pursue or implement such goals, in whole or in part, because of potential costs or technical, inaccurate assumptions or operational obstacles.

Certain public statements regarding ESG matters are subject to increasing regulatory, litigation and political scrutiny, including allegations of “greenwashing” or challenges from so-called “anti-ESG” constituencies, which could result in investigations, enforcement actions, litigation or reputational harm. Additionally, certain employment or business practices and social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. Such ESG-related matters may also impact our customers or suppliers, which may adversely impact our business, financial condition or results of operations.

Mergers, acquisitions and dispositions, including the integration of the Berry Merger completed in December 2025, involve substantial risks.

We engage in acquisition activities from time to time, including the Berry Merger which closed in December 2025. The Berry Merger and other acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs, experience delays or challenges in integrating assets, systems, personnel or operations (including, in the case of the Berry Merger, drilling services operations), or fail to achieve anticipated synergies;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks.

Although the Berry Merger was completed in December 2025, the integration of Berry’s assets, operations and personnel is ongoing and subject to execution risk, and we may not realize anticipated benefits within expected timeframes or at all.

In connection with mergers and acquisitions, we are often only able to perform limited due diligence, and assessments of reserves, production, costs and liabilities may be inaccurate or incomplete.

Future mergers and acquisitions may require approvals from shareholders, government agencies or other regulatory bodies, and there can be no assurance that such approvals will be obtained on acceptable terms or at all. If we are not able to successfully complete mergers and acquisitions, we may not be able to grow our reserves or production or develop our properties in a timely manner or at all.

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Our disposition activities carry risks that we may:

- not be able to realize reasonable prices or rates of return for assets;
- be required to retain liabilities that are greater than desired or anticipated;
- experience increased operating costs; and
- reduce our cash flows if we cannot replace associated revenue.

There can be no assurance that we will be able to divest assets on financially attractive terms or at all. Our ability to sell assets is also limited by the agreements governing our indebtedness. If we are not able to sell assets as needed, we may not be able to generate proceeds to support our liquidity and capital investments.

In addition, we have expended and will continue to expend significant time and resources in connection with any future acquisition and disposition activities.

We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events such as wildfires. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our business and assets are subject to risks from natural disasters and operating risks associated with oil and natural gas exploration and production activities. Pollution or environmental conditions with respect to our operations or on or from our properties, whether arising from our operations or those of our predecessors or third parties, could expose us to substantial costs and liabilities. Such events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. The cost of insurance for natural disasters has increased in recent years. In California, insurance coverage for certain operational and catastrophic risks such as wildfires may be limited, subject to exclusions or available only at significantly increased cost, which could result in greater self-insurance exposure. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Cybersecurity attacks, systems failures, and other disruptions could adversely affect our operations, financial condition and reputation.

We rely on electronic systems and networks to manage our operations, financial reporting, data storage and communications with employees, service providers and customers. Systems failures, data inaccuracies or outages could impair our ability to operate efficiently and make timely business decisions.

Cybersecurity attacks have become more frequent and sophisticated, and we or third parties with whom we interact may be targeted by malicious actors. We utilize various technologies, controls and procedures, as well as internal staff and external specialists to protect our systems and data, to identify and remediate vulnerabilities and to monitor and respond to threats. However, these measures may not prevent security breaches from occurring. If a breach occurs, it may remain undetected for an extended period of time. A cybersecurity incident could result in data loss, business interruption, reputational harm, regulatory scrutiny, litigation, financial loss and significant remediation costs.

Energy-related assets may be at a heightened risk of cybersecurity or other malicious attacks. Such attacks could disrupt energy markets, delay or prevent product delivery, impair accounting or settlement processes or result in environmental or safety incidents.

As cybersecurity threats continue to evolve in sophistication and magnitude, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any cybersecurity vulnerabilities. Further, state and federal cybersecurity and data privacy legislation could result in complex new requirements that increase our cost of doing business.

Risks Related to Regulation and Government Action

We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.

We must obtain various governmental permits to conduct exploration and production activities, as well as other aspects of our operations. Obtaining the necessary governmental permits is often a

complex and time-consuming process involving numerous federal, state and local agencies, and the duration and success of each permitting effort is contingent upon many variables not within our control.

In recent years, we experienced significant delays in obtaining new well, sidetrack, deepening and workover permits from CalGEM, including delays attributable to enhanced environmental review requirements, litigation challenging the Kern County environmental impact review process, agency resource constraints and policy developments. In early 2026, following the enactment of Senate Bill 237, CalGEM resumed issuing permits for new oil and gas wells in Kern County, and permitting activity has increased significantly with 31 permits for new wells issued in Kern County as of January 31, 2026. However, we cannot provide assurances that permit issuances will continue at anticipated levels or that future legislative, regulatory, administrative or judicial actions will not again delay or restrict permitting activity.

Although we have historically mitigated permitting risk by maintaining an inventory of approved permits, prolonged permitting delays or renewed uncertainty could limit our ability to execute drilling plans, adversely affect our capital program, reduce our ability to replace reserves and negatively impact our business, financial condition and results of operations.

We may face increased local restrictions on oil and gas exploration and production operations or even be prohibited from operating in certain areas as a result of recently enacted California legislation.

California law authorizes local governments to impose regulations, restrictions or prohibitions on oil and gas operations within their jurisdictions, including with respect to existing operations. While certain local measures have previously been challenged successfully in court, recently enacted legislation has expanded local authority in this area. Although we do not currently operate in certain jurisdictions that have proposed or adopted phase-outs or bans, similar actions by local governments in areas where we do operate could increase operating costs, reduce production or reserves, or otherwise adversely affect our business.

Local restrictions may be adopted notwithstanding state-level permitting frameworks, and the resulting regulatory landscape may vary significantly by jurisdiction, increasing compliance complexity and uncertainty.

Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material adverse effect on our business, results of operations and financial condition.

California continues to pursue policies aimed at reducing greenhouse gas emissions and transitioning the state's energy system over time. Legislative, regulatory and executive actions may increase compliance costs, restrict development activities, limit infrastructure availability or otherwise adversely affect the production, transportation or consumption of oil and natural gas in the state.

While recent legislation, including Senate Bill 237, has provided greater regulatory clarity for certain permitting activities in Kern County, we cannot predict the scope, timing or cumulative impact of future state actions or whether such actions may offset or limit the benefits of recent legislative developments.

Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products.

To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, inspection, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, protection of habitat and threatened or endangered species, air emissions, disposal of solid and hazardous waste, fluid injection and water disposal and consumption, recycling and reuse.

Failure to obtain the necessary permits, approvals and certificates or comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal fines and penalties, liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations or our access to property, water, minerals or other necessary resources, and may otherwise delay or restrict our operations and cause us to incur substantial costs. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation much of which is still being developed. Failure to comply with these regulations and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, financial condition and results of operations.

Successful development of CCS projects in the United States require that we comply with what we anticipate will be a stringent regulatory scheme requiring that we obtain certain permits applicable to subsurface injection of CO₂ for geologic sequestration. Moreover, as the operator of our CCS projects, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. There are no assurances that we will be successful in obtaining or maintaining permits or adequate levels of financial assurance for one or more of our CCS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition, or otherwise.

Separately, permitting CCS projects requires obtaining a number of other permits and approvals unrelated to subsurface injection from various U.S. federal and state agencies, such as for air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility. We cannot guarantee that we will be able to obtain or maintain all applicable permits for CCS activities on a timely basis or on favorable terms, if at all. Moreover, to the extent any of our CCS projects will require any supporting pipeline infrastructure, we could face additional costs and delays obtaining the necessary permits and rights of ways for such infrastructure, and increased risk of opposition to our projects, which may ultimately mean we are unable to successfully pursue certain CCS projects because of these risks.

As CCS and carbon management represent an emerging sector, laws and regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent additional legal or regulatory requirements are imposed, are amended, or more stringently enforced, we may incur additional costs in the pursuit of one or more of our carbon capture projects, which costs may be material or may render any one or more of our projects uneconomical.

New and developing regulations related to the CO₂ unitization, permitting and pipeline safety could negatively impact our business, financial condition and results of operations.

Senate Bill No. 905 contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Senate Bill No. 905 also provides for a unified permitting process to simplify the permitting process for CCS projects, although this will be optional for project applicants. Additionally, the law contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California. The California Air Resources Board has been tasked with developing this proposed framework. We believe our Carbon TerraVault projects will continue to be developed on a timeline consistent with our initial expectations. These initial projects are not reliant on the unitization or permitting regulations being developed. In addition, our Carbon TerraVault projects are expected to either use emitters that are directly sited above these storage facilities or rely on pipelines for transporting CO₂. Senate Bill No. 905 provides that pipelines may be used to transport carbon dioxide to or from a carbon dioxide capture, removal or sequestration project only upon conclusion of PHMSA's rulemaking strengthening safety requirements for carbon dioxide pipelines. Although PHMSA released a notice of proposed rulemaking to this effect in early January 2025, was subsequently withdrawn by the current administration prior to publication in the Federal Register. The lack of these final pipeline safety regulations may impair or prohibit projects that rely on the transportation of CO₂.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO₂ in connection with EOR projects. Although we do not have any existing oil and natural gas production or proved reserves associated with EOR projects, this legislation required us to transition our CalCapture project to target CCS and may require us to make other adjustments to projects in the future.

Senate Bill 614 (SB 614), enacted in October 2025, revises the definition of "pipeline" for purposes of the Elder California Pipeline Safety Act of 1981 to include intrastate pipelines used for the transportation of carbon dioxide (CO₂). The law requires the Office of the State Fire Marshal to adopt implementing regulations regarding the safe transportation of CO₂ in pipelines by July 1, 2026, establishing a pathway to lifting the current moratorium on the construction and operation of new CO₂ pipeline operations in the state. The legislation mandates stringent design, routing, and disclosure standards consistent with or exceeding a proposed revision to federal requirements under the Pipeline and Hazardous Materials Safety Administration that was subsequently withdrawn prior to federal enactment (Draft PHMSA Regulations). Under SB 614, CO₂ pipelines within a single facility and for which construction was permitted before July 1, 2025, shall not be required to subsequently comply with those regulations that pertain to design and construction if the pipeline is constructed to meet the standards of the Draft PHMSA Regulations. The CO₂ pipelines comprising our Carbon Terra Vault I (CTV I) project at our Elk Hills field were permitted prior to July 1, 2025, and have been constructed to meet the standards of the Draft PHMSA Regulations. Upon implementation, SB 614 is expected to help enable the development of carbon-capture and storage projects that rely upon capture of carbon dioxide from an emission source that is remote from the facility into which the emissions will be sequestered.

Our operations and financial performance may be negatively affected directly or indirectly by changes in trade policies and tariffs.

The United States government has indicated its intent to adopt a new approach to trade policy and in some cases to renegotiate, or potentially terminate, certain existing trade agreements. It has also initiated or is considering the imposition of tariffs on certain foreign goods and products. This has led to the United States increasing tariffs for certain goods, which triggered other nations to also increase

tariffs on certain of their goods. While the extent and duration of the such tariffs remain uncertain, these measures, including 50% tariffs on imported steel, are likely to lead to increased material costs.

Concerns about climate change and other environmental issues may prompt governmental action that could have a material adverse effect on our operations or results.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions, and regulation of GHGs and other air quality issues, may have a material adverse effect on our business in many ways, including increasing the costs to provide our products and services and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues at the federal, state and local level may increase our capital and operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions. California's cap-and-trade program operates under a market system and the costs of such allowances per metric ton of GHG emissions are expected to increase in the future as the CARB tightens program requirements and annually increases the minimum state auction price of allowances and reduces the state's GHG emissions cap. As the foregoing requirements become more stringent, we may be unable to implement them in a cost-effective manner, or at all.

In August 2022, President Biden signed the Inflation Reduction Act into law. The Inflation Reduction Act includes a charge on methane emissions that exceed certain thresholds from sources required to report their GHG emissions to the EPA, including certain oil and natural gas operations. In November 2024, the EPA issued a final rule implementing the methane emissions charge, although in February 2025, Congress repealed the rule. Additionally, the One Big Beautiful Bill Act, enacted in July 2025, delays implementation of the methane emissions charge until 2034. We cannot predict if Congress or the current administration may take actions to further repeal or revise the Inflation Reduction Act, including with respect to the methane emissions charge. In fact, the full impact of future climate regulations is uncertain at this time and it is unclear what additional actions may be taken that may have an adverse effect upon our carbon management business and its prospects.

To the extent financial markets view climate change and GHG or other emissions as an increasing financial risk, this could adversely impact our cost of, and access to, capital and the value of our stock and our assets. Current investors in oil and natural gas companies may elect in the future to shift some or all of their investments into other sectors, and institutional lenders may elect not to provide funding for oil and natural gas companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector, although this trend has waned recently and several high-profile banks and institutional investors have withdrawn from various associations that aim to limit financing of industries that emit significant GHG emissions. Additionally, California has enacted new laws requiring additional disclosure with respect to certain climate-related risks and GHG emissions reduction claims. The laws have been challenged and, in November 2025, the United States Court of Appeals for the Ninth Circuit ordered a preliminary injunction on one of the laws (which requires disclosure for certain climate-related risks), which stays enforcement of that law. Oral argument on the laws occurred in January 2026, although the Ninth Circuit has not yet released its decision. (See *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Climate Change and Greenhouse Gas (GHG) Emissions* for more information). Non-compliance with these new laws may result in the imposition of fines or penalties. Other states are considering similar laws. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate-related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, additional costs to comply with any such disclosure requirements and increased costs of and restrictions on access to capital.

We believe, but cannot guarantee, that our local production of oil, NGLs and natural gas will remain essential to meeting California's energy and feedstock needs for the foreseeable future. We have also established 2030 Sustainability Goals for water recycling, renewables integration, methane emission reduction and carbon capture and sequestration in our life-of-field planning in an attempt to align with the state's long-term goals and support our ability to continue to efficiently implement federal, state and local laws, regulations and policies, including those relating to air quality and climate, in the future. However, there can be no assurances that we will be able to design, permit, fund and implement such projects in a timely and cost-effective manner or at all, or that we, our customers or end users of our products will be able to satisfy long-term environmental, air quality or climate goals if those are applied as enforceable mandates.

The adoption and implementation of new or more stringent international, federal, state or local legislation, regulations or policies that impose more stringent standards for GHG or other emissions from our operations or otherwise restrict the areas in which we may produce oil, natural gas, NGLs or electricity or generate GHG or other emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or the value of our products and services. Additionally, political, litigation and financial risks may result in restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages or other losses as a result of climate change, or impairing our ability to continue to operate in an economic manner. Moreover, climate change may pose increasing risks of physical impacts to our operations and those of our suppliers, transporters and customers through damage to infrastructure and resources resulting from drought, wildfires, sea level changes, flooding and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Tax law changes could have an adverse effect on our business, financial condition and results of operations.

We are subject to taxation by various tax authorities at the federal, state and local levels where we do business. New legislation could be enacted by any of these government authorities that could adversely affect our business.

In addition, from time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and natural gas exploration and production companies. Such changes have included, but have not been limited to: (i) the repeal of percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) an extension of the amortization period for certain geological and geophysical expenditures; (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies; and (v) an increase in the U.S. federal income tax rate applicable to corporations such as us. However, it is unclear whether any such changes will be enacted and, if enacted, how soon any such changes would be effective. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced demand for our products. The passage of any such legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development or could increase costs and any such changes could have an adverse effect on our business, financial condition and results of operations. Similarly, legislation could be enacted that changes or terminates the current tax incentives that our CCS projects depend on to be economical. The enactment of any legislation that reduces, eliminates, delays, materially restricts or makes Section 45Q credits subject to more burdensome compliance requirements, could have an adverse effect on our business, financial condition and results of operations.

In California, there have been numerous state and local proposals for additional income, sales, excise and property taxes, including additional taxes on oil and natural gas production and a windfall profits tax on refineries. Although such proposals targeting the oil and natural gas industry have not become law, campaigns by various interest groups could lead to additional future taxes.

Financial assurance requirements related to plugging and abandonment costs, decommissioning, and site restoration on those who acquire the right to operate wells and production facilities could impact our ability to sell or acquire assets in California or increase our costs in connection with the same.

California law imposes stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in California, requiring them to file either an individual indemnity bond for single-well or production facility acquisitions, or a blanket indemnity bond for multiple wells or production facilities. The bond imposed on the acquirer is an amount determined by the state to sufficiently cover plugging and abandonment costs, decommissioning, and site restoration, and California law prohibits the closing of any acquisition of the right to operate a well or production facility until a determination on the appropriate bond amount has been completed by the state and the bond has been filed. This bonding requirement significantly impacts the economic feasibility of transferring the right to operate wells and production facilities, including transfers from smaller, less-capitalized operators to more financially stable operators such as ourselves. As of the year ended December 31, 2025, our asset retirement obligations were \$1,033 million. This law will continue to impact our ability to grow or divest our assets within California.

Our operations in Utah are subject to additional regulatory, permitting and legal risks, including risks associated with federal and tribal lands.

As a result of the Berry Merger, we have oil and gas operations and interests in Utah. Certain of these operations are located on federal lands administered by the U.S. Department of the Interior and the Bureau of Land Management, and certain acreage may be subject to tribal jurisdiction. Oil and gas development on federal and tribal lands is subject to regulatory regimes, approval processes and oversight that differ from those applicable to state or private lands and may be more complex, time-consuming or uncertain.

Development activities on federal lands may require compliance with the National Environmental Policy Act (NEPA) and other federal statutes and regulations, which can result in extended permitting timelines, additional environmental review requirements, increased costs, or litigation risk. Changes in federal laws, regulations, policies, enforcement practices or fiscal terms applicable to federal lands, including royalty rates, bonding requirements, leasing terms or permitting standards, could delay or restrict development activities or adversely affect the economics of our operations.

Operations on tribal lands may be subject to additional approvals, contractual requirements and regulatory authority of tribal governments. Disputes relating to tribal lands may be subject to different legal standards, forums or remedies, including limitations arising from tribal sovereign immunity, which could restrict our ability to enforce contractual rights or obtain judicial relief. Any of these factors could delay operations, increase costs, limit development opportunities or otherwise have a material adverse effect on our business, financial condition, results of operations or cash flows.

Risks Related to Our Indebtedness

We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.

Our ability to refinance our debt depends on a variety of factors, including our ability to access the commercial banking and debt capital markets. Changes in interest rates could also impact our ability to

refinance our debt. If interest rates increase, the interest expense burden of any refinanced debt or other variable rate debt would increase even though the amount borrowed remained the same. There can be no assurances that we will be successful in amending, replacing or refinancing our existing debt on acceptable terms or at all.

Our existing and future indebtedness may adversely affect our business, financial condition and financial flexibility.

As of December 31, 2025, we had \$1,283 million of total long-term debt, net and additional borrowing capacity of \$1,284 million under the Revolving Credit Facility (after giving effect to \$176 million of outstanding letters of credit). The terms of our Revolving Credit Facility and Senior Notes permit us to incur significant additional debt, some of which may be secured. Our level of future indebtedness could affect our business in several ways, including the following:

- limit management's discretion in operating our business and reacting to changes in market conditions;
- require us to dedicate a significant portion of our cash flow to debt service, thereby reducing funds available for operations, capital expenditures, acquisitions or shareholder returns;
- increase our vulnerability to commodity price volatility, economic downturns and adverse regulatory developments;
- limit our access to capital markets or increase the cost of future financing; and
- expose us to borrowing base reductions or interest rate increases that could adversely affect liquidity.

Our ability to execute our business strategy and satisfy our debt obligations depends on our future operating performance and on economic, financial, competitive and other factors, many of which are beyond our control.

We may not be able to generate sufficient cash to service all of our indebtedness, and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.

Our earnings and cash flows may vary significantly due to commodity price volatility and other industry factors, and the level of indebtedness that is manageable in some periods may be unsustainable in others. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments at that time. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control as discussed in this "Risk Factors" section. We may be unable to maintain cash flows sufficient to pay the principal, premium, if any, and interest on our indebtedness.

The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our use or access to capital.

Our Revolving Credit Facility is an important source of our liquidity. Our ability to borrow under our Revolving Credit Facility is limited by our borrowing base, the size of our lenders' commitments and our ability to comply with covenants. The borrowing base under our Revolving Credit Facility is redetermined semi-annually by our lenders who review the value of our reserves and other factors that may be deemed appropriate. A reduction in our borrowing base below the aggregate commitment amount of our lenders would have a material adverse effect on our liquidity and may hinder our ability to execute on our business strategy.

Restrictive covenants in our Revolving Credit Facility and the indentures governing our Senior Notes may limit our financial and operating flexibility and adversely affect our ability to execute our business strategy.

Our Revolving Credit Facility and the indentures governing our Senior Notes contain covenants that may adversely effect our business, financial condition or results of operations. These covenants limit our ability to, among other things, incur additional indebtedness, pay dividends or repurchase shares, dispose of assets, or make capital investments. The Revolving Credit Facility also requires us to comply with certain financial maintenance covenants, including a leverage ratio and current ratio. A breach of these covenants could result in a default under the Revolving Credit Facility and/or the Senior Notes. If a default occurs under the Revolving Credit Facility, the lenders may elect to declare all borrowings thereunder outstanding, together with accrued interest and other fees, to be immediately due and payable. If we are unable to repay our indebtedness when due or declared due, the lenders under the Revolving Credit Facility will also have the right to proceed against the collateral pledged to them to secure the indebtedness. An event of default under the Senior Notes may cause all outstanding Senior Notes to become due and payable immediately or give the trustee and the holders the right to declare all outstanding Senior Notes to become due and payable immediately.

Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Revolving Credit Facility are at variable rates of interest and expose us to interest rate risk. As of December 31, 2025, we had no amounts borrowed under our Revolving Credit Facility. If in the future we borrow under the Revolving Credit Facility, then our results of operations would be sensitive to movements in interest rates. There are many economic factors outside our control that have in the past and may, in the future, impact rates of interest including publicly announced indices that underlie the interest obligations related to our Revolving Credit Facility. Factors that impact interest rates include governmental monetary policies, inflation, economic conditions, changes in unemployment rates, international disorder and instability in domestic and foreign financial markets. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our results of operations would be adversely impacted. Such increases in interest rates could have a material adverse effect on our business, financial condition and results of operations if we borrow under the Revolving Credit Facility in the future.

Risks Related to Our Common Stock

Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.

We have adopted a cash dividend policy which anticipates a total annual dividend of \$1.62 per share, payable to shareholders in quarterly increments of \$0.405 per share of common stock, subject to board authorization and declaration each quarter. Our Board of Directors has authorized a share repurchase program to acquire up to \$1.78 billion of our common stock through December 31, 2027. After the increase and shares repurchased in January 2026, approximately \$600 million remained unused as of February 28, 2026. Any payment of future dividends or repurchasing shares of our common stock will be at the discretion of our Board of Directors and will depend upon, among other things, our earnings, liquidity, capital requirements, financial condition and other factors deemed relevant. Our Revolving Credit Facility and Senior Notes both limit our ability to pay dividends and repurchase shares of our common stock. In addition, cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. We can provide no assurances that we will continue to pay dividends at the anticipated rate or repurchase shares of our common stock within the authorized amount or at all.

The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.

The trading price of our common stock may be volatile and may decline for reasons beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. Numerous factors, including changes in our operating results, commodity prices, economic conditions, regulatory developments, capital allocation decisions, analyst estimates and market valuations of comparable companies, could adversely affect our stock price.

Future issuances of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may issue shares of common stock or securities convertible into common stock in public or private transactions. We may also issue additional shares of common stock or convertible securities in connection with mergers or acquisitions, such as in December 2025 when we issued 5.6 million shares of common stock in connection with the Berry Merger. We cannot predict the size of other future issuances of our common stock or securities convertible into common stock or the effect, if any, that such other future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock, or the perception that such sales could occur, may adversely affect the market price of our common stock.

The ownership position of certain of our stockholders limits other stockholders' ability to influence corporate matters and could affect the price of our common stock.

As of December 31, 2025, four of our shareholders owned at least 5% each and collectively owned approximately 41% of our common stock. As a result, each of these stockholders, or any entity to which such stockholders sell their stock, may be able to exercise significant control over matters requiring stockholder approval. Further, because of this large ownership position, if these stockholders sell their stock, the sales could depress our share price.

Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

Sales of our common stock by our executive officers may adversely impact the trading price of our common stock, even when done in compliance with our policies with respect to insider sales. Although we do not expect that the relatively small volume of such sales will itself significantly impact the trading price of our common stock, the market could react negatively to the announcement of such sales, which could in turn affect the trading price of our common stock.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 1C CYBERSECURITY

We rely on information systems, computer networks and digital technologies to operate our business, including managing our operations, protecting sensitive data, communicating internally and externally, and preparing financial and operational information. Our cybersecurity program is designed to protect these critical systems and data while supporting business operations and growth objectives.

We maintain a comprehensive, risk-based approach to assess, identify and manage material risks from cybersecurity threats. Our controls are based on the NIST Cybersecurity Framework (CSF). Our

cybersecurity risk management processes are integrated into our broader enterprise risk management framework and include: (i) regular assessment and monitoring of internal and external cybersecurity threats, (ii) evaluation of potential impacts on business operations, financial performance and stakeholder interests, (iii) periodic evaluation of control effectiveness to determine residual risk levels and guide program improvements, and (iv) integration of cybersecurity considerations into business strategy and technology decisions. Our cybersecurity risk management approach includes external threat analysis, vulnerability scanning and patching, monitoring of alerts, logs, and activities, penetration testing, and external vulnerability assessments. We also have insurance that may reduce the financial impacts of cybersecurity incidents.

Our cybersecurity framework is evaluated by internal and external experts on an ongoing basis or within the scope of certain projects or engagements. Where we use third-party service providers, we endeavor to ensure that cybersecurity threats are minimized including by establishing contractual protections that include minimum security and breach notification requirements. We regularly evaluate and adjust these processes based on changes in the threat landscape and business environment.

In accordance with our cybersecurity incident response plan, the severity of cybersecurity incidents is classified based on the degree of adverse impact on our business, scale of penetration, risk of propagation, significance of impact, impact on protected information, and our monitoring capability. Incident response is overseen by a cybersecurity incident response team steering committee comprised of members of management with the responsibility to inform senior management and/or the Audit Committee based on incident severity classification.

The Audit Committee of our Board of Directors is responsible for overseeing our risk assessment and risk management activities, including cybersecurity risks. The Audit Committee is briefed by our Chief Digital & Information Officer on cybersecurity risks at regular meetings and separately as circumstances warrant. Cybersecurity risks are also included in our enterprise risk management program which is reported separately to the Audit Committee. We maintain a dedicated cybersecurity team responsible for program implementation and operational security activities.

Our Chief Digital & Information Officer is responsible for assessing and managing our material risks from cybersecurity threats. In carrying out these responsibilities, he is informed about and monitors the prevention, detection, mitigation and remediation of cybersecurity incidents through regular briefings and reporting from our cybersecurity team. He has over 28 years of experience in information technology, including leadership roles responsible for cybersecurity and data privacy. He graduated from California State University, Bakersfield with a Bachelor of Science degree in Computer Science.

As of the date of this report, though we and our service providers have experienced certain cybersecurity incidents, we are not aware of any risks from cybersecurity threats that have materially affected or are reasonably likely to materially affect our business strategy, results of operations, or financial condition.

ITEM 3 LEGAL PROCEEDINGS

For information regarding legal proceedings, see *Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Lawsuits, Claims, Commitments and Contingencies* and *Part II, Item 8 – Financial Statements and Supplementary Data – Note 6 Lawsuits, Claims, Commitments and Contingencies*.

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5 MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information for Common Stock

Our common stock is traded under the symbol "CRC" on the New York Stock Exchange (NYSE).

Holders of Record

Our common stock was held by 20 stockholders of record at January 31, 2026, which does not include the beneficial owners for whom Cede and Co. or others act as nominees.

Dividend Policy

Our Board of Directors has approved a cash dividend policy that contemplates a total annual dividend of \$1.62 per share of common stock, payable to stockholders in quarterly increments of \$0.405 per share. This includes a recent amendment in November 2025 to our prior dividend policy that contemplated a total quarterly dividend of \$0.3875 per share of common stock. Changes to our dividend policy and all dividends are subject to approval by our Board of Directors and will be determined based on conditions including our earnings, liquidity, capital requirements, financial condition, restrictions under our Revolving Credit Facility and Senior Notes and other factors.

Share Repurchases

Our Board of Directors authorized a Share Repurchase Program to acquire up to \$1.78 billion of our common stock through December 31, 2027. This includes a recent increase of \$430 million and extension approved by our Board of Directors on February 24, 2026. For additional information, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 19 Subsequent Events*. Our Share Repurchase Program does not obligate us to acquire any number of shares and may be discontinued at any time. For further information regarding our Share Repurchase Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Results of Operations, Transactions Related to Our Common Stock*. Our share repurchase activity for the year ended December 31, 2025 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
January 1, 2025 - March 31, 2025	2,271,919	\$ 44.00	2,271,919	\$ —
April 1, 2025 - June 30, 2025	5,516,050	\$ 45.73	5,516,050	—
July 1, 2025 - September 30, 2025	—	\$ —	—	—
October 1, 2025 - October 31, 2025	—	\$ —	—	—
November 1, 2025 - November 30, 2025	—	\$ —	—	—
December 1, 2025 - December 31, 2025	540,294	\$ 46.25	540,294	—
Total 2025	8,328,263	\$ 45.29	8,328,263	\$ —

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes the securities available for issuance under equity compensation plans as of December 31, 2025. A description of our stock-based compensation plans can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stock-Based Compensation*.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders ⁽¹⁾	1,250,000	—	1,094,122
Equity compensation plan not approved by security holders ⁽²⁾	2,941,018	—	3,911,714
Total	4,191,018		5,005,836

(1) Reflects shares available under our Employee Stock Purchase Plan for purchase at 85% of the lower of the market price at either (i) the beginning of a quarter or (ii) the end of a quarter.

(2) The aggregate number of 9,257,740 shares of our common stock authorized for issuance under our Long-Term Incentive Plan were approved by the Bankruptcy Court as part of the joint plan of reorganization upon our emergence from bankruptcy in 2020. The number of securities to be issued upon vesting of performance stock units assumes all units are earned upon achieving absolute total shareholder returns and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation* for more information on these awards.

Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer group. The graph assumes that on December 31, 2020, \$100 was invested in our common stock, in each index and in each of the peer group companies' common stock weighted by their relative market capitalization, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

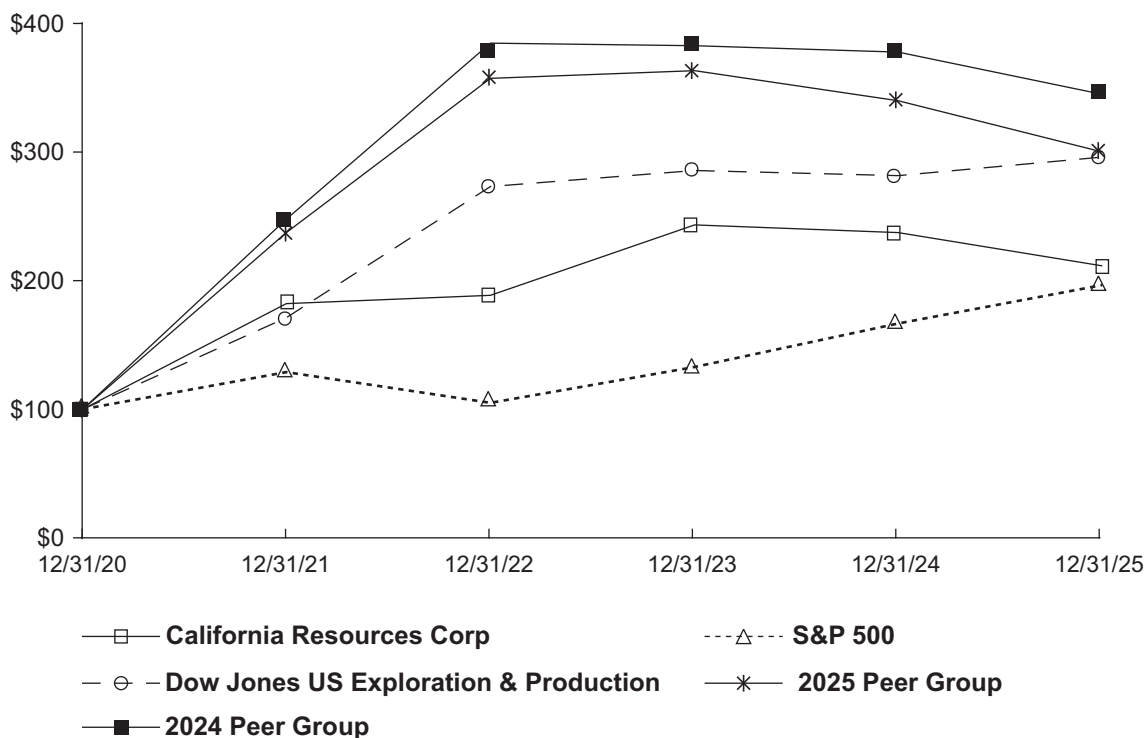
Our 2025 peer group consisted of APA Corporation; BKV Corporation; Chord Energy Corporation; Civitas Resources, Inc.; Comstock Resources Inc.; Crescent Energy Company; Gulfport Energy Corp; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; Northern Oil and Gas, Inc.; Range Resources Corporation; Sable Offshore Corporation; SM Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

Our 2025 peer group changed from 2024. We added Northern Oil and Gas, Inc. and Gulfport Energy Corporation due to their similar market capitalization and operations. We removed Antero Resources Corporation and Permian Resources Corporation from our peer group due to their larger market capitalization. We removed Berry Corporation from our peer group as a result of our merger with them in December 2025. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations* for additional information.

Our 2024 peer group consisted of Antero Resources Corporation; APA Corporation; Berry Corporation; BKV Corporation; Chord Energy Corporation; Civitas Resources, Inc.; Comstock Resources Inc.; Crescent Energy Company; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; Permian Resources Corporation; Range Resources Corporation; Sable Offshore Corporation; SM Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

PERFORMANCE GRAPH*

Among California Resources Corp, the S&P 500 Index,
the Dow Jones US Exploration & Production Index,
2024 Peer Group and 2025 Peer Group



*\$100 invested on 10/28/20 in stock or 10/31/20 in index, including reinvestment of dividends.
Fiscal year ending December 31.

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	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24	12/31/25
California Resources Corp	\$100.00	\$181.84	\$188.50	\$242.89	\$236.66	\$211.03
S&P 500	\$100.00	\$128.71	\$105.40	\$133.10	\$166.40	\$196.16
Dow Jones US Exploration & Production	\$100.00	\$170.92	\$272.74	\$285.07	\$280.73	\$295.11
2024 Peer Group	\$100.00	\$247.35	\$383.48	\$381.39	\$376.47	\$343.91
2025 Peer Group	\$100.00	\$237.14	\$356.11	\$362.06	\$338.68	\$299.13

* This performance graph shall not be deemed "soliciting material" or to be "filed" with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of CRC under the Securities Act of 1933, as amended, or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

ITEM 6 RESERVED

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with other sections of this report, including but not limited to, *Part I, Item 1 and 2 – Business and Properties* and *Part II, Item 8 – Financial Statements and Supplementary Data*.

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations* in our Annual Report on Form 10-K for the year ended December 31, 2024 (2024 Annual Report) for our analysis of the changes in our consolidated statements of operations and statements of cash flows for the year ended December 31, 2024 compared to December 31, 2023.

Basis of Presentation

All financial information presented consists of our consolidated results of operations, financial position and cash flows unless otherwise indicated. We have eliminated all intercompany transactions and accounts. We account for our share of oil and natural gas production activities, in which we have a direct working interest by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our balance sheets and statements of operations and cash flows. In applying the equity method of accounting, our investments in our unconsolidated subsidiaries are recognized either at cost, as is the case with Carbon TerraVault JV HoldCo, LLC, or at fair value if acquired in a business combination, as is the case for Midway Sunset Cogeneration Company. These investments are then adjusted for our proportionate share of income or loss in addition to contributions and distributions.

Supply Chain and Inflation

We continued to experience relatively flat pricing from our suppliers during the year ended December 31, 2025 compared to the prior year. U.S. tariff policy regarding both country of origin and material type remains highly uncertain and subject to future changes. During 2025, the United States expanded tariff rates on imported goods including a 50% tariff on the steel and aluminum value of imported products. If sustained, these expanded tariff rates could increase our cost of oilfield goods and extend delivery lead times over the longer term. We have taken measures to limit the effects of potential price increases caused by the recent expansion of U.S. tariffs by entering into fixed price contracts with terms of one to three years for a significant majority of our materials and services based on our current expected development plans. We also pre-purchased inventory prior to the implementation of the tariffs and continue to purchase from vendors who source domestic content to limit the impact of foreign tariffs on our business. Overall, we expect minimal impact from tariffs on our supply chain in 2026. However, if the current tariff regime persists or expands, our inventory, capital and operating costs could increase over the long term.

Statement of Operations Analysis

Consolidated Results of Operations

Our consolidated results of operations include the results of Berry beginning December 18, 2025, the closing date of the Berry Merger. Our consolidated results of operations include the results of Aera beginning July 1, 2024, the closing date of the Aera Merger. For more information on the Berry Merger and the Aera Merger, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations*. The Aera Merger and related integration activities significantly impacted the comparability of our financial results for the year ended December 31, 2025 compared to the prior year.

For financial information related to our subsidiaries designated as Unrestricted Subsidiaries under the 2026 Senior Notes Indenture, 2029 Senior Notes Indenture and 2034 Senior Notes Indenture, see

Part II, Item 8 – Financial Statements and Supplementary Data, Note 18 Condensed Consolidating Financial Information.

Year Ended December 31, 2025 vs. 2024

The following table presents our consolidated operating revenues:

	<u>Year ended December 31, 2025</u>	<u>Year ended December 31, 2024</u>
	(in millions)	
Oil, natural gas and natural gas liquids sales	\$ 2,910	\$ 2,537
Net gain from commodity derivatives	266	241
Revenue from marketing of purchased commodities	238	235
Electricity revenue	233	159
Other revenue	22	26
Total operating revenues	<u>\$ 3,669</u>	<u>\$ 3,198</u>

Oil, natural gas and natural gas liquids sales – Oil, natural gas and natural gas liquids sales, excluding the effects of cash settlements on our commodity derivative contracts, were \$2,910 million for the year ended December 31, 2025, which is an increase of \$373 million from \$2,537 million for the year ended December 31, 2024. The following table shows changes in oil, natural gas and natural gas liquids sales for the year ended December 31, 2025 compared to the year ended December 31, 2024:

	<u>Oil</u>	<u>NGLs</u>	<u>Natural Gas</u>	<u>Total</u>
	(in millions)			
Year ended December 31, 2024	\$ 2,255	\$ 186	\$ 96	\$ 2,537
Changes in realized prices	(304)	(14)	24	(294)
Changes in production and other	696	(8)	—	688
Changes in intersegment revenues	—	—	(21)	(21)
Year ended December 31, 2025	<u>\$ 2,647</u>	<u>\$ 164</u>	<u>\$ 99</u>	<u>\$ 2,910</u>

Note: See Results of Our Oil and Natural Gas Operations *Production* for volumes by commodity type and *Prices and Realizations* for index and average realized prices for each period.

Net gain from commodity derivatives – We report gains and losses on our derivative contracts related to our oil production and marketing activities in operating revenue. Net gain from commodity derivatives was \$266 million for the year ended December 31, 2025 compared to a net gain of \$241 million for the year ended December 31, 2024. The change primarily resulted from payments to settle commodity derivative contracts and the non-cash changes in the fair value of our outstanding commodity derivatives from the positions held at the end of each measurement period. Gains and losses from our commodity derivative contracts are shown in the table below:

	<u>Year ended December 31, 2025</u>	<u>Year ended December 31, 2024</u>
	(in millions)	
Non-cash commodity derivative gain	\$ 225	\$ 274
Net proceeds (settlements) and premium amortization	41	(33)
Net gain from commodity derivatives	<u>\$ 266</u>	<u>\$ 241</u>

Electricity revenue – Electricity revenue increased by \$74 million to \$233 million during the year ended December 31, 2025 compared to \$159 million for the year ended December 31, 2024. This increase was primarily a result of higher pricing from resource adequacy contracts and additional electricity sales in 2025 as a result of scheduled maintenance and unplanned downtime at our Elk Hills power plant in 2024.

The following table presents our consolidated operating and non-operating expenses and income for the years ended December 31, 2025 and 2024:

	<u>Year ended December 31, 2025</u>	<u>Year ended December 31, 2024</u>
	(in millions)	
Operating expenses		
Operating costs	1,252	966
General and administrative expenses	333	321
Depreciation, depletion and amortization	511	388
Asset impairment	59	14
Taxes other than on income	242	242
Costs related to marketing of purchased commodities	182	193
Electricity generation expenses	38	40
Transportation costs	79	81
Accretion expense	114	87
Net loss on natural gas purchase derivatives	50	30
Measurement period adjustments, net	1	(12)
Other operating expenses, net	209	239
Total operating expenses	<u>\$ 3,070</u>	<u>\$ 2,589</u>
(Loss) gain on asset divestitures	(1)	11
Operating income	<u>598</u>	<u>620</u>
Non-operating (expenses) income		
Interest and debt expense, net	(106)	(87)
Loss on early extinguishment of debt	(1)	(5)
Equity loss from unconsolidated subsidiaries	(4)	(10)
Other non-operating income (expense), net	15	(2)
Income before income taxes	502	516
Income tax provision	(139)	(140)
Net income	<u>\$ 363</u>	<u>\$ 376</u>

Operating costs – The following table presents our operating costs for the years ended December 31, 2025 and December 31, 2024:

	<u>Year ended December 31, 2025</u>	<u>Year ended December 31, 2024</u>
	(in millions)	
Energy operating costs	\$ 374	\$ 279
Gas processing costs	19	16
Non-energy operating costs	859	671
Operating costs	<u>\$ 1,252</u>	<u>\$ 966</u>

Energy operating costs consist of purchased natural gas used to generate electricity for our operations and steam for our steamfloods, purchased electricity and internal costs to generate electricity used in our operations. Gas processing costs include costs associated with compression, maintenance and other activities needed to run our gas processing facilities at Elk Hills. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs.

Energy operating costs – Energy operating costs for the year ended December 31, 2025 were \$374 million, which was an increase of \$95 million from \$279 million for the year ended December 31, 2024. Approximately \$94 million of this increase is related to the addition of the Aera fields for the full year of 2025 compared to only six months in 2024. The remaining increase primarily related to higher energy prices partially offset by savings related to the additional supply of electricity generated at our Elk Hills power plant which is used at our Elk Hills field in 2025. During the year ended December 31, 2024, our Elk Hills power plant experienced unplanned downtime and scheduled maintenance resulting in lower electricity generation available the Elk Hills field. For more information on our natural gas market prices, see *Segment Results of Oil and Natural Gas Operations, Production, Prices and Realizations* below.

Non-energy operating costs – Non-energy operating costs for the year ended December 31, 2025 were \$859 million, which was an increase of \$188 million from \$671 million for the year ended December 31, 2024. Of this increase, \$191 million related to the operation of the Aera fields for the full year ended December 31, 2025 compared to only six months in 2024. This increase was partially offset by lower maintenance activity during the year ended December 31, 2025 as compared to 2024.

General and administrative expenses – General and administrative expenses were \$333 million for the year ended December 31, 2025, which was an increase of \$12 million from \$321 million for the year ended December 31, 2024. The increase was primarily a result of additional compensation-related expense and other corporate expenses resulting from the Aera Merger.

Depreciation, depletion and amortization – Depreciation, depletion and amortization increased \$123 million to \$511 million for the year ended December 31, 2025 from \$388 million for the same prior year period. The increase was primarily the result of the addition of the Aera assets included in the full year ended December 31, 2025.

Asset impairment – We recognized a \$59 million asset impairment during the year ended December 31, 2025 of which \$57 million related to the write-down of our proved natural gas properties in the Sacramento basin. For more information on the impairment of natural gas properties in the Sacramento basin, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Property, Plant and Equipment*. During the year ended December 31, 2024, we recognized a \$14 million impairment primarily related to excess and obsolete materials and supplies related to our oilfield operations. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for more information.

Accretion expense – Accretion expense was \$114 million for the year ended December 31, 2025, which was an increase of \$27 million from \$87 million for the year ended December 31, 2024. The increase was primarily due to the addition of the Aera asset retirement liability related to the Aera fields in connection with the Aera Merger.

Net loss on natural gas purchase derivatives – Net loss on natural gas purchase derivatives was \$50 million for the year ended December 31, 2025. For the same prior year period, we recognized a net loss of \$30 million. The change primarily resulted from changes in the fair value of our outstanding commodity derivatives from the positions held, as well as the relationship between contract prices and the associated forward curves at the end of each measurement period. We added derivative positions held by Berry at December 18, 2025 and recognized a change in fair value between legal close and

December 31, 2025. Gains and losses from our commodity derivative contracts are shown in the table below. For more information on our derivatives, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

	Year ended December 31, 2025	Year ended December 31, 2024
	(in millions)	
Non-cash loss (gain) on natural gas purchase derivatives	\$ 24	\$ (2)
Settlements	26	32
Net loss on natural gas purchase derivatives	<u>\$ 50</u>	<u>\$ 30</u>

Measurement period adjustments, net – Measurement period adjustments relate to changes made to the initial accounting for assets acquired and liabilities assumed in the Aera Merger. The adjustments for the year ended December 31, 2025 included adjustments to depreciation, depletion and amortization expense resulting from changes to the initial purchase price allocation. The adjustments for the year ended December 31, 2024 related to accretion expense related to asset retirement obligations and depreciation, depletion and amortization expense resulting from changes to the initial purchase price allocation.

Other operating expenses, net – Other operating expenses, net decreased \$30 million to \$209 million for the year ended December 31, 2025 compared to \$239 million for the year ended December 31, 2024.

For the years ended December 31, 2025 and 2024, other operating expenses, net includes the following:

	Year ended December 31,	
	2025	2024
	(in millions)	
Carbon management expenses ^(a)	\$ 54	\$ 56
Transaction and integration costs	30	57
Incremental energy costs due to downtime at our Elk Hills power plant	4	50
Severance and termination costs	20	30
Litigation and settlement related expenses ^(b)	26	12
Offshore platforms maintenance and abandonment costs	19	5
Information technology infrastructure	13	—
Environmental remediation	9	—
All other	34	29
Total operating expenses, net	<u>\$ 209</u>	<u>\$ 239</u>

(a) Carbon management expenses relates to the development of our carbon management business and includes operating lease costs, payroll costs related to our technical teams and is included in other segment expenses. For more information on our carbon management segment, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 16 Segment Information*.

(b) See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Lawsuits, Claims, Commitments and Contingencies* for more information on a \$25 million payment we made to CalGEM.

(Loss) gain on asset divestitures – Our loss on asset divestitures for the year ended December 31, 2025 was \$1 million primarily related to the final purchase price adjustment related to the sale of oil and gas assets located in Ventura. Gain on asset divestitures for the year ended

December 31, 2024 was \$11 million primarily related to the divestiture of non-core assets and our Ventura divestiture. For more information on our asset divestitures, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions*.

Interest and debt expense, net – Interest and debt expense, net was \$106 million for the year ended December 31, 2025, which was an increase of \$19 million from \$87 million for the year ended December 31, 2024. The increase was predominately due to higher outstanding debt for the full year ended 2025 compared to 2024. Our 2029 Senior Notes were outstanding for only part of 2024 compared to the full year in 2025, as \$600 million was issued in June 2024 and \$300 million was issued in August 2024 in a follow-on issuance. Outstanding debt was also higher in 2025 due to the issuance of \$400 million of our 2034 Senior Notes completed in October 2025 resulting in increased interest expense. This increase in interest expense was partially offset by lower interest expense resulting from debt repayments, including the redemption of \$123 million of our 2026 Senior Notes in February 2025 and the redemption of the remaining \$122 million of the 2026 Senior Notes in October 2025, which reduced outstanding principal and related interest expense. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt* for information on our recent financings.

Other non-operating income (expenses), net – We recognized \$15 million other non-operating income during the year ended December 31, 2025 primarily related to actuarial gains on plan assets held in our pension and postretirement benefit plan. During the year ended December 31, 2024, we recognized \$2 million other non-operating expense primarily relating to the write-off of financing fees related to a bridge loan we entered into in connection with the Aera Merger which was partially offset by a prior service cost gain on our postretirement benefit plan.

Segment Results of Oil and Natural Gas Operations

The following tables includes financial results and key operating data for our oil and natural gas segment for the years ended December 31, 2025, 2024 and 2023. Our results of operations for the oil and natural gas segment include the financial and operating results of Aera beginning on July 1, 2024, the closing date of the Aera Merger. For more information on the Aera Merger, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations*.

	Year ended December 31,		
	2025	2024	2023
	(in millions, except as otherwise stated)		
Production and oil and gas segment financial data			
Net production sold (MBoe/d)	138	110	86
Total operating revenues	\$ 2,967	\$ 2,572	\$ 2,172
Segment profit	\$ 688	\$ 815	\$ 922
Items affecting comparability:			
Asset impairments ^(a)	\$ 57	\$ 13	\$ —
Net (loss) gain on asset divestitures ^(b)	\$ (1)	\$ 10	\$ 32
Key operating expenses per Boe			
Operating costs	\$ 25.42	\$ 24.51	\$ 26.24
Operating costs, after hedges on purchased natural gas	\$ 25.94	\$ 25.31	\$ 26.24
General and administrative expenses ^(c)	\$ 0.85	\$ 1.07	\$ 1.34
Depreciation, depletion and amortization ^(d)	\$ 9.77	\$ 8.83	\$ 6.61
Taxes other than on income	\$ 4.03	\$ 5.16	\$ 3.61
Field transportation expenses	\$ 0.81	\$ 0.90	\$ 0.99

(a) Asset impairment for the year ended December 31, 2025 includes the write-down of our proved properties in the Sacramento basin. Asset impairment for the year ended December 31, 2024 related to the write-off of excess and obsolete materials and supplies, generally requisitioned for wells and capitalized as part of drilling and completion activities. The table above excludes asset impairments that were not related to the oil and natural gas segment.

- (b) Loss on asset divestitures for the year ended December 31, 2025 related to the sale of our West Montalvo property in Ventura County, California. Gain on asset divestitures for the year ended December 31, 2024 related to the sale of our 0.9-acre Fort Apache real estate property in Huntington Beach, California as well as the remaining portion of our Ventura assets which were classified as held for sale. Gain on asset divestitures for the year ended December 31, 2023 related to the sale of our non-operated interest in the Round Mountain Unit and a non-producing asset in exchange for the assumption of liabilities.
- (c) Only includes general and administrative expenses allocated to our oil and natural gas segment.
- (d) Excludes depreciation, depletion and amortization related to our corporate assets and Elk Hills power plant.

Production, Prices and Realizations

The amounts in the production tables below show volumes from CRC's operated and non-operated fields for each of the periods presented. These amounts include volumes produced from Berry's operated and non-operated fields during the period from December 18, 2025 through December 31, 2025, and volumes produced from Aera's operated and non-operated fields beginning July 1, 2024.

Net Production Sold

The following table presents our net production sold per day in each of the basins in which we operate for the periods presented. The amounts in the production table below include volumes produced from operated and non-operated fields for each of the periods presented.

	Year ended December 31,		
	2025	2024	2023
Oil (MBbl/d)	109	80	52
NGLs (MBbl/d)	10	10	11
Natural gas (MMcf/d)	114	117	135
Total Daily Net Production (MBoe/d)	138	110	86

The following table summarizes the changes to our total daily net production per day for the periods presented:

	Year ended December 31,		
	2025	2024	2023
		(MBoe/d)	
Beginning of the year	110	86	91
Divestitures ^(a)	—	(1)	—
Plant downtime ^(b)	—	(2)	—
Acquisitions ^(c)	30	34	—
PSC effect	2	—	1
Natural decline and other	(4)	(7)	(6)
Total change	28	24	(5)
End of the year	138	110	86

- (a) See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* for more information. Note that for the year ended December 31, 2023, our divestitures did not have a significant impact on our production volumes because the sale of our non-operated working interest in the Round Mountain Unit closed on December 29, 2023 and we sold a non-producing asset during the year.
- (b) Included scheduled maintenance and unplanned downtime at our Elk Hills power plant for the year ended December 31, 2024.
- (c) We completed the Aera Merger on July 1, 2024 and the amount of production shown in the table above is averaged over a 12-month period. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations* for more information.

Prices and Realizations

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. These and other factors make it impossible to predict realized prices reliably. The following tables set forth average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the periods indicated below:

	2025		2024		2023	
	Price	Realization	Price	Realization	Price	Realization
Oil (\$ per Bbl)						
Brent	\$ 68.22		\$ 79.84		\$ 82.22	
Realized price without derivative settlements	\$ 66.52	98%	\$ 76.92	96%	\$ 80.41	98%
Derivative settlements	0.99		(1.26)		(14.44)	
Realized price with derivative settlements	<u>\$ 67.51</u>	99%	<u>\$ 75.66</u>	95%	<u>\$ 65.97</u>	80%
WTI	\$ 64.81		\$ 75.72		\$ 77.62	
Realized price without derivative settlements	\$ 66.52	103%	\$ 76.92	102%	\$ 80.41	104%
Realized price with derivative settlements	\$ 67.51	104%	\$ 75.66	100%	\$ 65.97	85%
Natural Gas Liquids (\$ per Bbl)						
Realized price (% of Brent)	\$ 45.30	66%	\$ 48.93	61%	\$ 48.94	60%
Realized price (% of WTI) ...	\$ 45.30	70%	\$ 48.93	65%	\$ 48.94	63%
Natural gas						
NYMEX Henry Hub (\$/ MMBtu)	<u>\$ 3.43</u>		<u>\$ 2.27</u>		<u>\$ 2.74</u>	
Realized price (\$/Mcf)	<u>\$ 3.57</u>	104%	<u>\$ 2.99</u>	132%	<u>\$ 8.59</u>	314%

Oil — Brent and our average realized price without derivative settlements were lower for the year ended December 31, 2025 compared to the same prior year period largely due to an increase in global oil production beginning in later 2025 as both OPEC+ and non-OPEC countries increased production.

NGLs — Prices for natural gas liquids were lower for the year ended December 31, 2025 compared to the prior year which is consistent with broader declines in oil commodity prices. The California market continued to carry a premium as compared to other markets in 2025.

Natural Gas — Average realized prices for our natural gas during the year ended December 31, 2025 were higher than the year ended December 31, 2024 as demand for U.S. natural gas reached record levels.

Results of Our Carbon Management Segment

Our carbon management segment, which we refer to as Carbon TerraVault, primarily pursues the development of CCS projects. We expect that our Carbon TerraVault CCS projects will inject CO₂ captured from industrial, power, agriculture and other emissions sources into subsurface reservoirs and permanently store CO₂ deep underground. We also expect to invest in projects that rely on CCS technology in connection with reducing our own emissions. In addition, we may participate in the development of projects that are the source of these CO₂ emissions. Our carbon management segment is in its early stages of development, and did not have any revenue for the years ended December 31, 2025, 2024 or 2023. We recently completed construction of our first carbon capture project at our cryogenic gas processing facility and expect first injection in spring 2026, subject to commissioning and final regulatory approval. We define carbon management expense to be our direct operating costs to run our carbon management segment.

The following tables include results for our carbon management segment, excluding unallocated corporate expenses for the years ended December 31, 2025, 2024 and 2023.

	Year ended December 31,		
	2025	2024	2023
	(in millions, except as otherwise stated)		
Segment loss	\$ (86)	\$ (94)	\$ (66)
Items affecting comparability:			
Asset impairments ^(a)	\$ 2	\$ 1	\$ 3

(a) Asset impairment for the years ended December 31, 2025, 2024 and 2023 related to land acquired for our carbon management activities. The table above excludes asset impairments that were not related to the carbon management segment.

We recognized our share of losses for the years ended December 31, 2025, 2024 and 2023 related to our Carbon TerraVault joint venture, as shown in the table below. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our Carbon TerraVault joint venture. Carbon management expense and general and administrative expense for the years ended December 31, 2025, 2024 and 2023 are included in the table below.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Carbon management expenses	\$ 54	\$ 56	\$ 37
Segment general and administrative expense	\$ 13	\$ 15	\$ 12
Loss from investment in the Carbon TerraVault JV	\$ 6	\$ 12	\$ 9

Carbon management expenses decreased in 2025 compared to 2024 as a result of lower community development activities which were partially offset by higher costs related to feasibility studies that were undertaken.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations, available cash and cash equivalents, proceeds from the issuance of our senior notes and available borrowing capacity under our Revolving Credit Facility. We consider our low leverage and ability to control costs to be a core strength and strategic advantage, which we are focused on maintaining. Our primary uses

of operating cash flow for the year ended December 31, 2025 were for capital investments, redemption of our 2026 Senior Notes, repurchase of our common stock, and payment of dividends.

The following table summarizes our liquidity:

	December 31, 2025
	(in millions)
Available cash and cash equivalents ^(a)	\$ 117
Revolving Credit Facility:	
Borrowing capacity	1,460
Outstanding letters of credit	(176)
Availability	\$ 1,284
Liquidity	\$ 1,401

(a) Excludes restricted cash of \$15 million.

Derivatives

Significant changes in oil and natural gas prices may have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow, and the inverse applies during periods of rising commodity prices. Our hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. We will continue to evaluate our hedging strategy based upon prevailing market prices and conditions.

Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as cash-flow or fair-value hedges. We did not have any commodity derivatives designated as accounting hedges as of and for the year ended December 31, 2025.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our open derivative contracts as of December 31, 2025 and *Note 5 Debt* for more information on the hedging requirements included in our Revolving Credit Facility.

Long-Term Debt

Our long-term debt consists of borrowings and indebtedness under our Revolving Credit Facility, 2029 Senior Notes and 2034 Senior Notes. Our previously issued 2026 Senior Notes were redeemed in full in 2025. For more information regarding our Revolving Credit Facility, 2026 Senior Notes, 2029 Senior Notes and 2034 Senior Notes, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt*.

Revolving Credit Facility

On April 26, 2023, we entered into an Amended and Restated Credit Agreement (Revolving Credit Facility) with Citibank, N.A., as administrative agent, and certain other lenders, which amended and restated in its entirety the prior credit agreement dated October 27, 2020. As of December 31, 2025, we were in compliance with all of the covenants of our Revolving Credit Facility. Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt* for more information on recent amendments to our Revolving Credit Facility.

2034 Senior Notes

On October 8, 2025, we completed an offering of \$400 million in an aggregate principal amount of 7.000% senior notes due 2034 (2034 Senior Notes). The terms of the 2034 Senior Notes are governed

by the Indenture, dated as of October 8, 2025, by and among us, our subsidiary guarantors and Wilmington Trust, National Association, as trustee (2034 Senior Notes Indenture). The net proceeds of \$393 million, after \$7 million of debt issuance costs, were used to repay Berry's long-term debt at closing of the Berry Merger.

2029 Senior Notes

On June 5, 2024, we completed an offering of \$600 million in aggregate principal amount of 8.25% senior notes due 2029 (2029 Senior Notes). The terms of the 2029 Senior Notes are governed by the Indenture, dated as of June 5, 2024, by and among us, our subsidiary guarantors and Wilmington Trust, National Association, as trustee (2029 Senior Notes Indenture). The net proceeds of \$590 million, after \$10 million of debt discount and issuance costs, were used along with available cash to repay all of Aera's outstanding debt at closing of the Aera Merger.

On August 22, 2024, we completed a follow-on offering of \$300 million in aggregate principal amount of 2029 Senior Notes. The net proceeds from this offering of \$298 million, after \$3 million of debt premium and \$5 million of debt issuance costs, were used to repurchase a portion of our outstanding 2026 Senior Notes as described below. The follow-on 2029 Senior Notes issued on August 22, 2024 are governed by the same indenture as the \$600 million of 2029 Senior Notes that were previously issued on June 5, 2024.

2026 Senior Notes

In the year ended December 31, 2025, we redeemed \$245 million of our 7.125% Senior Notes due 2026 (2026 Senior Notes) at 100% of the principal amount, resulting in an extinguishment loss in the amount of \$1 million for the write-off of unamortized debt issuance costs. Following this redemption, none of our 2026 Senior Notes were outstanding.

In the year ended December 31, 2024, we repurchased \$300 million in face value of our 2026 Senior Notes for \$303 million resulting in a loss on early extinguishment of debt in the amount of \$5 million which includes a \$2 million write-off of unamortized debt issuance costs.

Transactions Related to Our Common Stock

The following table is a summary of changes in our outstanding shares of our common stock during the year ended December 31, 2025:

	<u>Common Stock</u>
Balance at December 31, 2024	91,100,322
Issued as part of the Berry Merger ^(a)	5,572,115
Shares issued related to the Aera Merger ^(a)	107,265
Shares issued under ESPP	60,128
Shares issued under stock-based compensation arrangements	478,609
Repurchased shares held as treasury stock	(3,378,263)
Repurchased shares cancelled	(4,950,000)
Shares cancelled for taxes ^(b)	(236,011)
Balance at December 31, 2025	<u>88,754,165</u>

(a) Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations* for additional information.

(b) In connection with the vesting of equity awards, we withheld and cancelled shares to satisfy applicable tax-withholding requirements.

Common Stock Issued as Part of the Berry Merger

We issued 5,572,115 shares of CRC common stock in connection with the Berry Merger. The shares issued were registered under the Securities Act of 1933, as amended, pursuant to a registration statement on Form S-4 (File No. 333-290871) filed by CRC with the Securities and Exchange Commission on October 14, 2025, which became effective on November 3, 2025.

Dividends

Once declared, dividends are payable to shareholders in cash on a quarterly basis. The actual declaration of future cash dividends, and the establishment of record and payment dates, is subject to final determination by our Board of Directors each quarter after reviewing our financial performance.

On March 1, 2026, our Board of Directors declared a cash dividend of \$0.405 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 13, 2026 and is expected to be paid on March 20, 2026.

We paid the following cash dividends for each of the periods presented.

	<u>Total Dividend</u>	<u>Annual Rate Per Share</u>
	(in millions)	(\$ per share)
Year ended December 31, 2023	\$ 81	\$ 1.1575
Year ended December 31, 2024	113	1.3950
Year ended December 31, 2025	136	1.5675
	<u>\$ 330</u>	

Share Repurchase Program

Our Board of Directors authorized a Share Repurchase Program to acquire up to \$1.78 billion of our common stock through December 31, 2027. This includes a recent increase of \$430 million and extension approved by our Board of Directors on February 24, 2026. After the increase and shares repurchased in January 2026, we had approximately \$600 million of remaining unused capacity under this program as of February 28, 2026. For additional information, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 19 Subsequent Events*.

The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. The following is a summary of our share repurchases, held as treasury stock, for the periods presented:

	<u>Total Number of Shares Purchased</u>	<u>Dollar Value of Shares Purchased</u>	<u>Average Price Paid per Share</u>
	(number of shares)	(in millions)	(\$ per share)
Year ended December 31, 2023 . . .	3,407,655	\$ 143	\$41.69
Year ended December 31, 2024 . . .	3,649,348	\$ 192	\$52.12
Year ended December 31, 2025 . . .	8,328,263	\$ 377	\$45.29
Inception of Program (May 2021) through December 31, 2025	26,841,526	\$1,173	\$43.59

Note: The total value of shares purchased includes approximately \$2 million and \$1 million in the years ended December 31, 2024 and 2023 related to excise taxes on share repurchases. Excise taxes in 2025 were insignificant and include a reversal for 2024 excise taxes that were no longer due. Commissions paid were not significant in all periods presented.

Uses of Cash

At current commodity prices, we expect to generate operating cash flow to support and invest in our assets as part of our planned 2026 capital program described below. We regularly review our financial position, commodity prices, market conditions and other considerations to evaluate and optimize the deployment of our cash. We believe we have sufficient sources of liquidity to meet our obligations for the next twelve months.

2026 Capital Program

We expect our total 2026 capital program to range between \$430 million and \$470 million. Of this amount, \$410 million to \$435 million is related to our oil and natural gas segment, \$12 million to \$20 million is for our carbon management segment and \$8 million to \$15 million is for corporate and other activities. The above amounts related to carbon management projects do not include amounts funded by Brookfield through the Carbon TerraVault JV, such as drilling injection and monitoring wells at our 26R reservoir. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our joint venture with Brookfield.

Oil and natural gas segment – With respect to oil and natural gas development, we expect to run a four rig program in 2026. We currently hold the majority of permits necessary to undertake our 2026 capital program. We expect to obtain additional new well permits for the remainder of our 2026 capital program on a timely basis. For more information on permitting, refer to *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Carbon management segment – Our 2026 capital for carbon management projects includes approximately \$15 million for the completion of the carbon capture project at our cryogenic gas processing facility at Elk Hills. This gas processing facility is adjacent to the 26R storage reservoir held by Carbon TerraVault JV. For more information this project, refer to *Part I, Item 1 and 2 – Business and Properties, Carbon Management Segment*.

Other Uses of Cash

Other than our 2026 capital program, our expected material uses of cash during 2026 may include, subject to available liquidity, commodity prices, market conditions and other considerations, one or more of the following: (1) operating expenses; (2) dividends, share and debt repurchases; (3) settlements on commodity derivative contracts; (4) income taxes and other taxes not on income; (5) settlement of asset retirement obligations; and (6) costs related to advancing our carbon management activities not included in our capital program, such as employee costs and front-end engineering and design studies.

Our long-term material uses of cash include the following:

- repayment of principal and interest on our 2029 Senior Notes and 2034 Senior Notes (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt*)
- operating lease liabilities including our commercial office space, fleet vehicles, easements and certain facilities (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 13 Leases*)
- obligations associated with our defined benefit and post-employment benefit plans (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Pension and Postretirement Benefit Plans*)
- asset retirement obligations over the longer term (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other, Asset Retirement Obligations*)

We have certain off-balance sheet commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline transportation capacity, oil and natural gas leases, obligations under long-term service agreements and field equipment. The table below summarizes our undiscounted current and long-term purchase obligations as of December 31, 2025.

	<u>One Year or Less</u>	<u>More Than One Year</u>	<u>Total</u>
	(in millions)		
Oil and gas leases, surface easements and pipeline right-of-way ^(a)	\$ 1	\$ 2	\$ 3
Oil and gas transportation, throughput and storage arrangements ^(b)	19	72	91
Software licenses and other contracts	48	58	106
Contracts related to our carbon management segment ^(c)	1	—	1
Total	<u>\$ 69</u>	<u>\$ 132</u>	<u>\$ 201</u>

(a) Oil and natural gas leases reflect obligations for fixed payments under our contracts.

(b) Purchase obligations for pipeline capacity include ship or pay arrangements that are based on contractual volumes and current market rates for firm transportation capacity during the contract period.

Cash Flow Analysis

Cash flows from operating activities – Our net cash provided by operating activities is sensitive to many variables, particularly changes in commodity prices. Commodity price movements may also lead to changes in other variables in our business, including adjustments to our capital program. We experienced peak pricing for resource adequacy contracts in 2025 as compared to 2024. However, market prices for 2026 resource adequacy contracts declined due to growth in available resource adequacy-eligible capacity in the California market. As a result, we expect that our 2026 revenues from resource adequacy contracts will decrease between \$125 million to \$135 million in 2026 as compared to 2025.

Our operating cash flow for the year ended December 31, 2025 was \$865 million, which was an increase of \$255 million, from \$610 million for the year ended December 31, 2024. The increase was primarily driven by increased production after the Aera Merger which occurred on July 1, 2024. For the year ended December 31, 2025 we produced 138 MBoe/d, which was an increase of 37 MBoe/d from 110 MBoe/d for the year ended December 31, 2024. Our oil production increased to 109 MBbl/d for the year ended December 31, 2025 compared to 80 MBbl/d for the year ended December 31, 2024. Increases in production were partially offset by lower realized oil prices in 2025. Our average realized price for oil without the effects of derivative settlements decreased by \$10.40 to \$66.52 for the year ended December 31, 2025 compared to \$76.92 for the same prior year period. For more information on our production and price changes, see *Segment Results of Oil and Natural Gas Operations* above.

Settlement proceeds from our derivative contracts increased \$79 million from \$64 million settlement payments for the year ended December 31, 2024 to \$15 million settlement proceeds for the year ended December 31, 2025. For more information on our derivative contracts see, *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

Operating costs and general and administrative expenses increased in 2025 as compared to 2024 primarily due to the addition of Aera’s operations for the full year. As a result, we had higher compensation-related costs and additional costs related to surface maintenance, energy and purchase injectant.

Cash flows used in investing activities – The following table provides a comparative summary of net cash used in investing activities:

	Year ended December 31,	
	2025	2024
	(in millions)	
Capital investments	\$ (322)	\$ (255)
Changes in accrued capital investments	35	29
Proceeds from asset divestitures	8	15
Purchase of a business, net of cash acquired	(440)	(853)
Asset acquisitions	—	(6)
Other, net	(6)	(7)
Net cash used in investing activities	<u>\$ (725)</u>	<u>\$ (1,077)</u>

For the years ended December 31, 2025 and 2024, purchase of a business, net of cash acquired includes our investing activities related to the Berry Merger and the Aera Merger, respectively. In connection with the Berry Merger, we repaid \$449 million of Berry’s outstanding long-term debt and acquired cash of \$12 million (after a \$3 million payment for settlement of certain stock-based compensation awards). Additionally, we increased our 2025 capital program following the Aera Merger. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations* for more information on these transactions.

Proceeds from asset divestitures for the year ended December 31, 2025 primarily included the sale of properties for carbon management activities. Proceeds from asset divestitures for the year ended December 31, 2024 included the sale of our 0.9-acre Fort Apache real estate property in Huntington Beach, California as well as the remaining portion of our Ventura assets which were classified as held for sale. In the year ended December 31, 2024, the acquisitions shown in the table above related to purchasing storage reservoirs for our carbon management segment. *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* for more information on our divestitures and acquisitions.

Cash flows used in financing activities – The following table provides a comparative summary of net cash used in financing activities:

	Year ended December 31,	
	2025	2024
	(in millions)	
Proceeds from Revolving Credit Facility	\$ 220	\$ 30
Repayments of Revolving Credit Facility	(220)	(30)
Proceeds from 2029 Senior Notes, net	—	888
Proceeds from 2034 Senior Notes, net	393	—
Repurchases of common stock ^(a)	(377)	(192)
Common stock dividends	(136)	(113)
Dividend equivalents on equity-settled awards	(3)	(4)
Issuance of common stock	3	2
Bridge loan commitment costs	—	(5)
Debt redemption	(245)	(303)
Debt amendment costs	(3)	(18)
Stock warrants exercised	—	130
Shares cancelled for taxes	(12)	(42)
Net cash (used in) provided by financing activities	<u>\$ (380)</u>	<u>\$ 343</u>

(a) The total value of shares purchased reported on our statement of cash flows includes approximately \$2 million in the year ended December 31, 2024, related to excise taxes on share repurchases. Excise taxes in 2025 were insignificant and include a reversal for 2024 excise taxes that were no longer due. Commissions paid on share repurchases were not significant in all periods presented.

As noted above in *Long-Term Debt*, in October 2025, we completed an offering of \$400 million in aggregate principal amount of our 7.000% 2034 Senior Notes. We also redeemed \$245 million of our 2026 Senior Notes at 100% of the principal amount. In the year ended December 31, 2024, we completed an initial offering and a follow-on offering for our 2029 Senior Notes and we repurchased \$300 million in face value of our 2026 Senior Notes at a premium. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt* for more information on our financing arrangements.

Cash used for repurchases of our common stock under our Share Repurchase Program increased in 2025 as compared to 2024. Additionally, our Board of Directors increased the quarterly dividend rate on our common stock during 2025. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for more information on our Share Repurchase Program and cash dividends.

Divestitures and Acquisitions

From time to time, we review our extensive portfolio of assets for potential divestitures. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* for more information.

Lawsuits, Claims, Commitments and Contingencies

We are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2025 and 2024 were not material to our consolidated balance sheets as of such dates.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE's order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and we are challenging the order from BSEE. In March 2024, we entered into a cost sharing agreement with former lessees to share in ongoing maintenance costs during the pendency of the challenge to the BSEE order. In September 2025, the parties amended the cost sharing agreement to include well abandonment work. As of December 31, 2025, we recognized a liability of \$12 million, included in accrued liabilities in our consolidated balance sheet related to this abandonment work.

We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

See Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Lawsuits, Claims, Commitments and Contingencies.

Critical Accounting Estimates

Our critical accounting estimates that could result in a material impact to the consolidated financial statements due to the levels of subjectivity and management judgment include the following:

Title	Description	Estimation and Uncertainties	Sensitivities
Oil and Natural Gas Properties	<p>The carrying value of our property, plant and equipment represents the costs incurred to acquire or develop the asset, including any asset retirement obligations, net of accumulated depreciation, depletion and amortization. For assets acquired in a business combination, PP&E cost is based on fair values at the acquisition date. We use the successful efforts method of accounting for our oil and natural gas producing activities. Under this method, we capitalize the cost of acquiring properties, development costs and the costs of drilling successful exploration wells.</p> <p>The estimated amount of proved reserve volumes is used as the basis for recording depletion expense. We determine depletion on our oil and natural gas producing properties using the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are depleted based on proved developed oil and natural gas reserves.</p> <p>Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities.</p>	<p>The determination of quantities of proved reserves is a highly technical process performed by our engineers and geoscientists. The analysis is based on drilling results, reservoir performance, subsurface interpretation and future development plans. Production rate forecasts are primarily derived from estimates from decline-curve analysis and type-curve analysis. Secondary inputs may include material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes. Additional inputs may also include seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continuous reassessment of the viability of future production volumes under varying economic conditions.</p> <p>Several other factors could change our proved oil and gas reserves including changes in energy costs, inflation, deflation and the political and</p>	<p>Our total proved reserves were 654 MMBoe and our total proved developed reserves were 541 MMBoe at December 31, 2025. We estimate our 2026 depletion rate for oil and natural gas producing properties using the unit-of-production method will be approximately \$9/Boe. A 5% change in our reserves would increase or decrease this DD&A rate by approximately \$0.47/Boe.</p>

Title	Description	Estimation and Uncertainties	Sensitivities
	<p>Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill. The preliminary fair value of Berry's proved reserves acquired in the acquisition approximated \$637 million. We do not have significant capitalized costs related to unproved properties and have not identified significant unproved properties as a result of the acquisition of Berry.</p>	<p>regulatory environment, all of which are beyond our control.</p> <p>We estimated the fair value of Berry's proved reserves at the acquisition date using the expected present value of discounted future cash flows, on an after-tax basis, and applying a reasonable discount rate. We have used all available information to make a fair value determination, including assistance from third-party valuation experts. The assumptions used are believed to be reasonable but could change. This would have the effect of increasing or decreasing the amount of DD&A we recognized on acquired assets.</p>	
<p>Asset Retirement Obligations</p>	<p>Our asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells and facilities used in the oil and natural gas segment.</p> <p>We determine our asset retirement obligation, including the obligations related to Berry's assets we acquired, by calculating the present value of estimated future cash outflows related to the abandonment obligation.</p> <p>The asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset or included in the fair value estimate in a business combination. In periods subsequent to initial measurement, the asset retirement cost is depreciated using the unit-of-production method, while increases in the ARO liability resulting from the passage of time (accretion expense) is included in operating expenses on our consolidated statements of operations.</p>	<p>The recognition of an asset retirement obligation requires us to make assumptions including an estimate of future abandonment costs and inflation rates, timing of activity and our credit-adjusted discount rate among others. Changes in the legal, regulatory and political environment could also affect our estimated future cash outflows.</p>	<p>As of December 31, 2025 and 2024, we had asset retirement obligations of \$1,033 million and \$1,129 million, respectively.</p> <p>A 1% increase in the inflation rate would increase our liability by \$94 million and a 1% decrease in the inflation rate would decrease our liability by \$89 million as of December 31, 2025.</p>

Forward-Looking Statements

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

Although we believe the expectations and forecasts reflected in our 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 our 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 our actual results to be materially different than those expressed in our forward-looking statements include:

- fluctuations in commodity prices, including supply and demand considerations for our products and services, and the impact of such fluctuations on revenues and operating expenses;
- decisions as to production levels and/or pricing by OPEC+ or U.S. producers in future periods;
- government policy, war and political conditions and events, including the military conflicts in Israel and Ukraine and geopolitical uncertainty in the Middle East and Venezuela;
- the ability to successfully execute integration efforts in connection with the Berry Merger, and achieve projected synergies and ensure that such synergies are sustainable;
- regulatory actions and changes that affect the oil and gas industry generally and us in particular, including (1) the availability or timing of, or conditions imposed on, EPA and other governmental permits and approvals necessary for drilling or development activities or our carbon management segment; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (3) the protection of health, safety and the environment, or (4) the transportation, marketing and sale of our products;
- refinery closures and reductions in pipeline transportation capacity;
- the expected timing and resumption of the issuance of well permits following the enactment of SB 237;
- the efforts of activists to delay prevent oil and gas activities or the development of our carbon management segment through a variety of tactics, including litigation;
- the impact of inflation, tariffs and changes in domestic or global trade policies on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and the ability and financial resources to execute our capital plan in a timely manner;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to our estimates of reserves and related future cash flows, including changes arising from our inability to develop such reserves in a timely manner, and any inability to replace such reserves;
- the recoverability of resources and unexpected geologic conditions;
- general economic conditions and trends, including conditions in the worldwide financial, trade and credit markets;
- production-sharing contracts’ effects on production and operating costs;

- the lack of available equipment, service or labor price inflation;
- limitations on transportation or storage capacity and the need to shut-in wells;
- any failure of risk management;
- results from operations and competition in the industries in which we operate;
- our ability to realize the anticipated benefits from prior or future efforts to reduce costs;
- environmental risks and liability under federal, regional, state, provincial, tribal, local and international environmental laws and regulations (including remedial actions);
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of our operations;
- our ability to claim and utilize tax credits or other incentives in connection with our CCS projects;
- our ability to realize the benefits contemplated by our energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects, power projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and our ability to convert our MOUs and CDMAAs to definitive agreements and enter into other offtake agreements;
- our ability to grow and develop our carbon management segment and achieve projected injection and storage rates;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms;
- uncertainty around the accounting of emissions and our ability to successfully gather and verify emissions data and other environmental impacts;
- changes to our dividend policy and share repurchase program, and our ability to declare future dividends or repurchase shares under our debt agreements;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- our access to and the terms of credit in commercial banking and capital markets, including our ability to refinance our debt or obtain separate financing for our carbon management segment;
- changes in state, federal or international tax rates, including our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- effects of hedging transactions;
- the effect of our stock price on costs associated with incentive compensation;
- inability to enter into desirable transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19 pandemic;
- transaction costs;
- unknown liabilities; and
- other factors discussed in *Part I, Item 1A – Risk Factors*.

We caution you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and we undertake no obligation to update this information. This document may also contain information from third party sources. This data may involve a number of assumptions and limitations, and we have not independently verified them and do not warrant the accuracy or completeness of such third-party information.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our financial results are sensitive to fluctuations in oil, NGL and natural gas prices. These commodity price changes also impact volumes under PSCs. We maintain a commodity hedging program focused on crude oil and natural gas to help protect our cash flows, margins and capital program from the volatility of crude oil and natural gas prices. We have not designated any instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. We believe we have limited price volatility risk in the near term as a result of our current hedges in place. As of December 31, 2025, we had hedges on approximately 65% of our anticipated oil production through 2026 and approximately 40% through 2027.

The primary market risk relating to our derivative contracts relates to fluctuations in market prices as compared to the fixed contract price for a notional amount of our production. As of December 31, 2025, we had net assets of \$229 million for our derivative commodity positions which are carried at fair value, using industry-standard models with various inputs, including the forward curve for the relevant price index. We estimate that a \$10/bbl increase in Brent oil forward prices could increase our settlement payments by \$179 million in 2026, limiting our upside. We estimate that a \$10/bbl decrease in Brent oil forward prices could decrease our settlement payments by \$294 million in 2026, negating the downside price movement for hedged volumes.

A summary of our Brent-based crude oil derivative contracts at December 31, 2025 are included in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

Counterparty Credit Risk

Our counterparty credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each counterparty is monitored for outstanding balances and current activity. Counterparty credit limits have been established based upon the financial health of counterparties, and these limits are actively monitored. In the event counterparty credit risk is heightened, we may request collateral or accelerate payment dates for product deliveries. Approximately 79% of our production during 2025 was oil which was sold predominately to refineries in California. Trade receivables for all commodities are collected within 30 to 60 days following the month of delivery. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We have master netting agreements with each of our derivative counterparties, which allow us to net our settlement payments for the same commodity with the same counterparty. Therefore, our loss is limited to the net amount due from a defaulting counterparty. The majority of our credit exposure was with investment grade counterparties. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

Interest-Rate Risk

Changes in interest rates may affect the amount of interest we pay on our long-term debt. However, we had no variable-rate debt outstanding as of December 31, 2025. Our 2029 Senior Notes bear interest at a fixed rate of 8.250% per annum. Our 2034 Senior Notes bear interest at a fixed rate of 7.000% per annum.

Other Competition Risk

We face competition in our oil and natural gas segment from other sources of energy, including wind and solar power. These products compete directly with the electricity we generate from certain power plants we own, including our Elk Hills power plant, and indirectly as substitutes for oil, natural gas and NGLs. We expect competition from these sources to intensify in the future due to technological advances and as California may continue to develop renewable energy and implement climate-related policies.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors California Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company acquired Berry Corporation during 2025, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2025, Berry Corporation's internal control over financial reporting associated with approximately 12% of total assets and less than 1% of total revenues included in the consolidated financial statements of the Company as of and for the year ended December 31, 2025. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Berry Corporation.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Assessment of and Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our

audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of estimated oil and gas reserves on depletion expense for proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, the Company determines depletion of oil and gas producing properties by the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are amortized based on proved developed oil and gas reserves. The Company recorded depreciation, depletion, and amortization expense of \$511 million for the year ended December 31, 2025.

Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration estimates of future production, operating and development costs and commodity prices. The Company employs personnel who possess technical expertise, such as reservoir engineers and geoscientists, who estimate proved oil and gas reserves. The Company also engages independent reservoir engineering specialists to perform an independent evaluation of the Company's proved oil and gas reserves estimates. We identified the assessment of estimated proved oil and gas reserves on the determination of depreciation, depletion and amortization expense for proved

oil and gas properties as a critical audit matter. Subjective auditor judgment was required to evaluate the Company's estimate of proved oil and gas reserves, which is an input to the determination of depreciation, depletion, and amortization expense. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to estimated future oil and gas production and future operating and development costs.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's depletion process, including controls related to the estimation of proved oil and gas reserves. We evaluated (1) the professional qualifications of the Company's internal reserve engineers, as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm to the Company. We evaluated the process and assessed the methodology used by the Company's internal reservoir engineers and the independent reservoir engineering specialist to estimate the reserves used in the determination of depreciation, depletion and amortization expense for compliance with industry and regulatory standards. We compared estimated future oil and gas production and estimated future operating and development costs estimated by the technical personnel employed by the Company to historical results. We read and considered the reports of the independent reservoir engineering specialist in connection with our evaluation of the Company's proved oil and gas reserves estimates.

Evaluation of the fair value measurement of oil and gas properties acquired in the Berry Corporation business combination

As discussed in Note 2 to the consolidated financial statements, on December 18, 2025, the Company completed a merger with Berry Corporation for cash and equity consideration of approximately \$709 million. The transaction was accounted for as a business combination using the acquisition method, with the Company being identified as the accounting acquirer. Under the acquisition method of accounting the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. As a result of the transaction, the Company acquired proved oil and gas properties which were recognized at their acquisition date fair value of \$709 million.

We identified the evaluation of the initial fair value measurement of the oil and gas properties acquired in the Berry transaction as a critical audit matter. Subjective auditor judgment was required in evaluating the key assumptions used to estimate the fair value of the proved oil and gas properties as changes to those assumptions could have had a significant effect on the fair value. The key assumptions used by the Company to determine fair value included forecasted commodity prices, reserve category risk adjustment factors, estimated future oil and gas production, estimated future operating and capital costs and discount rate. Additionally, the audit effort associated with evaluating the forecasted commodity prices, reserve category risk adjustment factors, and discount rate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's acquisition-date valuation process, including controls related to the determination of the key assumptions, as noted above, used to measure the initial fair value of the acquired proved oil and gas properties. We evaluated the professional qualifications of the Company's internal reservoir engineers and their knowledge, skills, and ability relative to the valuation process. We evaluated the process and assessed the methodology used by the Company's internal reservoir engineers to estimate the proved future production volumes for compliance with industry and regulatory standards. We compared the estimated future proved oil and gas production and estimated future operating and capital costs determined by the technical personnel employed by the Company to historical Berry production volumes and historical costs. In addition,

we involved valuation professionals with specialized skills and knowledge, who assisted in: 1) evaluating the Company's discount rate by comparing it to a discount rate range that was independently developed using publicly available market data for comparable entities, 2) evaluating the reserve category risk adjustment factors used by the Company by comparing them to third party publications of risk adjustment factors utilized by market participants, 3) evaluating the forecasted commodity price assumption by comparing it to an independently developed range of forward price estimates using data from analysts and other industry sources.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Los Angeles, California
March 2, 2026

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2025 and 2024
(in millions, except share data)

	2025	2024
CURRENT ASSETS		
Cash and cash equivalents	\$ 132	\$ 372
Trade receivables	333	330
Inventory	106	90
Assets held for sale	—	10
Receivables from affiliate	14	46
Other current assets, net	353	176
Total current assets	938	1,024
PROPERTY, PLANT AND EQUIPMENT	7,523	6,738
Accumulated depreciation, depletion and amortization	(1,618)	(1,058)
Total property, plant and equipment, net	5,905	5,680
INVESTMENT IN UNCONSOLIDATED SUBSIDIARIES	111	86
DEFERRED INCOME TAXES	76	73
OTHER NONCURRENT ASSETS	373	272
TOTAL ASSETS	\$ 7,403	\$ 7,135
 CURRENT LIABILITIES		
Accounts payable	452	369
Accrued liabilities	598	611
Total current liabilities	1,050	980
NONCURRENT LIABILITIES		
Long-term debt, net	1,283	1,132
Asset retirement obligations	913	995
Deferred tax liabilities	154	113
Other long-term liabilities	329	377
STOCKHOLDERS' EQUITY		
Preferred stock (20,000,000 shares authorized at \$0.01 par value); no shares outstanding at December 31, 2025 and 2024	—	—
Common stock (200,000,000 shares authorized at \$0.01 par value); (110,645,691 and 109,613,585 shares issued; 88,754,165 and 91,100,322 shares outstanding at December 31, 2025 and 2024, respectively)	1	1
Treasury stock (21,891,526 shares held at cost at December 31, 2025 and 18,513,263 shares held at December 31, 2024)	(944)	(796)
Additional paid-in capital	2,625	2,578
Retained earnings	1,905	1,680
Accumulated other comprehensive income	87	75
Total stockholders' equity	3,674	3,538
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 7,403	\$ 7,135

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2025, 2024 and 2023
(in millions, except per share data)

	Year ended December 31,		
	2025	2024	2023
REVENUES			
Oil, natural gas and natural gas liquids sales	\$ 2,910	\$ 2,537	\$ 2,155
Net gain (loss) from commodity derivatives	266	241	(12)
Revenue from marketing of purchased commodities	238	235	407
Electricity revenue	233	159	211
Other revenue	22	26	40
Total operating revenues	<u>3,669</u>	<u>3,198</u>	<u>2,801</u>
OPERATING EXPENSES			
Operating costs	1,252	966	822
General and administrative expenses	333	321	267
Depreciation, depletion and amortization	511	388	225
Asset impairment	59	14	3
Taxes other than on income	242	242	165
Costs related to marketing of purchased commodities	182	193	224
Electricity generation expenses	38	40	103
Transportation costs	79	81	67
Accretion expense	114	87	46
Net loss on natural gas purchase derivatives	50	30	8
Measurement period adjustments, net	1	(12)	—
Other operating expenses, net	209	239	95
Total operating expenses	<u>3,070</u>	<u>2,589</u>	<u>2,025</u>
(Loss) gain on asset divestitures	(1)	11	32
OPERATING INCOME	598	620	808
NON-OPERATING (EXPENSES) INCOME			
Interest and debt expense, net	(106)	(87)	(56)
Loss on early extinguishment of debt	(1)	(5)	(1)
Equity loss from unconsolidated subsidiaries	(4)	(10)	(9)
Other non-operating income (expense), net	15	(2)	6
INCOME BEFORE INCOME TAXES	502	516	748
Income tax provision	(139)	(140)	(184)
NET INCOME	<u>\$ 363</u>	<u>\$ 376</u>	<u>\$ 564</u>
Net income per share			
Basic	\$ 4.17	\$ 4.74	\$ 8.10
Diluted	\$ 4.15	\$ 4.62	\$ 7.78
Weighted-average common shares outstanding			
Basic	87.0	79.3	69.6
Diluted	87.4	81.4	72.5

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
For the years ended December 31, 2025, 2024 and 2023
(in millions)

	Year ended December 31,		
	2025	2024	2023
Net income	\$ 363	\$ 376	\$ 564
Other comprehensive income ^(a) :			
Actuarial gain (loss) associated with pension and postretirement plans	19	3	(1)
Prior service credit	—	2	—
Recognition of net actuarial gain due to settlement	(2)	—	—
Recognition of prior service credit due to curtailment	—	—	(2)
Recognition of net actuarial loss due to curtailment	—	(3)	—
Recognition of net actuarial gain due to special termination benefits	—	3	—
Amortization of prior service cost credit included in net periodic benefit cost	(4)	(4)	(4)
Amortization of net actuarial gain	(1)	—	—
Total other comprehensive income (loss)	12	1	(7)
Comprehensive income	\$ 375	\$ 377	\$ 557

(a) Amounts are net of a tax provision of \$5 million, tax provision of \$1 million, and tax benefit of \$3 million in tax for the years ended December 31, 2025, 2024, and 2023, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders' Equity (Deficit)
For the years ended December 31, 2025, 2024 and 2023
(in millions)

	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
Balance, December 31,						
2022	\$ 1	\$ (461)	\$ 1,305	\$ 938	\$ 81	\$ 1,864
Net income	—	—	—	564	—	564
Share-based compensation ..	—	—	28	—	—	28
Repurchases of common stock	—	(143)	—	—	—	(143)
Cash dividends	—	—	—	(83)	—	(83)
Shares cancelled for taxes ...	—	—	(3)	—	—	(3)
Issuance of common stock ...	—	—	—	—	—	—
Other comprehensive income, net of tax	—	—	—	—	(7)	(7)
Other	—	—	(1)	—	—	(1)
Balance, December 31,						
2023	\$ 1	\$ (604)	\$ 1,329	\$ 1,419	\$ 74	\$ 2,219
Net income	—	—	—	376	—	376
Share-based compensation ..	—	—	25	—	—	25
Repurchases of common stock	—	(192)	—	—	—	(192)
Shares issued for warrants ...	—	—	130	—	—	130
Shares issued for Aera Merger	—	—	1,136	—	—	1,136
Cash dividends	—	—	—	(115)	—	(115)
Shares cancelled for taxes ...	—	—	(42)	—	—	(42)
Other comprehensive income, net of tax	—	—	—	—	1	1
Balance, December 31,						
2024	\$ 1	\$ (796)	\$ 2,578	\$ 1,680	\$ 75	\$ 3,538
Net income	—	—	—	363	—	363
Share-based compensation ..	—	—	27	—	—	27
Repurchases of common stock	—	(148)	(228)	—	—	(376)
Shares issued for Berry Merger	—	—	253	—	—	253
Shares issued for Aera Merger	—	—	6	—	—	6
Cash dividends	—	—	—	(138)	—	(138)
Shares cancelled for taxes ...	—	—	(12)	—	—	(12)
Other comprehensive income, net of tax	—	—	—	—	12	12
Other	—	—	1	—	—	1
Balance, December 31,						
2025	\$ 1	\$ (944)	\$ 2,625	\$ 1,905	\$ 87	\$ 3,674

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2025, 2024 and 2023
(in millions)

	Year ended December 31,		
	2025	2024	2023
CASH FLOW FROM OPERATING ACTIVITIES			
Net income	\$ 363	\$ 376	\$ 564
<i>Adjustments to reconcile net income to net cash provided by operating activities:</i>			
Depreciation, depletion and amortization	511	388	225
Asset impairments	59	14	3
Deferred income tax provision	85	71	35
Net (gain) loss from commodity derivatives	(216)	(211)	20
Net proceeds (payments) on settled commodity derivatives	15	(64)	(272)
Net loss on early extinguishment of debt	1	5	1
Loss (gain) on asset divestitures	1	(11)	(32)
Other non-cash charges to income, net	187	139	103
Changes in operating assets and liabilities, net:			
Decrease in trade receivables	83	58	110
Increase in inventories	(6)	(1)	(12)
Decrease in other current assets, net	2	28	—
Decrease in accounts payable and accrued liabilities	(220)	(182)	(92)
Net cash provided by operating activities	865	610	653
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(322)	(255)	(185)
Changes in accrued capital investments	35	29	(13)
Proceeds from asset divestitures	8	15	32
Purchase of a business, net of cash acquired	(440)	(853)	—
Asset acquisitions	—	(6)	(5)
Other, net	(6)	(7)	(4)
Net cash used in investing activities	(725)	(1,077)	(175)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from Revolving Credit Facility	220	30	—
Repayments of Revolving Credit Facility	(220)	(30)	—
Proceeds from 2029 Senior Notes, net	—	888	—
Proceeds from 2034 Senior Notes, net	393	—	—
Repurchases of common stock	(377)	(192)	(143)
Common stock dividends	(136)	(113)	(81)
Dividend equivalents on equity-settled awards	(3)	(4)	—
Issuance of common stock	3	2	2
Bridge loan commitments	—	(5)	—
Stock warrants exercised	—	130	—
Debt amendment costs	(3)	(18)	(8)
Shares cancelled for taxes	(12)	(42)	(3)
Debt redemption	(245)	(303)	(56)
Net cash (used in) provided by financing activities	(380)	343	(289)
(Decrease) increase in cash and cash equivalents	(240)	(124)	189
Cash and cash equivalents—beginning of period	372	496	307
Cash and cash equivalents—end of period	\$ 132	\$ 372	\$ 496

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

NOTE 1 NATURE OF BUSINESS, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

Nature of Business

We are an independent energy and carbon management company committed to energy transition. We focus on environmental stewardship while safely providing local, responsibly sourced energy. We also seek to maximize the value of our land, mineral ownership, and energy expertise for decarbonization by developing carbon capture and storage (CCS) and other emissions-reducing projects.

Our business is organized into two reporting segments: oil and natural gas and carbon management. Our oil and natural gas segment explores for, develops, and produces oil and condensate, natural gas liquids and natural gas. Our carbon management segment, which we refer to as Carbon TerraVault, is focused on building, installing, operating and maintaining CO₂ capture equipment, transportation assets and underground storage facilities. Our carbon management segment also owns an investment in the Carbon TerraVault joint venture. See *Note 4 Investments and Related Party Transactions* and *Note 16 Segment Information* for additional information.

On December 18, 2025, pursuant to the Agreement and Plan of Merger, dated as of September 14, 2025 (the Berry Merger Agreement), we obtained all of the ownership interests in Berry Corporation (bry) (Berry) in an all-stock transaction (Berry Merger). Our consolidated results of operations include the results of Berry beginning December 18, 2025, the closing date of the Berry Merger. The Berry Merger did not significantly impact the comparability of our financial results for the year ended December 31, 2025 as compared to the year ended December 31, 2024. See *Note 2 Business Combinations* for transaction details.

On July 1, 2024, pursuant to the Agreement and Plan of Merger, dated as of February 7, 2024 (the Aera Merger Agreement), we obtained all of the ownership interests in Aera Energy LLC (Aera) in an all-stock transaction (Aera Merger). Our consolidated results of operations include the results of Aera beginning July 1, 2024, the closing date of the Aera Merger. The Aera Merger significantly impacted the comparability of our financial results for the year ended December 31, 2025 as compared to the years ended December 31, 2024 and 2023. See *Note 2 Business Combinations* for transaction details.

Except when the context otherwise requires or where otherwise indicated, all references to “CRC,” the “Company,” “we,” “us” and “our” refer to California Resources Corporation and its consolidated subsidiaries as of the date presented.

Basis of Presentation

We have prepared this report in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and the rules and regulations of the U.S. Securities and Exchange Commission applicable to annual financial information.

All financial information presented consists of our consolidated results of operations, financial position and cash flows. We have eliminated intercompany transactions and balances. We account for our share of oil and natural gas producing activities, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our consolidated financial statements. We have conformed Berry’s and Aera’s accounting policies to our legacy methods for all significant balances included in our consolidated financial statements.

In applying the equity method of accounting, our investments in our unconsolidated subsidiaries are recognized either at cost, as is the case with Carbon TerraVault JV HoldCo, LLC, or at fair value if acquired in a business combination, as is the case for Midway Sunset Cogeneration Company. These investments are then adjusted for our proportionate share of income or loss in addition to contributions and distributions.

Certain 2023 balances related to natural gas liquid (NGL) marketing activities were reclassified to conform to our 2025 and 2024 presentation. For the year ended December 31, 2023, we reclassified \$6 million related to NGL storage activities from other revenue to revenue from marketing of purchased commodities on our consolidated statements of operations. For the year ended December 31, 2023, we reclassified \$3 million related to NGL processing fees from other operating expenses, net to costs related to marketing of purchased commodities on our consolidated statements of operations.

Use of Estimates

The process of preparing financial statements in conformity with U.S. GAAP requires management to select appropriate accounting policies and make informed estimates and judgments regarding certain types of financial statement balances and disclosures. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements and judgments on expected outcomes as well as the materiality of transactions and balances. Changes in facts and circumstances or discovery of new information relating to such transactions and events may result in revised estimates and judgments. Further, actual results may differ from estimates upon settlement. Management believes that these estimates and judgments provide a reasonable basis for the fair presentation of our consolidated financial statements.

Risks and Uncertainties

The revenue, profitability and future growth of our oil and natural gas segment are substantially dependent upon prevailing and future prices for the commodities we produce and sell, which can be volatile and fluctuate significantly due to factors beyond our control. Additionally, our oil and natural gas operations and development activities are subject to evolving state and local regulations, which may be subject to change or re-interpretation, which could result in increased compliance costs, delays or restrictions.

We are developing a carbon capture and sequestration business which is subject to risks as an emerging industry and availability of tax incentives. We operate primarily in California which is a highly regulated environment.

Concentration of Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other customers that have access to transportation and storage facilities. We do not believe that the loss of any single customer would have a material adverse effect on our consolidated financial statements taken as a whole.

For the year ended December 31, 2025, two customers of our oil and gas segment each accounted for at least 10%, and collectively 51%, of our sales (before the effects of hedging). For the year ended December 31, 2024, four customers of our oil and gas segment each accounted for at least 10%, and collectively 67%, of our sales (before the effects of hedging). For the year ended December 31, 2023, three customers of our oil and gas segment each accounted for at least 10%, and collectively accounted for 44%, of our sales (before the effects of hedging).

Recently Issued but not Adopted Accounting and Disclosure Changes

In November 2024, the Financial Accounting Standards Board (FASB) issued new disclosure requirements to enhance disclosure of certain costs and expenses. These new expense disclosures

will apply to us. The rules are effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027, early adoption is permitted. The adoption of these rules will only impact our disclosures and have no impact to our results of operations, cash flows and financial condition.

Accounting Policies

Fair Value Measurements

Our assets and liabilities measured at fair value are categorized in a three-level fair-value hierarchy, based on the inputs to the valuation techniques:

- Level 1—using quoted prices in active markets for the assets or liabilities;
- Level 2—using observable inputs other than quoted prices for the assets or liabilities; and
- Level 3—using unobservable inputs.

Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discount rates.

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. Our commodity derivatives comprise of over-the-counter bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices based on transactions executed in the marketplace. We classify these measurements as Level 2.

Our PP&E may be written down to fair value if we determine that there has been an impairment. The fair value is determined as of the date of the assessment generally using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves, inclusive of market differentials, as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate. Refer to *Note 3 Property, Plant and Equipment* for more information on our asset impairments.

The carrying amounts of cash and other on-balance sheet financial instruments, other than fixed-rate debt, approximate fair value. See *Note 5 Debt* for the fair value of our fixed-rate debt.

Consolidations

We may enter into joint ventures that are considered to be a variable interest entity (VIE). A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. We consolidate a VIE if we determine that we have (i) the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) the obligation to absorb losses or the right to receive benefits from the VIE that are more than insignificant to the VIE. If an entity is determined to be a VIE but we do not have a controlling interest, the entity is accounted for under either the cost or equity method depending on whether we exercise significant influence. See *Note 4 Investments and Related Party Transactions* for more information on the Carbon TerraVault JV.

We also may enter into investments in entities that are considered to be voting interest entities (VOEs). A VOE is a legal entity that does not meet the conditions of a VIE as outlined above. We consolidate a VOE if we determine that we have a controlling financial interest in the VOE. If an entity is determined to be a VOE but we do not have a controlling financial interest, the entity is accounted for under either the cost or equity method, depending on the structure of the entity. See *Note 4 Investments and Related Party Transactions* for more information on our investment in the Midway Sunset Cogeneration Company.

These evaluations are highly complex and involve management judgment and may involve the use of estimates and assumptions based on available information. The evaluation requires continual assessment. Investments in unconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred, which is other than temporary.

Business Combinations

We account for business combination in accordance with Accounting Standards Codification Topic 805, *Business Combinations* (ASC 805). Under the acquisition method of accounting in ASC 805, the assets acquired and liabilities assumed are measured as of their acquisition date fair value. Fair value is the price that we estimate would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill. If the fair value of the assets acquired and the liabilities assumed are greater than the purchase price, then a bargain purchase gain is recognized. Transaction and integration costs associated with business combinations are expensed as incurred. Refer to *Note 2 Business Combinations* for additional information.

Revenue Recognition

We derive substantially all of our revenue from sales of oil, natural gas and NGLs, with the remaining revenue generated from sales of electricity and marketing activities (related to storage and managing excess pipeline capacity). Revenues are recognized when control of promised goods is transferred to our customers, in an amount that reflects the consideration we expect to receive in exchange for those goods. See *Note 15 Revenue* for more information on our revenue from contracts with customers.

Restricted Cash

Restricted cash of \$15 million and \$18 million, included in cash and cash equivalents on our consolidated balance sheet, at December 31, 2025 and December 31, 2024, respectively, primarily includes funds held in an escrow account established to secure well and infrastructure abandonment and habitat restoration at an oil and gas field previously owned by Aera. Funds will be released from the escrow account as work is completed. The Aera Merger Agreement provides that 50% of the amount of released funds exceeds the cumulative abandonment and habitat restoration expenditures from January 1, 2024 onward is payable to the prior owners of Aera (Sellers). We do not expect this return of excess cash to be significant.

Inventory

Materials and supplies, which primarily consist of well equipment and tubular goods used in oil and natural gas operations, are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods are predominantly comprised of oil and natural gas liquids (NGLs), which are valued at the lower of cost or net realizable value. Inventory, by category, are as follows:

	<u>2025</u>	<u>2024</u>
	(in millions)	
Materials and supplies	\$ 98	\$ 86
Finished goods	8	4
Total	<u>\$ 106</u>	<u>\$ 90</u>

In the year ended December 31, 2024, we recorded an impairment of excess and obsolete materials and supplies of \$13 million. The impairment related to the write-down of obsolete materials and supplies to fair value using Level 3 inputs in the fair value hierarchy.

In 2025, we acquired materials and supplies inventory with an estimated value of \$6 million in connection with the Berry Merger. See *Note 2 Business Combinations* for additional information on the Berry Merger.

Derivative Instruments

The fair value of our derivative contracts are netted when a legal right of offset exists with the same counterparty with an intent to offset. Since we did not apply hedge accounting to our commodity derivatives for any of the periods presented, we recognized fair value adjustments, on a net basis, in our consolidated statements of operations. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not accounted for as cash-flow or fair-value hedges.

Property, Plant and Equipment (PP&E)

We use the successful efforts method to account for our oil and natural gas properties. Under this method, we capitalize costs of acquiring properties, costs of drilling successful exploration wells and development costs. The costs of exploratory wells, including permitting, land preparation and drilling costs, are initially capitalized pending a determination of whether we find proved reserves. If we find proved reserves, the costs of exploratory wells remain capitalized. Otherwise, we charge the costs of the related wells to expense. In cases where we cannot determine whether we have found proved reserves at the completion of exploration drilling, we conduct additional testing and evaluation of the wells. We generally expense the costs of such exploratory wells if we do not find proved reserves within a one-year period after initial drilling has been completed.

Proved Reserves – Proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a specific date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. We have no proved oil and natural gas reserves for which the determination of economic producibility is subject to the completion of major capital investments.

Several factors could change our proved oil and natural gas reserves. For example, for long-lived properties, higher commodity prices typically result in additional reserves becoming economic and lower commodity prices may lead to existing reserves becoming uneconomic. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded as well as availability of capital to implement the development activities contemplated in the reserves estimates and changes in management’s plans with respect to such development activities.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserve estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. Any impairment loss would be calculated as the excess of the asset's net book value over its estimated fair value. We recognize any impairment loss on proved properties by adjusting the carrying amount of the asset.

Unproved Properties – When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved to proved based on the initially determined acquisition cost per BOE. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, regulatory changes, contractual conditions or other factors, the capitalized costs of the related properties would be expensed.

Impairments of unproved properties are primarily based on qualitative factors including intent of property development, lease term and recent development activity. The timing of impairments on unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

Depreciation, Depletion and Amortization – We determine depreciation, depletion and amortization (DD&A) of oil and natural gas producing properties by the unit-of-production method. Our unproved reserves are not subject to DD&A until they are classified as proved properties. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Our gas and power plant assets are depreciated over the estimated useful lives of the assets, using the straight-line method, with expected initial useful lives of the assets of up to 30 years. We depreciate other property and equipment using the straight-line method based on expected useful lives of the individual assets or group of assets. The useful lives typically include ranges of 5-10 for well servicing equipment, 4-10 years for leasehold improvements, 1-4 years for software and telecommunications equipment and up to 5 years for computer hardware.

We expense annual lease rentals, the costs of injection used in production and exploration, and geological, geophysical and seismic costs as incurred. Costs of maintenance and repairs are expensed as incurred, except that the costs of replacements that expand capacity or add proven oil and natural gas reserves are capitalized.

Stock-Based Incentive Plans

The terms of our long-term incentive plan were approved by our board of directors in January 2021. In accordance with this long-term incentive plan, we reserved 9,257,740 shares of common stock (subject to adjustment) for future issuances to certain executives, employees and non-employee directors that are more fully described in *Note 10 Stock-Based Compensation*.

Earnings Per Share

Basic earnings per share is calculated as net income divided by the weighted average number of our common shares outstanding during the period. Diluted earnings per share is calculated by dividing net income by the weighted average number of our common shares outstanding including the effect of

dilutive potential common shares. We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities, when applicable, and the treasury stock method when participating securities are not in place. Certain restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights, which participate at the same rate as common stock.

Under the two-class method, net income allocated to participating securities is subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations (ARO) in the period in which a determination is made that a legal obligation exists to dismantle an asset and reclaim or remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The fair value of the retirement obligation is based on future retirement cost estimates and incorporates many assumptions such as time of abandonment, current regulatory requirements, technological changes, future inflation rates and a risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related PP&E balances. If the estimated future cost or timing of cash flow changes, we adjust the fair value of the liability and PP&E. Over time the liability is increased, and expense is recognized for accretion. The cost capitalized to PP&E is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

We have asset retirement obligations for certain of our facilities, which includes plant and field decommissioning, and the plugging and abandonment of wells. In certain cases, we will recognize ARO in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and, accordingly, we have not recorded a liability.

The following table summarizes the activity related to our 2025 and 2024 ARO:

	<u>Year ended December 31,</u>	
	<u>2025</u>	<u>2024</u>
	(in millions)	
Beginning balance	\$ 1,129	\$ 521
Liabilities assumed	151	646
Liabilities settled and divested	(122)	(94)
Accretion expense ^(a)	113	84
Revisions of estimated cash flows	(242)	(32)
Additions	4	4
Ending balance	<u>\$ 1,033</u>	<u>\$ 1,129</u>
Current liability (included in accrued liabilities)	\$ 120	\$ 134
Non-current liability	\$ 913	\$ 995

(a) For the year ended December 31, 2024, we recognized a \$3 million adjustment included in measurement period adjustments on our consolidated statement of operations related to accretion on the Aera asset retirement obligation.

Liabilities assumed during 2025 and 2024 include \$151 million related to the Berry Merger and \$646 million related to the Aera Merger, respectively. See *Note 2 Business Combinations* for more information on these transactions. Our liabilities settled and divested in 2025 related to settlement

payments. Our liabilities settled and divested in 2025 for \$122 million, included \$35 million for Aera settlement payments. Our liabilities settled and divested in 2024 for \$94 million, included \$92 million for settlement payments and \$2 million related to the divestiture of our Fort Apache real estate property in Huntington Beach, California. Revisions of our estimated cash flows decreased \$210 million in 2025, which primarily relates to Aera fields and reflects efficiencies gained in how we perform our well abandonment and also extension of field economic limits due to operating cost savings, mostly related to steamfloods. Revisions of estimated cash flows for 2025 also included \$19 million related to purchase price adjustments related to the Aera Merger.

Revisions of our estimated cash flows decreased \$32 million in 2024, which reflects efficiencies gained in how we perform our well abandonment.

Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to losses in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a tax authority. We recognize interest and penalties, if any, related to uncertain tax positions as a component of the income tax provision. No interest or penalties related to uncertain tax positions were recognized in the financial statements for the periods presented.

Production-Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover certain capital and operating costs that we incur, (ii) for our share of contractually defined base production where applicable, and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these

contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented approximately 3% and 12% of our production for the years ended December 31, 2025 and 2024, respectively.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

Pension and Postretirement Benefit Plans

All of our regular, full-time employees participate in postretirement benefit plans we sponsor. These plans are primarily funded as benefits are paid. In addition, some of our employees also participate in defined benefit pension plans sponsored by us. We recognize the net overfunded or underfunded amounts in the consolidated financial statements at each measurement date.

We determine our defined benefit pension and postretirement benefit plan obligations based on various assumptions and discount rates. The discount rate assumptions used are meant to reflect the interest rate at which the obligations could effectively be settled on the measurement date. We estimate the rate of return on assets with regard to current market factors but within the context of historical returns.

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market.

Actuarial gains and losses that have not yet been recognized through income, are recorded in accumulated other comprehensive income within equity, net of taxes, until they are amortized as a component of net periodic benefit cost.

Leases

We account for our leases in which we are the lessee, other than mineral leases including oil and natural gas leases, under an accounting standard which requires us to recognize most leases, including operating leases, on the balance sheet. We categorize leases as either operating or financing at lease commencement. We recognize a right-of-use (ROU) asset and associated lease liability for each operating and finance lease with contractual terms of greater than 12 months on the balance sheet. In considering whether a contract contains a lease, we first consider whether there is an identifiable asset and then consider how and for what purpose the asset would be used over the contract term. Our ROU assets are measured at the initial amount of the lease liability determined by measuring the present value of the fixed minimum lease payments, adjusted for any payments made before or at the lease commencement date, discounted using our incremental borrowing rate (IBR). In determining our IBR, we consider the average cost of borrowing for publicly traded corporate bond yields, which are adjusted to reflect our credit rating, the remaining lease term for each class of our leases and frequency of payments.

The ROU assets for operating leases are amortized over the term of the lease using the straight-line method. Lease expense also includes accretion of the lease liability recognized using the effective interest method. ROU assets are tested for impairment in the same manner as long-lived assets.

Share Repurchase Program

We repurchase shares of our common stock from time to time under a program authorized by our Board of Directors, including pursuant to a contract, instruction or written plan meeting requirements of Rule 10b5-1(c)(1) of the Exchange Act. Share repurchases which have not been retired are presented as treasury stock on our consolidated balance sheets.

Supplemental Cash Flow Information

Supplemental disclosures to our consolidated statements of cash flows, excluding leases and ARO, are presented below:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Supplemental cash flow information			
Interest paid, net of amount capitalized	\$ (85)	\$ (80)	\$ (44)
Interest income	\$ 11	\$ 18	\$ 21
Supplemental disclosure of non-cash investing and financing activities			
Contributions to the Carbon TerraVault JV	\$ 36	\$ 20	\$ 15
Issuance of shares for stock-based compensation awards	\$ 23	\$ 90	\$ 5
Dividend equivalents for stock-based compensation awards	\$ 3	\$ 2	\$ 3
Excise tax on share repurchases ^(a)	\$ (1)	\$ 2	\$ 1

(a) Excise tax on share repurchases for 2025 includes a reversal for 2024 excise taxes that were no longer due.

NOTE 2 BUSINESS COMBINATIONS

Berry Merger

On September 14, 2025, we entered into an agreement to combine with Berry in the Berry Merger. Berry was an independent upstream energy company that explored for and produced oil and natural gas in California, primarily in the San Joaquin basin, and in the Uinta basin in Utah. Berry also provided well servicing and abandonment services, which is included in our oil and natural gas segment. The Berry Merger added high quality, oil-weighted, mostly conventional proved developed reserves and sustainable cash flows to our operations.

Pursuant to the Berry Merger Agreement, on the effective date of the merger, December 18, 2025, we issued 5,572,115 shares of our common stock, which was calculated as 0.0718 shares of our common stock for each outstanding share of Berry stock as of December 17, 2025. As of December 18, 2025, and immediately following the closing of the Berry Merger, the former Berry stockholders owned 6% of CRC. We paid cash or issued replacement equity awards in settlement of certain Berry restricted and performance units. Refer to *Note 10 Stock-Based Compensation* for more information on these awards. Upon closing of the Berry Merger, Berry's outstanding debt was repaid and the underlying credit agreements were terminated. We repaid a significant portion of this indebtedness with proceeds from our 2034 Senior Notes, which closed in October 2025. For more information on the 2034 Senior Notes, refer to *Note 5 Debt*.

At the date of this filing, our assessment of the fair value of assets acquired and liabilities assumed remains preliminary. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of Berry's property, plant and equipment,

evaluation of Berry's materials and supplies inventory, measurement of leases, valuation of certain assets and liabilities, determination of Berry's asset retirement obligations and preparation of tax returns that will provide underlying tax basis of the assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period subsequent to the Berry Merger closing date and adjustments may be made to the provisional amounts recorded as of December 31, 2025.

We measured assets and liabilities at acquisition date fair value on a nonrecurring basis.

The following table summarizes the consideration transferred:

	Merger Consideration
	(in millions, except share and per share data)
Shares of common stock	5,572,115
Common stock per share fair value on December 17, 2025	\$ 45.49
Fair value of share consideration	\$ 253
Settlement of Berry debt	449
Stock-based compensation (see <i>Note 10 Stock-Based Compensation</i>)	7
Total consideration	<u>\$ 709</u>

The following table presents the preliminary purchase price allocation to the identifiable assets acquired and the liabilities assumed based on their estimated fair values as of the closing date of the Berry Merger:

	Preliminary Purchase Price
	(in millions)
Assets Acquired	
Cash	\$ 12
Accounts receivable	87
Inventories	6
Other current assets	29
Property, plant and equipment	659
Fair value of derivative contracts	109
Deferred tax asset	121
Other noncurrent assets	4
Total Assets Acquired	<u>1,027</u>
Liabilities Assumed	
Accounts payable	\$ (62)
Accrued liabilities	(50)
Asset retirement obligations	(151)
Fair value of derivative contracts	(21)
Other long-term liabilities	(34)
Total Liabilities Assumed	<u>(318)</u>
Net Assets Acquired	<u>\$ 709</u>

For the period of December 18, 2025 through December 31, 2025, total operating revenue associated with Berry totaled \$18 million and loss before income taxes was \$25 million, respectively.

In connection with the Berry Merger, we incurred transaction and integration costs of \$20 million, employee severance and related retention costs of \$13 million, and \$3 million related to the acceleration of certain replacement equity awards during the year ended December 31, 2025, which are included in other operating expenses, net on our consolidated statement of operations.

We recorded cash based on Berry's bank balances as of December 18, 2025. The measurements for predominately all of the other current and other noncurrent assets acquired and accounts payable, accrued liabilities and other long-term liabilities assumed are based on contracts in place at Berry on the acquisition date.

The fair value of certain acquired property, plant and equipment, primarily consisting of proved oil and natural gas properties, cogeneration power plants, a gas processing plant, well servicing and support equipment and other corporate assets, was based on preliminary reviews. These assets are still under review for measurement based on final appraisals. The fair value of proved oil and natural gas properties as of the acquisition date is based on estimated discounted future net cash flows incorporating market participant assumptions on an after-tax basis. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices, a weighted average cost of capital and reserve adjustment factors. When estimating the fair value of proved properties, additional risk adjustments were applied to proved reserves to reflect the relative uncertainty of the reserve class. These inputs are classified as Level 3 unobservable inputs, including the underlying commodity price assumptions which are based on the five-year NYMEX forward strip prices, escalated for inflation thereafter, and adjusted for price differentials.

The liability for future asset retirement obligations was determined by calculating the present value of estimated future abandonment costs. We utilized several assumptions, including a credit-adjusted risk-free interest rate, estimated remediation costs, estimated timing of when the work will be performed and a projected inflation rate.

Deferred income taxes, included in other noncurrent assets, represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed.

Lease-related assets and liabilities acquired are remeasured as if the leases were new at the merger date. These agreements are still under review for measurement at an updated incremental borrowing rate. Lease assets are included in other assets and the liabilities are included in accrued liabilities and other long-term liabilities.

Supplemental Unaudited Pro Forma Financial Information

The following supplemental unaudited pro forma financial information presents the total operating revenue, net income and earnings per share for the years ended December 31, 2025 and 2024 as if the Berry Merger had occurred on January 1, 2024.

	Year ended December 31,	
	2025	2024
	(in millions)	
Total operating revenue	\$ 4,298	\$ 3,961
Net income	\$ 329	\$ 434
EPS		
Basic	\$ 3.56	\$ 5.11
Diluted	\$ 3.54	\$ 4.99

The pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the Berry Merger been completed on

January 1, 2024, nor is it necessarily indicative of future operating results of the combined entity. The pro forma financial information for the years ended December 31, 2025 and 2024 is a result of combining our statements of operations with Berry's pre-merger results from January 1, 2025 and 2024 and includes adjustments for revenues and direct expenses. The pro forma results do not reflect any cost savings anticipated as a result of the Berry Merger and exclude the impact of any employee severance or retention. The pro forma results include adjustments to (i) depreciation, depletion and amortization (DD&A) based on the purchase price allocated to property, plant, and equipment and the estimated useful lives, (ii) interest assuming the issuance of our 2034 Senior Notes, (iii) accretion expense, and (iv) intercompany eliminations with C&J Well Services. We also included pro forma adjustments for certain nonrecurring compensation-related costs and transaction costs we incurred related to the Berry Merger. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the Berry Merger are properly reflected. Future results may vary significantly from the results reflected in the above pro forma information.

Aera Merger

On July 1, 2024, we obtained by way of merger all of the ownership interests in Aera. We applied the acquisition method of accounting and are the accounting acquirer. The Aera Merger added significant oil-weighted production and proved developed reserves to CRC, primarily in the San Joaquin and Ventura basins.

In connection with the closing of the Aera Merger, we issued 21,315,707 shares of common stock to the Sellers. We issued an additional 107,265 shares in February 2025 and we expect to issue an insignificant amount of shares for deferred consideration. This deferred consideration is related to pre-effective date and restructuring income taxes of the former owners of Aera. We also paid approximately \$990 million in connection with the extinguishment of all of Aera's outstanding indebtedness using the proceeds from the issuance of our 8.25% senior notes due 2029 (2029 Senior Notes) and cash on hand. The net cash paid by us at legal close to acquire Aera was \$853 million, consisting of \$990 million to repay Aera's outstanding debt less Aera's cash on hand of \$137 million. For more information on the 2029 Senior Notes and recent amendments to our Revolving Credit Facility, refer to *Note 5 Debt*.

As of July 1, 2024, immediately following the closing of the Aera Merger, our existing stockholders prior to the Aera Merger owned 76% of CRC and the Sellers owned 24% of CRC.

We have measured assets and liabilities at acquisition date fair value on a nonrecurring basis. The purchase price allocation was final as of June 30, 2025. The following table summarizes the consideration transferred:

	Merger Consideration
	(in millions, except share and per share data)
Shares of common stock issued (dividend adjusted)	21,422,972
Common stock per share fair value on July 1, 2024	\$ 53.28
Fair value of share consideration	\$ 1,141
Settlement of Aera debt	990
Purchase price settlement, net	(10)
Total purchase consideration	<u>\$ 2,121</u>

The following table represents the final purchase price allocation to the identifiable assets acquired and the liabilities assumed based on their estimated fair values as of the closing date of the Aera Merger:

	Preliminary Purchase Price as of December 31, 2024	Adjustments <small>(in millions)</small>	Purchase Price as of June 30, 2025
Assets Acquired			
Cash	\$ 137	\$ —	\$ 137
Accounts receivable	176	—	176
Inventories	30	(1)	29
Other current assets	49	13	62
Investment in unconsolidated subsidiary	59	(7)	52
Property, plant and equipment	3,048	32	3,080
Pension and other postretirement benefits	73	—	73
Other noncurrent assets	57	13	70
Total Assets Acquired	<u>3,629</u>	<u>50</u>	<u>3,679</u>
Liabilities Assumed			
Accounts payable	\$ (158)	\$ —	\$ (158)
Accrued liabilities	(157)	(4)	(161)
Asset retirement obligations	(646)	19	(627)
Fair value of derivative contracts	(351)	—	(351)
Pension and other postretirement benefits	(35)	—	(35)
Deferred tax liability	(101)	(70)	(171)
Other long-term liabilities	(37)	(18)	(55)
Total Liabilities Assumed	<u>(1,485)</u>	<u>(73)</u>	<u>(1,558)</u>
Net Assets Acquired	<u>\$ 2,144</u>	<u>\$ (23)</u>	<u>\$ 2,121</u>

For the period of July 1, 2024 through December 31, 2024, total operating revenue and income before income taxes associated with Aera totaled \$1,205 million and \$512 million, respectively.

In connection with the Aera Merger, we incurred transaction and integration costs of \$57 million and employee severance and related costs of \$30 million during the year ended December 31, 2024, which are included in other operating expenses, net on our consolidated statements of operations.

The accelerated vesting of certain awards for former Aera executives was \$7 million, and is included in general and administrative expenses for the year ended December 31, 2024. The accelerated vesting was based on existing change of control provisions within the former Aera employee award agreements.

The fair value of an investment in an unconsolidated subsidiary was based on an appraisal using both the cost approach and available market data. The fair value of derivative instruments was based on observable inputs, primarily forward commodity-price curves. These inputs are considered Level 2 inputs in the fair value hierarchy.

The fair value of certain acquired property, plant and equipment, primarily consisted of proved oil and natural gas properties, land and corporate assets including software and computer equipment,

was based on appraisals. The fair value of proved oil and natural gas properties as of the acquisition date was based on estimated discounted future net cash flows incorporating market participant assumptions on an after-tax basis. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices, a weighted average cost of capital and a projected inflation rate. When estimating the fair value of proved properties, additional risk adjustments were applied to proved undeveloped reserves to reflect the relative uncertainty of the reserve class. These inputs are classified as Level 3 unobservable inputs, including the underlying commodity price assumptions which are based on the five-year NYMEX forward strip prices, escalated for inflation thereafter, and adjusted for price differentials.

The liability for future asset retirement obligations was determined by calculating the present value of estimated future abandonment costs. We utilized several assumptions, including a credit-adjusted risk-free interest rate, estimated remediation costs, estimated timing of when the work will be performed and a projected inflation rate.

Deferred income taxes represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed.

Lease-related assets and liabilities acquired were remeasured as if the leases were new at the merger date. These agreements were measured at an updated incremental borrowing rate. Lease assets are included in property, plant and equipment and the liabilities are included in accrued liabilities and other long-term liabilities.

Supplemental Unaudited Pro Forma Financial Information

The following supplemental unaudited pro forma financial information presents the consolidated results of operations for the years ended December 31, 2024 and 2023 as if the Aera Merger had occurred on January 1, 2023.

	<u>Year ended December 31,</u>	
	<u>2024</u>	<u>2023</u>
	(in millions)	
Total operating revenue	\$ 3,883	\$ 4,838
Net income	\$ 355	\$ 721
EPS		
Basic	\$ 3.94	\$ 7.93
Diluted	\$ 3.85	\$ 7.65

The pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the Aera Merger been completed on January 1, 2023, nor is it necessarily indicative of future operating results of the combined entity. The pro forma financial information for the years ended December 31, 2024 and 2023 is a result of combining our statements of operations with Aera's premerger results from January 1, 2024 and 2023 and includes adjustments for revenues and direct expenses. The pro forma results do not reflect any cost savings anticipated as a result of the Aera Merger and exclude the impact of any severance. The pro forma results include adjustments to depreciation, depletion and amortization (DD&A) based on the purchase price allocated to property, plant, and equipment and the estimated useful lives as well as adjustments to interest and accretion expense. We also included pro forma adjustments for certain compensation related costs and transaction costs we incurred related to the Aera Merger. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the Aera Merger are properly reflected. Future results may vary significantly from the results reflected in the following pro forma information.

NOTE 3 PROPERTY, PLANT AND EQUIPMENT

We capitalize the costs incurred to acquire, develop and explore our oil and natural gas assets, including ARO and interest. Our total property, plant and equipment increased \$659 million related to our provisional allocation of fair value to assets acquired in the Berry Merger on the effective date. We evaluate long-lived assets on a quarterly basis for possible impairment.

Property, plant and equipment, net consisted of the following:

	December 31, 2025	December 31, 2024
	(in millions)	
Proved oil and natural gas properties	\$ 7,097	\$ 6,343
Unproved oil and natural gas properties	11	—
Facilities and other	415	395
Total property, plant and equipment	7,523	6,738
Accumulated depreciation, depletion and amortization	(1,618)	(1,058)
Total property, plant and equipment, net	<u>\$ 5,905</u>	<u>\$ 5,680</u>

The following table summarizes the activity of capitalized exploratory well costs:

	December 31, 2025	December 31, 2024	December 31, 2023
	(in millions)		
Beginning balance	\$ 1	\$ 1	\$ 1
Additions to capitalized exploratory well costs	10	—	—
Ending balance	<u>11</u>	<u>1</u>	<u>1</u>

Asset Impairments

In 2025, we recognized impairments of \$59 million, of which \$57 million related to proved natural gas properties in the Sacramento basin. At December 31, 2025, we determined that the carrying value of these assets was not recoverable due to a change in development plans after the Berry Merger and current market conditions. The fair value of our proved natural gas properties was determined as of the date of the assessment using undiscounted cash flow models based on management's expectations for the future development and on Level 3 inputs within fair value measurement hierarchy, including unobservable inputs such as estimates of future natural gas production, forward commodity price curves, inflation, pricing adjustments for differentials, reserve adjustment factors and estimated future operating costs. We used a market-based weighted average cost of capital to discount the future net cash flows.

We also recognized asset impairments in the years ended December 31, 2025 and 2024 related to our carbon management assets. Refer to *Note 9 Divestitures and Acquisitions* for more information. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for information on a \$13 million impairment on materials and supplies inventory recognized in 2024.

NOTE 4 INVESTMENTS AND RELATED PARTY TRANSACTIONS

The following tables present changes to our investments in unconsolidated subsidiaries for the periods presented:

	Carbon TerraVault JV
	(in millions)
Investment, December 31, 2023	\$ 19
Share of net loss	(12)
Contributions	20
Investment, December 31, 2024	27
Share of net loss	(6)
Contributions	36
Investment, December 31, 2025	\$ 57
	Midway Sunset Cogeneration Company
	(in millions)
Investment, December 31, 2024	\$ 59
Purchase price adjustment (Aera Merger)	(7)
Share of net income	2
Investment, December 31, 2025	\$ 54

Carbon TerraVault JV

In August 2022, we entered into a joint venture with BGTF Sierra Aggregator LLC (Brookfield) for the further development of a carbon management business in California (Carbon TerraVault JV). We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Our initial contribution included rights to inject CO₂ into the 26R reservoir in our Elk Hills field for permanent CO₂ storage (26R reservoir). Brookfield has contributed \$92 million to date. The remaining amount of Brookfield's initial investment is based on the permitted storage capacity, subject to certain contractual adjustments. This remaining amount will be contributed to the joint venture upon entering into contracts for the injection of specified volumes with respect to the 26R reservoir.

We determined that the Carbon TerraVault JV is a variable interest entity (VIE); however, we share decision-making power with Brookfield on all matters that most significantly impact the economic performance of the joint venture. Therefore, we account for our investment in the Carbon TerraVault JV under the equity method of accounting. Transactions between us and the Carbon TerraVault JV are related party transactions.

Because the parties have certain put and call rights (repurchase features) with respect to the 26R reservoir if certain milestones are not met, the initial investment (including accrued interest) by Brookfield is reflected as a contingent liability included in other long-term liabilities on our consolidated balance sheets. The contingent liability was \$117 million and \$107 million at December 31, 2025 and 2024, respectively, inclusive of interest. The amount payable to Brookfield under the put and call rights, if exercised, includes additional capital contributions made by Brookfield to develop the 26R storage reservoir, inclusive of interest. This payment would differ from the contingent liability currently recognized because the contingent liability reported in other long-term liabilities on our consolidated balance sheet relates solely to the initial investment by Brookfield and does not include capital

contributions made for ongoing development activities of the 26R reservoir. The joint venture does not have a definitive term and terminates upon either party holding all of the ownership interests in the joint venture.

Both Brookfield and CRC have granted the other party a right to participate in projects that involve the capture, transportation and storage of CO₂ in California. These projects may be developed through the Carbon TerraVault JV or other joint ventures. This right expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the investment committee of the Carbon TerraVault JV for storage projects representing in excess of 5 million metric tons per annum (MMTPA) in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of \$500 million (unless Brookfield elects to increase its commitment). The non-presenting party has the option to accept, decline or defer its decision to participate. If the decision is deferred, then the presenting party may continue to pursue development; however during this time and prior to a final investment decision, the non-presenting party may elect to participate provided they pay their share of the project development costs incurred up to that point. The joint venture does not have a definitive term and terminates upon either party holding all of the ownership interests in the joint venture.

The tables below present the summarized financial information related to our equity method investment in the Carbon TerraVault JV (and do not include amounts we have incurred related to development of our carbon management segment, Carbon TerraVault), along with related party transactions for the periods presented.

	December 31, 2025	December 31, 2024
	(in millions)	
Receivables from affiliate ^(a)	\$ 14	\$ 46
Other long-term liabilities ^(b)	\$ 117	\$ 107

(a) At December 31, 2025, the amount of \$14 million includes the remaining \$8 million of Brookfield's first and second installments of their initial investment which is available to us and \$6 million related to the Master Service Agreement (MSA) and vendor reimbursements. At December 31, 2024, the amount of \$46 million includes \$43 million remaining of Brookfield's initial contribution available to us and \$3 million related to the MSA and vendor reimbursements.

(b) Other long-term liabilities include the contingent liability related to the Carbon TerraVault JV put and call rights.

We have a Management Services Agreement (MSA) with the Carbon TerraVault JV whereby we provide administrative, operational and commercial services under a cost-plus arrangement. Services may be supplemented by using third parties and payments to us under the MSA are limited to the amounts in an approved budget. The MSA may be terminated by mutual agreement of the parties, among other events. For the years ended December 31, 2025, 2024 and 2023 we invoiced \$11 million, \$9 million and \$8 million, respectively, to the Carbon TerraVault JV under the MSA for back-office, operational and commercial services. These amounts reduced our carbon management segment expenses.

We also completed well abandonment work at our Elk Hills field as part of the permitting process for injection of CO₂ at the 26R reservoir. During the years ended December 31, 2025 and 2024, we performed abandonment work and sought reimbursement in the amounts of \$9 million and \$14 million, respectively, from the Carbon TerraVault JV. We have recorded these reimbursements as a reduction to property, plant and equipment on our consolidated balance sheets.

The underlying net assets of the Carbon TerraVault JV were \$367 million and \$309 million as of December 31, 2025 and 2024, respectively, which includes cash on hand and PP&E, net of current liabilities. The difference between the carrying value of our investment of \$57 million and \$27 million at December 31, 2025 and 2024, respectively, and the carrying value of the underlying net assets of the joint venture relates to our accounting for the contribution of the 26R reservoir as a financing arrangement due to the put and call features of the joint venture. The joint venture recognized the contributions by the members at fair value.

Midway Sunset Cogeneration Company

In July 2024, our merger with Aera led to our partial ownership of Midway Sunset Cogeneration Company, which is a partnership designed to own, manage, and operate a cogeneration facility in Kern County, California. We hold a 50% interest in Midway Sunset Cogeneration Company and San Joaquin Energy Company, a subsidiary of NRG Energy, Inc. (NRG), holds a 50% interest. We determined that Midway Sunset Cogeneration Company is a voting interest entity, where we share decision-making power with San Joaquin Energy Company on all matters that most significantly impact the economic performance of Midway Sunset Cogeneration Company. Therefore, we account for our investment in Midway Sunset Cogeneration Company under the equity method of accounting. We recorded our investment at a fair value of \$52 million which was \$41 million in excess of Aera's investment in the underlying assets of the partnership. This difference is associated with PP&E and we expect this amount will reverse over the remaining useful life of the power plant. There are no significant transactions between us and Midway Sunset Cogeneration Company.

NOTE 5 DEBT

As of December 31, 2025 and 2024, our long-term debt consisted of the following:

	December 31, December 31, 2025 2024		Interest Rate	Maturity
	(in millions)			
Revolving Credit Facility	\$ —	\$ —	SOFR plus 2.50%-3.50% ABR plus 1.50%-2.50%	March 16, 2029
2026 Senior Notes	—	245	7.125%	
2029 Senior Notes	900	900	8.250%	June 15, 2029
2034 Senior Notes	400	—	7.000%	January 15, 2034
Principal amount	<u>1,300</u>	<u>1,145</u>		
Unamortized debt discount and issuance costs	(19)	(16)		
Unamortized premium	2	3		
Long-term debt, net	<u>\$ 1,283</u>	<u>\$ 1,132</u>		

Revolving Credit Facility

On April 26, 2023, we entered into an Amended and Restated Credit Agreement (as amended, restated supplemented or modified as of the date hereof, the Revolving Credit Facility) with Citibank, N.A., as administrative agent, and certain other lenders, which amended and restated in its entirety the prior credit agreement, dated October 27, 2020. As of December 31, 2025, our Revolving Credit Facility consisted of a senior revolving loan facility with an aggregate commitment of \$1.46 billion. The amount we are able to borrow under our Revolving Credit Facility is limited to the amount of these commitments. Our Revolving Credit Facility also included a sub-limit of \$300 million for the issuance of letters of credit. As of December 31, 2025, \$176 million letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters. As of December 31, 2025, we had \$1,284 million of availability on our Revolving Credit Facility after taking into account \$176 million in letters of credit outstanding. Our borrowing base of \$1.5 billion is redetermined semi-annually and was re-affirmed in October 2025 as part of our recent amendment.

The proceeds of all or a portion of the Revolving Credit Facility may be used for our working capital needs and for other purposes subject to meeting certain criteria.

Security – The lenders have a first-priority lien on a substantial majority of our assets.

Interest Rate – We can elect to borrow at either an adjusted SOFR rate or an alternate base rate (ABR), plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent prime rate and (iii) the one-month SOFR rate plus 1%. The applicable margin is adjusted based on the borrowing base utilization percentage and will vary from (i) in the case of SOFR loans, 2.5% to 3.5% and (ii) in the case of ABR loans, 1.5% to 2.5%. The unused portion of the facility is subject to a commitment fee which will vary between 0.375% and 0.50% per annum based on the borrowing base utilization. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on SOFR loans is payable at the end of each SOFR period, but not less than quarterly.

Amortization Payments – The Revolving Credit Facility does not include any obligation to make amortizing payments.

Borrowing Base – The borrowing base, currently \$1.5 billion, will be redetermined semi-annually each April and October.

Financial Covenants – Our Revolving Credit Facility includes the following financial covenants:

Ratio	Components	Required Levels	Tested
Consolidated Total Net Leverage Ratio	Ratio of Consolidated Total Debt to Consolidated EBITDAX ^(a)	Not greater than 3.00 to 1.00	Quarterly
Current Ratio	Ratio of consolidated current assets to consolidated current liabilities ^(b)	Not less than 1.00 to 1.00	Quarterly

(a) Consolidated EBITDAX is calculated as defined in the Revolving Credit Facility.

(b) The available credit under our Revolving Credit Facility is included in consolidated current assets as part of the calculation of the current ratio.

Other Covenants – Our Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We are also restricted in the amount of cash dividends we can pay on our common stock unless we meet certain covenants included in the Revolving Credit Facility.

Our Revolving Credit Facility, among other things, permits us to make certain restricted payments (such as dividends and share repurchases) and certain investments (including in our carbon management segment); provides for the release of liens on certain assets securing the loans made under the Revolving Credit Facility, including our Elk Hills power plant; permits us to designate the entities that hold certain of our assets, including our Elk Hills power plant, as unrestricted subsidiaries subject to meeting certain conditions; sets the period for which we can enter into hedges on our production at 60 months. In October 2023, we further amended our Revolving Credit Facility to increase our flexibility to incur new indebtedness in the form of term loans secured on a pari passu basis with the obligations under the Revolving Credit Facility. The aggregate amount of such term loans shall not exceed the lesser of the following: (i) the borrowing base then in effect minus the Aggregate Elected Revolving Commitment Amounts (as defined in the Revolving Credit Facility) then in effect and (ii) an amount equal to 33 1/3% of the sum of (A) the Aggregate Elected Revolving Commitment Amounts (as defined in the Revolving Credit Facility) then in effect plus (B) the aggregate term loan exposure of any lender then outstanding.

Our Revolving Credit Facility requires us to maintain hedges on a minimum amount of crude oil production (determined on (i) the date of delivery of annual and quarterly financial statements and (ii) the date of delivery of a reserve report delivered in connection with an interim borrowing base

redetermination) of no less than (i) in the event that our Consolidated Total Net Leverage Ratio (as defined in the Revolving Credit Facility) is greater than 2.0:1.0 as of the end of the most recent fiscal quarter test period, 50.0% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period and (ii) in the event that our Consolidated Total Net Leverage Ratio is less than or equal to 2.0:1.0 but greater than 1.5:1.0 as of the end of the most recent fiscal quarter test period, 33.0% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period. The foregoing minimum hedge requirements do not apply to the extent that our Consolidated Total Net Leverage Ratio is less than or equal to 1.5:1.0 as of the last day of the most recently ended fiscal quarter test period.

Furthermore, the restricted payment and investments covenants permit unlimited investments and/or restricted payments so long as either (a) (i) no Default, Event of Default or Borrowing Base Deficiency shall have occurred and be continuing under the Revolving Credit Facility, (ii) the undrawn availability under the Revolving Credit Facility at such time is not less than 20.0% of the total commitment, (iii) the Consolidated Total Net Leverage Ratio is less than or equal to 2.5:1.0 and (iv) Distributable Free Cash Flow is greater than or equal to zero on such date of determination; or (b) (i) no Default, Event of Default or Borrowing Base Deficiency shall have occurred and be continuing under the Revolving Credit Facility at the time of such investment or restricted payment, (ii) the undrawn availability under the Revolving Credit Facility at such time is not less than 25.0% of the total commitment and (iii) the Consolidated Total Net Leverage Ratio is less than or equal to 1.75:1.0.

Events of Default and Change of Control – Our Revolving Credit Facility provides for certain events of default, including upon a change of control, as defined in the Revolving Credit Facility, that entitles our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

Amendments

In February 2024, in connection with the Aera Merger, we entered into a second amendment to our Revolving Credit Facility to, among other things, permit the incurrence of indebtedness under a bridge loan facility. We did not utilize a bridge loan facility in connection with the Aera Merger and wrote-off \$6 million of bridge loan and commitment fees during the year ended December 31, 2024 included in other non-operating (loss) income on our consolidated statement of operations. We capitalized approximately \$3 million in financing fees related to this amendment to other assets on our consolidated statement of financial position.

In March 2024, we entered into a third amendment to our Revolving Credit Facility. This amendment facilitated certain matters with respect to the Aera Merger, including the postponement of the regular spring borrowing base redetermination until the fall of 2024 and certain other amendments.

In July 2024, we entered into a fourth amendment to our Revolving Credit Facility as part of the Aera Merger. This amendment increased the aggregate revolving commitments available under the Revolving Credit Facility from \$630 million to \$1.1 billion. Our ability to borrow under our Revolving Credit Facility is limited to the amount of these commitments. This amendment also increased the borrowing base from \$1.2 billion to \$1.5 billion, among other matters. We capitalized approximately \$7 million in financing fees related to this amendment to other assets on our consolidated statement of financial position.

In November 2024, we entered into a fifth amendment to our Revolving Credit Facility. The amendments included, among other things:

- increased the amount of the elected commitments by \$50 million to \$1,150 million to reflect changes to our lender group;

- extended the maturity date of the facility from July 31, 2027 to March 16, 2029;
- amended the springing maturity to permit our 2026 Senior Notes to remain outstanding past October 31, 2025 so long as the aggregate availability (less the outstanding 2026 Senior Notes) is not less than 25% of the total revolving commitments;
- increased our capacity to issue letters of credit from \$250 million to \$300 million; and
- other technical amendments.

We capitalized approximately \$7 million in financing fees related to this amendment to other assets on our consolidated statement of financial position.

In September 2025, in connection with the Berry Merger, we entered into a sixth amendment to our Revolving Credit Facility to, among other things, allow for the incurrence of the 2034 Senior Notes without a corresponding reduction in our existing borrowing base.

In October 2025, we entered into a seventh amendment to our Revolving Credit Facility to, among other things, (i) add certain new lenders to the facility, and (ii) increase the aggregate elected commitment from \$1.15 billion to \$1.45 billion.

In December 2025, we entered into an eighth amendment to our Revolving Credit Facility to, among other things, (i) add a new lender to the facility, and (ii) increase the aggregate elected commitment from \$1.45 billion to \$1.46 billion.

2026 Senior Notes

In February 2025, we redeemed \$123 million of our 7.125% senior notes due 2026 (2026 Senior Notes) at 100% of the principal amount, resulting in an extinguishment loss in the amount of \$1 million for the write-off of unamortized debt issuance costs.

In October 2025, we redeemed \$122 million of our 2026 Senior Notes at 100% of the principal amount, resulting in an insignificant extinguishment loss for the write-off of unamortized debt issuance costs. Following this redemption, none of our 2026 Senior Notes were outstanding.

2029 Notes Offering and Follow-On Offering

In June 2024, we completed the offering of \$600 million in aggregate principal amount of the 2029 Senior Notes. The terms of the 2029 Senior Notes are governed by the indenture, dated as of June 5, 2024, by and among us, the guarantors and Wilmington Trust, National Association, as trustee (2029 Senior Notes Indenture). The net proceeds of \$590 million, after \$10 million of debt discount and issuance costs, were used along with available cash to repay all of Aera's outstanding debt for approximately \$990 million at closing of the Aera Merger. See *Note 2 Business Combinations* for more information on the Aera Merger.

On August 22, 2024, we completed a follow-on offering of an additional \$300 million in aggregate principal amount of 2029 Senior Notes. The net proceeds from this offering of \$298 million, after \$3 million of debt premium and \$5 million of debt issuance costs, were used to repurchase a portion of our 2026 Senior Notes. The 2029 Senior Notes issued on August 22, 2024 are governed by the same indenture as the \$600 million of 2029 Senior Notes that were previously issued on June 5, 2024.

Security – Our 2029 Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by all of our existing subsidiaries that guarantee our obligations under the Revolving Credit Facility and our existing 2026 Senior Notes.

Redemption – We may redeem the 2029 Senior Notes at any time on or after June 15, 2026 at the redemption prices of (i) 104.125% during the twelve-month period beginning on June 15, 2026, (ii) 102.063% during the twelve-month period beginning on June 15, 2027 and (iii) 100% after June 15, 2028 and before the maturity date. Prior to June 15, 2026, we may redeem up to 35% of the aggregate principal amount of the 2029 Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at the redemption price of 108.250%. In addition, before June 15, 2026, we may redeem some or all of the 2029 Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the 2029 Senior Notes redeemed, plus the applicable premium as specified in the 2029 Senior Notes Indenture and accrued and unpaid interest, if any, to, but excluding, the redemption date.

Other Covenants – Our 2029 Senior Notes include covenants that, among other things, restrict our ability to incur additional indebtedness, issue preferred stock, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions, and enter into transactions that would result in fundamental changes.

Events of Default and Change of Control – Our 2029 Senior Notes provide for certain triggering events, including upon a change of control, as defined in the indenture, that would require us to repurchase all or any part of the 2029 Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

2034 Senior Notes

On October 8, 2025, we completed a private offering of \$400 million in an aggregate principal amount of 7.000% senior notes due 2034 (2034 Senior Notes). The terms of the 2034 Senior Notes are governed by the Indenture, dated as of October 8, 2025, by and among us, the guarantors and Wilmington Trust, National Association, as trustee (2034 Senior Notes Indenture). The 2034 Senior Notes will mature on January 15, 2034. The net proceeds of \$393 million, after \$7 million of issuance costs, were used along with available cash to repay all of Berry's outstanding debt for \$449 million at closing of the Berry Merger. See *Note 2 Business Combinations* for more information on the Berry Merger.

Security – Our 2034 Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by all of our existing subsidiaries that guarantee our obligations under the Revolving Credit Facility and our existing 2029 Senior Notes.

Redemption – We may redeem the 2034 Senior Notes at any time on or after January 15, 2029 at the redemption prices of (i) 103.500% during the twelve-month period beginning on January 15, 2029, (ii) 101.750% during the twelve-month period beginning on January 15, 2030 and (iii) 100.000% after January 15, 2031 and before the maturity date. Prior to January 15, 2029, we may on one or more occasions redeem up to 40% of the aggregate principal amount of the 2034 Senior Notes with an amount not greater than the net cash proceeds of one or more equity offerings at the redemption price of 107.000% provided that (i) at least 60% of the aggregate principal amount of the 2034 Senior Notes originally issued remains outstanding immediately after the redemption and (ii) the redemption occurs within 180 days of the date of the closing of the equity offering.

In addition, before January 15, 2029, we may redeem some or all of the 2034 Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the 2034 Senior Notes redeemed, plus the applicable premium as specified in the 2034 Senior Notes Indenture and accrued and unpaid interest, if any, to, but excluding, the redemption date.

Other Covenants – Our 2034 Senior Notes include covenants that, among other things, restrict our ability to incur additional indebtedness, issue preferred stock, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions, and enter into transactions that would result in fundamental changes.

Events of Default and Change of Control – Our 2034 Senior Notes provide for certain triggering events, including upon a change of control, as defined in the 2034 Senior Notes Indenture, that would require us to repurchase all or any part of the 2034 Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Fair Value

As shown in the table below, we estimate the fair value of our fixed rate 2029 Senior Notes and 2026 Senior Notes based on known prices from market transactions (using Level 1 inputs on the fair value hierarchy).

	<u>December 31, 2025</u>	<u>December 31, 2024</u>
	(in millions)	
Variable rate debt	\$ —	\$ —
Fixed rate debt		
2026 Senior Notes	—	245
2029 Senior Notes	943	913
2034 Senior Notes	394	—
Fair Value of Long-Term Debt	<u>\$ 1,337</u>	<u>\$ 1,158</u>

Other

At December 31, 2025, all obligations under our Revolving Credit Facility and Senior Notes are guaranteed by certain of our material wholly owned subsidiaries. See *Note 18 Condensed Consolidating Financial Information* for additional information.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

At December 31, 2025, we were in compliance with all debt covenants under our Revolving Credit Facility.

NOTE 6 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2025 and 2024 were not material to our consolidated balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE’s order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution

Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and are challenging the order from BSEE. In March 2024, we entered into a cost sharing agreement with former lessees to share in ongoing maintenance costs during the pendency of the challenge to the BSEE order. In September 2025, the parties amended the cost sharing agreement to include well abandonment work. As of December 31, 2025, we recognized a liability of \$12 million, included in accrued liabilities in our consolidated balance sheet related to this abandonment work. For the year ended December 31, 2025 and 2024, other operating expenses, net on our consolidated statements of operations includes \$19 million and \$5 million, respectively, for our ongoing share of maintenance costs and well abandonment work. We continue to challenge the BSEE order.

In 2023 and 2024, the California Geologic Energy Management Division (CalGEM) plugged and abandoned approximately 120 “orphaned” oil and gas wells located in Cat Canyon, Santa Barbara County, at an aggregate cost of \$25 million. These wells had previously been operated by us prior to being sold to their current operators. CalGEM is seeking to recover these costs from us due to our prior operatorship of the wells, and we are disputing these claims. In connection with this dispute, we were required to remit \$25 million to CalGEM under protest pending the outcome of this matter. For the year ended December 31, 2025, other operating expenses, net on our consolidated statement of operations includes \$25 million related to this matter.

We have certain commitments under contracts, including drilling commitments of \$8 million in 2026 and \$9 million in 2027 and purchase commitments for goods and services used in the normal course of business such as pipeline capacity, easements, obligations under long-term service agreements and field equipment.

At December 31, 2025, total purchase obligations on a discounted basis were as follows:

	December 31, 2025
	(in millions)
2026	\$ 69
2027	36
2028	22
2029	21
2030	27
Thereafter	26
Total	201
Less: Interest	(42)
Present value of purchase obligations	<u>\$ 159</u>

NOTE 7 DERIVATIVES

We continue to maintain a commodity hedging program to help protect our cash flows, margins and capital program from the volatility of commodity prices. We enter into natural gas swaps for the purpose of hedging our fuel consumption in our steamflood operations as well as swaps related to our marketing activities. We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2025, 2024 and 2023. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as accounting hedges. For more information on the hedging requirements of our Revolving Credit Facility, see *Note 5 Debt*.

Summary of Derivative Contracts

We held the following Brent-based contracts as of December 31, 2025:

	<u>Q1 2026</u>	<u>Q2 2026</u>	<u>Q3 2026</u>	<u>Q4 2026</u>	<u>2027</u>	<u>2028</u>
Sold Calls:						
Barrels per day	37,078	36,000	36,000	36,000	2,465	1,534
Weighted-average price per barrel	\$ 83.45	\$ 83.51	\$ 83.51	\$ 83.51	\$ 71.06	\$70.59
Purchased Puts						
Barrels per day	37,078	36,000	36,000	36,000	2,465	1,534
Weighted-average price per barrel	\$ 61.08	\$ 61.11	\$ 61.11	\$ 61.11	\$ 61.01	\$60.00
Swaps						
Barrels per day	51,861	44,487	42,869	41,703	50,110	7,285
Weighted-average price per barrel	\$ 69.25	\$ 68.52	\$ 68.20	\$ 67.98	\$ 65.76	\$66.98

At December 31, 2025, we also held the following swaps to hedge purchased natural gas used in our operations as shown in the table below. The natural gas price index used to hedge each position is based on a number of factors including liquidity and transportation cost.

	<u>Q1 2026</u>	<u>Q2 2026</u>	<u>Q3 2026</u>	<u>Q4 2026</u>	<u>2027</u>	<u>2028</u>
SoCal Border						
MMBtu per day	20,350	13,250	10,750	9,908	—	—
Weighted-average price per MMBtu . . .	\$ 5.18	\$ 4.82	\$ 4.83	\$ 4.84	\$ —	\$ —
NWPL Rockies						
MMBtu per day	91,750	91,750	91,750	91,750	71,861	1,576
Weighted-average price per MMBtu . . .	\$ 4.35	\$ 3.77	\$ 3.76	\$ 4.17	\$ 4.13	\$ 3.95

In the years ended December 31, 2025 and 2024, we also had a limited number of derivative contracts related to our natural gas marketing activities that were intended to lock in locational price spreads. These derivative contracts were not significant to our results of operations or financial statements taken as a whole.

The outcomes of the derivative positions are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Swaps – with respect to swaps for crude oil, we make settlement payments for prices above the indicated weighted-average price per barrel and receive settlement payments for prices below the indicated weighted-average price per barrel. With respect to swaps for purchased natural gas, we receive settlement payments for prices above the indicated weighted-average price per MMBtu and we make settlement payments for prices below the weighted-average price per MMBtu.

Fair Value of Derivatives

Derivative instruments not designated as hedging instruments are required to be recorded on the balance sheet at fair value. We report gains and losses on our derivative contracts related to our oil production and our marketing activities in operating revenue on our consolidated statements of operations as shown in the table below:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Non-cash commodity derivative gain	\$ 225	\$ 274	\$ 260
Net proceeds (settlements) and premium amortization	41	(33)	(272)
Net gain (loss) from commodity derivatives	<u>\$ 266</u>	<u>\$ 241</u>	<u>\$ (12)</u>

We report gains and losses on our commodity derivative contracts to purchases of natural gas in operating expenses on our consolidated statements of operations as shown in the table below:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Non-cash loss (gain) on natural gas purchase derivatives	\$ 24	\$ (2)	\$ 8
Settlements	26	32	—
Net loss on natural gas purchase derivatives	<u>\$ 50</u>	<u>\$ 30</u>	<u>\$ 8</u>

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented.

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented. The following tables present the fair values of our outstanding commodity derivatives as of December 31, 2025 and December 31, 2024.

December 31, 2025			
Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
Assets:		(in millions)	
Other current assets, net	\$ 193	\$ (6)	\$ 187
Other noncurrent assets	106	(5)	101
Liabilities:			
Current liabilities	(48)	6	(42)
Noncurrent liabilities	(22)	5	(17)
	<u>\$ 229</u>	<u>\$ —</u>	<u>\$ 229</u>

December 31, 2024

Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
Assets:			
		(in millions)	
Other current assets, net	\$ 26	\$ (12)	\$ 14
Other noncurrent assets	32	(16)	16
Liabilities:			
Current liabilities	(62)	12	(50)
Noncurrent liabilities	(61)	16	(45)
	<u>\$ (65)</u>	<u>\$ —</u>	<u>\$ (65)</u>

Counterparty Credit Risk

As of December 31, 2025, the majority of our credit exposure was with investment-grade counterparties. We actively evaluate the creditworthiness of our counterparties, assign credit limits and monitor exposure against those assigned limits. We believe exposure to credit-related losses was not significant for all periods presented. At December 31, 2025, and 2024, we did not have collateral posted for financial instruments.

NOTE 8 INCOME TAXES

Income before income taxes, for all periods presented, was generated from domestic operations. The provision (benefit) for income taxes includes the following components:

	Year ended December 31,		
	2025	2024	2023
		(in millions)	
U.S. federal	\$ 30	\$ 42	\$ 146
State and local	24	27	3
Current tax provision	54	69	149
U.S. federal	\$ 61	\$ 51	\$ (12)
State and local	24	20	47
Deferred tax provision	85	71	35
Income tax provision	<u>\$ 139</u>	<u>\$ 140</u>	<u>\$ 184</u>

Income taxes paid, net of refunds, by jurisdiction are as follows:

	Year ended December 31,		
	2025	2024	2023
		(in millions)	
Federal	\$ 31	\$ 73	\$ 120
State and local	5	32	1
Total taxes paid	<u>\$ 36</u>	<u>\$ 105</u>	<u>\$ 121</u>

Our effective tax rate differs from the amount computed by applying the U.S. federal income tax statutory rate to income before income taxes as follows:

	Year ended December 31,					
	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory tax rate	\$ 106	21%	\$ 108	21%	\$ 157	21%
State and local income taxes, net of federal income tax effect ^(a)	38	7	38	7	40	5
Tax credits						
Marginal well credit	(12)	(2)	(12)	(2)	—	—
Other tax credit	(1)	—	—	—	(1)	—
Nontaxable or nondeductible items ^(b)	8	2	9	2	6	1
Change in valuation allowance	—	—	—	—	(17)	(2)
Other adjustments	—	—	(3)	(1)	(1)	—
Effective tax rate	<u>\$ 139</u>	<u>28%</u>	<u>\$ 140</u>	<u>27%</u>	<u>\$ 184</u>	<u>25%</u>

(a) State and local income taxes are predominately in California and, with the closing of the Berry Merger, Utah.

(b) Nontaxable or nondeductible items include executive compensation where the deduction is limited and transaction costs which must be capitalized. These transaction costs are generally only deductible upon the disposition on the acquired stock.

During the year ended December 31, 2023, we released a valuation allowance for a portion of the tax loss on the sale of assets after we jointly agreed to amend the original tax treatment with the buyer. This valuation allowance was initially recorded during the year ended December 31, 2022 for the realizability of a capital loss on the asset sale, the deductibility of which was limited. Changes related to the valuation allowance related to state taxes is included as state and local income taxes, net of federal income tax effect in our rate reconciliation above.

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2025 and 2024 were as follows:

	2025		2024	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Property, plant and equipment	\$ —	\$ (698)	\$ —	\$ (700)
Deferred compensation and benefits	70	—	66	—
Asset retirement obligations	315	—	342	—
Operating loss and tax credit carryforwards	63	—	33	—
Business interest carryforward	167	—	158	—
All other	106	(101)	136	(75)
Total deferred taxes	<u>\$ 721</u>	<u>\$ (799)</u>	<u>\$ 735</u>	<u>\$ (775)</u>

We expect to realize our deferred tax assets through future operating income and reversal of taxable temporary differences. The amount of deferred tax assets considered realizable is not assured and could be adjusted if estimates change.

Changes in our deferred tax assets and liabilities in 2025 includes an increase in our deferred tax asset of \$121 million related to the Berry Merger and an increase in our deferred tax liability of \$70 million related to finalizing the purchase accounting for the Aera Merger. See *Note 2 Business Combinations* for additional information on these transactions. Additionally, we allocated \$5 million income tax benefit to accumulated other comprehensive income during 2025.

Carryforwards

As of December 31, 2025, our U.S. federal net operating loss carryforwards were \$19 million, which begin to expire in 2037, and our federal tax credit carryforwards were \$85 million, which begin to expire in 2037.

As of December 31, 2025, our California net operating loss carryforwards were \$2 billion, which begins to expire in 2029, and our tax credit carryforwards were \$21 million, which begin to expire in 2038. California has suspended the use of net operating loss carryforwards for tax years 2024 through 2026 and limited the amount of tax credits that may be claimed to \$5 million per year for the same period.

Our ability to utilize a portion of our net operating loss, tax credit and business interest carryforwards is subject to an annual limitation. As a result, we recognized a deferred tax asset of \$3 million for U.S. federal net operating loss carryforwards (that do not expire) and \$24 million for California net operating loss carryforwards. Additionally, we recognized a deferred tax asset for \$28 million for U.S. federal tax credit carryforwards and \$8 million for our California tax credit carryforwards. We expect our remaining tax credit carryforwards will expire unused.

Our carryforward for federal disallowed business interest expense of \$794 million does not expire and may be utilized in future periods to the extent we generate sufficient taxable income and interest capacity. Although our business interest carryforwards are subject to an annual limitation, we recognized a deferred tax asset of \$167 million included in the accompanying consolidated balance sheet because these carryforwards do not expire.

Other

On July 4, 2025, An Act to Provide for Reconciliation Pursuant to Title II of H. Con. Res. 14th and commonly referred to as the One Big Beautiful Bill Act was signed into law. This law contains several legislative changes including the reinstatement of full expensing for qualified assets placed in service after January 19, 2025. This law also reinstated the expensing of all domestic research and development costs, including favorable transition rules, and increases the limitation on the amount of annual business interest expense which can be deducted each year. As a result of these changes, we are able to accelerate deductions related to property, plant and equipment, research and development expenses and interest expense carryforwards resulting in a current income tax benefit, and corresponding reduction in our cash tax liability, of approximately \$40 million in 2025.

We did not record a liability for unrecognized tax benefits as of December 31, 2025 and 2024. We remain subject to audit by the Internal Revenue Service for calendar years 2022 through 2024 and by California for calendar years 2021 through 2024.

NOTE 9 DIVESTITURES AND ASSET ACQUISITIONS

Divestitures

Fort Apache in Huntington Beach

In March 2024, we sold our 0.9-acre Fort Apache real estate property in Huntington Beach, California for purchase price of \$10 million and recognized a \$6 million gain.

Ventura

During 2021, 2022 and 2024, we entered into transactions to sell our Ventura basin assets. The Ventura divestiture contemplated multiple closings that were subject to customary closing conditions. The closings that occurred in the second half of 2021 resulted in the divestiture of the vast majority of our Ventura basin assets. The transfer of the remaining assets in the Ventura basin was approved in

June 2024 by the State Lands Commission. In October 2024, we completed the sale of the Ventura basin assets and recognized a \$4 million gain and during 2025, we recognized a loss related to settling purchase price adjustments of \$1 million.

Round Mountain Unit

In December 2023, we entered into an agreement to sell our non-operated working interest in the Round Mountain Unit in the San Joaquin basin, recognizing a gain of \$25 million. We retained an option to capture, transport and store CO₂ emissions from the production at Round Mountain Unit for future carbon management projects. This option can be terminated by the buyer after January 1, 2028.

Other Divestitures

In 2024, we sold non-core assets recognizing a \$1 million gain. In 2023, we sold a non-producing asset in exchange for the assumption of liabilities recognizing a \$7 million gain.

Carbon Management Assets

In 2022, we acquired properties for carbon management activities with the intent to divest a portion of these assets. In 2024, we reduced the carrying value of the surface acreage to fair value and recognized an impairment charge of \$1 million. In May 2025, we sold a portion of these properties for \$1 million and did not recognize a gain or loss on this transaction.

In September 2025, we reduced the carrying value of the remainder of these properties classified as held for sale to fair value and recognized an impairment charge of \$2 million. The remaining assets were sold in December 2025 for \$6 million and we did not recognize a gain or loss on this transaction. The fair value measurement was determined, using Level 3 inputs in the fair value hierarchy and, declined due to market conditions, resulting in an impairment.

Asset Acquisitions

In 2024, we acquired land for our carbon management segment for approximately \$6 million. In 2023, we acquired land for our carbon management segment for approximately \$5 million.

NOTE 10 STOCK-BASED COMPENSATION

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (Long Term Incentive Plan). The Long Term Incentive Plan provides for potential grants of stock options, stock appreciation rights, restricted stock awards, restricted stock units, vested stock awards, dividend equivalents, other stock-based awards and substitute awards to employees, officers, non-employee directors and other service providers of the Company and its affiliates.

The Long Term Incentive Plan provides for the reservation of 9,257,740 shares of common stock for future issuances, subject to adjustment as provided in the Long Term Incentive Plan. Shares of stock subject to an award under the Long Term Incentive Plan that expires or is cancelled, forfeited, exchanged, settled in cash or otherwise terminated without the actual delivery of shares (restricted stock awards are not considered “delivered shares” for this purpose) will again be available for new awards under the Long Term Incentive Plan. However, (i) shares tendered or withheld in payment of any exercise or purchase price of an award or taxes relating to awards, (ii) shares that were subject to an option or a stock appreciation right but were not issued or delivered as a result of the net settlement or net exercise of the option or stock appreciation right, and (iii) shares repurchased on the open market with the proceeds from the exercise price of an option, will not, in each case, again be available for new awards under the Long Term Incentive Plan.

Shares of our common stock may be withheld by us in satisfaction of tax withholding obligations arising upon the vesting of restricted stock units (RSUs) and performance stock units (PSUs).

Stock-based compensation expense is recorded on our consolidated statements of operations based on job function of the employees receiving the grants as shown in the table below.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
General and administrative expenses	\$ 30	\$ 32	\$ 40
Operating costs	7	6	7
Other operating expenses, net	2	2	1
Total stock-based compensation expense	<u>\$ 39</u>	<u>\$ 40</u>	<u>\$ 48</u>
Income tax benefit	<u>\$ 7</u>	<u>\$ 8</u>	<u>\$ 9</u>

We paid \$21 million, \$18 million, and \$11 million for our long-term cash incentive awards for the years ended December 31, 2025, December 31, 2024, and December 31, 2023, respectively.

Stock Settled Awards

Berry Merger

Certain Berry restricted and performance stock unit awards included a single-trigger change in control provision which accelerated the vesting of such awards on the closing date of the Berry Merger. We settled these awards in cash and the amounts were accounted for as consideration transferred. Other Berry performance and restricted stock unit awards included a change in control provision as well as a subjective acceleration clause, which did not automatically accelerate the vesting of the awards on the closing date of the Berry Merger. In connection with the Berry Merger, we granted 203,873 RSUs as a replacement for such Berry restricted and performance stock units that did not automatically accelerate. The fair value of these replacement units was \$9 million, \$4 million of which was related to pre-combination services and included in consideration transferred. The remaining \$5 million will be recognized as a post-combination expense over the employee service period of which, \$3 million relates to Berry executives who separated from service upon the closing of the Berry Merger and is included in other operating expenses, net on our consolidated statement of operations for the year ended December 31, 2025.

Restricted Stock Units

Executives and non-employee directors were granted RSUs, which are in the form of, or equivalent in value to, actual shares of our common stock. The awards generally vest over three years following the grant date, with the exception of the RSUs granted on November 4, 2025 that generally vest over the five years following the grant date. Dividend equivalents are accumulated and paid when the shares are issued.

The following table sets forth RSU activity for the year ended December 31, 2025:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2024 ^(a)	650	\$ 40.49
Granted	585	\$ 45.46
Vested	(206)	\$ 44.27
Forfeited or cancelled	(36)	\$ 47.74
Unvested at December 31, 2025	<u>993</u>	<u>\$ 42.37</u>

(a) Includes additional 6,730 RSUs granted in 2024 at \$52.54 per unit.

Compensation expense was measured on the date of grant using the quoted market price of our common stock and is primarily recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any.

As of December 31, 2025, the unrecognized compensation expense for our unvested RSUs was approximately \$25 million and is expected to be recognized over a weighted-average remaining service period of approximately three years.

Performance Stock Units

In 2025, 2024 and 2023, executives were granted PSUs which are earned based on our absolute total shareholder return and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. The PSUs have payouts that range from 0% to 200% of the target award and settle in common shares once certified. Dividend equivalents for these awards are accumulated and paid out upon certification of the award. The grant date fair value and associated equity compensation expense was measured using a Monte Carlo simulation model which runs a probabilistic assessment of the number of units that will be earned based on a projection of our stock price during the three-year service period. Although certain events may accelerate vesting, earned PSUs generally vest on the third anniversary of the grant date, and are settled in shares of our common stock at the three-year anniversary of the grant date.

The following table sets forth PSU activity for the year ended December 31, 2025:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2024	764	\$ 48.83
Granted	351	\$ 35.53
Vested ^(a)	(284)	\$ 39.35
Forfeited or Cancelled	(53)	\$ 47.74
Unvested at December 31, 2025	<u>878</u>	<u>\$ 45.57</u>

(a) Includes additional net 100,314 PSUs earned based on achievement of specified performance metrics.

The range of assumptions used in the valuation of PSUs granted during 2025, 2024 and 2023 were as follows:

	2025	2024	2023
Expected volatility ^(a)	34.20%	38.58% - 40.30%	42.36% - 55.00%
Risk-free interest rate ^(b)	4.08%	4.52% - 4.86%	3.81% - 4.95%
Dividend yield ^(c)	— %	— %	— %
Forecast period (in years)	2.85	2.5 - 3	1.5 - 3

(a) Expected volatility was calculated using the historic volatility of our stock.

(b) Based on the U.S. Treasury yield for a three-year term at the grant date, as applicable.

(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

Compensation expense is recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any. Events that accelerate the vesting of an award have no effect on the requisite service period until such an event becomes probable.

As of December 31, 2025, the unrecognized compensation expense for our unvested PSUs was approximately \$15 million and is expected to be recognized over a weighted-average remaining service period of approximately two years.

Cash Incentive Awards

In each of the years of 2025, 2024 and 2023, we granted performance cash-settled awards to approximately 800 non-executive employees where half of the award is variable with payouts ranging from 75% to 150% of the grant value. The variable portion of the award is determined based upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock preceding each vesting date. These awards vest ratably over a three-year service period, with one third of the grants vesting on each of the first three anniversaries of the grant date. The fair value of the awards is adjusted on a quarterly basis for the cumulative change in the value determined using a Monte Carlo simulation model which runs a probabilistic assessment of our stock price for each of the three-year service periods.

The assumptions used in the valuation of our cash awards as of December 31, 2025 were as follows:

	2025 Awards	2024 Awards	2023 Awards
Expected volatility ^(a)	39 %	41 %	25 %
Risk-free interest rate ^(b)	3.60 %	3.65 %	3.71 %
Dividend yield ^(c)	— %	— %	— %
Forecast period (in years)	2.15	1.15	0.15

(a) Expected volatility was calculated using the historical volatility of our stock.

(b) Based on the U.S. Treasury yield for the remaining terms.

(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

As of December 31, 2025, the unrecognized compensation expense for all of our unvested cash-settled awards was \$14 million and is expected to be recognized over a weighted-average remaining service period of approximately two years. The value of awards forfeited during the year ended December 31, 2025 was approximately \$3 million.

Aera Incentive Awards

Upon closing of the Aera Merger we assumed cash-settled incentive awards that had been granted to certain Aera employees. The awards were granted by Aera in 2022, 2023, and 2024 and vest ratably over periods between two to three years. Awards that vested prior to July 1, 2024 were earned based on the performance metrics of Aera and we assumed a liability of \$8 million for the vested awards. Following July 1, 2024, the unvested awards will be earned based on our absolute total shareholder return and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. The awards pay out between 0% to 200%.

	2024 Awards
Expected volatility ^(a)	41.94 %
Risk-free interest rate ^(b)	3.48 %
Dividend yield ^(c)	— %
Forecast period (in years)	1

(a) Expected volatility was calculated using the historical volatility of our stock.

(b) Based on the U.S. Treasury yield for the remaining terms.

(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

As of December 31, 2025, the unrecognized compensation expense for these cash-settled awards was approximately \$1 million and is expected to be recognized over a weighted-average remaining service period of one year.

Employee Stock Purchase Plan

In May 2022, our shareholders approved a new California Resources Corporation Employee Stock Purchase Plan (ESPP), which took effect in July 2022. The ESPP provides our employees with the ability to purchase shares of our common stock at a price equal to 85% of the closing price of a share of our common stock as of the first or last day of each fiscal quarter, whichever amount is less. The maximum number of shares of our common stock which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 1,250,000 shares.

As of December 31, 2025, a total of 60,128 common shares were issued under our ESPP.

NOTE 11 STOCKHOLDERS' EQUITY

The following is a summary of changes in our common shares outstanding:

	Common Shares Outstanding
Balance, December 31, 2023	68,693,885
Issued as part of the Aera Merger	21,315,707
Shares issued for warrant exercises	3,769,703
Shares issued under ESPP	38,257
Shares issued under stock-based compensation arrangements ^(a)	1,740,189
Repurchased shares held as treasury stock	(3,649,348)
Shares cancelled for taxes ^(b)	(808,071)
Balance, December 31, 2024	91,100,322
Issued as part of the Berry Merger	5,572,115
Additional shares issued as part of the Aera Merger	107,265
Shares issued under ESPP	60,128
Shares issued under stock-based compensation arrangements	478,609
Repurchased shares held as treasury stock	(3,378,263)
Repurchased shares cancelled	(4,950,000)
Shares cancelled for taxes ^(b)	(236,011)
Balance at December 31, 2025	88,754,165

(a) A significant number of stock-based compensation awards were settled in the first quarter of 2024. These awards were primarily granted in January 2021 following our emergence from bankruptcy.

(b) In connection with the vesting of equity awards, we withheld and cancelled shares to satisfy applicable tax-withholding requirements.

Share Repurchase Program

Our Board of Directors authorized a Share Repurchase Program to acquire up to \$1.35 billion of our common stock through June 30, 2026. Refer to *Note 19 Subsequent Events* for additional information on a recent increase and extension to our Share Repurchase Program. Since the inception of the Share Repurchase Program through December 31, 2025, we acquired 26,841,526 shares of our common stock for \$1,173 million. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. The following is a summary of our share repurchases, held as treasury stock, for the periods presented:

	<u>Total Number of Shares Purchased</u>	<u>Dollar Value of Shares Purchased</u>	<u>Average Price Paid per Share</u>
	(number of shares)	(in millions)	(\$ per share)
Year ended December 31, 2023 . . .	3,407,655	\$143	\$41.69
Year ended December 31, 2024 . . .	3,649,348	\$192	\$52.12
Year ended December 31, 2025 . . .	<u>8,328,263</u>	<u>\$377</u>	<u>\$45.29</u>

Note: The total value of shares purchased includes approximately, \$2 million and \$1 million in the years ended December 31, 2024 and 2023 related to excise taxes on share repurchases. Excise taxes in 2025 were insignificant and include a reversal for 2024 excise taxes that were no longer due. Commissions paid were not significant in all periods presented.

Dividends

Dividends are payable to shareholders in quarterly increments, subject to the quarterly approval of our Board of Directors. The actual declaration of future cash dividends, and the establishment of record and payment dates, is subject to final determination by our Board of Directors each quarter after reviewing our financial performance. See *Note 19 Subsequent Events* for information on future cash dividends.

Our Board of Directors declared quarterly cash dividends of \$0.2825 per share of common stock for each of the first three quarters of 2023. On November 1, 2023, our Board of Directors increased our dividend policy to an expected total annual dividend of \$1.24 per share. On August 2, 2024, our Board of Directors increased the cash dividend policy to anticipate a total annual dividend of \$1.55 per share. On November 4, 2025, our Board of Directors increased the cash dividend policy to anticipate a total annual dividend of \$1.62 per share.

Our Board of Directors declared the following cash dividends for each of the periods presented.

	<u>Total Dividend</u>	<u>Annual Rate Per Share</u>
	(in millions)	(\$ per share)
Year ended December 31, 2023	\$ 81	\$ 1.1575
Year ended December 31, 2024	113	\$ 1.3950
Year ended December 31, 2025	136	\$ 1.5675
	<u>\$ 330</u>	

Warrants

In October 2020, we reserved an aggregate 4,384,182 shares of our common stock for issuance upon the exercise of warrants, which were exercisable at \$36 per share through October 28, 2024. As of December 31, 2025, we had no outstanding warrants.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of after-tax amounts for our pension and postretirement benefit plans. See *Note 14 Pension and Postretirement Benefit Plans* for further information.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Beginning accumulated other comprehensive income	\$ 75	\$ 74	\$ 81
Actuarial gain (loss) associated with pension and postretirement	26	4	(2)
Prior service credit	—	3	—
Recognition of prior service credit due to curtailment	—	—	(3)
Recognition of net actuarial loss due to settlement	(2)	—	—
Recognition of net actuarial loss due to curtailment	—	(4)	—
Recognition of net actuarial gain due to special termination benefits	—	4	—
Amortization of prior service credit	(5)	(5)	(5)
Amortization of net actuarial gain	(2)	—	—
Other comprehensive income (loss)	17	2	(10)
Total recorded in accumulated other comprehensive income, before tax	92	76	71
Income tax (provision) benefit	(5)	(1)	3
Total recorded in accumulated other comprehensive income, net of tax	\$ 87	\$ 75	\$ 74

NOTE 12 EARNINGS PER SHARE

Basic and diluted earnings per share (EPS) were calculated using the treasury stock method. Our restricted and performance stock unit awards, as described in *Note 10 Stock-Based Compensation*, are not considered participating securities since the dividend rights on unvested shares are forfeitable.

For basic EPS, the weighted-average number of common shares outstanding excludes underlying shares related to equity-settled awards and warrants. For diluted EPS, the basic shares outstanding are adjusted by adding potential common shares, if dilutive. Under the treasury stock method, we assume that proceeds from the exercise of options, warrants and similar instruments are used to purchase common stock at average market price of our stock each period. For PSUs, we measure the performance of our common stock against certain market conditions to determine the percentage earned for each period and the number of potential common shares included in diluted EPS. An insignificant number of potential common shares were not earned, and therefore were not treated as issued in our diluted EPS calculation for the year ended December 31, 2025.

The following table presents the calculation of basic and diluted EPS.

	Year ended December 31,		
	2025	2024	2023
	(in millions, except per share amounts)		
Numerator for Basic and Diluted EPS			
Net income	\$ 363	\$ 376	\$ 564
Denominator for Basic EPS			
Weighted-average shares	87.0	79.3	69.6
Potential common shares, if dilutive:			
Warrants	—	1.0	1.0
Restricted stock units	0.3	0.5	1.0
Performance stock units	0.1	0.5	0.9
Deferred Consideration Obligation (related to the Aera Merger)	—	0.1	—
Denominator for Diluted EPS			
Weighted-average shares	87.4	81.4	72.5
EPS			
Basic	\$ 4.17	\$ 4.74	\$ 8.10
Diluted	\$ 4.15	\$ 4.62	\$ 7.78

NOTE 13 LEASES

We have operating leases primarily for carbon sequestration easements, vehicles, colocation arrangements for servers and commercial office space. We have finance leases primarily for vehicles. ASC 805 *Business Combinations*, requires lease-related assets and liabilities acquired to be measured as if the lease were new at the acquisition date, using our incremental borrowing rate. The leases acquired in the Aera Merger and the Berry Merger retained the previous lease classification.

We have recorded the following amounts on our balance sheet as of December 31, 2025 and 2024:

	Classification	2025	2024
(in millions)			
Assets			
Operating lease	<i>Other noncurrent assets</i>	\$ 83	\$ 105
Finance lease	<i>PP&E</i>	2	3
Total lease assets		<u>\$ 85</u>	<u>\$ 108</u>
Liabilities			
Current			
Operating lease	<i>Accrued liabilities</i>	\$ 15	\$ 15
Finance lease	<i>Accrued liabilities</i>	1	1
Long-term			
Operating lease	<i>Other long-term liabilities</i>	\$ 61	\$ 76
Finance lease	<i>Other long-term liabilities</i>	1	2
Total lease liabilities		<u>\$ 78</u>	<u>\$ 94</u>

We combine lease and nonlease components in determining fixed minimum lease payments for our commercial office space. If applicable, fixed minimum lease payments are reduced by lease incentives for our commercial office space. Certain of our lease agreements include options to extend or terminate the lease, which we may exercise at our sole discretion. For our existing leases, we did not include these options in determining our fixed minimum lease payments over the lease term. Our

leases do not include options to purchase the leased property. Lease agreements for our fleet vehicles include residual value guarantees, none of which are recognized in our financial statements until the underlying contingency is resolved.

Variable lease costs for commercial office space include utilities and common area maintenance charges. Variable lease costs for our fleet vehicles include other-than-routine maintenance and other various amounts in excess of our fixed minimum rental fee.

Our lease costs, including amounts capitalized to PP&E, shown in the table below are before joint-interest recoveries. Lease payments are reduced by joint interest recoveries on our consolidated statement of operations through our joint-interest billing process.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Operating lease costs	\$ 30	\$ 26	\$ 23
Short-term lease costs ^(a)	112	50	52
Variable lease costs	2	2	2
Total operating lease costs	144	78	77
Finance lease costs	2	1	—
Sublease income ^(b)	(1)	(2)	(2)
Total lease costs	<u>\$ 145</u>	<u>\$ 77</u>	<u>\$ 75</u>

(a) Contracts with terms of less than one month or less are excluded from our disclosure of short-term lease costs.

(b) We sublease certain commercial office space to third parties where we are the primary obligor under the head lease. The lease terms on those subleases never extend past the term of the head lease and the subleases contain no extension options or residual value guarantees. Sublease income is recognized based on the contract terms and included as a reduction of operating lease cost under our head lease.

Other supplemental information related to our operating leases as of December 31, 2025 and 2024 is provided below:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Cash paid for lease liabilities			
Lease liabilities associated with operating activities	\$ 34	\$ 29	\$ 28
Lease liabilities associated with investing activities	\$ 19	\$ 8	\$ 2
Lease liabilities associated with financing activities	\$ 1	\$ 1	\$ —
Noncash operating lease assets obtained in exchange for new operating lease liabilities	\$ 37	\$ 52	\$ 32
Noncash finance lease assets obtained in exchange for new finance lease liabilities	\$ 3	\$ 3	\$ —

	<u>2025</u>	<u>2024</u>
Operating Leases		
Weighted-average remaining lease term (in years)	7.00	5.95
Weighted-average discount rate	8.4%	8.1%
Finance Leases		
Weighted-average remaining lease term (in years)	3.01	3.37
Weighted-average discount rate	8.5%	9.0%

Our operating and finance lease payments as of December 31, 2025 are as follows:

	<u>Operating Leases</u>	<u>Finance Leases</u>
	(in millions)	
2026	\$ 18	\$ 2
2027	16	1
2028	15	1
2029	13	—
Thereafter	46	—
Less: Interest	(32)	(2)
Present value of lease liabilities	<u>\$ 76</u>	<u>\$ 2</u>

NOTE 14 PENSION AND POSTRETIREMENT BENEFIT PLANS

Prior to the Aera Merger, we maintained two qualified defined benefit pension plans covering union employees and a postretirement health care plan for certain retired employees. In connection with the Aera Merger, we acquired a qualified defined benefit cash balance pension plan and a non-qualified cash balance pension plan that restores benefits lost due to governmental limitations on the qualified plan. We also acquired two postretirement benefit plans that provide health care benefits for certain retired employees. Certain of the postretirement benefit obligations are funded through 401(h) accounts under the qualified pension plans. Aera's pension and postretirement obligations were remeasured as of the July 1, 2024 acquisition date. At that time, for Aera's pension plans, we recognized a net benefit asset of \$64 million and a net benefit liability of \$8 million and for Aera's postretirement benefit plans, we recognized a net benefit asset of \$9 million and a net benefit liability of \$27 million. Accumulated other comprehensive income balances for the acquired Aera plans were eliminated in purchase accounting.

In August 2024, we amended Aera's pension and postretirement benefit plans. For Aera's defined benefit pension plans and post age 65 postretirement benefit plan, participants no longer accrue additional benefits for service after September 30, 2024. However, for each of the foregoing plans, future service will count towards vesting of benefits accrued based on past service. In addition, for both of Aera's postretirement benefit plans, we expanded the eligibility provisions in the event of an involuntary layoff. Following the Aera Merger, we recognized a curtailment gain of \$4 million and a one-time cost of special termination benefits of \$4 million included in net periodic benefit costs for the year ended December 31, 2024.

Defined Contribution Plans

All of our employees are eligible to participate in our tax-qualified, defined contribution retirement plan that provides for periodic cash contributions by us based on annual cash compensation and employee deferrals.

Certain salaried employees participate in non-qualified supplemental defined contribution plans that restore benefits lost due to government limitations on qualified plans. We recognized \$28 million and \$30 million in other long-term liabilities for the years ended December 31, 2025 and 2024, respectively, related to these supplemental plans.

We expensed \$31 million in 2025, \$27 million in 2024 and \$19 million in 2023 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2025, only approximately 52 employees were accruing benefits at year-end, all of whom were union employees.

Pension costs for the defined benefit pension plans, determined by independent actuarial valuations, are funded by us through payments to trust funds, which are administered by independent trustees.

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. Our former employees are required to make monthly contributions for the coverage, but the benefits are primarily funded by us as claims are paid during the year.

Obligations and Funded Status of our Defined Benefit Plans

The following table shows the amounts recognized on our balance sheets related to pension and postretirement benefit plans, as well as plans that we or our subsidiaries sponsor:

	December 31, 2025		December 31, 2024	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)		(in millions)	
Amounts recognized on the balance sheet				
Other assets	\$ 97	\$ 19	\$ 67	\$ 13
Accrued liabilities	—	(5)	(1)	(6)
Other long-term liabilities	(5)	(52)	(6)	(53)
	<u>\$ 92</u>	<u>\$ (38)</u>	<u>\$ 60</u>	<u>\$ (46)</u>
Accumulated other comprehensive income, net of tax	\$ 17	\$ 70	\$ 2	\$ 73

The following table shows the funding status of our pension and post-retirement benefit plans along with a reconciliation of our benefit obligations and changes in fair value of plan assets:

	Year ended December 31,	
	2025	2024
	(in millions)	
Pension		
Changes in the benefit obligation		
Benefit obligation - beginning of year	\$ 272	\$ 34
Liabilities assumed in the Aera Merger	—	249
Service cost - benefits earned during the period	1	3
Interest cost on projected benefit obligation	14	8
Actuarial loss (gain) ^(a)	6	(2)
Benefits paid	(39)	(20)
Benefit obligation - end of year	<u>\$ 254</u>	<u>\$ 272</u>
Changes in plan assets		
Fair value of plan assets - beginning of year	\$ 332	\$ 34
Additions due to the Aera Merger	—	305
Actual return on plan assets	51	10
Employer contributions	2	3
Benefits paid	(39)	(20)
Fair value of plan assets - end of year	<u>\$ 346</u>	<u>\$ 332</u>
Net benefit asset	<u>\$ 92</u>	<u>\$ 60</u>
Postretirement		
Changes in the benefit obligation		
Benefit obligation - beginning of year	\$ 100	\$ 37
Liabilities assumed in the Aera Merger	—	70
Service cost - benefits earned during the period	2	2
Interest cost on projected benefit obligation	5	4
Actuarial loss (gain) ^(b)	2	(5)
Cost of special termination benefits	—	4
Curtailement gain	—	(4)
Benefits paid	(11)	(5)
Plan amendment	—	(3)
Benefit obligation - end of year	<u>\$ 98</u>	<u>\$ 100</u>
Changes in plan assets		
Fair value of plan assets - beginning of year	\$ 54	\$ 1
Additions due to the Aera Merger	—	52
Actual gain on plan assets	9	2
Employer contributions	8	4
Benefits paid	(11)	(5)
Fair value of plan assets - end of year	<u>\$ 60</u>	<u>\$ 54</u>
Net benefit liability	<u>\$ (38)</u>	<u>\$ (46)</u>

(a) The loss reflected in the changes in the pension benefit obligation for the year ended December 31, 2025 was primarily due to movement in the discount rates.

(b) The loss reflected in the changes in the postretirement benefit obligation for the year ended December 31, 2025 was primarily due to movement in the discount rate.

The following table sets for the details of our obligations and assets related to our defined benefit pension plans for the years ended December 31, 2025 and 2024:

	<u>2025</u>	<u>2024</u>
	(in millions)	
Projected benefit obligation	\$ 254	\$ 272
Accumulated benefit obligation	\$ 251	\$ 268
Fair value of plan assets	\$ 346	\$ 332

Components of Net Periodic Benefit Cost

We record the service cost component of net periodic pension cost with other employee compensation and all other components, including settlement costs, are reported as other non-operating income (expenses), net on our consolidated statements of operations. The following table set forth the components of our net periodic pension and postretirement benefit costs:

	<u>Year ended December 31,</u>		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
	(in millions)		
Pension			
Net periodic benefit costs			
Service cost - benefits earned during the period	\$ 1	\$ 3	\$ 1
Interest cost on projected benefit obligation	14	8	1
Expected return on plan assets	(22)	(13)	(2)
Settlement costs	(2)	—	—
Net periodic benefit costs	<u>\$ (9)</u>	<u>\$ (2)</u>	<u>\$ —</u>
Postretirement			
Net periodic benefit costs			
Service cost - benefits earned during the period	\$ 2	\$ 2	\$ 2
Interest cost on projected benefit obligation	5	4	2
Expected return on plan assets	(3)	(2)	—
Cost of special termination benefits	—	4	—
Amortization of prior service cost credit	(5)	(5)	(5)
Amortization of net actuarial gain	(2)	(1)	(2)
Curtailement gain	—	(4)	(3)
Net periodic benefit costs	<u>\$ (3)</u>	<u>\$ (2)</u>	<u>\$ (6)</u>

Components of accumulated other comprehensive income (loss) (AOCI) are presented net of tax. The following table presents the changes in plan assets and benefit obligations recognized in other comprehensive (loss) income:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Pension			
Net actuarial gain	\$ (23)	\$ —	\$ (1)
Settlement costs	2	—	—
Total	<u>\$ (21)</u>	<u>\$ —</u>	<u>\$ (1)</u>
Postretirement			
Net actuarial (gain) loss	\$ (3)	\$ (5)	\$ 1
Prior service credit	—	(3)	—
Actuarial net gain due to curtailment	—	4	—
Special termination benefits	—	(4)	—
Amortization of prior service credit due to curtailment	—	—	(2)
Amortization of prior service credit	5	5	(4)
Amortization net actuarial gain (loss)	2	2	(1)
Total	<u>\$ 4</u>	<u>\$ (1)</u>	<u>\$ (6)</u>

The following table sets forth the valuation assumptions, on a weighted-average basis, used to determine our benefit obligations and net periodic benefit cost:

	Year ended December 31,	
	2025	2024
Pension		
<i>Benefit Obligation Assumptions</i>		
Discount rate	5.52 %	5.61 %
Rate of compensation increase	4.00 %	4.93 %
Interest crediting rate	5.00 %	5.28 %
<i>Net Periodic Benefit Cost Assumptions</i>		
Discount rate	5.61 %	5.22 %
Expected return on assets	6.99 %	7.00 %
Rate of compensation increase	4.00 %	4.96 %
Interest crediting rate	5.28 %	6.37 %
Postretirement		
<i>Benefit Obligation Assumptions</i>		
Discount rate	5.18 %	5.50 %
<i>Net Periodic Benefit Cost Assumptions</i>		
Discount rate	5.51 %	5.13 %
Expected return on assets	6.99 %	6.99 %

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the FTSE Above Median AA yield curve in 2025 and in 2024. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in pension plans that determine benefits using compensation. The assumed return on assets is estimated with regard to current market factors but within the context of historical returns for the asset mix that exists at year end.

In 2025 and 2024, we used the Society of Actuaries Pri-2012 mortality assumptions reflecting the MP-2021 scale which plan sponsors in the U.S. use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 2.4% and 2.45% as of December 31, 2025 and 2024, respectively. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that, as of December 31, 2025, health care cost trend rates would be 8.00% in 2026 decreasing until they reach 4.00% in 2034 and remain at 4.00% thereafter. For those union employees, we projected that, as of December 31, 2024, health care cost trend rates would be 6.50% in 2025 decreasing until they reach 4.50% in 2033 and remain at 4.50% thereafter.

The actuarial assumptions used could change in the near term as a result of changes in expected future trends and other factors that, depending on the nature of the changes, could cause increases or decreases in the plan assets and liabilities.

Fair Value of Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In both 2025 and 2024, the target allocation of pension plan assets was 45% equity securities and 55% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

The fair values of our pension plan assets by asset category are as follows:

Fair Value Measurements at December 31, 2025				
Asset Class	Level 1	Level 2	Level 3	Total
	(in millions)			
Commingled funds				
Bonds	18	170	—	188
Commodities	11	—	—	11
U.S. equity	—	73	—	73
International equity	40	34	—	74
Total pension plan assets	<u>\$ 69</u>	<u>\$ 277</u>	<u>\$ —</u>	<u>\$ 346</u>

Fair Value Measurements at December 31, 2024				
Asset Class	Level 1	Level 2	Level 3	Total
	(in millions)			
Commingled funds				
Bonds	24	162	—	186
Commodities	17	—	—	17
U.S. equity	—	84	—	84
International equity	24	20	—	44
Total pension plan assets	<u>\$ 65</u>	<u>\$ 266</u>	<u>\$ —</u>	<u>\$ 331</u>

The fair values of our postretirement benefit plan assets by asset category are as follows:

Fair Value Measurements at December 31, 2025				
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Commingled funds				
Bonds	3	29	—	32
Commodities	2	—	—	2
U.S. equity	—	12	—	12
International equity	8	4	—	12
Total pension plan assets	<u>\$ 13</u>	<u>\$ 45</u>	<u>\$ —</u>	<u>\$ 58</u>

Fair Value Measurements at December 31, 2024				
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Commingled funds				
Bonds	4	26	—	30
Commodities	3	—	—	3
U.S. equity	—	13	—	13
International equity	4	2	—	6
Total pension plan assets	<u>\$ 11</u>	<u>\$ 41</u>	<u>\$ —</u>	<u>\$ 52</u>

Expected Contributions and Benefit Payments

In 2026, we expect to contribute an insignificant amount to our pension plans and expect to contribute \$6 million to our postretirement benefit plans. Estimated future undiscounted benefit payments by the plans, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits		Postretirement Benefits	
For the years ended December 31,	(in millions)			
2026	\$	23	\$	10
2027	\$	15	\$	9
2028	\$	18	\$	8
2029	\$	16	\$	8
2030	\$	16	\$	8
2031 - 2035	\$	76	\$	40

NOTE 15 REVENUE

The following is a description of our principal activities from which we generate revenue. Revenue from customers is recognized when a customer obtains control of promised goods and the obligations under the terms of a contract are satisfied.

Sales of our Produced Oil, Natural Gas and NGLs

Revenue from sales of our oil, natural gas and NGL production is recognized upon delivery (and transfer of control) of the commodity to the customer. In certain instances, transportation and processing fees are incurred by us prior to delivery to customers. We record these transportation and processing fees as transportation costs on our consolidated statements of operations.

Our contracts with customers are generally less than a year and based on index prices. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following the month of delivery. The following table provides disaggregated revenue for sales of produced oil, natural gas and NGLs to external customers:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Oil	\$ 2,647	\$ 2,255	\$ 1,534
Natural gas	99	96	309
Natural gas liquids	164	186	198
Oil, natural gas and natural gas liquids sales	<u>\$ 2,910</u>	<u>\$ 2,537</u>	<u>\$ 2,041</u>

We also process third-party wet gas at one of our gas processing facilities and the purity products are then sold to customers. We recognized \$3 million, \$3 million and \$15 million included in other revenue on our consolidated statements of operations for the years ended December 31, 2025, 2024 and 2023, respectively.

Electricity Revenue

The electrical output of our Elk Hills power plant that is not used in our operations is primarily sold into the California Independent System Operator (CAISO) wholesale power market. We also enter into contracts with load-serving entities to ensure there is sufficient capacity to support forecasted demand in the California market. Our contracts for capacity are at market prices and generally for a term that does not exceed twelve months. For the twelve months ended December 31, 2023, we sold power to a California utility under a power purchase and sales agreement (PPA), which included a monthly capacity payment plus a variable payment based on the quantity of power purchased each month.

As part of the Berry Merger, we acquired four cogeneration plants. The electrical output of one of these plants that is not used in our operations is sold to a California investor-owned utility, Pacific Gas and Electric under a power purchase and sales agreement that expires in November 2026.

Revenue is recognized when obligations under the terms of a contract are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on CAISO market pricing with payment due the month following delivery. We recognize electricity revenue using the output method and consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of capacity is made available to the customer in the case of capacity payments.

Revenue from Marketing of Purchased Commodities

From time-to-time, we enter into transactions for third-party production, which we report as revenue from marketing of purchased commodities on our consolidated statements of operations. Revenues from marketing of purchased commodities results from (1) the storage or transportation of natural gas to take advantage of differences in pricing or location, (2) marketing oil sales that have resulted from third-party purchases or (3) sales of NGLs from inventory storage. To transport our natural gas as well as third-party volumes, we have entered into firm pipeline transportation commitments. We report associated expense related to the cost of marketing purchased commodities in operating expenses on our consolidated statements of operations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Oil	\$ 86	\$ 99	\$ —
Natural gas	144	128	401
Natural gas liquids	8	8	6
Revenue from marketing of purchased commodities	<u>\$ 238</u>	<u>\$ 235</u>	<u>\$ 407</u>

NOTE 16 SEGMENT INFORMATION

We conduct our business primarily through two reportable segments: (1) oil and natural gas exploration and production and (2) carbon management. We identified these segments based on the nature of their activities, the types of products sold and services to be provided. Our oil and natural gas segment explores for, develops, and produces oil and condensate, natural gas liquids and natural gas. Our carbon management segment, that we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO₂ capture equipment, transportation assets and storage facilities. Our oil and natural gas segment operates assets located in California and Utah. Our carbon management segment operates exclusively in California.

Our chief operating decision maker (CODM), the Chief Executive Officer, uses segment profit or loss to assess the performance of each business, as well as our overall performance, and to make decisions about resources to be allocated to each segment, including capital investments.

The following tables provide segment profit or loss and reconciliations to consolidated income before income taxes for the years ended December 31, 2025, 2024, and 2023. The consolidation and elimination entries necessary to arrive at our consolidated financial information is presented separately.

	Year ended December 31, 2025				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments (in millions)	Elimination	Total
Oil, natural gas and natural gas liquids sales	\$ 2,957	\$ —	\$ 2,957	\$ (47)	\$ 2,910
Other revenue	10	—	10	—	10
Segment operating revenues	<u>2,967</u>	<u>—</u>	<u>2,967</u>		
Other revenues and income ^(a)				749	<u>749</u>
Total operating revenues					<u>\$ 3,669</u>

(a) Other revenues and income includes net gain from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

Year ended December 31, 2025

	<u>Oil and Natural Gas</u>	<u>Carbon Management</u>	<u>Total Reportable Segments</u> (in millions)	<u>Reconciliation (Income)/ Expense</u>	<u>Total</u>
Segment operating revenues	\$ 2,967	\$ —	\$ 2,967		\$ 2,967
Less:					
Operating costs:					
Energy operating costs	405	—	405	(31)	374
Gas processing costs	19	—	19	—	19
Non-energy operating costs	856	—	856	3	859
General and administrative expenses	43	13	56	277	333
Depreciation, depletion and amortization	492	—	492	19	511
Taxes other than on income	203	—	203	39	242
Interest and debt expense, net	—	11	11	95	106
Equity loss (income) from unconsolidated subsidiaries	—	6	6	(2)	4
Other segment expenses ^(a)	261	56	317	—	317
Segment profit or (loss)	<u>\$ 688</u>	<u>\$ (86)</u>	<u>\$ 602</u>		
Other profit or loss ^(b) ...				(204)	(204)
Unallocated amounts ^(c)				(96)	<u>(96)</u>
Income before income taxes					<u>\$ 502</u>

- (a) Other segment expenses for our oil and natural gas segment include transportation costs, accretion expense, asset impairment and other operating expenses, net. Other segment expenses for our carbon management segment primarily includes operating lease costs and asset impairment.
- (b) Other profit or loss includes the margin we earn from marketing activities and the margin we earn on sales of electricity from our Elk Hills power plant to customers.
- (c) Unallocated amounts include net gain from commodity derivatives, net loss on natural gas purchase derivatives, transportation costs, other operating expenses, net, interest income, unallocated other revenue, and other non-operating income.

Year ended December 31, 2024

	Oil and Natural Gas	Carbon Management	Total Reportable Segments <small>(in millions)</small>	Elimination	Total
Oil, natural gas and natural gas liquids sales	\$ 2,565	\$ —	\$ 2,565	\$ (28)	\$ 2,537
Other revenue	<u>7</u>	<u>—</u>	<u>7</u>	<u>—</u>	<u>7</u>
Segment operating revenues	<u>2,572</u>	<u>—</u>	<u>2,572</u>		
Other revenues and income ^(a)				654	<u>654</u>
Total operating revenue					<u>\$ 3,198</u>

(a) Other revenues and income includes net gain from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

Year ended December 31, 2024

	Oil and Natural Gas	Carbon Management	Total Reportable Segments <small>(in millions)</small>	Reconciliation (Income)/ Expense	Total
Segment operating revenues	\$ 2,572	\$ —	\$ 2,572		\$ 2,572
Less:					
Operating costs:					
Energy operating costs	296	—	296	(17)	279
Gas processing costs	16	—	16	—	16
Non-energy operating costs	671	—	671	—	671
General and administrative expenses	43	15	58	263	321
Depreciation, depletion and amortization	354	—	354	34	388
Taxes other than on income	207	—	207	35	242
Interest and debt expense, net	—	9	9	78	87
Equity loss (income) from unconsolidated subsidiaries	—	12	12	(2)	10
Other segment expenses ^(a)	<u>170</u>	<u>58</u>	<u>228</u>	<u>—</u>	<u>228</u>
Segment profit or (loss)	<u>\$ 815</u>	<u>\$ (94)</u>	<u>\$ 721</u>		
Other profit or loss ^(b)				(133)	(133)
Unallocated amounts ^(c)				(53)	(53)
Income before income taxes ..					<u>\$ 516</u>

(a) Amounts for our oil and natural gas segment include transportation costs, accretion expense, asset impairment, and other operating expenses, net and gain on asset divestitures. Amounts for our carbon management segment primarily include operating lease costs.

(b) Other profit or loss includes margin from purchased commodities and the margin we earn on sales of electricity from our Elk Hills power plant to customers.

- (c) Unallocated amounts include net gain from commodity derivatives, net loss on natural gas purchase derivatives, transportation costs, other operating expenses, net, other non-operating loss, interest income, unallocated other revenue and loss on early extinguishment of debt, and gain on asset divestiture.

Year ended December 31, 2023					
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Elimination	Total
	(in millions)				
Oil, natural gas and natural gas liquids sales	\$ 2,041	\$ —	\$ 2,041	\$ —	\$ 2,041
Other revenue	17	—	17	—	17
Intersegment revenue	114	—	114	—	114
Segment operating revenues	<u>2,172</u>	<u>—</u>	<u>2,172</u>		<u>2,172</u>
Other revenues and income ^(a)				629	<u>629</u>
Total operating revenues					<u>\$ 2,801</u>

- (a) Other revenues and income includes net loss from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

Year ended December 31, 2023					
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation (Income)/ Expense	Total
	(in millions)				
Segment operating revenues	\$ 2,172	\$ —	\$ 2,172		\$ 2,172
Less:					
Operating costs:					
Energy operating costs	323	—	323	—	323
Gas processing costs	18	—	18	—	18
Non-energy operating costs	481	—	481	—	481
General and administrative expenses	42	12	54	213	267
Depreciation, depletion and amortization	205	—	205	20	225
Taxes other than on income	114	—	114	51	165
Interest and debt expense, net	—	5	5	51	56
Equity loss from unconsolidated subsidiary	—	9	9	—	9

	Year ended December 31, 2023				Total
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation (Income)/Expense	
			(in millions)		
Other segment expenses ^(a)	67	40	107	—	107
Segment profit or (loss)	<u>\$922</u>	<u>\$(66)</u>	<u>\$856</u>		
Other profit or loss ^(b)				(291)	(291)
Unallocated amounts ^(c)				64	64
Income before income taxes					<u>\$ 748</u>

(a) Amounts for our oil and natural gas segment include transportation costs, accretion expense, other operating expenses and gain on asset divestitures. Amounts for our carbon management segment primarily include operating lease costs.

(b) Other profit or loss includes margin from purchased commodities and the margin we earn on sale of electricity from our Elk Hills power plant to customers.

(c) Unallocated amounts include net loss from commodity derivatives, net loss on natural gas purchase derivatives, transportation costs, other operating expenses, net, other non-operating income, interest income, unallocated other revenue and loss on early extinguishment of debt.

Total assets by segment is not provided to our CODM for decision-making; however, we regularly provide capital investment by segment to our CODM. The table below presents capital by segment with a reconciliation to our consolidated capital investment for the years ended December 31, 2025, 2024 and 2023. See *Note 4 Investments and Related Party Transactions* for information on our investment in the Carbon TerraVault JV, which is part of our carbon management segment. See *Note 13 Leases* for information leases we have entered into for our carbon management business. Included in our oil and gas segment is \$659 million of oil and gas property, inclusive of C&J Well Services, we acquired in the Berry Merger and \$3 billion of oil and gas property acquired in the Aera Merger. Refer to *Note 2 Business Combinations* for additional information on these transactions.

	Oil and Natural Gas	Carbon Management	Corporate and Other	Consolidated
		(in millions)		
Year ended December 31, 2025	\$ 276	\$ 33	\$ 13	\$ 322
Year ended December 31, 2024	\$ 234	\$ 12	\$ 9	\$ 255
Year ended December 31, 2023	\$ 153	\$ 5	\$ 27	\$ 185

NOTE 17 SUPPLEMENTAL ACCOUNT BALANCES

Other current assets, net — Other current assets, net include the following:

	December 31, 2025	December 31, 2024
	(in millions)	
Net amounts due from joint interest partners ^(a)	\$ 56	\$ 41
Fair value of commodity derivative contracts	187	14
Prepaid expenses	38	28
Greenhouse gas allowances	—	27
Income tax receivable	52	50
Other	20	16
Other current assets, net	<u>\$ 353</u>	<u>\$ 176</u>

(a) The amounts due from joint interest partners include \$2 million and an insignificant amount of allowances for credit losses as of December 31, 2025 and December 31, 2024, respectively.

Other noncurrent assets — Other noncurrent assets include the following:

	December 31, 2025	December 31, 2024
	(in millions)	
Operating lease right-of-use assets	\$ 83	\$ 105
Deferred financing costs - Revolving Credit Facility	20	23
Emission reduction credits	11	11
Fair value of commodity derivative contracts	101	16
Funded pension	97	67
Postretirement plan	19	13
Other	42	37
Other noncurrent assets	<u>\$ 373</u>	<u>\$ 272</u>

Accrued liabilities — Accrued liabilities include the following:

	December 31, 2025	December 31, 2024
	(in millions)	
Compensation-related liabilities	\$ 159	\$ 184
Taxes other than on income	105	100
Asset retirement obligations - current portion	120	134
Interest	12	12
Operating lease liability	15	15
Settlements and premiums due on commodity derivative contracts	22	15
Advanced payments	19	25
Payables to the former owners of Aera	—	29
Greenhouse gas liability	27	—
Signal Hill offshore platform expense accrual	13	1
Fair value of derivative contracts	42	50
Other	64	46
Accrued liabilities	<u>\$ 598</u>	<u>\$ 611</u>

Other long-term liabilities — Other long-term liabilities includes the following:

	December 31, 2025	December 31, 2024
	(in millions)	
Compensation-related liabilities	\$ 48	\$ 50
Postretirement and pension benefit plans	57	59
Operating lease liability	61	76
Fair value of commodity derivative contracts	17	45
Contingent liability ^(a)	117	107
Other	29	40
Other long-term liabilities	<u>\$ 329</u>	<u>\$ 377</u>

(a) See Note 4 Investments and Related Party Transactions for information on the contingent liability related to the Carbon TerraVault JV.

NOTE 18 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

We have designated certain of our subsidiaries as Unrestricted Subsidiaries under the indenture governing our 2026 Senior Notes (2026 Senior Notes Indenture), 2029 Senior Notes (2029 Senior Notes Indenture) and 2034 Senior Notes (2034 Senior Notes Indenture). Unrestricted Subsidiaries (as

defined in the 2026 Senior Notes Indenture, 2029 Senior Notes Indenture, and 2034 Senior Notes Indenture) are subject to fewer restrictions under the indentures. We are required under the 2026 Senior Notes Indenture, 2029 Senior Notes Indenture and 2034 Senior Notes Indenture to present the financial condition and results of operations of CRC and its Restricted Subsidiaries (as defined in the 2026 Senior Notes Indenture, 2029 Senior Notes Indenture, and 2034 Senior Notes Indenture) separate from the financial condition and results of operations of its Unrestricted Subsidiaries. The following consolidating balance sheets as of December 31, 2025 and 2024 and the consolidating statements of operations for the year ended December 31, 2025, 2024, and 2023, as applicable, reflect the consolidating financial information of CRC (Parent), our combined Unrestricted Subsidiaries, our combined Restricted Subsidiaries and the elimination entries necessary to arrive at the information for the Company on a consolidated basis. The financial information may not necessarily be indicative of the financial condition and results of operations had the Unrestricted Subsidiaries operated as independent entities.

**Condensed Consolidating Balance Sheets
As of December 31, 2025 and 2024**

	As of December 31, 2025				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total current assets	\$ 203	\$ 20	\$ 715	\$ —	\$ 938
Total property, plant and equipment, net	27	21	5,857	—	5,905
Investments in consolidated subsidiaries	6,579	(51)	18,099	(24,627)	—
Deferred tax asset	76	—	—	—	76
Investment in unconsolidated subsidiaries	—	57	54	—	111
Other assets	22	31	320	—	373
TOTAL ASSETS	\$ 6,907	\$ 78	\$ 25,045	\$ (24,627)	\$ 7,403
Total current liabilities	180	6	864	—	\$ 1,050
Long-term debt	1,283	—	—	—	1,283
Asset retirement obligations	—	—	913	—	913
Other long-term liabilities . . .	110	130	89	—	329
Deferred tax liability	154	—	—	—	154
Amounts due to (from) affiliates	1,508	61	(1,569)	—	—
Total equity	3,674	(120)	24,747	(24,627)	3,674
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 6,909	\$ 77	\$ 25,044	\$ (24,627)	\$ 7,403

As of December 31, 2024					
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total current assets	\$ 437	\$ 46	\$ 541	\$ —	\$ 1,024
Total property, plant and equipment, net	14	31	5,635	—	5,680
Investments in consolidated subsidiaries	4,869	(32)	15,050	(19,887)	—
Deferred tax asset	73	—	—	—	73
Investment in unconsolidated subsidiaries	—	27	59	—	86
Other assets	113	58	101	—	272
TOTAL ASSETS	\$ 5,506	\$ 130	\$ 21,386	\$ (19,887)	\$ 7,135
Total current liabilities	224	14	742	—	\$ 980
Long-term debt	1,132	—	—	—	1,132
Asset retirement obligations	—	—	995	—	995
Other long-term liabilities	114	138	125	—	377
Amounts due to (from) affiliates	385	—	(385)	—	—
Deferred tax liability	113	—	—	—	113
Total equity	3,538	(22)	19,909	(19,887)	3,538
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 5,506	\$ 130	\$ 21,386	\$ (19,887)	\$ 7,135

Condensed Consolidating Statement of Operations
For the years ended December 31, 2025, 2024 and 2023

Year ended December 31, 2025					
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total operating revenues	\$ 10	\$ —	\$ 3,741	\$ (82)	\$ 3,669
Total costs and other	381	62	2,709	(82)	3,070
Loss on asset divestitures	—	—	(1)	—	(1)
Non-operating (loss) income	(94)	(16)	14	—	(96)
(LOSS) INCOME BEFORE INCOME TAXES	(465)	(78)	1,045	—	502
Income tax provision	(139)	—	—	—	(139)
NET (LOSS) INCOME	\$ (604)	\$ (78)	\$ 1,045	\$ —	\$ 363

Year ended December 31, 2024

	<u>Parent</u>	<u>Combined Unrestricted Subsidiaries</u>	<u>Combined Restricted Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
			(in millions)		
Total operating revenues	\$ 18	\$ —	\$ 3,345	\$ (165)	\$ 3,198
Total costs and other	290	66	2,398	(165)	2,589
Gain on asset divestitures . . .	—	—	11	—	11
Non-operating (loss) income	(92)	(21)	9	—	(104)
(LOSS) INCOME BEFORE INCOME TAXES	(364)	(87)	967	—	516
Income tax provision	(140)	—	—	—	(140)
NET (LOSS) INCOME	<u>\$ (504)</u>	<u>\$ (87)</u>	<u>\$ 967</u>	<u>\$ —</u>	<u>\$ 376</u>

Year ended December 31, 2023

	<u>Parent</u>	<u>Combined Unrestricted Subsidiaries</u>	<u>Combined Restricted Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
			(in millions)		
Total operating revenues	\$ 21	\$ —	\$ 2,780	\$ —	\$ 2,801
Total costs and other	239	49	1,737	—	2,025
Gain on asset divestitures	—	—	32	—	32
Non-operating (loss) income	(51)	(14)	5	—	(60)
(LOSS) INCOME BEFORE INCOME TAXES	(269)	(63)	1,080	—	748
Income tax provision . .	(184)	—	—	—	(184)
NET (LOSS) INCOME	<u>\$ (453)</u>	<u>\$ (63)</u>	<u>\$ 1,080</u>	<u>\$ —</u>	<u>\$ 564</u>

NOTE 19 SUBSEQUENT EVENTS

Reorganization

In February 2026, we undertook a reduction in force following the Berry Merger that resulted in a reduction of our headcount and we expect to recognize a charge of approximately \$22 million in other operating expenses, net on our condensed consolidated statement of operations for the three months ended March 31, 2026, which primarily includes severance.

Dividends

On March 1, 2026, our Board of Directors declared a cash dividend of \$0.405 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 13, 2026 and is expected to be paid on March 20, 2026.

Share Repurchase Program

In February 2026, our Board of Directors increased the Share Repurchase Program by \$430 million and extended the program through December 31, 2027.

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), NGLs and natural gas and changes in such quantities. Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. Our proved reserves are located within the United States.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil ^(a) (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total ^(b) (MMBoe)
Balance at December 31, 2022	294	38	511	417
Revisions of previous estimates ^(c)	(12)	1	51	(2)
Improved recovery	1	—	—	1
Extensions and discoveries	4	—	7	5
Acquisitions and divestitures	(12)	—	—	(12)
Production	(19)	(4)	(51)	(32)
Balance at December 31, 2023	256	35	518	377
Revisions of previous estimates ^(c)	(19)	2	(72)	(29)
Improved recovery	1	—	—	1
Acquisitions and divestitures	234	1	5	236
Production	(29)	(4)	(42)	(40)
Balance at December 31, 2024	443	34	409	545
Revisions of previous estimates ^(c)	33	2	6	36
Improved recovery	16	3	45	27
Extensions and discoveries	2	—	6	3
Acquisitions and divestitures	87	1	31	93
Production	(40)	(3)	(42)	(50)
Balance at December 31, 2025	541	37	455	654
PROVED DEVELOPED RESERVES				
December 31, 2022	251	36	458	363
December 31, 2023	223	34	445	331
December 31, 2024	412	32	370	506
December 31, 2025	452	30	351	541
PROVED UNDEVELOPED RESERVES				
December 31, 2022	43	2	53	54
December 31, 2023	33	1	73	46
December 31, 2024	31	2	39	39
December 31, 2025	89	7	104	113

(a) Includes proved reserves related to economic arrangements similar to PSCs of 51 MMBbl, 62 MMBbl, 76 MMBbl and 92 MMBbl at December 31, 2025, 2024, 2023 and 2022, respectively.

- (b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.
- (c) Commodity price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Long Beach operations in the Wilmington field because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data.
- (d) Approximately 10% of proved developed oil reserves, 6% of proved developed NGLs reserves, 7% of proved developed natural gas reserves and, overall, 10% of total proved developed reserves at December 31, 2025 are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

2025

Revisions of previous estimates – We had net negative price-related revisions of 25 MMBoe. Included in these revisions are negative price-related revisions of 37 MMboe, which were partially offset by 23 MMBoe of positive revisions. These negative revisions are primarily a result of lower average realized SEC Prices in 2025 as compared to 2024, including lower natural gas realizations in certain areas. These negative revisions were partially offset by positive revisions primarily from lower operating costs related to steamflood management.

Also included in the net negative price-related revisions are negative revisions of 12 MMBoe offset by 1 MMBoe of positive revisions, which were due the extension of the cap-and-invest program. The majority of these revisions were located in the San Joaquin basin. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

We had 61 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 80 MMBoe and negative performance-related revisions of 19 MMBoe. Our positive performance-related revisions primarily related to additional drilling activity in the San Joaquin basin, maintaining higher than forecasted base production, and extension of field life through steam management. Our negative performance-related revisions primarily were due to lower overall expected recovery from certain projects in the San Joaquin basin.

Extensions and discoveries – We added 3 MMBoe related to drilling in the San Joaquin basin.

Improved recovery – We added 27 MMBoe related to increased drilling activity associated with steamfloods in the San Joaquin basin.

Acquisitions and divestitures – We added 93 MMBoe related to the Berry Merger in the San Joaquin and Uinta basins. See *Note 2 Business Combinations* for more information on this transaction.

2024

Revisions of previous estimates – We had net negative price-related revisions of 15 MMBoe primarily resulting from lower average realized prices in 2024 as compared to 2023, including lower natural gas realizations in 2024. These revisions included negative price-related revisions of 18 MMBoe, which were partially offset by 3 MMBoe of positive revisions from operating cost efficiencies.

We had 2 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 12 MMBoe and negative performance-related revisions of 10 MMBoe. Our positive performance-related revisions primarily related to better-than-expected well performance. Our negative performance-related revisions primarily were due to lower overall expected recovery in the San Joaquin basin.

We had 7 MMBoe of negative revisions due to lower maximum allowable surface injection pressure at the Wilmington field in the Los Angeles basin. We had 1 MMBoe of negative revisions due to the impact of AB 2716 at the Inglewood field in the Los Angeles basin. We had 2 MMBoe of negative revisions due to the retraction of the SB 1137 referendum and our analysis of sensitive receptor designations. The majority of these revisions were located in the Los Angeles basin. We had 6 MMBoe of negative revisions associated with delays in obtaining new well drilling permits. The majority of the revisions related to permits was in the San Joaquin basin. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Improved recovery – We added 1 MMBoe related to increased well performance in certain areas in the San Joaquin basin.

Acquisitions and divestitures – We acquired 236 MMBoe in the Aera Merger. See *Note 2 Business Combinations* for more information on this transaction.

2023

Revisions of previous estimates – We had net negative price-related revisions of 13 MMBoe primarily resulting from a lower commodity price environment in 2023 compared to 2022. Negative price-related revisions of 22 MMBoe were partially offset by 9 MMBoe of positive revisions from operating cost efficiencies.

We had 23 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 38 MMBoe and negative performance-related revisions of 15 MMBoe. Our negative performance-related revisions primarily were due to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. Our positive performance-related revisions primarily related to better-than-expected well performance. The majority of these revisions were located in the San Joaquin basin.

We had 12 MMBoe of negative revisions to our proved reserves due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137. The majority of these volumes are in the Los Angeles basin. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions and discoveries – We added 5 MMBoe from extensions resulting from successful drilling and workovers in the San Joaquin, Los Angeles and Sacramento basins.

Acquisitions and divestitures – We had a reduction of 12 MMBoe which related to our Round Mountain Unit divestiture. See *Note 9 Divestitures and Acquisitions* for more information on this transaction.

CAPITALIZED COSTS

Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	December 31, 2025	December 31, 2024
	(in millions)	
Proved properties	\$ 7,097	\$ 6,343
Unproved properties	11	1
Total capitalized costs	7,108	6,344
Accumulated depreciation, depletion and amortization	(1,511)	(953)
Net capitalized costs	\$ 5,597	\$ 5,391

COSTS INCURRED

Costs incurred relating to oil and natural gas activities include capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations but exclude corporate items. The following table summarizes our costs incurred:

	Year ended December 31,		
	2025	2024	2023
	(in millions)		
Acquisition of properties			
Proved properties	\$ 637	\$ 2,975	\$ —
Unproved properties	—	—	—
Exploration costs	12	2	3
Development costs ^(a)	296	207	198
Costs incurred	\$ 945	\$ 3,184	\$ 201

(a) Development costs include a \$238 million decrease, \$28 million decrease and \$44 million increase in ARO (including assets held for sale) in 2025, 2024 and 2023, respectively. Development costs in 2025 include \$6 million related to installing carbon capture infrastructure at our Elk Hills gas processing facility. The remaining \$45 million related to facility construction in 2024 and 2025 is included in our carbon management business.

RESULTS OF OPERATIONS

Our oil and natural gas producing activities, which exclude items such as asset dispositions, corporate overhead and interest, were as follows:

	Year ended December 31,					
	2025		2024		2023	
	(millions)	(\$/Boe)	(millions)	(\$/Boe)	(millions)	(\$/Boe)
Oil, natural gas and natural gas liquids						
sales	\$ 2,910	\$ 57.79	\$ 2,537	\$ 63.27	\$ 2,041	\$ 65.15
Other revenue	10	0.20	7	0.17	17	0.54
Intersegment revenues	47	0.93	28	0.70	114	3.64
Operating costs	1,280	25.42	983	24.51	822	26.24
Depreciation, depletion and amortization	492	9.77	354	8.83	207	6.61
Taxes other than on income	203	4.03	207	5.16	113	3.61
Asset impairment	57	1.13	13	0.32	—	—
Exploration expenses	2	0.04	2	0.05	3	0.10
Pretax income	933	18.53	1,013	25.27	1,027	32.77
Income tax provision ^(a)	(249)	(4.94)	(268)	(6.69)	(286)	(9.12)
Results of operations	\$684	\$13.59	\$745	\$18.58	\$741	\$23.65

Note: Beginning in 2025, we updated our Results of Operations to include revenues, including sales to affiliates, less operating costs, exploration expenses, DD&A impairment and income taxes. Results of Operations do not include the effects of derivatives. The results presented in 2024 and 2023 have been updated to conform to the current presentation.

(a) Income taxes are calculated on the basis of a stand-alone tax filing entity. The combined U.S. federal and California statutory tax rate was 27% in 2025 and 2024 and 28% in 2023. The effective tax rates for 2025 and 2024 include the benefit of marginal well tax credits.

STANDARDIZED MEASURE, INCLUDING YEAR-TO-YEAR CHANGES THEREIN, OF DISCOUNTED FUTURE NET CASH FLOWS

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and natural gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2025, 2024 and 2023, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2025, 2024 and 2023. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	December 31, 2025	December 31, 2024	December 31, 2023
	(in millions)		
Future cash inflows	\$ 39,836	\$ 37,190	\$ 24,813
Future costs			
Operating costs ^(a)	(20,671)	(19,331)	(12,479)
Development costs ^(b)	(3,583)	(2,675)	(1,805)
Future income tax expense	(3,733)	(3,707)	(2,784)
Future net cash flows	11,849	11,477	7,745
Ten percent discount factor	(5,183)	(4,775)	(3,676)
Standardized measure of discounted future net cash flows	\$ 6,666	\$ 6,702	\$ 4,069

(a) Includes general and administrative expenses related to our field operations and taxes other than on income.

(b) Includes asset retirement costs.

Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserve Quantities

	2025	2024	2023
	(in millions)		
Beginning of year	\$ 6,702	\$ 4,069	\$ 6,726
Sales of oil and natural gas, net of production and other operating costs	(1,851)	(1,036)	(1,604)
Changes in price, net of production and other operating costs	(1,045)	(706)	(2,829)
Previously estimated development costs incurred	164	234	164
Change in estimated future development costs	(99)	132	(47)
Extensions, discoveries and improved recovery, net of costs	271	7	99
Revisions of previous quantity estimates ^(a)	593	(687)	(103)
Accretion of discount	807	515	853
Net change in income taxes	124	(710)	1,029
Purchases and sales of reserves in place	1,285	4,569	(270)
Change in timing of estimated future production and other	(285)	315	51
Net change	(36)	2,633	(2,657)
End of year	\$6,666	\$6,702	\$4,069

(a) Includes revisions related to performance and price changes.

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management has assessed the effectiveness of our internal control system as of December 31, 2025 based on the criteria for effective internal control over financial reporting described in Internal Control – Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, our management believes that, as of December 31, 2025, our system of internal control over financial reporting is effective. As described in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations*, we completed a merger with Berry on December 18, 2025. Berry was excluded from the scope of our assessment of internal controls over financial reporting as of December 31, 2025, because it was acquired in a business combination during 2025. The total assets of Berry represented approximately 12% of the related consolidated financial statement amounts as of December 31, 2025. The total revenue of Berry represented less than 1% of the related consolidated financial statement amount for the year ended December 31, 2025.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8 – Financial Statements and Supplementary Data*.

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer supervised and participated in management's evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this Annual Report on Form 10-K. Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that as of December 31, 2025, our disclosure controls and procedures were effective and were designed to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC), and that such information is accumulated and communicated to our management,

including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. As disclosed in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Business Combinations*, we completed the Berry Merger on December 18, 2025. As part of the ongoing integration of Berry, we are in process of incorporating the controls and related procedures of Berry. Management’s evaluation of our disclosure controls and procedures as of December 31, 2025 excludes an evaluation of the disclosure controls and procedures of Berry. The total assets of Berry represented approximately 12% of the related consolidated financial statement amounts as of December 31, 2025. The total revenue of Berry represented less than 1% of the related consolidated financial statement amount for the year ended December 31, 2025.

Changes in Internal Control

Other than the on-going incorporation of Berry’s controls, there were no changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act of 1934) during the three months ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

Rule 10b5-1 Trading Arrangements

During the three months ended December 31, 2025, no directors or officers adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408 of Regulation S-K.

Second Amended and Restated Bylaws

On February 24, 2026, the Board amended and restated the Company’s Amended and Restated Bylaws to clarify, among other things, (i) notice requirements for adjournment of remote meetings, (ii) requirements for notices of shareholder meetings, (iii) information to be provided by shareholders who submit proposals at the Company’s annual meeting and (iv) make various other updates, including clarifying, ministerial and conforming changes. The above description of the Company’s Second Amended and Restated Bylaws is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to such Second Amended and Restated Bylaws filed herewith as Exhibit 3.4 to this Annual Report on Form 10-K.

ITEM 9C DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our Proxy Statement for the 2026 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2025 (2026 Proxy Statement). See the list of our executive officers and related information below.

Our board of directors has adopted a code of business conduct applicable to all officers, directors and employees, which is available on our website (www.crc.com). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our code of business conduct by posting such information on our website at the address specified above.

EXECUTIVE OFFICERS

Executive officers are appointed annually by the Board of Directors. The following table sets forth our current executive officers:

<u>Name</u>	<u>Employment History</u>	<u>Age at March 2, 2026</u>
Francisco J. Leon	President, Chief Executive Officer and Director since 2023; Executive Vice President and Chief Financial Officer 2020 to 2023; Executive Vice President - Corporate Development and Strategic Planning 2018 to 2020; Vice President - Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director - Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	49
Clio Crespy	Executive Vice President and Chief Financial Officer since 2025; Guggenheim Securities Senior Managing Director, Investment Banking, Global Energy & Power 2020 to 2024; Evercore Managing Director 2017 to 2020; BNP Paribas VP, Investment Banking 2008 to 2017.	40
Omar Hayat	Executive Vice President and Chief Operating Officer since 2025; Executive Vice President Operations 2023 to 2025; Senior Vice President Operations 2023; Vice President of Operations for Elk Hills production complex from 2021 to 2023; Operations Manager 2019 to 2021; various technical and operational positions with the Company, Occidental Petroleum, Aera Energy and Engro Chemical (formerly Exxon Chemical) 1997 to 2019.	50
Michael L. Preston	Executive Vice President, Chief Strategy Officer and General Counsel since 2023; Executive Vice President, Chief Administrative Officer and General Counsel 2019 to 2023; Executive Vice President, General Counsel and Corporate Secretary 2014 to 2019; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	61
Jay A. Bys	Executive Vice President and Chief Commercial Officer since 2021; Private Energy Advisor 2019 to 2020 and 2015 to 2016; GenOn Energy and affiliate companies Chief Commercial Officer 2017 to 2018; Luminant Energy Vice President Origination and Capital Management 2007 to 2014; TXU, Enserch Energy various positions 1997 to 2007.	61
Chris D. Gould	Executive Vice President and Chief Sustainability Officer since 2021; Exelon Corporation Senior Vice President Corporate Strategy and Chief Innovation and Sustainability Officer 2010 to 2021; Exelon Corporation Vice President, Corporate Financial Planning and Analysis 2008 to 2010.	55

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2026 Proxy Statement. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis – Compensation Committee Report* section shall not be deemed to be “soliciting material,” or to be “filed” with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference from our 2026 Proxy Statement. See also *Part II, Item 5 – Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our 2026 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Los Angeles, CA, Auditor ID: 185.

The information required by this item is incorporated by reference from our 2026 Proxy Statement.

PART IV

ITEM 15 EXHIBITS

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way the Company and investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
2.2	Amended Debtors' Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed October 19, 2020 and incorporated herein by reference).
2.3***	Agreement and Plan of Merger, dated February 7, 2024, between California Resources Corporation and Petra Merger Sub I, LLC, Petra Merger Sub C, LLC, Petra Merger Sub O, LLC, Petra Merger Sub O2, LLC, Petra Merger Sub O3, LLC, each a Delaware limited liability company and a wholly-owned direct subsidiary of the Company, Petra Merger Sub S, LLC, a Delaware limited liability company and a wholly-owned direct subsidiary of the Company, IKAV Impact USA Inc., a Delaware corporation, CPPIB Vedder US Holdings LLC, a Delaware limited liability company, Opps Xb Aera E CTB, LLC, a Delaware limited liability company, Opps XI Aera E CTB, LLC, a Delaware limited liability company, Green Gate COI, LLC, a Delaware limited liability company and solely for purposes of the Member Provisions (as defined in the Merger Agreement), IKAV Impact S.a.r.l., a Luxembourg corporation, Simlog Inc., a Delaware corporation, and IKAV Energy Inc., a Delaware corporation, CPP Investment Board Private Holdings (6), Inc., a Canadian corporation, OCM Opps Xb AIF Holdings (Delaware), L.P., a Delaware limited partnership, Oaktree Huntington Investment Fund II AIF (Delaware), L.P. – Class C, a Delaware limited partnership, OCM Opps XI AIV Holdings (Delaware), L.P., a Delaware limited partnership and OCM Aera E Holdings, LLC, a Delaware limited liability company. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 9, 2024 and incorporated herein by reference).
2.4***	Agreement and Plan of Merger, dated September 14, 2025, by and among California Resources Corporation, Berry Corporation (bry) and Dornoch Merger Sub, LLC (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on September 17, 2025 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).

Exhibit Number	Exhibit Description
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 6, 2022 and incorporated herein by reference).
3.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 1, 2023 and incorporated herein by reference).
3.4*	Second Amended and Restated Bylaws of California Resources Corporation.
4.1	Description of Registrant's Securities (filed as Exhibit 4.1 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
4.2	Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
4.3	First Supplemental Indenture to the 2026 Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors, Elk Hills Power, LLC, EHP Midco Holding Company, LLC, EHP Topco Holding Company, LLC and Wilmington Trust, National Association (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
4.4	Second Supplemental Indenture to the 2026 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, Aera Energy LLC, Aera Energy Services Company, Aera Federal LLC, Belridge Farms & Packing LLC, Green Gate San Ardo LLC, Terrain Technology Inc., Green Gate Intermediate LLC, Green Gate Resources E LLC, Green Gate Resources S LLC, Green Gate Resources Holdings LLC, Green Gate Resources Parent LLC, Petra Merger Sub S, LLC, the other guarantors party thereto and Wilmington Trust, National Association (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
4.5	Indenture, dated June 5, 2024, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed June 5, 2024 and incorporated herein by reference).
4.6	First Supplemental Indenture to the 2029 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, Aera Energy LLC, Aera Energy Services Company, Aera Federal LLC, Belridge Farms & Packing LLC, Green Gate San Ardo LLC, Terrain Technology Inc., Green Gate Intermediate LLC, Green Gate Resources E LLC, Green Gate Resources S LLC, Green Gate Resources Holdings LLC, Green Gate Resources Parent LLC, Petra Merger Sub S, LLC, the other guarantors party thereto and Wilmington Trust, National Association (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
4.7	Second Supplemental Indenture to the 2029 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed August 22, 2024 and incorporated herein by reference).
4.8	Indenture, dated October 8, 2025, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed October 8, 2025 and incorporated herein by reference).
10.1	Contractors' Agreement, by and between the City of Long Beach, Humble Oil & Refining Company, Shell Oil Company, Socony Mobil Oil Company, Inc., Texaco, Inc., Union Oil Company of California, Pauley Petroleum, Inc., Allied Chemical Corporation, Richfield Oil Corporation and Standard Oil Company of California (filed as Exhibit 10.12 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.2	Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated November 5, 1991, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, Atlantic Richfield Company and ARCO Long Beach, Inc. (filed as Exhibit 10.10 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014 and incorporated herein by reference).
10.3	Amendment to the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated January 16, 2009, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, and Oxy Long Beach, Inc. (filed as Exhibit 10.11 to Amendment No. 2 to the Registrant's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.4	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.5	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.6	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.7***	Warrant Agreement, dated as of October 27, 2020, by and between California Resources Corporation and American Stock Transfer & Trust Company, LLC, as Warrant Agent (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.8	Registration Rights Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the holders party thereto (filed as Exhibit 10.1 to the Registrant's Registration Statement on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.9	Stockholder Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the stockholders party thereto (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.10	Stockholder Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the stockholders party thereto (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.11	Amended and Restated Credit Agreement, dated as of April 26, 2023, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed May 4, 2023 and incorporated herein by reference).
10.12**	First Amendment to the Amended and Restated Credit Agreement, dated as of October 30, 2023, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 2, 2023 and incorporated herein by reference).
10.13	Second Amendment to the Amended and Restated Credit Agreement, entered into effective as of February 2, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 14, 2024 and incorporated herein by reference).
10.14	Third Amendment to the Amended and Restated Credit Agreement, entered into effective as of March 8, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 11, 2024 and incorporated herein by reference).
10.15	Fourth Amendment to the Amended and Restated Credit Agreement, entered into effective as of July 1, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.16	Fifth Amendment to the Amended and Restated Credit Agreement, entered into effective as of July 1, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2024 and incorporated herein by reference).
10.17	Sixth Amendment to the Amended and Restated Credit Agreement, entered into effective as of September 22, 2025, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed September 24, 2025 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.18**	Seventh Amendment to the Amended and Restated Credit Agreement, entered into effective as of October 29, 2025, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 31, 2025 and incorporated herein by reference).
10.19**	Eighth Amendment to the Amended and Restated Credit Agreement, entered into effective as of December 15, 2025, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 18, 2025 and incorporated herein by reference). The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.20	Form of Indemnification Agreement by and between California Resources Corporation and its directors and executive officers (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 27, 2020 and incorporated herein by reference).
10.21	California Resources Corporation 2021 Long Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed January 22, 2021 and incorporated herein by reference).
10.22	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.45 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.27**	Employment Agreement by and between Michael L. Preston and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed August 6, 2021 and incorporated herein by reference).
10.28**	Amended and Restated Employment Agreement by and between Michael L. Preston and California Resources Corporation, dated August 4, 2025 (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed August 6, 2025 and incorporated herein by reference).
10.29**	Employment Agreement by and between Jay A. Bys and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.30**	Amended and Restated Employment Agreement by and between Jay A. Bys and California Resources Corporation, dated August 4, 2025 (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed August 6, 2025 and incorporated herein by reference).
10.31**	Employment Agreement by and between Francisco J. Leon and California Resources Corporation, dated February 23, 2023 (filed as Exhibit 10.25 to Registrant's Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.32**	Employment Agreement by and between Omar Hayat and California Resources Corporation, dated July 27, 2023 (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed on August 1, 2023 and incorporated herein by reference).
10.33**	Amended and Restated Employment Agreement by and between Christopher D. Gould and California Resources Corporation, dated July 27, 2023 (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed on August 1, 2023 and incorporated herein by reference).
10.34**	Employment Agreement by and between Clio Catherine Crespy and California Resources Corporation, dated January 1, 2025 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 25, 2024 and incorporated herein by reference).
10.35	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.26 to Registrant's Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.36	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.27 to Registrant's Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.37	Form of Cash Retention Bonus Agreement (filed as Exhibit 10.28 to Registrant's Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.38	California Resources Corporation Employee Stock Purchase Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 6, 2022 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.39	2024 Form of California Resources Corporation 2021 Long-Term Incentive Plan Restricted Stock Unit for Non-Employee Directors Grant Agreement (filed as Exhibit 10.6 to Registrant's Form 10-Q filed on August 7, 2024 and incorporated herein by reference).
10.40	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.29 to Registrant's Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
10.41	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.30 to Registrant's Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
10.42	2025 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.36 to Registrant's Annual Report on Form 10-K filed on March 3, 2025 and incorporated herein by reference).
10.43	2025 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.37 to Registrant's Annual Report on Form 10-K filed on March 3, 2025 and incorporated herein by reference).
10.44	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (Retention Award) (filed as Exhibit 10.5 to Registrant's Quarterly Report on Form 10-Q filed on November 5, 2025 and incorporated herein by reference).
19.1	Insider Trading Policy (filed as Exhibit 99.2 to Registrant's Annual Report on Form 10-K filed on March 3, 2025 and incorporated herein by reference).
19.2	Business Ethics and Conduct Policies (filed as Exhibit 99.3 to Registrant's Annual Report on Form 10-K filed on March 3, 2025 and incorporated herein by reference).
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.
23.3*	Consent of Independent Petroleum Engineers, DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	California Resources Corporation Incentive-Based Compensation Recoupment Policy. (filed as Exhibit 97.1 to Registrant's Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
99.1*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2025.
99.2*	DeGolyer and MacNaughton Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2025.
99.3*	Unaudited pro forma condensed combined financial statements of California Resources Corporation.
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted in inline XBRL and contained in Exhibits 101).

* Filed herewith.

Certain portions of this exhibit (indicated by "[***]") have been omitted pursuant to Item 601(b)(10) of Regulation S-K

***This filing excludes certain schedules and exhibits pursuant to Item 601(a)(5) of Regulation S-K, which the registrant agrees to furnish supplementally to the SEC upon request by the SEC; provided, however, that the registrant may request confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended, for any schedules or exhibits so furnished

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Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held virtually at 11:00 a.m. Pacific Time on April 30, 2026. You will not be able to attend the annual meeting physically. If you wish to attend the annual meeting, you must follow the instructions under "Attending the Annual Meeting" in the proxy statement.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

Odyssey Transfer and Trust Company
2155 Woodlane Drive, Suite 100,
Woodbury, MN 55125
(888) 290-1175
contactus@odysseytrust.com
www.odysseytrust.com/us/

Investor Relations

Company financial information, public disclosures and other information are available through our website at www.crc.com. We will promptly deliver free of charge, upon request, an annual report on Form 10-K to any stockholder requesting a copy. Requests should be directed to our Investor Relations team at our corporate headquarters address or sent to CRC_IR@crc.com.

Stock Exchange Listing

California Resources Corporation's common stock is listed on the New York Stock Exchange (NYSE). The symbol is CRC.

CRC
LISTED
NYSE

Officers

Francisco J. Leon
President and Chief Executive Officer

Jay A. Bys
Executive Vice President and Chief Commercial Officer

Clio Crespy
Executive Vice President and Chief Financial Officer

Chris D. Gould
Executive Vice President, Chief Sustainability Officer and Managing Director, Carbon TerraVault Holdings, LLC

Omar Hayat
Executive Vice President and Chief Operating Officer

Michael L. Preston
Executive Vice President, Chief Strategy Officer and General Counsel

Board of Directors

Tiffany (TJ) Thom Cepak
Chair of the Board, Member of the Finance Committee and Director since 2020

Andrew B. Bremner
Member of the Compensation Committee, Finance Committee, Sustainability Committee and Carbon TerraVault Committee and Director since 2021

James N. Chapman
Chair of the Compensation Committee and Finance Committee, Member of the Carbon TerraVault Committee and Director since 2020

James R. Jackson
Member of the Sustainability Committee and Director since 2024

Christian S. Kendall
Chair of the Nominating and Governance Committee, Member of the Audit Committee and Carbon TerraVault Committee and Director since 2024

Francisco J. Leon
President, Chief Executive Officer and Director since 2023

Mark A. (Mac) McFarland
Chair of the Carbon TerraVault Committee and Director since 2020

William B. Roby
Chair of the Sustainability Committee, Member of the Audit Committee, Compensation Committee, and Nominating and Governance Committee and Director since 2020

Alejandra (Ale) Veltmann
Chair of the Audit Committee, Member of the Nominating and Governance Committee and Director since 2021



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A DIFFERENT
KIND OF ENERGY
COMPANY