2023

ANNUAL REPORT

A DIFFERENT KIND OF ENERGY COMPANY

CALIFORNIA RESOURCES CORPORATION | CARBON TERRAVAULT

FINANCIAL & OPERATIONAL HIGHLIGHTS

FINANCIAL HIGHLIGHTS	2023	2022	2021
Dollar amounts in millions, except share and per-share amounts, as of and for the years ended December 31,			
Total Operating Revenue	$ 2,801	$ 2,707	$ 1,889
Net Income	$ 564	$ 524	$ 625
Net Income Attributable to Noncontrolling Interests	$ 0	$ 0	$ 13
Net Income Attributable to Common Stock	$ 564	$ 524	$ 612
Adjusted Net Income Attributable to Common Stock[a]	$ 372	$ 384	$ 506
Net Income Attributable to Common Stock per Share – Diluted	$ 7.78	$ 6.75	$ 7.37
Adjusted Net Income Attributable to Common Stock per Share – Diluted[a]	$ 5.13	$ 4.95	$ 6.10
Net Cash Provided by Operating Activities	$ 653	$ 690	$ 660
Capital Investments	$ 185	$ 379	$ 194
Free Cash Flow[a]	$ 468	$ 311	$ 466
Net Cash Used by Financing Activities	$ (289)	$ (371)	$ (222)
Total Assets	$ 3,998	$ 3,967	$ 3,846
Long-Term Debt, Net	$ 540	$ 592	$ 589
Stockholders' Equity	$ 2,219	$ 1,864	$ 1,688
Weighted-Average Shares Outstanding - Diluted	72.5	77.6	83.0
Year-End Shares	68.7	71.9	79.3

OPERATIONAL HIGHLIGHTS	2023	2022	2021
Production:			
Oil (MBbl/d)	52	55	60
NGLs (MBbl/d)	11	11	13
Natural Gas (MMcf/d)	135	147	159
Total (MBoe/d)[b]	86	91	100
Average Realized Prices:			
Oil with hedge ($/Bbl)	$ 65.97	$ 61.80	$ 56.05
Oil without hedge ($/Bbl)	$ 80.41	$ 98.26	$ 70.43
NGLs ($/Bbl)	$ 48.94	$ 64.33	$ 53.62
Natural Gas ($/Mcf)	$ 8.59	$ 7.68	$ 4.22
Reserves:			
Oil (MMBbl)	256	294	343
NGLs (MMBbl)	35	38	41
Natural Gas (Bcf)	518	511	576
Total (MMBoe)[b]	377	417	480
Standardized Measure of Discounted Future Net Cash Flows (in billions)	$ 4.1	$ 6.7	$ 4.5
PV-10 of Cash Flows (in billions)[a]	$ 5.5	$ 9.2	$ 6.2
Net Mineral Acreage (in thousands):			
Developed	684	689	699
Undeveloped	1,008	1,178	1,192
Total	1,692	1,867	1,891
Closing Share Price	$ 54.68	$ 43.51	$ 42.71

(a) See www.crc.com, Investor Relations for a discussion of these performance and non-GAAP measures, including a reconcililation 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.

2023 CEO Annual Report Letter

Dear Shareholders,

California Resources Corporation (CRC) is a different kind of energy company. We are committed to providing innovative energy solutions that will continue to deliver the reliable energy Californians need while finding pathways to advance California's decarbonization initiatives. During 2023 we made remarkable progress to advance our business objectives. CRC has a leading market position with a clear path to address today's complex energy challenges and create real value for our shareholders.

We accomplished a lot in 2023:

- ***Achieved strong financial, operating and safety results***. We had strong net income, improved capital efficiency, low reservoir declines, and delivered sound capital discipline. Net income was $564 million, or $7.78 per diluted share, net cash provided by operating activities was $653 million and free cash flow[1] was $468 million. Results reflected total net production of 86 thousand barrels of oil equivalent per day (MBoe/d), of which 60% was oil. We also achieved the second-best total recordable incident rate in our Company's history, highlighting our strong safety culture.
- ***Delivered robust returns to shareholders.*** We funded our capital projects with less than half of our annual cash flow. The other half was returned to shareholders, approximately $225 million in 2023, and approximately $760 million over the last three years.
- ***Maintained premier balance sheet.*** CRC has an exceptional capital structure; it's the financial foundation for all that we do. We reduced our debt by $55 million during 2023, exiting the year with a nearly zero leverage ratio[1].
- ***Enhanced future profitability.*** We implemented $65 million in annual, sustainable cost savings. Our talented workforce found additional safe and innovative ways to streamline our processes and strengthen our margins. This tremendous effort will pay dividends in 2024 and beyond.
- ***Advanced California's decarbonization efforts.*** Recent progress has allowed us to scale our carbon management business, which we refer to as Carbon TerraVault (CTV). Through CTV, we have entered into several Carbon Dioxide Management Agreements (CDMA)[2] to date allowing for the capture and sequestration of nearly 900,000 metric tons of carbon dioxide (CO_2) per year. Our California Direct Air Capture (DAC) Hub was selected to receive nearly $12 million in funding from the U.S. Department of Energy (DOE), highlighting federal support for the consortium of organizations across industry, technology, academia, national labs, community, government, and labor. We are proud to be California's carbon capture and storage (CCS) leader.

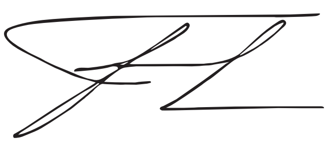
CRC is "all in" for advancing the energy transition and providing lower carbon solutions to California. As we continue to help the state achieve its carbon neutrality goal, reality tells us this won't happen overnight. Today, California tops the list of the largest U.S. economies, consuming nearly 1.5 million barrels of oil every day[3]. With less than 25% of this oil produced in our Golden state[3], demand is met with more expensive, higher-carbon intensive foreign barrels that are not produced according to the leading environmental regulations that we adhere to. CRC is also California's largest natural gas producer providing a local option that competes with imported volumes from other parts of the U.S.

During the year, our CTV business has grown significantly as we expanded our CO_2 storage capacity in proximity to major California markets by 36%. We are anticipating reaching important milestones, including the Environmental Protection Agency's (EPA) release of California's first final Class VI well permits for the 26R reservoir, located within the CTV I CCS vault at the Elk Hills Field. With these anticipated permits, we remain on track for the first CO_2 injection by year end 2025. Today, California stakeholders and market participants are showing tremendous interest in our growing carbon management business and solutions for hard-to-abate industries. We look forward to reporting on our progress in the coming months.

In early 2024, we announced a transaction to merge with Aera Energy, LLC. The transaction, which is expected to close in the second half of 2024, will enhance our shareholder returns, strengthen our conventional energy business, and continue to provide local, low carbon intensity production to fuel California. Importantly, it also expands our CO_2 sequestration pore space portfolio and helps decarbonize high emissions sectors of the Golden State's economy. This is a win for all stakeholders. We are confident in our ability to integrate Aera's assets following closing and expect to capture significant operational synergies to create a more durable new energy business.

As we look to the remainder of 2024, we are focused on maximizing our free cash flow through continued discipline of our capital investments. We intend to run at one rig for the remainder of the year. This will allow us to return significant cash to shareholders through our dividends and recently expanded share repurchase program, while continuing to further reduce debt. We understand the importance of sustainable returns to shareholders and our commitment to a strong balance sheet is unwavering.

It is an honor and privilege to work side-by-side each day with the incredibly talented and driven team at CRC. I am confident that our workforce is aligned with our business strategy. We are executing our plan to generate long-term value for shareholders while providing needed solutions to meet California's present and future energy needs.



Francisco J. Leon
President and Chief Executive Officer
California Resources Corporation

[1] 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.

[2] The CDMA frames the contractual terms between parties by outlining the material economics and terms of the project and includes conditions precedent to close. The CDMA provides a path for the parties to reach final definitive documents and final investment decision.

[3] Source: CalGEM

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, 2023

☐ **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	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(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 Date 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, 2023: $3,121,405,912.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

At January 31, 2024, there were 69,274,418 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2023 with the Securities and Exchange Commission in connection with the registrant's 2024 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:

- ***ABR*** - Alternate base rate.
- ***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.
- ***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.
- ***Boe/d*** - Barrel of oil equivalent per day.
- ***Btu*** - British thermal unit.
- ***CalGEM*** - California Geologic Energy Management Division.
- ***CCS*** - Carbon capture and storage.
- ***CDMA*** - Carbon Dioxide Management Agreement.
- ***CO_2*** - Carbon dioxide.
- ***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.
- ***Full-Scope Net Zero*** - Achieving permanent storage of captured or removed carbon emissions in a volume equal to all of our scope 1, 2 and 3 emissions by 2045.
- ***GAAP*** - United States Generally Accepted Accounting Principles.
- **G&A** - General and administrative expenses.
- ***GHG*** - Greenhouse gases.
- ***JV*** - Joint venture.
- ***LCFS*** - Low Carbon Fuel Standard.
- ***MBbl*** - One thousand barrels of crude oil, condensate or NGLs.
- **MBbl/d** - One thousand barrels per day.
- ***MBoe/d*** - One thousand barrels of oil equivalent per day.
- **MBw/d** - 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.
- ***MMcf/d*** - 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.
- ***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 Overview and History

We are an independent oil and natural gas exploration and production and carbon management company operating properties exclusively within California. We are committed to energy transition and have some of the lowest carbon intensity production in the United States. We are in the early stages of developing several carbon capture and storage projects in California. Our carbon management business, that we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and storage facilities in California.

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.

Recent Developments

Pending Aera Merger

On February 7, 2024, we entered into a definitive agreement and plan of merger (Merger Agreement) to combine with Aera Energy, LLC (Aera) in an all-stock transaction (Aera Merger) with an effective date of January 1, 2024. Aera is a leading operator of mature fields in California, primarily in the San Joaquin and Ventura basins, with high oil-weighted production.

Pursuant to the Merger Agreement, we have agreed to issue 21,170,357 shares of common stock (subject to customary adjustments in the event of stock splits, dividend paid in stock and similar items) plus an additional number of shares determined by reference to the dividends declared by us having a record date between the effective date and closing as more fully described in the Merger Agreement. Under the terms of the Merger Agreement, we have also agreed to assume Aera's outstanding long-term indebtedness of $950 million at closing. We expect to repay a significant portion of this indebtedness with cash on hand and borrowings under our Revolving Credit Facility. We intend to refinance the balance through one or more debt capital markets transactions and, only to the extent necessary, borrowings under a bridge loan facility provided by Citigroup Global Markets, Inc. (the Bank). Under the terms of our debt commitment letter with the Bank, it has committed, subject to satisfaction of customary conditions, to provide us with an unsecured 364-day bridge loan facility in an aggregate principal amount of $500 million (Bridge Loan Facility).

Closing of the Aera Merger is subject to certain conditions, including, among others, approval of the stock issuance by our stockholders, expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, prior authorization by the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act and other customary closing conditions.

Upon completion of the transaction, we currently expect our existing stockholders to own approximately 77.1% of the combined company and the existing Aera owners to own approximately 22.9% of the combined company, on a fully diluted basis. The Aera Merger is expected to close in the second half of 2024. Post closing of the Aera Merger, and subject to Board approval, we expect to increase our quarterly dividend.

Amendment to our Revolving Credit Facility

In connection with the Merger Agreement, on February 9, 2024, we entered into a second amendment to our Revolving Credit Facility to permit us to incur indebtedness under the Bridge Loan Facility.

Sale of Fort Apache in Huntington Beach

In February 2024, we entered into an agreement to sell our 0.9-acre Fort Apache real estate property in Huntington Beach, California for approximately $10 million.

Oil and Natural Gas Operations

As of December 31, 2023, our proved reserves totaled an estimated 377 MMBoe, of which 256 MMBbl were crude oil and condensate reserves, 35 MMBbl were NGL reserves and 518 BcF, or 86 MMBoe, were natural gas reserves.

As of December 31, 2023, we held approximately 1.7 million net mineral acres, the largest privately owned mineral acreage position in California. Our operated asset base spans 97 distinct fields with approximately 9,000 net operated wells. We had average net production of approximately 86 MBoe/d (60% oil) for the year ended December 31, 2023.

The following table highlights key information about our operations as of and for the year ended December 31, 2023:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin(a)	Sacramento Basin	Other	Total Operations
Mineral Acreage						
Net mineral acreage (thousands)	1,111	28	6	430	117	1,692
Average net mineral acreage held in fee (%)	89 %	49 %	— %	45 %	97 %	77 %
Number of producing fields we operate	42	5	—	50	—	97
Average drilling rigs	—	1	—	—	—	1
Net wells drilled and completed	4.0	26.5	—	—	—	30.5
Proved reserves						
Oil (MMBbl)	165	91	—	—	—	256
NGLs (MMBbl)	35	—	—	—	—	35
Natural gas (Bcf)	456	5	—	57	—	518
Total (MMBoe)	276	92	—	9	—	377
Oil percentage of proved reserves	60 %	99 %	— %	— %	— %	68 %
Production						
Total net production (MMBoe)	23	7	—	1	—	31
Average daily net production (MBoe/d)	64	19	—	3	—	86

(a) Reflects one non-operated field in the Ventura basin included in assets held for sale. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information on our Ventura Basin divestiture.

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.*

San Joaquin Basin

Commercial petroleum development in the San Joaquin basin began in the 1800s. The basin 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.

We hold substantially all the working, surface and mineral interests in the Elk Hills field, which is our largest producing asset in the San Joaquin basin and have a large ownership interest in several other oil fields located in the San Joaquin basin including Buena Vista and Coles Levee. We have also been successfully developing steamfloods in our Kern Front operations.

At Elk Hills we operate efficient natural gas processing facilities, including a cryogenic gas plant, with a combined gas processing capacity of 330 MMcf/d. Additionally, our Elk Hills power plant generates electricity to power our oil and gas operations at the Elk Hills field, and offers excess power to the California Independent System Operator (CAISO) wholesale energy marketplace. We also market power plant capacity in excess of our internal needs to the CAISO Resource Adequacy (RA) marketplace. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of the producing wells.

We believe our extensive 3D seismic library, which covers over 800,000 acres in the San Joaquin basin, or over 50% 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. 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. Large active oil fields in this basin include the Wilmington and Huntington Beach fields, where we have significant operations. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) under which we first recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and then receive our share of profits. See *Production, Price and Cost History* below for more information on our PSCs.

We are pursuing the potential divestiture of our 90-acre Huntington Beach field, which is currently a producing oil field with average daily net production of 3 MBoe/d. At our Huntington Beach field we have begun the plugging and abandonment work of approximately 50 wells in 2024. We are working towards the longer-term remediation of this property to provide flexibility for real estate sales in the future. Refer to *Recent Developments* above for information on an agreement to sell a one-acre parcel of land in Huntington Beach.

Sacramento Basin

The 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. We are in the process of pursuing permits to facilitate production growth and develop this resource, leveraging the existing infrastructure already in place.

Ventura Basin

We divested a vast majority of our assets in the Ventura basin other than a de minimis non-operated asset, during the fourth quarter of 2021 and the first quarter of 2022. We expect the sale of our remaining Ventura basin asset could occur in 2024.

Other

Other than the basins described above, we also have mineral interests in undeveloped acreage throughout California including in the Salinas basin and the Santa Maria basin.

Mineral Acreage

The following table summarizes our gross and net developed and undeveloped mineral acreage as of December 31, 2023.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Other[a]	Total
			(in thousands)			
Developed[b]						
Gross[c]	457	20	6	255	2	740
Net[d]	420	15	6	242	1	684
Undeveloped[e]						
Gross[c]	811	15	—	226	140	1,192
Net[d]	691	13	—	188	116	1,008
Total						
Gross[c]	1,268	35	6	481	142	1,932
Net[d]	1,111	28	6	430	117	1,692

(a) Reflects remaining mineral acreage retained in the Ventura Basin and nearby areas. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information on our Ventura Basin divestiture.
(b) Mineral acres spaced or assigned to productive wells.
(c) Total number of mineral acres in which interests are owned.
(d) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under our PSCs.
(e) 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, 2023, 77% of our total net mineral interest position was held in fee and the remainder was leased. Of our leased acreage, approximately 87% 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 leasing that acreage. 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 2,000 net mineral acres will expire in 2024, 21,000 net mineral acres will expire in 2025 and 14,000 net mineral acres will expire in 2026. These leases represent 4% of our total net undeveloped acreage and 2% of our total net acreage as of December 31, 2023 and these expirations, should they occur, would not have a material adverse impact 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.

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 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 activity as well as the impact of commodity price increases and inflation on our operating costs per Boe, among other factors.

	Year Ended December 31,		
	2023	**2022**	**2021**
Average daily net production			
Oil (MBbl/d)	52	55	60
NGLs (MBbl/d)	11	11	13
Natural gas (MMcf/d)	135	147	159
Total daily net production (MBoe/d)	86	91	100
Total production (MMBoe)	31	33	36
Average realized prices			
Oil with hedge ($/Bbl)	$ 65.97	$ 61.80	$ 56.05
Oil without hedge ($/Bbl)	$ 80.41	$ 98.26	$ 70.43
NGLs ($/Bbl)	$ 48.94	$ 64.33	$ 53.62
Natural gas without hedge ($/Mcf)	$ 8.59	$ 7.68	$ 4.22
Average benchmark prices			
Brent oil ($/Bbl)	$ 82.22	$ 98.89	$ 70.79
WTI oil ($/Bbl)	$ 77.62	$ 94.23	$ 67.91
NYMEX gas ($/MMBtu) - Average Monthly Settled Price	$ 2.74	$ 6.64	$ 3.84
Operating costs per Boe			
Operating costs	$ 26.24	$ 23.75	$ 19.39

Oil, natural gas and NGL production for our two largest fields are presented in the table below:

	Elk Hills			Wilmington		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
Average daily net production						
Oil (MBbl/d)	16	17	17	16	15	16
NGLs (MBbl/d)	8	8	10	—	—	—
Natural gas (MMcf/d)	68	75	81	—	—	—
Total daily net production (MBoe/d)	35	38	40	16	15	16

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 are variable over the lifecycle of our fields.

Our share of production and reserves from operations in the Wilmington field in the Los Angeles basin is subject to contractual arrangements similar to 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 our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production, 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 18% of our total production for the year ended December 31, 2023.

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:

	Year ended December 31,					
	2023		2022		2021	
	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)
Operating costs	$ 822	$ 26.24	$ 785	$ 23.75	$ 705	$ 19.39
Excess costs attributable to PSCs	(71)	(2.25)	(74)	$ (2.23)	(66)	$ (1.83)
Operating costs, excluding effects of PSCs(a)	$ 751	$ 23.99	$ 711	$ 21.52	$ 639	$ 17.56

(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.

The following table reconciles our average net production to our average gross production (which includes production from the fields we operate and our share of production for fields operated by others) for the periods presented:

	Year ended December 31,		
	2023	**2022**	**2021**
(MBoe/d)			
Average Daily Net Production	86	91	100
Partners' share under PSC-type contracts	7	8	8
Working interest and royalty holders' share	7	6	8
Other	1	1	1
Average Daily Gross Production	101	106	117

Estimated Proved Reserves and Future Net Cash Flows

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

The following tables summarize our estimated proved oil (including condensate), NGLs and natural gas reserves and PV-10 as of December 31, 2023. 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 $82.84 per barrel was adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of $2.64 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, 2023 were $80.97 per barrel for oil, $50.00 per barrel for NGLs and $4.57 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, 2023				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves					
Oil (MMBbl)	136	87	—	—	223
NGLs (MMBbl)	34	—	—	—	34
Natural Gas (Bcf)	389	5	—	51	445
Total (MMBoe)[(a)]	235	88	—	8	331
Proved undeveloped reserves					
Oil (MMBbl)	29	4	—	—	33
NGLs (MMBbl)	1	—	—	—	1
Natural Gas (Bcf)	67	—	—	6	73
Total (MMBoe)	41	4	—	1	46
Total proved reserves					
Oil (MMBbl)	165	91	—	—	256
NGLs (MMBbl)	35	—	—	—	35
Natural Gas (Bcf)	456	5	—	57	518
Total (MMBoe)	276	92	—	9	377
Reserves to production ratio (years)[(b)]	12	13	—	9	12

(a) As of December 31, 2023, approximately 18% of proved developed oil reserves, 7% of proved developed NGLs reserves, 10% of proved developed natural gas reserves and, overall, 15% 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.

(b) Calculated as total proved reserves as of December 31, 2023 divided by total production for the year ended December 31, 2023.

Changes to Proved Reserves

The components of the changes to our proved reserves during the year ended December 31, 2023 were as follows:

	San Joaquin Basin	Los Angeles Basin(a)	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2022	295	113	—	9	417
Revisions related to price	(6)	(5)	—	(2)	(13)
Revisions related to performance	20	1	—	2	23
Revisions due to California regulatory changes and court challenges	(1)	(11)		—	(12)
Extensions	3	1	—	1	5
Improved recovery	1	—	—	—	1
Divestitures	(12)	—	—	—	(12)
Production	(24)	(7)	—	(1)	(32)
Balance at December 31, 2023	276	92	—	9	377

(a) Includes proved reserves related to PSCs of 76 MMBoe and 92 MMBoe at December 31, 2023 and 2022, respectively.

Revisions related to price – 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.

Revisions related to performance – 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 positive performance-related revisions primarily related to better-than-expected well performance. 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. The majority of these revisions were located in the San Joaquin basin.

Revisions due to California regulatory changes and court challenges – 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 *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions – We added 5 MMBoe from extensions resulting from successful drilling and workovers in the San Joaquin, Los Angeles and Sacramento basins.

Divestitures – We had a reduction of 12 MMBoe which related to our Round Mountain Unit divestiture. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information on this transaction.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2023 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
		(in MMBoe)			
Balance at December 31, 2022	38	16	—	—	54
Revisions related to price	(2)	1	—	—	(1)
Revisions related to performance	4	—	—	—	4
Revisions due to California regulatory changes and court challenges	(1)	(11)	—	—	(12)
Extensions	1	1	—	1	3
Improved recovery	1	—	—	—	1
Transfers to proved developed reserves	—	(3)	—	—	(3)
Balance at December 31, 2023	41	4	—	1	46

Revisions related to price – We had 1 MMBoe of net negative price-related revisions. Negative price-related revisions of 3 MMBoe were offset by 2 MMBoe of positive cost recovery barrels under our PSCs.

Revisions related to performance – We had 4 MMBoe of net positive performance-related revision, which included positive revisions of 9 MMBoe, partially offset by negative revisions of 5 MMBoe. Our positive performance-related revisions of 9 MMBoe primarily related to proved undeveloped reserves which were added to our five-year development plan in 2023. The majority of these revisions were located in the San Joaquin basin.

Revisions due to California regulatory changes and court challenges – We removed 12 MMBoe from proved undeveloped reserves due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137 as discussed above. The majority of these revisions were located in the Los Angeles basin. See *Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

Extensions – We added 3 MMBoe of proved undeveloped reserves through extensions as a result of successful drilling and workover programs in the San Joaquin, Los Angeles and Sacramento basins.

Transfers to proved developed reserves – We converted 3 MMBoe of proved undeveloped reserves to proved developed reserves in the Los Angeles basin. This resulted in a conversion rate of approximately 6% of our beginning-of-year proved undeveloped reserves, with an investment of approximately $65 million of drilling and completion capital. We plan to increase our active rig count in the second half of 2024 assuming the resumption of permitting of new wells and sidetracks. We believe we will have sufficient capital to develop all year end 2023 proved undeveloped reserves within five years of their original booking date. For more information on the 2024 Capital Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources* and for more information on permitting, refer to *Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

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 measures 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, 2023	
	(in millions)	
Standardized measure of discounted future net cash flows	$	4,069
Present value of future income taxes discounted at 10%		1,464
PV-10 of cash flows[a]	$	5,533

(a) The average realized prices for estimating our PV-10 of cash flow as of December 31, 2023 were $80.97 per barrel for oil, $50.00 per barrel for NGLs and $4.57 per Mcf for natural gas.

Reserves Evaluation and Review Process

Our estimates of proved reserves and related discounted future net cash flows as of December 31, 2023 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. He has over 15 years of experience in the upstream oil and gas industry, with projects ranging from appraisal of primary production reservoirs to enhanced oil recovery floods. 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, which reviewed and approved our oil and natural gas reserves for 2023. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Netherland, Sewell & Associates, Inc. (NSAI) was engaged to provide independent audits of our reserves estimates for our fields. For the year ended December 31, 2023, NSAI audited 88% of our total proved reserves.

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 it had resolved its 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 issued an unqualified audit opinion on the applicable portions of our proved reserves as of December 31, 2023, which is attached as Exhibit 99.1 to this Form 10-K and incorporated herein by reference.

NSAI qualifications – The primary technical engineer responsible for our audit has more than 22 years of petroleum engineering experience, with the majority spent evaluating California properties, and is a registered Professional Engineer in the state of Texas. The primary geoscientist for the audit has more than 25 years of experience practicing petroleum geoscience and is a Licensed Professional Geoscientist in the state of Texas.

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.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
2023					
Productive					
Exploratory	—	—	—	—	—
Development	4.0	26.5	—	—	30.5
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2022					
Productive					
Exploratory	—	—	—	—	—
Development	114.3	35.0	—	—	149.3
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2021					
Productive					
Exploratory	—	—	—	—	—
Development	109.4	6.5	—	—	115.9
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—

The following table sets forth information on our development wells where drilling was either in progress or pending completion as of December 31, 2023.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
Gross	1.0	—	—	—	1.0
Net	1.0	—	—	—	1.0

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 96% as of December 31, 2023. 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 capable of production) as of December 31, 2023, excluding wells that have been idle for more than five years:

	As of December 31, 2023			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	6,532	6,347	142	139
Los Angeles Basin	1,699	1,610	—	—
Ventura Basin	20	20	—	—
Sacramento Basin	—	—	904	843
Total	8,251	7,977	1,046	982
Multiple completion wells included in the total above	52	49	18	15

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

Exploration Inventory

We have had minimal investment in exploration activity in recent years, and our 2024 capital plan does not allocate any capital towards exploration drilling.

Marketing Arrangements

Crude Oil – We sell nearly all of our crude oil to California refiners. A majority of our crude oil production is connected to third-party pipelines and California refining markets via our gathering systems. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements.

The prices paid by California refiners are typically based on local third-party postings that are closely tied to Brent prices. 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.

Natural Gas – We sell all of our natural gas not used in our operations into the California market. A majority of these sales are made on index based prices. Natural gas prices and differentials are strongly affected by local market fundamentals, such as storage capacity and the availability of transportation capacity in the market and producing areas. Transportation capacity influences prices because California imports more than 90% of its natural gas from other states and Canada. As a result, we typically obtain higher realizations relative to out-of-state producers due to lower transportation costs on the delivery of our natural gas.

In addition to selling natural gas, we also use natural gas in steam generation for our steamfloods and power generation. As a result, the positive impact of higher natural gas prices is partially offset by higher operating costs of our steamflood projects and power generation, but higher prices still have a net positive effect on our operating results due to net higher revenue. Conversely, lower natural gas prices lower these operating costs but have a net negative effect on our financial results.

We currently hold transportation capacity contracts to transport all of our natural gas volumes for multiple years.

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 operating results. Our natural gas-processing plants also facilitate access to third-party delivery points near the Elk Hills field.

We currently have a ship-or-pay pipeline transportation contract for approximately 6,100 barrels per day of NGLs through March 2026. Our contract to transport NGLs requires us to cash settle any shortfall between the committed quantities and volumes actually shipped. We have met all our shipping commitments under this contract for the periods presented.

Electricity – A portion of the electrical output of the Elk Hills power plant is used by Elk Hills and other nearby production fields. This provides a reliable source of power. We sell remaining electrical output to the CAISO wholesale power market. We sell capacity in excess of our site needs into the CAISO RA marketplace.

Delivery Commitments

We have commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2023, we had oil delivery commitments averaging 9 MMBbl in 2024 and 1 MMBbl in 2025, NGL delivery commitments of 1 MMBbl through March 2024 and natural gas delivery commitments of 15 Bcf through December 2024. We generally have significantly more production than the amounts committed for delivery and have the ability to secure additional volumes of products as needed. These commitments are typically index-based contracts with prices set at the time of delivery.

Derivatives

We protect our operating cash flow from volatility in the commodities market through our hedging strategy. Our hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our prior credit agreement included covenants that required us to maintain a certain level of hedges at all times. Our current Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges unless the ratio of our indebtedness to Consolidated EBITDAX (as defined in the Revolving Credit Facility) is less than or equal to 1.5:1.0. We also entered into a limited number of hedges above and beyond those that were required for certain periods. In prior years, these hedges prevented us from realizing the full benefits of price increases. We continuously evaluate our hedging strategy to take into account changes in prevailing market prices and conditions.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Derivatives* for more information on our open derivative contracts as of December 31, 2023 and *Note 4 Debt* for more information on an amendment to the hedging requirements included in our Revolving Credit Facility.

Our Principal Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other purchasers that have access to transportation and storage facilities. Our ability to sell our products can be affected by factors that are beyond our control and cannot be accurately predicted. 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 on our customers.

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 which secure our debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt.*

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 who operate in California. We also compete with foreign oil and gas companies because California imports approximately 75% of the oil it consumes. 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 similar characteristics to the low-carbon intensity oil produced from our fields. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using our firm capacity contracts.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. Higher commodity prices could intensify competition for drilling and workover rigs, pipe, other oil field equipment and personnel. However, in the current environment, we anticipate modest price increases for materials and services as contracts are renewed in the future. We believe our relative size and activity level, compared to other in-state producers, favorably influences the pricing we receive from third-party providers in the markets in which we operate.

We also face competition in our oil and natural gas operations from other sources of energy, including wind and solar power. These products compete directly with the electricity we generate from 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 continues to develop renewable energy and implements climate-related policies.

In our carbon management business, we compete with other potential storage providers to acquire and develop storage reservoirs and enter into agreements with existing and future emission sources.

Infrastructure

The infrastructure used in our operations, including plants and facilities located in the Wilmington field, is presented below:

Description	Quantity	Unit	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants[a]	5	MMcf/d	335	18	353
Power Plants[b]	3	MW	595	48	643
Steam Generators/Plants[c]	25	MBbl/d	120	—	120
Compressors	300	MHp	320	21	341
Water Management Systems[c]		MBw/d	1,900	1,980	3,880
Water Softeners[c]	16	MBw/d	125	—	125
Oil and NGL Storage[d]		MBbls	408	195	603
Pipelines[e]		Miles			>8,000

(a) 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.

(b) Includes our 550-megawatt combined-cycle Elk Hills power plant, located adjacent to the Elk Hills natural gas processing facility and typically generates all the electricity needed by our Elk Hills field and certain other operations. We utilize approximately a third of its capacity for operations and market the remaining capacity into the resource adequacy market. We offer the balance of the available energy to the CAISO grid. Also included is a 45-megawatt cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations and a 48-megawatt power generating facility that is part of the Long Beach Unit located in the Los Angeles basin.

(c) 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 operations in the San Joaquin basin and supports our high-margin oil fields.

(d) 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.

(e) 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 settings 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.

Carbon Management Business

Our carbon management business, which we refer to as Carbon TerraVault, pursues CCS projects that are directly sited or within close proximity to significant sources of CO_2 emissions in California.

EPA Class VI Permits and CCS Projects

We are in the early stages of developing several CCS projects in California. To date, we have submitted Class VI permit applications to the EPA for two permanent sequestration projects at our Elk Hills field. In December 2023, the EPA released draft Class VI permits for one of these projects. This project is held by a joint venture with BGTF Sierra Aggregator LLC (Brookfield) (Carbon TerraVault JV), which is discussed further below. The draft permits for this project are currently subject to public comment, and we expect to receive the final Class VI permits in the middle of 2024. We have also submitted permit applications for four permanent sequestration projects in the Sacramento Basin that are under review by the EPA.

To date, we have executed six carbon dioxide management agreements (CDMAs) with emitters to provide permanent carbon storage. The CDMAs frame the material economics and terms of the project and include conditions precedent to close. These CDMAs contemplate the construction of production facilities for hydrogen, ammonia and other substances, some of which may be co-located with our planned CCS sites. The CDMAs are also subject to negotiation of definitive documents and a final investment decision. We are separately in discussions with other potential emitters and may enter into joint ventures or other commercial arrangements with respect to CCS projects.

Once completed, we expect that our Carbon TerraVault CCS projects will inject CO_2 captured from industrial, electrical, agriculture and carbon removal sources into subsurface reservoirs and permanently store CO_2 deep underground. As part of our commitment to carbon management, we are also installing and upgrading carbon capture equipment at our cryogenic gas processing facility at Elk Hills field which will remove CO_2 from inlet gas, where the CO_2 will be stored at a nearby storage reservoir owned by the Carbon TerraVault JV. We expect this project will increase operational efficiency of the cryogenic gas processing plant, improving propane recovery, and reduce the carbon intensity of the electricity generated from our Elk Hills Power Plant. We are also evaluating the feasibility of developing a carbon capture system for our 550-megawatt Elk Hills power plant (CalCapture). We continue to work with a consortium of industry participants to advance the development of a direct air capture hub to be located in Kern County and have been selected by the U.S. Department of Energy grant for this project.

We expect that the size and scope of our projects providing these and similar services and capital spent on such projects will continue to grow given our strategy of expansion into these services and the development of our carbon management business as a stand-alone business. For more information about the risks involved in our carbon management business, see *Part I, Item 1A – Risk Factors.*

Carbon TerraVault JV

In August 2022, we entered into a joint venture with Brookfield for the further development of our carbon management business. We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. At the formation of the Carbon TerraVault JV, we contributed rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage (26R reservoir) and Brookfield committed to make an initial investment of $137 million, subject to adjustment based on permitted storage capacity, payable in three installments with the last two installments subject to the achievement of certain milestones. Brookfield contributed the first $46 million installment of their initial investment to the Carbon TerraVault JV during the year ended December 31, 2022. The next two installments are due upon completion of certain pre-agreed milestones, which are anticipated to occur in 2024. This amount may, at our sole discretion, be distributed to us or used to satisfy future capital contributions, among other items. The parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met. Future storage projects for Brookfield's initial commitment are subject to approval of the joint venture, including Brookfield.

Several other projects are being considered by the Carbon TerraVault JV for future development. If Brookfield elects to participate in a project, a portion of our upfront costs to evaluate and permit that project will be subsequently recovered through Brookfield's investment in the Carbon TerraVault JV. We may also pursue the development of CCS projects independently of the Carbon TerraVault JV if Brookfield elects not to participate.

The Carbon TerraVault JV has an option to participate in certain projects that involve the capture, transportation and storage of CO_2 in California. This option expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the Carbon TerraVault JV for storage projects representing in excess of 5 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). Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our Carbon TerraVault JV.

Human Capital Management

Our employees are our most valuable asset and we strive to provide a safe and healthy workplace, development opportunities and financial rewards, ensuring focus on fair and equitable treatment. We believe our core values of Character, Responsibility and Commitment and our comprehensive business and ethical conduct policies sustain shareholder value.

Our comprehensive business and ethical conduct policies apply to all directors, officers and employees, each of whom personally commits to following our code of conduct and our corporate policies, as well as to suppliers and vendors working in our operations. Our position is that no business goal is worth our employees compromising their integrity or our shared values.

We had approximately 970 employees as of December 31, 2023 as compared to 1,060 as of December 31, 2022, all in the United States. In 2023, we undertook initiatives to streamline our operations and implemented organizational changes that resulted in a headcount reduction of approximately 75 employees. That decrease was partially offset by growth in our headcount in our carbon management business. Of the total 970 employees, approximately 50 full-time equivalent employees are focused on our carbon management business. Approximately 55 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third-party contractors throughout our operations.

Continued Employee Development

Employee development opportunities are provided to enhance leadership development and expand career opportunities. Our employees undergo mandatory annual training on our policies including health and safety, business ethics, harassment, IT security and others. Our mandatory training reinforces our company-wide commitment to operate in accordance with all applicable laws, rules and regulations and to sustain a diverse and empowered workforce comprising of our employees and those of our suppliers, vendors and joint ventures. In addition to training, our employees receive regular performance and career development discussions from their direct managers. All employees receive annual performance reviews.

Our largest development initiatives in the past couple of years included the Future Leaders Development Program with the University of California, Los Angeles (UCLA) Anderson School; our Intrepid Women's Program, a program of coaching and development circles for women; and ELEVATE, a manager workshop on communication styles and culture changing behaviors to develop our future leaders.

We have taken steps to promote the development of a pipeline of candidates as we develop our carbon management business. In 2022, we pledged $2.5 million to fund several Kern County initiatives with Kern Community College District (Kern CCD) and California State University, Bakersfield (CSUB) to help advance the energy transition and further benefit local communities. As of December 31, 2023, we contributed approximately $1.9 million of the $2.5 million pledged. We anticipate contributing the remainder of our commitment in 2024.

We will collaborate with Kern CCD to establish the CRC Carbon Management Institute, a first-of-its-kind initiative that will empower local private and public partnerships to lead the way in defining how collaboration between education and industry can positively impact communities. Funding will also be used for research and development, community outreach and education, workforce training and education, and carbon management academics that will focus on advancing CCS and emerging technologies. Additionally, CSUB will launch the CRC Energy Transition Lecture Series on relevant topics and emerging issues related to CCS and technologies that will lead the way to achieving a net zero future. Finally, the CRC Carbon TerraVault Scholarship will be established to help provide students with academic opportunities.

Diversity, Equity and Inclusion

Our goal is to foster an open and diverse culture and we are committed to advancing people of all backgrounds and perspectives, including women and persons from historically underrepresented communities in our workplace. We believe supporting diversity, equity and inclusion (DE&I) efforts encourages higher levels of workforce engagement by helping to enable team members to bring diverse experiences and perspectives to their day-to-day jobs. We believe this, in turn, leads to more thoughtful and innovative business decisions and higher levels of engagement and lower levels of turnover. We established an Advisory Council focused on career development, promotion, recruitment and retention to help support our DE&I commitments. We have all employees attend DE&I training to reinforce an open and diverse culture.

The table below approximates our self-reported gender diverse and ethnically and racially diverse employees and members of our Board of Directors as of December 31, 2023.

	Gender Diverse	Ethnically and Racially Diverse
All Employees	19%	39%
Managers	23%	27%
Executives	28%	28%
Board of Directors	33%	44%

Employee Safety

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 a threshold TRIR as a quantitative metric that directly impacts incentive compensation for all of our employees. We achieved a 99.9999% oil spill prevention rate in 2023 and registered a workforce TRIR of 0.31. We have achieved exemplary, steadily improved 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 throughout the 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 host regular townhalls so employees can engage with them through question and answer sessions.

We provide our employees industry competitive base wages and annual and long-term incentive compensation opportunities, as well as matching and profit-sharing retirement contributions to employees' 401(k) accounts; comprehensive health benefits; life, disability and accident insurance coverages; sick pay, paid holidays, paid parental leave and vacation; employee assistance for confidential counseling services, a wellness program to promote the well-being of our employees and their families; and various group discount programs. Our employee stock purchase program allows our employees to purchase shares of our common stock at a discounted price. We also provide options for alternate work schedules, flexible work hours, part-time work options and telecommuting.

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. The State Lands Commission provides additional administration of the state's surface and mineral interests.

Regulation of Exploration and Production Activities

Well Permitting

In 2023, we experienced significant delays with respect to obtaining new well, sidetrack, deepening and rework permits from CalGEM for our operations. A variety of factors outside of our control led to such delays, including recent changes in CalGEM management. Since December 2022, CalGEM has issued a limited number of permits for new production wells in California, and those permits were issued to other operators. In addition, CalGEM effectively ceased issuing permits for sidetracks, deepenings and reworks at various points in 2023 pending the development of standard operating procedures (SOPs). CalGEM recently finalized its SOP for the review of permit applications for reworks in December 2023 and a noticeable increase in rework approvals has followed. CalGEM also recently finalized its Lead Agency Preliminary Review process. Since the implementation of that process, the pace of approvals has been slow, with only a limited number of sidetrack permits issued to other operators.

We cannot guarantee that these issues or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. Any continuing failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, operations, properties, results of operations, and our financial condition. See *Part 1, Item IA – Risk Factors, 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*.

CalGEM currently requires an operator to identify the manner in which the California Environmental Quality Act (CEQA) has been satisfied prior to issuing various state permits, typically through either an environmental review or an exemption by a state or local agency. In Kern County, this requirement has typically been satisfied by complying with the local oil and natural gas ordinance which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015.

Kern County EIR Litigation

Our operations in Kern County have been subject to significant uncertainty over the past several years as a result of ongoing challenges to the County's ability to rely on an existing EIR to meet the County's obligations under CEQA. In December 2015, several groups challenged the sufficiency of the EIR for satisfying CEQA requirements in Kern County for oil and natural gas permit approvals. Litigation proceedings remain ongoing; currently, the use of the EIR is stayed and has been throughout most of the litigation. Although the County has issued a supplemental EIR to address the plaintiffs' concerns, operators still cannot rely on this supplemental EIR at this time as a result of the ongoing litigation. A ruling as to whether oil and natural gas permitting shall remain suspended for the duration of the appeals process is expected sometime in the first half of 2024.

We have pursued and continue to pursue alternative pathways for addressing CEQA compliance for oil and natural gas permits in Kern County and have submitted applications for conditional use permits from Kern County for projects located at our Elk Hills, Kern Front and Buena Vista fields.

However, subject to one narrow exception, CalGEM has not approved any permits for new drill wells in Kern County since December 2022, through alternative pathways or otherwise. We expect that our pursuit of the conditional use permits in Kern County will be a lengthy process. The timing of this process is difficult to estimate and could extend well into 2025.

As a result of these issues and current lack of permits with respect to our Kern County properties, we plan to operate one active rig within Kern County in the first half of 2024 and have the requisite number of permits in hand to keep that rig active throughout 2024. We plan to increase our active rig count in Kern County to three rigs in the second half of 2024 assuming the resumption of permitting of new wells and sidetracks or through alternative pathways. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations. Approximately $75 million of our aggregate capital for oil and natural gas development in 2024 relates to drilling and completing wells in Kern County for which we do not presently have a permit. If we are unable to obtain the necessary permits for the development of these wells, we will pursue alternatives for the deployment of this capital. For more information on our 2024 Capital Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources.*

Wilmington Oil Field

In addition, commencing in February 2023, CalGEM began returning our applications for permits in the Wilmington Oil Field, including permits for new production wells, workovers and plugging and abandonment operations. CalGEM cited concerns regarding the adequacy of the related environmental impact report for purposes of meeting CEQA requirements. We are working together with the City of Long Beach to address CalGEM's concerns regarding conducting future re-drills, workover and plugging and abandonment activities.

Approximately $25 million of our aggregate capital for oil and natural gas development in 2024 relates to drilling and completing wells in Wilmington for which we do not presently have a permit. If we are unable to obtain the necessary permits for the development of these wells, we will pursue alternatives for the deployment of this capital.

We plan to operate one active rig on the THUMS Islands in the second half of 2024 assuming the resumption of permitting of sidetracks and deepenings. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations.

Regulatory Activity

The California Legislature and Governor have significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years through legislation and policy pronouncements. For example, 2019 state legislation expanded CalGEM's duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs, and will require CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators.

CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements. CalGEM issued updated regulations in

April 2019 governing management of idle wells and underground fluid injection, which include specific implementation periods. The updated idle well management regulations require operators to either submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or pay additional annual fees and perform additional testing to retain greater flexibility to return long-term idle wells to service in the future. The updated underground injection regulations address injection approvals, project data requirements, testing of injection wells, monitoring and reporting requirements with respect to injection parameters, containment and incident response, among other topics.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general and well stimulation, completion or injection activities in particular, impose setback distances from certain other land uses, or ban such activities outright. For example, both the City and the County of Los Angeles have voted to prohibit new oil and natural gas wells and phase out existing wells over a number of years. Our operations in unincorporated areas of Los Angeles are not affected by these bans, and we do not anticipate a material impact from these bans to our future drilling operations as we have no drilling plans or proved undeveloped reserves within the area that would be covered by these bans. However, from time to time, other local governments in California have sought to enact similar bans and others may seek to do so in the future. Other local governments have sought to ban natural gas or the transportation of natural gas through their cities. The cities of Brentwood and Antioch have refused to extend the necessary franchise agreements to preserve an existing pipeline that runs through their jurisdictions. In July 2023, one of our subsidiaries submitted an application with the CPUC to convert this pipeline to common carrier status. The application is still pending. A response is tentatively expected by year-end 2024.

Setbacks

On September 16, 2022, the Governor of California signed Senate Bill No. 1137 into law, which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public and separately imposing a number of potential impact analysis and mitigation and reporting requirements effective January 1, 2023. On January 6, 2023, CalGEM’s emergency regulations to support implementation of Senate Bill No. 1137 were approved by the Office of Administrative Law and final regulations were published. Proponents of a voter referendum to repeal Senate Bill No. 1137 (the Referendum) have collected more than the requisite number of signatures required and the Secretary of State of California certified the signatures and confirmed that the Referendum qualifies for the November 2024 ballot. Accordingly, Senate Bill No. 1137 is stayed until it is put to a vote. CalGEM could attempt to initiate rulemaking with regard to setbacks during the stay, although this has not occurred thus far.

The majority of our production is in rural areas in the San Joaquin basin and is unlikely to be affected by Senate Bill No. 1137 should the outcome of the Referendum result in the bill being implemented. We would not expect the implementation of this law to result in any change in our existing proved developed producing reserves or current production rates or any material change to the timing of plugging and abandonment liabilities. However, there is significant uncertainty with respect to our ability to book proved undeveloped reserves within the setback zones established by Senate Bill No. 1137. As a result, we have not booked any proved undeveloped reserves located within setback zones, except for those reserves for which we have drilling permits or intend to have drilling permits for, prior to the November 2024 ballot. Due to Senate Bill No. 1137, in 2023 we reduced the net present value of our proved undeveloped reserves by 19% and our overall proved reserves by 2%.

Separately, in early 2023, Senate Bill No. 556 was introduced into the California Senate providing for presumptive liability for certain adverse health conditions in a setback zone, subject to limited defenses. The bill did not advance through the legislature in 2023. However, similar proposed legislation was introduced as Assembly Bill 3155 in February 2024. If AB 3155, or similar bills, are ultimately enacted, such legislation would further impact our ability to operate in a setback zone and increase our exposure to liability.

Pipeline Transportation

Federal and state pipeline regulations have also been recently revised. CalGEM imposed more stringent inspection and integrity management requirements in 2019 and 2020 with respect to certain natural gas pipelines in specified locations, with additional regulations anticipated in 2022 regarding digital mapping of such lines. The Office of the State Fire Marshal adopted regulations in 2020 to require risk assessment of various oil lines in the coastal zone, followed by retrofitting of certain of those lines with the best available control technology to mitigate oil spills over a specified implementation period. Finally, the federal PHMSA has, from time to time, issued new regulations expanding or otherwise revising pipeline integrity requirements. For example, in November 2021, PHMSA issued a final rule imposing safety regulations on an aggregate of approximately 400,000 miles of previously unregulated onshore gas gathering lines across the United States that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. And, in August 2022, PHMSA finalized additional pipeline safety rules, which adjusted the repair criteria for pipelines in high consequence areas, created new criteria for pipelines in non-high consequence areas, and strengthened integrity management assessment requirements, among other items. Additionally, in May 2023, PHMSA published a proposed rule that would enhance requirements for detecting and repairing leaks on new and existing natural gas distribution, gas transmission and gas gathering pipelines and, separately, in September 2023, 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.

Water Injection

Our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. These operations are subject to regulation by the City of Long Beach and CalGEM. We are currently in discussions with the City of Long Beach and CalGEM with respect to what injection well pressure gradient complies with CalGEM’s requirements for the protection of underground aquifers, while at the same time mitigating subsidence risks and have supplied technical information to CalGEM in support of our position. If CalGEM were to ultimately disagree and determine to reduce the injection well pressure gradient other than in a gradual manner, and we were unable to reverse that decision on appeal or other legal challenge, we expect any material reduction in injection well pressure gradient for our operations in the Wilmington Oil Field would result in a decrease in production and reserves from the field.

Collectively, the effect of these regulations is to potentially limit the number and location of our wells and the amount of oil and natural gas that we can produce from our wells compared to what we otherwise would be able to do.

Bonding

On October 7, 2023, the California Governor signed into law Assembly Bill 1167 (AB 1167), which imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in the state of 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. Upon signing AB 1167, Governor Newsom called for further legislative changes to these new requirements to mitigate against the potential risk of the implementation of AB 1167 ultimately increasing the number of orphaned idle or low-producing wells in California, although no such changes have yet been announced. We cannot predict what form these changes may ultimately take or if the legislature will act on the Governor's request. Implementation of this law may lead to the delay or additional costs with respect to certain acquisitions or dispositions, which could impact our ability to grow or explore new strategic areas – or exit others – within the state of California.

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, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and NEPA, among others. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;
- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, and implementation of inspection, monitoring and repair programs to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation and reclamation measures, impose energy efficiency or renewable energy standards on us or users of our products and services, and restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and

- may restrict our rate of oil, NGLs, natural gas and electricity production.

These requirements can result in restrictions on our operations. For example, in 2014, at the request of the EPA, CalGEM commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the SDWA. In 2015, the state set deadlines to obtain the EPA's confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. During the review, the state has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. The state continues to work with EPA to resolve these issues. The aquifer exemption process has slowed in part due to the determination by CalGEM and the State Water Resources Control Board that certain of the remaining applications require additional "conduit analysis" to ensure that injected fluid will not escape from the intended area of subsurface confinement and EPA's delays in approval of the exemption proposals that remain outstanding. Of the 30 original aquifer exemption proposals addressing permitted injection into a potential underground source of drinking water, 21 have been approved by EPA, with nine applications outstanding. In connection with legal challenges filed against the state by industry stakeholders, the Kern County Superior Court has issued an order generally barring the blanket enforcement of CalGEM's aquifer exemption regulations mandating grant of an aquifer exemption as a precondition to continued injection activities. In a January 2024 status hearing, the court also preserved the stay and preliminary injunction for an additional six months at which time it will reevaluate case management due to the age of the lawsuit.

At the federal level, recent modifications to regulations implementing NEPA may impose additional restrictions on oil and natural gas activities on federal lands. In October 2021, the Biden Administration announced three significant changes to a 2020 rule finalized under the Trump Administration. These changes included (i) authorizing agencies to consider the direct, indirect and cumulative effects of major federal actions including upstream and downstream impacts of fossil fuel projects; (ii) allowing agencies to determine the purpose and need of a project (thereby allowing consideration of less-harmful alternatives); and (iii) affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council of Environmental Quality (CEQ) regulations, so as to meet the agencies' and public's need. To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes—"Phase I" of the Biden Administration's two-phased approach to modifying NEPA. In July 2023—"Phase 2"—the CEQ published a proposed rule revising the implementing regulations of the procedural provisions of NEPA and implementing amendments to NEPA included in the Fiscal Responsibility Act of 2023. The final rule is expected in the second quarter of 2024.

In addition, due to the risk of future drought conditions in California, water districts and the state government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Water management, including our ability to recycle, reuse and dispose of produced water and our access to water supplies from third-party sources, in each case at a reasonable cost, in a timely manner and in compliance with applicable laws, regulations and permits, is an essential component of our operations to produce crude oil, natural gas and NGLs economically and in commercial quantities. As such, any limitations or restrictions on wastewater disposal or water availability could have an adverse impact on our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, waterflooding, steamflooding and well drilling, completion and stimulation. We also provide reclaimed produced water to certain agricultural water districts. We also use supplied water from various local and regional sources, particularly for power plants and steam generation. We are a net fresh water supplier to the state. While our production to date has not been impacted by restrictions on access to third-party water sources, we cannot guarantee that there may not be restrictions in the future.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions 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.

Regulation of Carbon Capture, Sequestration and Storage

Unitization and Pipelines

On September 16, 2022, the Governor of California signed Senate Bill No. 905 into law, which 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. A unified permit application is to be adopted by January 1, 2025. We believe permitting for our Carbon TerraVault projects, for which the EPA has issued draft permits that are open to public notice and comment until March 20, 2024, 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. Our Carbon TerraVault projects are expected to either use emitters that are directly sited above these storage facilities or rely on pipelines for transporting CO_2. Those projects that will rely only on pipelines for transporting CO_2 will need to comply with yet to be developed CO_2 pipeline safety regulations from the federal PHMSA, which could take a number of years to effect. Further, the terms of the final pipeline safety regulations may impair or prohibit those projects that rely on the transportation of CO_2. In addition, delays in developing the required pipeline safety regulations would delay projects requiring pipeline transportation of CO_2. The lack of compulsory unitization could also delay project timelines.

The unified permitting process contemplated by Senate Bill No. 905 will be optional for project applicants and is intended to simplify the permitting process for CCS projects. In the meantime, pursuant to this legislation, we are permitted to proceed with our existing and future permit applications with the EPA. This law also 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 Department of Conservation has been tasked with developing this proposed framework, an initial draft of which was expected in December 2023 and remains pending.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO_2 in connection with Enhanced Oil Recovery (EOR) projects. In light of this prohibition and the enhancement of energy credits under the Inflation Reduction Act of 2022, we transitioned our CalCapture project to target CCS. We currently do not have any oil and natural gas production or proved reserves associated with EOR projects that rely on CO_2 floods. As a result, we do not expect the limitations on EOR activities included in Senate Bill No. 905 to impact our existing oil and natural gas production or proved reserves.

CCS Project Permitting

The development, construction and operation of our CCS projects is contingent upon securing certain permits from federal, state and local authorities, including “Class VI” injection well permits from EPA and conditional use permits from the county in which a project is sited. Draft permits and corresponding draft EIRs are subject to public review and comment. The process for permitting CCS projects continues to evolve. In December 2023, EPA released draft Class VI permits for our “CTV I – 26R” CCS project located at our Elk Hills field in Kern County. These draft permits are the first draft permits released by EPA in California. In December 2023, Kern County also released the draft EIR prepared in connection with the conditional use permit application for CTV I – 26R. The draft Class VI permits and draft EIR are subject to public review and comment. We anticipate that EPA and Kern County will deliver their final decisions on the permits in the second half of 2024.

Federal Tax Credits

The Inflation Reduction Act also enhanced existing credits for the capture and sequestration of carbon oxide (45Q credit) by increasing the size of the maximum credit to $85 per metric ton of qualified carbon oxide when such carbon oxide is captured from industrial and power generation facilities and to $180 per metric ton of carbon oxide when a direct air capture facility is utilized to capture such carbon oxide, and, in each case, when such captured carbon oxide 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, and the Inflation Reduction Act provides an option to monetize the 45Q credit through a sale of the 45Q credit to another taxpayer. These additional energy-related tax incentives are effective for new projects beginning on January 1, 2023, and enhance the economics for development of CCS projects in California. The accessibility of direct pay, tax equity financing, and the credit transfers market for tax credits provided under the Inflation Reduction Act is still developing and is subject to further guidance from the IRS, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45Q credit exist.

The Inflation Reduction Act also incentivizes the development of clean hydrogen production projects through the clean hydrogen production tax credit under section 45V of the Code (45V credit). The credit amount is up to $3 per kilogram multiplied by an applicable percentage for clean hydrogen for a ten-year period beginning when a qualified facility is placed in service. On December 26, 2023, the IRS released proposed regulations to amend the Income Tax Regulations under section 45V. The proposed regulations would provide rules for determining lifecycle greenhouse gas emissions rates resulting from hydrogen production processes; petitioning for provisional emissions rates; verifying production and sale or use of clean hydrogen; modifying or retrofitting existing qualified clean hydrogen production facilities; using electricity from certain renewable or zero-emissions sources to produce qualified clean hydrogen; and electing to treat part of a specified clean hydrogen production facility instead as property eligible for the energy credit.

The amount of the available 45V credit from which we may directly or indirectly benefit in connection with our Carbon TerraVault business will depend on our ability to satisfy certain requirements of the regulations that will be adopted by the IRS upon the conclusion of its rulemaking process. The proposed regulations indicate that the Treasury Department and IRS are considering imposing certain requirements, restrictions and potential limitations that may eliminate or reduce the amount of the credit available to us (or our partners), which may impact our ability to successfully develop clean hydrogen production projects. Moreover, the accessibility of direct pay, tax equity financing, and the credit transfers market for tax credits provided under the Inflation Reduction Act is still developing and is subject to further guidance from the IRS, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45V credit still exist.

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. President Biden has issued several executive orders on climate change, which have ultimately resulted in the United States rejoining the Paris Agreement, EPA issuing final methane emissions standards for new, modified and existing oil and natural gas and an increased emphasis on climate-related risk across governmental agencies and economic sectors. Additionally, the EPA has adopted federal regulations to:

- require reporting of annual GHG emissions from oil and natural gas exploration and production, power plants and natural gas processing plants; gathering and boosting compression and pipeline facilities; and certain completions and workovers;

- incorporate measures to reduce GHG emissions in permits for certain facilities; and
- restrict GHG emissions from certain mobile sources.

California has adopted stringent laws and regulations to reduce GHG emissions. These state laws and regulations:

- established a "cap-and-trade" program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the 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.

On December 19, 2023, CARB released its proposed amendments to the LCFS Regulation, which focus on "key concepts" including increasing the stringency of the program "to more aggressively decarbonize fuels", incentivizing production of clean fuels, such as "low-carbon hydrogen", and supporting methane emissions reductions. The proposed amendments would increase both the pre- and post-2030 stringency of the LCFS carbon intensity (CI) benchmarks, including a 30% reduction in fuel CI by 2030 and a 90% reduction in fuel CI by 2045 from the 2010 baseline, near-term step-down of a 5% reduction in the CI benchmark in 2025 that increases the stringency of the CI target, and an automatic acceleration mechanism which advances all annual carbon intensity benchmarks by one year when specific regulatory conditions are met.

In connection with the foregoing, CARB has proposed the adoption of a new Oil Production Greenhouse Gas Emission Estimator (OPGEE), which models an increase in the CI of crudes. CARB has also proposed a phase-out of project-based crediting and limiting the duration of the crediting period for innovative petroleum projects. Any changes to the LCFS or other California initiatives related to climate change, including the foregoing proposals, could result in increased compliance costs if we are forced to purchase additional credits or otherwise adversely impact demands for the hydrocarbons we produce.

The proposed amendments also exclude "blue" hydrogen from the definition of "Renewable Hydrogen". Blue hydrogen is produced primarily from natural gas using a steam reformation process, which brings together natural gas and heated water in the form of steam. The output is hydrogen. Carbon dioxide is produced as a by-product of this process. The produced hydrogen constitutes "blue" hydrogen if the produced carbon dioxide is captured and permanently sequestered. If adopted, the exclusion of blue hydrogen as a "Renewable Hydrogen" may directly or indirectly impact our ability to develop, construct and operate blue hydrogen production projects if such projects were to become economically unviable as a result.

In addition, the current and former Governors 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 and adverse effect on our business, results of operations and financial condition.*

The EPA and the CARB have also expanded direct regulation of methane as a contributor to GHG emissions. In response to President Biden's executive order calling on the EPA to revisit federal regulations regarding methane, 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. Under the final rules, states have two years to prepare and submit their plans to impose methane emissions controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirement using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and requirements will be subject to legal challenges. CARB has implemented similar regulations.

Relatedly, beginning in 2025, certain oil and gas facilities, including those we own and operate, must pay a fee to EPA pursuant to the Inflation Reduction Act, starting at $900 per metric ton of methane emitted in 2024 and annually thereafter, with the fee rising to $1,200 in 2025 and $1,500 in 2026 and thereafter. However, compliance with the EPA's methane rules, discussed above, would exempt an otherwise covered facility from the requirement to pay the fee.

California Climate Disclosures

In October 2023, the Governor of California signed two bills that will require climate-related disclosures, both of which apply to us. Senate Bill 253 (SB-253) requires both public and private U.S. companies that are "doing business in California" and that have a total annual revenue of $1 billion to publicly disclose, on an annual basis, Scope 1, Scope 2 and Scope 3 GHG emissions, with certain GHG emissions data subject to third-party assurance. The bill requires disclosure beginning in 2026 (for the 2025 reporting year). Senate Bill 261 (SB-261) requires public and private U.S. companies "doing business in California" with a total annual revenue of $500 million to publish biennial disclosures on the company's website related to climate-related financial risks and the measures a company has adopted to reduce and adapt to such risks, with the report in line with the Task Force on the Climate-related Financial Disclosure recommendations or equivalent disclosure requirements under the International Sustainability Standards Board's climate-related disclosure standards. Additionally, in October 2023, the Governor of California also signed Assembly Bill 1305 (AB 1305) which creates new reporting obligations related to voluntary carbon offsets. AB 1305 requires business entities that (1) market or sell voluntary carbon offsets in California, (2) purchase or use voluntary carbon offsets sold in California that make emissions-related claims, or (3) make claims that an entity or product has eliminated or made significant reductions to its carbon dioxide or GHG emissions to make certain public disclosures on the business entity's website. Under the final prong, such claims covered by AB 1305 include "significant reductions" to carbon dioxide or GHG emissions and the achievement of net zero.

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. In 2015, the U.S. federal government lifted restrictions on the export of domestically produced oil that allows for the sale of U.S. oil production, including ours, in additional markets.

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. For example, on January 1, 2020, the International Maritime Organization reduced the maximum sulfur content in marine fuels from 3.5% to 0.5% by weight under the International Convention for the Prevention of Pollution from Ships. Under this IMO 2020 rule, ships must either switch to low-sulfur fuels or install scrubbing facilities for emission controls, which may affect the price of and demand for varying grades of crude oil, both internationally and in California.

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. For example, in January 2020, the California Public Utilities Commission (CPUC) commenced a rulemaking to develop a long-term natural gas planning strategy to ensure safe and reliable gas systems at just and reasonable rates during what it describes as a 25-year transition from natural gas-fueled technologies to meet the state's GHG goals. In addition, several municipalities in California enacted ordinances in 2019 that restrict the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market of our utility customers and the demand and prices we receive for the natural gas we produce. Several of these ordinances face legal challenges.

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.

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 materially and adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.
- Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.
- Drilling for and producing oil and natural gas carry significant operational risks and uncertainty. We may not drill wells at the times we scheduled, 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.
- We have been negatively impacted by inflation.
- 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 military conflicts in Ukraine, Israel and Yemen and the Red Sea have caused related price volatility and geopolitical instability could negatively impact our business.
- From time to time we may engage in step-out drilling, or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.
- Many of our competitors have greater resources than us and we may not be able to successfully compete in acquiring and developing new properties.
- Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.
- 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 prove to be higher or lower than estimated.

Risks Related to Carbon TerraVault and Our Carbon Management Business

- Our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to carbon management activities, is subject to risks and uncertainties.
- We may not be able to grow our Carbon TerraVault business and develop large scale CCS projects.
- 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.
- Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties which could adversely affect our ability to implement our carbon management strategy.

Risk Factors Related to Our Business Generally

- Increasing activism against the oil and gas industry presents risks to our business.
- Increasing attention to ESG matters may adversely impact our business.
- We may not decide to separate our carbon management business from our E&P business, or be successful in the event we choose to pursue such separation.

- Acquisition and disposition activities, including the Aera Merger, involve substantial risks.
- While the Aera Merger is pending, we will be subject to certain contractual restrictions that could adversely affect our business and operations.
- We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- Cybersecurity attacks, systems failures and other disruptions could adversely affect us.

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.
- 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 requirements 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.
- New and developing regulations related to CO_2 unitization, permitting and pipeline safety could negatively impact our business, financial condition and results of operations.
- Concerns about climate change and other air quality issues may prompt governmental action that could materially affect our operations or results.
- The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.
- Tax law changes could have an adverse effect on our financial conditions, results of operations and cash flows.
- Recent action by the State of California imposing additional 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 the state of California or increase our costs in connection with the same.

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 and limit our financial flexibility.
- 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.
- The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our ability to use or access to capital.
- Restrictive covenants in our Revolving Credit Facility and the indenture governing our Senior Notes may limit our financial and operating flexibility.
- Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

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.
- 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.
- There is an increased potential for short sales of our common stock due to the sales of shares issued upon exercise of warrants, which could materially affect the market price of the 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.
- Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

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 materially and adversely affect 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. A substantial decline in prices for these products would reduce our cash flows from operations and could reduce our borrowing capacity or cause a default under our financing agreements.

Prices for oil, natural gas and NGL may fluctuate widely in response to relatively minor changes in domestic and global supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and global inventory levels;
- political and economic conditions, including international disputes such as the conflicts in Ukraine, Israel and Yemen and the Red Sea;
- pandemics, epidemics, outbreaks or other public health events, such as the COVID-19 pandemic;
- the actions of OPEC and other significant producers and governments;
- changes or disruptions in actual or anticipated production, refining and processing;
- worldwide drilling and exploration activities;
- government energy policies and regulation, including with respect to climate change;
- the effects of conservation;
- natural disasters, weather conditions and other seasonal impacts;
- speculative trading in derivative contracts;
- currency exchange rates;
- technological advances;
- transportation and storage capacity, bottlenecks and costs in producing areas;
- the price, availability and acceptance of alternative energy sources;
- regional market conditions; and
- other matters affecting the supply and demand dynamics for these products.

Lower prices could have adverse effects on our business, financial condition, results of operations and cash flow, including:

- reducing our proved oil and natural gas reserves over time;
- limiting our capital expenditures and our ability to grow or maintain future production;

- causing a reduction in our borrowing base under our Revolving Credit Facility, which could affect our liquidity;
- reducing our cash flow and ability to make interest payments or maintain compliance with financial covenants in the agreements governing our indebtedness, which could trigger mandatory loan repayments and default and foreclosure by our lenders and bondholders against our assets; and
- limiting our access to funds through the capital markets and the price we could obtain for asset sales or other monetization transactions.

Our hedging program does not provide downside protection for all of our production. As a result, our hedges do not fully protect us from commodity price declines, and we may be unable to enter into acceptable additional hedges in the future.

Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Our operations are concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. These 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. 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 carry significant operational risks and uncertainty. We may not drill wells at the times we scheduled, 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 are subject to numerous operational risks, including the risks of permitting or construction delays, equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts), cost over-runs and other associated risks.

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 forgoing 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.

We have specifically identified locations for drilling over the next several years, which are an integral part of our production strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient production and reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that our identified drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. 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 4% of our total net undeveloped acreage at December 31, 2023.

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.

Our development activities involve substantial capital investments. We intend to fund our 2024 capital program using cash flow from operations. Accordingly, a reduction in projected operating cash flow could cause us to reduce our future capital investments. In general, the ability to execute our capital plan depends on a number of factors, including:

- the amount of oil, natural gas and NGLs we are able to produce;
- 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 liquidity and ability 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. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production levels and development activities and limit our ability to make acquisitions or enter into partnerships and farmout arrangements.

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. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent we have insufficient cash flow from operations or liquidity to fund those activities. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

We have been negatively impacted by inflation.

Increases in inflation may have an adverse effect on us. Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability. We have taken measures to limit the effects of the inflationary market by entering into contracts for materials and services with terms of one to three years. Additionally, we continually look at productivity and performance improvements from our vendors in order to mitigate these price increases and also to reduce volumes consumed. However, there can be no assurances that such measures will be effective. Inflation could also result in higher interest rates in the United States, which could increase the cost of future financing efforts.

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 is dependent upon the existence of adequate markets for our products. Imbalances between the supply of and demand for these products, including as a result of economic downturns or the effects of public health events, could cause extreme market volatility and a substantial adverse effect on commodity prices. A world health event, the extent of actions that may be taken to contain or treat their impact, and the impacts on the economy generally and oil prices in particular, are uncertain, rapidly changing and hard to predict. This uncertainty could force us to reduce costs, including by decreasing operating expenses and lowering capital expenditures, and such actions 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.

Additionally, to the extent a world health event adversely impacts the global business and economic environment, which adversely affects our business and financial results, it may also have the effect of heightening or exacerbating many of the other risks described in the *Risk Factors* herein.

The military conflicts in Ukraine, Israel and Yemen and the Red Sea have caused price volatility and geopolitical instability could negatively impact our business.

The military conflicts in Ukraine, Israel and Yemen and the Red Sea have caused volatility in the prices of natural gas, oil and NGLs, and the extent and duration of the military action, sanctions and resulting market disruptions have been significant and could continue to have a substantial impact on the global economy and our business for an unknown period of time.

During the fourth quarter of 2023, OPEC+ announced a continuation of its combined 4 million barrels per day voluntary reduction in production quotas. While actual OPEC+ production capabilities are difficult to discern, any return to previous targeted production levels—coupled with expanding Iranian, Venezuelan, Brazilian and U.S. production—could cause commodity prices to decline which would reduce the revenues we receive for our oil and natural gas production.

Materialization of either of the events described above may also magnify the impact of the other risks described in this "*Risk Factors*" section.

From time to time we may engage in step-out drilling or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is 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, in particular for drilling in unconventional reservoirs, which are in unproven geologic plays. Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, capital availability, costs, drilling results, regulatory approvals, available transportation capacity and other factors. We may not find commercial amounts of oil or natural gas or the costs of drilling, completing, stimulating and operating wells in these locations 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.

Many 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 natural gas, NGLs or oil. Competitors include a multinational oil company, independent production companies and individual producers and operators. In California, our competitors are few and large, which may limit available acquisition opportunities.

Many 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. In addition, we have previously entered into incremental hedges above these requirements for certain time periods. 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 prove to be higher or lower than estimated.

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions that require significant judgment in the evaluation of available information. Our assumptions may ultimately prove to be inaccurate. Additionally, reservoir data may change over time as more information becomes available from development and appraisal activities.

Our ability to add reserves, other than through acquisitions, depends on the success of improved recovery, extension and discovery projects, each of which depends on reservoir characteristics, technology improvements and oil and natural gas prices, as well as capital 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.

Generally, lower prices adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the applicable rules or may be removed due to the lack of drilling permits or insufficient capital to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although 88% of our estimated proved reserve volumes as of December 31, 2023, were audited by our independent petroleum engineer, NSAI, we cannot guarantee that the estimates are accurate.

Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions. Changes in these variables and assumptions could require us to make significant negative reserves revisions, which could affect our liquidity by reducing the borrowing base under our Revolving Credit Facility. In addition, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions.

Risks Related to Carbon TerraVault and Our Carbon Management Business

Our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to our carbon management activities is subject to risks and uncertainties.

We have adopted a number of targets and objectives related to sustainability matters, including our 2045 Full-Scope Net Zero target and our energy transition strategy. Our efforts to research, establish, accomplish, and accurately report on these targets and objectives expose us to numerous operational, reputational, financial, legal, and other risks. Our ability to achieve any stated target or objective is not guaranteed and is subject to numerous factors and conditions, some of which are outside of our control. In particular, our 2045 Full-Scope Net Zero goal includes Scope 1, 2 and 3 emissions and estimation and management of Scope 3 emissions is subject to some degree of uncertainty. We cannot guarantee that we have been able to completely quantify the full scope of our emissions and account for mitigating all such emissions in our Full-Scope Net Zero goal.

Our ability to achieve our 2045 Full-Scope Net Zero goal relies heavily on our ability to develop our Carbon TerraVault business and related CCS projects, which is subject to uncertainties and risks (including those risks described herein). In addition, the commercial and regulatory environment related to emissions reductions and reporting is evolving and uncertain, and changes in GHG emission accounting methodologies or new developments related to climate science could impact our ability to claim emissions reductions related to our sequestration activities and timely achieve our 2045 Full-Scope Net Zero goal or at all. If we are not able to successfully develop Carbon TerraVault and its CCS projects and claim related emissions reductions, or we are successful in separating our carbon management business, our ability to achieve our 2045 Full-Scope Net Zero goal would be materially and adversely affected.

Our business may face increased scrutiny from investors and other stakeholders related to our sustainability activities, including the goals, targets, and objectives that we announce, and our methodologies and timelines for pursuing them. If our sustainability practices do not meet investor or other stakeholder expectations and standards, which continue to evolve, our reputation, our ability to attract or retain employees, and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue or fulfill our sustainability-focused goals, targets, and objectives, to comply with ethical, environmental, or other standards, regulations, or expectations, or to satisfy various reporting standards with respect to these matters, within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation.

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. To our knowledge, there are no existing large-scale CCS projects in California similar to those that we are seeking to develop. These projects face operational, technological and regulatory risks that could be considerable due to the early-stage nature of these projects and the sector generally. Our ability to successfully develop these projects depends on a number of factors that we are not able to fully control, including the following:

- The development of large-scale CCS projects is an emerging sector and there are no meaningful precedents to gauge the likely range of economic terms upon which these projects may be feasibly developed. 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.

- The development of CCS and related projects will require us, our joint venture partner, and third-party emitters to make significant capital investments in the relevant technology and infrastructure and we may not have sufficient capital resources to fund such investments. Such projects may also depend on third party financing and such financing may not be available on reasonable terms or at all. In some cases, these projects will involve the production and sale of hydrogen, ammonia or other products and markets for some of these products are still emerging.
- The development of a CCS project will require us to enter into long term binding agreements with large carbon emitters and other third parties and we may not be able to do so on agreeable terms or at all. Such agreements are complex and may involve allocation of not only fees but also various credits, incentives and environmental attributes associated with the storage of CO_2. Not all emission sources produce sufficiently large quantities of pure or relatively pure streams of CO_2, or have installed equipment to capture such CO_2, so as to be useable in one or more of our CCS projects. As a result, we cannot assure whether we will be able to access CO_2 emissions in sufficient quantities or on terms that are acceptable to us.
- The development and operation of cost-effective, commercial-scale hydrogen and ammonia production facilities and associated sequestration facilities is highly complex. We may participate in the development of production facilities that provide the emissions for our CCS business. There can be no assurances that we or our partners will be able to successfully develop these production facilities, or that we will be able to develop the related sequestration facilities, in a timely manner or at all. In addition, there can be no assurances that these facilities can be maintained and operated over the longer term. The financing and development of these projects may depend on the availability of long term off-take agreements for these products and the market for hydrogen is still developing. It may not be possible for us or our partners to enter into these types of agreements on acceptable terms or at all.
- Certain of our anticipated CCS project sites rely on pore space that we do not own and we may need to enter into agreements with landowners to allow us to inject CO_2. The market for such landowner agreements is evolving with the evolution of the CCS industry and it may not be possible for us to enter into these types of agreements 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 to CCS projects from environmental groups, local residents and legislators.
- We may need to transport CO_2 in pipelines if a CCS project relies on storage space that is not co-located with the production facilities. Our ability to transport CO_2 is subject to regulatory uncertainty, see *Risks Related to Regulation and Government Action – New and developing regulations related to the CO_2 unitization, permitting and pipeline safety could negatively impact our business, financial condition and results of operations* described below.
- Other regulatory uncertainties described below.

There can be no assurances that we will successfully develop our CCS projects, including CalCapture, and such failure could have an adverse effect on our business. Our carbon management business is currently in an early stage of development, and 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 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.

Congress has incentivized the development of carbon capture projects, clean hydrogen production projects and other projects relating to the production of certain clean fuels through the establishment of various tax credits, including the 45Q credit (credit for carbon oxide sequestration) and the 45V credit (credit for production of clean hydrogen). The successful development of our Carbon TerraVault business and other CCS projects is dependent upon our ability to directly or indirectly benefit from these tax credits. The amount of tax credits from which we may directly or indirectly benefit in connection with our Carbon TerraVault business and other CCS projects is dependent upon satisfaction of certain requirements, some of which have not been fully developed and issued by the Treasury Department and IRS, and we cannot assure you that we (or our partners) will be able to satisfy those requirements. For example, the Treasury Department and IRS recently issued proposed regulations pertaining to the 45V credit which, among other things, indicated that the Treasury Department and IRS are considering imposing certain requirements, restrictions and potential limitations on the use of renewable natural gas in connection with the production of clean hydrogen that qualifies for the 45V credit, which, if implemented, could have a negative impact on our Carbon TerraVault business. Additional financial incentives may also be required for our Carbon TerraVault business and other CCS projects to be economical. In particular, we anticipate that CCS projects associated with carbon emission reductions for transportation fuels will generate LCFS credits and that these additional credits will improve the economics of CCS projects. If the existing legal requirements for incentives such as the 45Q credit, the 45V credit or LCFS credits are subsequently amended in a manner that such incentives no longer apply or are restricted in application, directly or indirectly, to our projects, we may not be able to successfully achieve an economic return from our Carbon TerraVault business and our other CCS projects or, alternatively, the construction or operation of applicable projects may be substantially delayed such that one or more projects is unprofitable or otherwise infeasible.

The ability to monetize the 45Q credit is not certain. Either the owner of the carbon capture equipment or the sequester must have the ability to use the 45Q credit itself, or the owner of the carbon capture equipment must utilize direct pay (which is limited to the first five years of the twelve-year credit period), procure tax equity financing, or transfer the credits to another taxpayer. Similar issues exist with respect to the monetization of the 45V credit. The accessibility of direct pay, tax equity financing, and the credit transfers market for tax credits provided under the Inflation Reduction Act is still developing and is subject to further guidance from the IRS, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45Q credit and the 45V credit exist.

The 45Q credit and the LCFS credits require that the captured CO_2 be stored in secure geological storage for long periods of time. If we are not able to satisfy this requirement for the duration of time required, there is the risk of recapture of 45Q credits or LCFS credits from us (or our partners) by the government, as well as a risk of indemnification obligations to our partners, claims from landowners and potential for fines and penalties for violations of environmental requirements. Accidental releases of CO_2 could also adversely impact our ability to meet our 2045 Full-Scope Net Zero goal.

There can be no assurances that we (or our partners) will successfully comply with the requirements for the available tax credits or LCFS, and such failure could have an adverse effect on our liquidity, financial condition and results of operations.

Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties which 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 business in California. The management and financing of the joint venture are subject to inherent uncertainties. These uncertainties could potentially force us to delay or cancel CCS projects or to seek alternative sources of capital to fund our CCS projects, any of which could adversely affect our ability to achieve our 2045 Full-Scope Net Zero target and other goals related to our carbon management activities.

Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through Carbon TerraVault JV, of which $46 million has been funded to date. At the time the Carbon TerraVault JV was formed, Brookfield committed to make an initial investment of $137 million payable in three installments. The first $46 million installment was contributed to the joint venture in August 2022, and the next two installments are due upon completion of certain pre-agreed milestones related to the permitting process with the EPA and final investment decision which are anticipated (but not certain) to occur in 2024. 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.

Furthermore, even though we own a 51% interest in the Carbon TerraVault JV, we share decision making power 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 oil and gas industry presents risks to our business.

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 business 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 including seeking changes to laws, pressuring governmental agencies to promulgate regulations or engage in rulemaking, or pursuing litigation. Due to heightened concerns around global warming and GHG emissions, there is often considerable pressure on lawmakers, regulators and others to take action with respect to these allegations regardless of their perceived merit. We may need to incur significant costs associated with responding to these initiatives and such actions may materially adversely affect our financial results. Complying with any resulting additional legal or regulatory requirements that are substantial or prevent our activity could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Increasing attention to ESG matters may adversely impact our business.

Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to evaluate their investment and voting decisions. Companies in the energy industry, and in particular those focused on oil or natural gas extraction, often do not score as well under ESG assessments compared to companies in other industries. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of their investment away from the fossil fuel industry to other industries which could have a negative impact on our stock price and our access to and costs of capital. To the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures will be based on expectations and assumptions that may or may not be representative of actual risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many ESG matters. Additionally, while we may also announce various voluntary ESG targets, such targets are aspirational. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. 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 that, notwithstanding our reliance on any reputable third-party registries, that the offsets we do purchase will successfully achieve the emissions reductions they represent. 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 implement such goals because of potential costs or technical or operational obstacles.

Public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," *i.e.*, misleading information or false claims overstating potential ESG benefits. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further ESG-related focus and scrutiny.

Such ESG matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

We may not decide to separate our carbon management business from our E&P business, or be successful in the event we choose to pursue separation.

We are considering the potential separation of our E&P and carbon management businesses at some point in the future. We are also pursuing financing options for our carbon management business that are separate from the rest of our business. Our carbon management business faces operational, technological and regulatory risks that could be considerable due to early stage nature of these projects and the sector generally, which may make it more difficult to independently finance and there are no assurances that it will be a viable standalone business in the near term or at all. Further, there can be no assurances that we will be able to successfully separate our E&P and carbon management businesses. We also may decide not to pursue such separation if we do not believe it would maximize shareholder value.

Acquisition and disposition activities, including the Aera Merger, involve substantial risks.

On February 7, 2024, we entered into the Merger Agreement with Aera. In addition, from time to time, we engage in acquisition activities. The Aera Merger and other such 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 or experience other integration difficulties;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing for recovering the reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and incomplete, and we may be unable to make these assessments with a high degree of accuracy.

The Aera Merger is expected to close in the second half of 2024 and is subject to certain closing conditions, including the approval of the stock issuance by our stockholders and the receipt of certain required government approvals, and other customary closing conditions. Our other acquisition activities may similarly require us to seek approvals from government agencies and other regulatory bodies, depending on the nature and extent of the businesses being acquired. There can be no assurances that we would be able to obtain such approvals. If we are not able to complete acquisitions, we may not be able to grow our reserves 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 the Aera Merger, as well as any future acquisition and disposition activities. For example, time and resources will be expended in connection with seeking regulatory approvals for the Aera Merger.

While the Aera Merger is pending, we will be subject to certain contractual restrictions that could adversely affect our business and operations.

Due to certain restrictions in the Merger Agreement on the conduct of business prior to completing the Aera Merger, we may be unable, during the pendency of the Aera Merger, to pursue strategic transactions, undertake certain significant financing transactions and otherwise pursue other actions, even if such actions would prove beneficial, and we may have to forgo certain opportunities we might otherwise pursue.

In addition, the Merger Agreement prohibits us from initiating, soliciting or knowingly encouraging any competing acquisition proposals, subject to certain limited exceptions. The Merger Agreement also contains certain termination rights for us and Aera. Upon termination of the Merger Agreement in accordance with its terms, under certain circumstances, we will be required to pay Aera a termination fee of $50 million, or $100 million in certain circumstances, including if the Merger Agreement is terminated by Aera due to our Board changing its recommendation in favor of the Aera Merger to support a competing acquisition proposal.

We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. 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 and availability of obtaining insurance for natural disasters has increased in recent years. 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 us.

We rely on electronic systems and networks to communicate, control and manage our exploration, development and production activities. We also use these systems and networks to prepare our financial management and reporting information, to analyze and store data and to communicate internally and with third parties, including our service providers and customers. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

Cybersecurity attacks on businesses have escalated and become more sophisticated. If we or the third parties with whom we interact were to experience a successful attack, the potential consequences to our business, workforce and the communities in which we operate could be significant, including financial losses, loss of business, litigation risks and damage to reputation. 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, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. If a breach occurs, it may remain undetected for an extended period of time. If we or third parties with whom we interact were to experience a cybersecurity attack or a successful breach, the potential consequences could be significant, including loss of data, loss of business, damage to our reputation, potential financial or legal liability requiring us to incur significant costs, disruptions related to investigations and costs related to remediation.

Energy-related assets may be at a greater risk of strategic terrorist attacks or cybersecurity attacks than other targets. A cybersecurity attack on the digital technology that controls most oil and natural gas refining and distribution necessary to transport and market our products could impact critical distribution and storage assets or the environment, disrupt energy markets by delaying or preventing product delivery, or make it difficult or impossible to accurately account for production and settle transactions.

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. The duration and success of each permitting effort is contingent upon many variables not within our control. In the context of obtaining permits or approvals, the Company will need to comply with known standards, existing laws (such as CEQA), and regulations that may entail greater or lesser costs and delays depending on the nature of the activity to be permitted and the interpretation of the laws and regulations implemented by the permitting authority.

In 2023 we experienced significant delays with respect to obtaining new well, sidetrack, deepening and rework permits from CalGEM for our operations. A variety of factors outside of our control can lead to such delays. Recent changes in CalGEM management have contributed to permitting delays and uncertainty with respect to our ability to timely obtain permits for our operations. Following such change in management, during the second half of 2023 CalGEM focused on the development of standard operating procedures (SOPs) for permit review, and as a practical matter ceased issuing permits pending the completion of this process. CalGEM released its SOP for the review of applications for rework permits in late Q4 2023 and recently finalized its Lead Agency Preliminary Review process for sidetrack permits. CalGEM has recently resumed issuing permits for reworks to CRC and other operators. It has issued some permits for sidetracks to other operators. Subject to limited exceptions, CalGEM has not issued any permits for new production wells to any operators since December 2022.

We have experienced delays obtaining permits as a result of litigation related to the Kern County EIR for the past several years. Following a favorable trial court order in 2022, plaintiffs appealed, and, the appellate court issued a preliminary order reinstating a suspension of Kern County's ability to rely on the existing EIR pending the outcome of a final order determining whether oil and natural gas permitting shall remain suspended for the duration of the appeals process. We expect the Appellate Court to issue its ruling on the matters at issue in the second quarter of 2024. We are in the process of pursuing alternative pathways for addressing CEQA compliance for our oil and natural gas permitting process, this would be a lengthy process and we cannot predict with complete certainty whether we would be able to timely obtain permits using this alternative.

As a result of these issues and current lack of permits with respect to our Kern County properties, we currently plan to operate one active rig within Kern County in the first half of 2024, and have the requisite number of permits in hand to keep that rig active throughout the year. We plan to increase our active rig count in Kern County from one rig to three in the second half of 2024, assuming new well and sidetrack permitting resumes in Kern County. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations. Approximately $75 million of our aggregate capital for oil and natural gas development in 2024 relates to drilling and completing wells in Kern County for which we do not presently have a permit.

We have also experienced delays obtaining drilling permits from CalGEM since the passage of Senate Bill No. 1137, which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public. The law became effective January 1, 2023 and CalGEM issued emergency regulations implementing the requirements of the law on January 6, 2023. However, on February 3, 2023, the Secretary of State of California certified voter signatures collected in connection with a referendum for the November 2024 ballot to repeal Senate Bill No. 1137. As a result, any implementation of Senate Bill No. 1137 is stayed until it is put to a vote. There is significant uncertainty with respect to the ability to book proved undeveloped reserves and drill within the setback zone established by Senate Bill No. 1137 and, as a result, we have only booked proved undeveloped reserves for which we already have permits within the zone or intend to have permits for prior to the November 2024 ballot. As a result of Senate Bill No. 1137, in 2023 we reduced the net present value of our proved undeveloped reserves by 19% and our overall proved reserves by 2%. (*See Part I, Item 1 and 2 – Business and Properties, Regulation of Exploration and Production Activities* for more information).

In addition, commencing in February 2023, CalGEM began returning our applications for permits in the Wilmington Oil Field, including permits for new production wells, workovers and plugging and abandonment operations. CalGEM cited concerns regarding the adequacy of the related environmental impact report for purposes of meeting CEQA requirements. We are working together with the City of Long Beach to address CalGEM's concerns regarding conducting future re-drills, workover and plugging and abandonment activities.

Approximately $25 million of our aggregate capital for oil and natural gas development in 2024 relates to drilling and completing wells in Wilmington for which we do not presently have a permit. We plan to operate one active rig on the THUMS Islands in the second half of 2024, assuming permitting of sidetracks and deepenings resumes. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations.

We cannot guarantee that these issues or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. In the past we have generally been able to mitigate permitting risks by building up a reserve of drilling permits for use throughout the year, but as a result of the issues described above, we have not been able to build our reserve of approved permits to the same level as we have in the past. If we cannot obtain new drilling or sidetrack permits in a timely manner, we have limited options to meet our drilling plans, such as the use of workovers to extend the life of existing production, that may not ultimately be sufficient to achieve our business goals. Any continuing failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, operations, properties, results of operations, and our financial condition.

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.

In recent years, the Governor of California, the Legislature and state agencies have taken a series of actions that could materially and adversely affect the state's oil and natural gas sector. For additional information, see *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities,* and *Risk Factors, 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*.

The trend in California is to impose increasingly stringent restrictions on oil and natural gas activities. We cannot predict what actions the Governor of California, the Legislature or state agencies may take in the future, but we could face increased compliance costs, delays in obtaining the approvals necessary for our operations, exposure to increased liability, or other limitations as a result of future actions by these parties. Moreover, new developments resulting from the current and future actions of these parties could also materially and adversely affect our ability to operate, successfully execute drilling plans, or otherwise develop our reserves. Accordingly, recent and future actions by the Governor of California, the Legislature, and state agencies could materially and adversely affect 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 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 disposal and water consumption, recycling and reuse. For example, our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. These operations are subject to regulation by both the City of Long Beach and CalGEM. We are currently in discussions with the City of Long Beach and CalGEM with respect to what injection well pressure gradient complies with CalGEM’s requirements for the protection of underground aquifers while at the same time mitigating subsidence risks. CalGEM’s local office has preliminarily indicated that the injection well pressure gradient should be reduced from the gradient that has been used for several decades. As part of our ongoing discussions, we and the City of Long Beach have provided CalGEM with technical information regarding how the historical injection well pressure gradient complies with CalGEM’s requirements and to inform them of the absence of risk of leakage and a plan to gradually lower the injection gradient over time in a manner that we believe would mitigate subsidence risks. If CalGEM were to ultimately disagree and determine to reduce the injection well pressure gradient other than in a gradual manner, and we were unable to reverse that decision on appeal or other legal challenge, we expect any material reduction in injection well pressure gradient for our operations in the Wilmington Oil Field would result in a decrease in production and reserves from the field.

Failure to comply 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 ability to timely obtain and maintain permits for our operations in 2023, including from CalGEM, has been subject to significant delays and uncertainties and is subject to factors that are not within our control. These factors include changes in agency practices, new regulations, or legal challenges to existing approvals for our operations from individual citizens and non-governmental organizations. For example, beginning in 2021, CalGEM ceased issuing new well stimulation permits. In 2023, CalGEM virtually ceased issuing permits for new wells, sidetracks, deepenings, and reworks throughout the state (though it recently resumed issuing permits for reworks, and has slowly been resuming the issuance of permits for sidetracks), even as it continues approving permits for plugging and abandonment. CalGEM communicated that permitting would resume (with the exception of permits for new wells in Kern County, the issuance of which has been stayed pending the final ruling of the Appellate Court) upon its development of standard operating procedures for reviewing permit applications and cited staffing shortages within its CEQA unit as an additional reason for the delays. See *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in which we Operate, Regulations of Exploration and Production Activities*.

We cannot guarantee that these issues or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. In the past we have generally been able to mitigate permitting risks by building up a reserve of drilling permits for use throughout the year, but as a result of the issues described above, we have not been able to build our reserve of approved permits to the same level as we have in the past. Changes to elected or appointed officials or their priorities and policies could result in different approaches to the regulation of the oil and natural gas industry. If we cannot obtain new drilling or sidetrack permits in a timely manner, we have limited options to meet our drilling plans, such as the use of workovers to extend the life of existing production, that may not ultimately be sufficient to achieve our business goals. Any continuing failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, operations, properties, results of operations, and our financial condition.

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 requirements 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.

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 CO_2 for geologic sequestration. Moreover, as 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. 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 CO_2 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. A unified permit application is to be adopted by January 1, 2025. We believe our Carbon TerraVault projects, for which the EPA has issued draft permits that are open to public notice and comment until March 20, 2024, 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 CO_2 that will need to comply with yet to be developed CO_2 pipeline safety regulations from the federal Pipeline and Hazardous Materials Safety Administration, which could take a number of years to effect. Delays in developing required pipeline safety regulations would delay projects requiring pipeline transportation of CO_2. The lack of compulsory unitization could also delay project timelines.

The unified permitting process contemplated by Senate Bill No. 905 will be optional for project applicants and is intended to simplify the permitting process for CCS projects. In the meantime, pursuant to this legislation we are permitted to proceed with our existing and future CCS Class VI permit applications with the EPA. This law also 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.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO_2 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.

Concerns about climate change and other air quality issues may prompt governmental action that could materially affect 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 materially affect 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 is expected to be applicable to the reported annual methane emissions of certain oil and natural gas facilities, above specified methane intensity thresholds, starting in 2024. 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 operations.

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. Additionally, in March 2022, the Securities and Exchange Commission (SEC) released a proposed rule that would establish a framework for the reporting of climate risks, targets and metrics. We cannot predict the final form and substance of the rule and its requirements. Relatedly, California has enacted new laws requiring additional disclosure with respect to certain climate-related risks and GHG emissions reduction claims. (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, California Climate Disclosures* for more information). Non-compliance with these new laws may result in the imposition of substantial 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.

The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the Inflation Reduction Act into law. The Inflation Reduction Act contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and CCS, amongst other provisions. In addition, the Inflation Reduction Act imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The Inflation Reduction Act amends the Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the

EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year thereafter. Calculation of the fee is based on certain thresholds established in the Inflation Reduction Act. However, compliance with the EPA's new methane rules (*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*) would exempt an otherwise covered facility from the requirement to pay the fee. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from fossil fuels towards lower- or zero-carbon emission alternatives. The methane charges and various incentives for clean energy industries could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently materially and adversely affect our business and results of operations.

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

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 financial condition, results of operations and cash flows. 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 or eliminates 45Q credits or tax credits for the production of clean hydrogen could have an adverse effect on our financial condition, results of operations and cash flows.

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.

Recent action by the State of California imposing additional 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 the state of California or increase our costs in connection with the same.

On October 7, 2023, the California Governor signed into law Assembly Bill 1167 (AB 1167), which imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in the state of 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 will be in an amount determined by the state to sufficiently cover plugging and abandonment costs, decommissioning, and site restoration, and AB 1167 prohibits the closing of any acquisition of 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. We are still assessing the impact of AB 1167. In addition, although AB 1167 has been signed into law, Governor Newsom has called for further legislative changes to these new requirements to mitigate against the potential risk of the implementation of AB 1167 ultimately increasing the number of orphaned idle or low-producing wells in California, although no such changes have yet been announced. We cannot predict what form these changes may ultimately take or if the legislature will act on the Governor's request. Implementation of this law may lead to the delay or additional costs with respect to acquisitions or dispositions, which could impact our ability to grow or explore new strategic areas – or exit others – within the state of California.

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*.**

In light of our strategic goals and the restrictions under our existing debt, we are evaluating options to replace our Senior Notes. 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 and limit our financial flexibility.

As of December 31, 2023, we had $545 million of total long-term debt, and additional borrowing capacity of $477 million under the Revolving Credit Facility (after taking into account $153 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 our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- require us to dedicate a portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities due to restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- limit our ability to pay dividends and repurchase shares;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses, or to refinance existing indebtedness;
- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- make us vulnerable to increases in interest rates as our indebtedness under the Revolving Credit Facility varies with prevailing interest rates.

Our ability to satisfy our obligations depends on our future operating performance and on economic, financial, competitive and other factors, many of which are beyond our control. Our business may not generate sufficient cash flow, and future financings may not be available to provide sufficient net proceeds, to meet these obligations or to successfully execute our business strategy.

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 flow could vary significantly from year to year due to the nature of our industry despite our commodity price risk-management activities. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. 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 not be able to maintain a level of cash flows from operating activities sufficient to permit us 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. Currently, our borrowing base is set at $1.2 billion and the availability under our Revolving Credit Facility is limited by the aggregate elected commitment amount of our lenders, which as of February 1, 2024 was set at $630 million.

A reduction in our borrowing base below the aggregate commitment amount of our lenders would materially and adversely affect our liquidity and may hinder our ability to execute on our business strategy.

Restrictive covenants in our Revolving Credit Facility and the indenture governing our Senior Notes may limit our financial and operating flexibility.

Both our Revolving Credit Facility and the indenture governing our Senior Notes contain certain restrictions, which may have adverse effects on our business, financial condition, cash flows or results of operations. These restrictions limit our ability to, among other things, (i) incur additional indebtedness; (ii) pay dividends or repurchase shares; (iii) sell properties; and (iv) 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 any of these restrictive 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, 2023, 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 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 $1.24 per share, payable to shareholders in quarterly increments of $0.31 per share of common stock, subject to board authorization and declaration each quarter. We recently increased the size of our share repurchase program by $250 million to $1.35 billion and extended the program through December 31, 2025. As of February 6, 2024 we had approximately $747 million of remaining authorized capacity. 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 decline for many reasons, some of which are 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 those referred to in this *Risk Factors* section could affect our stock price. These factors include, among other things, changes in our results of operations and financial condition; changes in commodity prices; changes in the national and global economic outlook; changes in applicable laws and regulations; variations in our capital plan; changes in financial estimates by securities analysts or ratings agencies; changes in market valuations of comparable companies; and additions or departures of key personnel.

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 sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2023, we had 68,693,885 outstanding shares of common stock and 4,182,521 shares of common stock issuable upon exercise of outstanding warrants. Upon the completion of the Aera Merger, we expect to issue 21,170,357 shares of common stock. 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 (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

There is an increased potential for short sales of our common stock due to the sales of shares issued upon exercise of warrants, which could materially affect the market price of the stock.

Downward pressure on the market price of our common stock that likely will result from sales of our common stock issued in connection with the exercise of warrants could encourage short sales of our common stock by market participants. Generally, short selling means selling a security, contract or commodity not owned by the seller. The seller is committed to eventually purchase the financial instrument previously sold. Short sales are used to capitalize on an expected decline in the security's price. Such sales of our common stock could have a tendency to depress the price of the stock, which could increase the potential for short sales.

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, 2023, four of our shareholders owned at least 5% each and collectively owned approximately 40% 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 to communicate, control and manage our operations, prepare our financial and reporting information, analyze and store data and communicate internally and with third parties, including our service providers and customers. Our cybersecurity program focuses on ensuring the protection of our information systems, computer networks, infrastructure, and industrial control systems.

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 Information Officer on cybersecurity risks at its 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 take a risk-based approach to assess, identify, and manage cybersecurity risks, including evaluating the likelihood of a cybersecurity incident as well as the impact it would have on our business, reputation, assets, health and safety of individuals and the environment. Our controls are based on the NIST Cybersecurity Framework (CSF). The effectiveness of our controls are evaluated periodically to determine residual risk levels and guide ongoing program improvement and cybersecurity project work. 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 establishing contractual protections including minimum security and breach notification requirements.

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.

Our Chief Information Officer has managerial responsibility for our cybersecurity risk program and is a member of our cybersecurity incident response team steering committee. Our Chief Information Officer has over 34 years of experience in information technology and cybersecurity, including leadership roles responsible for cybersecurity and data privacy for large publicly-traded and global companies. He graduated from Bellevue University with an M.S. in Computer Information Systems and an MBA.

As of the date of this report, we are not aware of any material 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 5 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 4 stockholders of record at January 31, 2024, 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 $1.24 per share of common stock, payable to stockholders in quarterly increments of $0.31 per share. This includes a recent amendment in November 2023 to our prior dividend policy that contemplated a total quarterly dividend of $0.2825 per share of common stock. Post closing of the Aera Merger, we expect to increase our quarterly dividend. 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 $1.35 billion of our common stock through December 31, 2025. This includes a recent increase of $250 million and extension approved by our Board of Directors on February 6, 2024. 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, Share Repurchase Program.* Our share repurchase activity for the year ended December 31, 2023 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[(a)]
January 1, 2023 - March 31, 2023	1,423,764	$ 41.25	1,423,764	$ —
April 1, 2023 - June 30, 2023	1,618,746	$ 39.12	1,618,746	—
July 1, 2023 - September 30, 2023	365,145	$ 54.75	365,145	—
October 1, 2023 - October 31, 2023	—	$ —	—	—
November 1, 2023 - November 30, 2023	—	$ —	—	—
December 1, 2023 - December 31, 2023	—	$ —	—	—
Total 2023	3,407,655	$ 41.69	3,407,655	$ —

(a) The remaining capacity for shares that may be acquired under our Share Repurchase Program was $497 million as of December 31, 2023 and $747 million as of February 6, 2024.

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, 2023. A description of our stock-based compensation plans can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 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	—	1,192,507
Equity compensation plan not approved by security holders(2)	3,149,598	—	5,920,463
Total	4,399,598		7,112,970

(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 either (i) achieving the specified 60-trading day volume weighted average prices for shares of our common stock or (ii) the 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. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 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 October 28, 2020, $100 was invested in our common stock and in each of the peer group companies' common stock weighted by their relative market capitalization, or invested on October 31, 2020 in an index, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

Our 2023 peer group consisted of Antero Resources Corporation; Berry Corporation; Callon Petroleum Company; 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; SM Energy Company; Southwestern Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

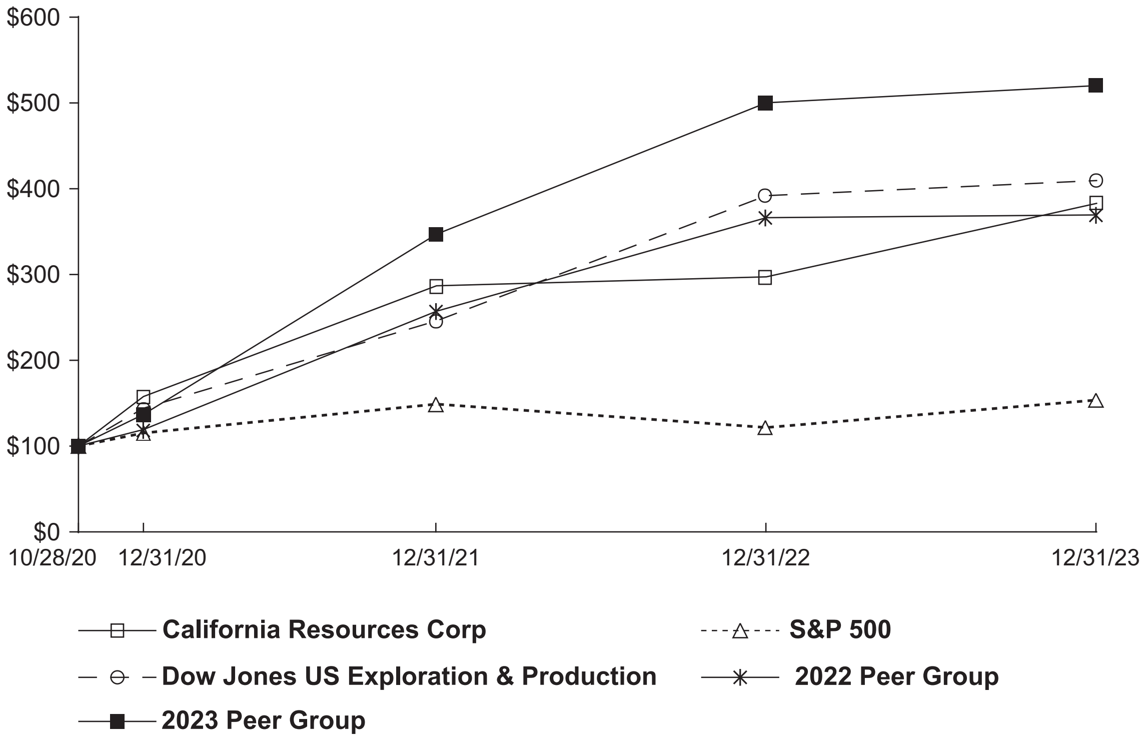
Our peer group changed from 2022. We added Civitas Resources, Inc. which is a newly formed company with similar market capitalization and operations. We also added Permian Resources Corporation to our peer group due to its similar market capitalization and operations. We removed Denbury Inc. and PDC Energy, Inc. from our peer group after they were acquired in 2023. We also removed Coterra Energy, Inc., which had a much larger market capitalization.

Our 2022 peer group consisted of Antero Resources Corporation; Berry Corporation; Callon Petroleum Company; Chord Energy Corporation; Comstock Resources Inc.; Coterra Energy Inc.; Crescent Energy Company; Denbury Inc.; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; PDC Energy, Inc.; Range Resources Corporation;

SM Energy Company; Southwestern Energy Company; Talos Energy Inc.; and Vermilion Energy Inc. Denbury Inc. and PDC Energy, Inc. have been excluded from the table below as they were acquired in 2023.

PERFORMANCE GRAPH*

Among California Resources Corp, the S&P 500 Index,
the Dow Jones US Exploration & Production Index,
2022 Peer Group and 2023 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.

	10/28/20	12/31/20	12/31/21	12/31/22	12/31/23
California Resources Corp	**$100.00**	**$157.27**	**$285.97**	**$296.45**	**$381.98**
S&P 500	**$100.00**	**$115.21**	**$148.28**	**$121.43**	**$153.35**
Dow Jones US Exploration & Production	**$100.00**	**$143.37**	**$245.05**	**$391.02**	**$408.69**
2022 Peer Group	**$100.00**	**$118.70**	**$256.53**	**$365.51**	**$368.66**
2023 Peer Group	**$100.00**	**$136.65**	**$346.08**	**$498.98**	**$518.83**

* 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 2022 Form 10-K for our analysis of the changes in our consolidated statements of operations and statements of cash flows for the year ended December 31, 2022 compared to December 31, 2021.

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 significant 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.

Pending Aera Merger

On February 7, 2024, we entered into a definitive agreement and plan of merger (Merger Agreement) to combine with Aera Energy, LLC (Aera) in an all-stock transaction (Aera Merger) with an effective date of January 1, 2024. Aera is a leading operator of mature fields in California, primarily in the San Joaquin and Ventura basins, with high oil-weighted production.

Pursuant to the Merger Agreement, we have agreed to issue 21,170,357 shares of common stock (subject to customary adjustments in the event of stock splits, dividend paid in stock and similar items) plus an additional number of shares determined by reference to the dividends declared by us having a record date between the effective date and closing as more fully described in the Merger Agreement. Under the terms of the Merger Agreement, we have also agreed to assume Aera's outstanding long-term indebtedness of $950 million at closing. We expect to repay a significant portion of this indebtedness with cash on hand and borrowings under our Revolving Credit Facility. We intend to refinance the balance through one or more debt capital markets transactions and, only to the extent necessary, borrowings under a bridge loan facility provided by Citigroup Global Markets, Inc. (the Bank). Under the terms of our debt commitment letter with the Bank, it has committed, subject to satisfaction of customary conditions, to provide us with an unsecured 364-day bridge loan facility in an aggregate principal amount of $500 million (Bridge Loan Facility).

Closing of the Aera Merger is subject to certain conditions, including, among others, approval of the stock issuance by our stockholders, expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, prior authorization by the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act and other customary closing conditions.

Upon completion of the transaction, we currently expect our existing stockholders to own approximately 77.1% of the combined company and the existing Aera owners to own approximately 22.9% of the combined company, on a fully diluted basis. The Aera Merger is expected to close in the second half of 2024. Post closing of the Aera Merger, and subject to Board approval, we expect to increase our quarterly dividend.

Production, Prices and Realizations

The following table sets forth our average net production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2023, 2022 and 2021:

	2023	2022	2021
Oil (MBbl/d)			
San Joaquin Basin	33	37	39
Los Angeles Basin	19	18	19
Ventura Basin	—	—	2
Total	52	55	60
NGLs (MBbl/d)			
San Joaquin Basin	11	11	13
Total	11	11	13
Natural gas (MMcf/d)			
San Joaquin Basin	119	129	135
Los Angeles Basin	1	1	1
Ventura Basin	—	—	4
Sacramento Basin	15	17	19
Total	135	147	159
Total Daily Net Production (MBoe/d)	86	91	100

The following table summarizes the changes to our total daily net production per day for the years ended December 31, 2023, 2022 and 2021:

	Year ended December 31, 2023	Year ended December 31, 2022	Year ended December 31, 2021
		(in MBoe/d)	
Beginning of the year	91	100	111
Divestitures[(a)]	—	(5)	(1)
Plant downtime[(b)]	—	(1)	—
Acquisitions[(a)]	—	1	1
PSC effect	1	—	(3)
Natural decline and other	(6)	(4)	(8)
Total change	(5)	(9)	(11)
End of the year	86	91	100

(a) See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information. Note that in 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) In the first quarter of 2022, we conducted routine maintenance at one of our gas processing facilities.

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. Global commodity prices decreased during 2023 compared to 2022 predominately as a result of growing inventories and decreased demand. 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:

	2023		2022		2021	
	Average Price	Realization	Average Price	Realization	Average Price	Realization
Oil ($ per Bbl)						
Brent	$ 82.22		$ 98.89		$ 70.79	
Realized price without derivative settlements	$ 80.41	98%	$ 98.26	99%	$ 70.43	99%
Effects of derivative settlements	(14.44)		(36.46)		(14.38)	
Realized price with derivative settlements	$ 65.97	80%	$ 61.80	62%	$ 56.05	79%
WTI	$ 77.62		$ 94.23		$ 67.91	
Realized price without derivative settlements	$ 80.41	104%	$ 98.26	104%	$ 70.43	104%
Realized price with derivative settlements	$ 65.97	85%	$ 61.80	66%	$ 56.05	83%
NGLs ($ per Bbl)						
Realized price[(a)]	$ 48.94	60%	$ 64.33	65%	$ 53.62	76%
Realized price[(b)]	$ 48.94	63%	$ 64.33	68%	$ 53.62	79%
Natural gas						
NYMEX ($/MMBTU) - Average Monthly Settled Price	$ 2.74		$ 6.64		$ 3.84	
Realized price without derivative settlements ($/Mcf)	$ 8.59	314%	$ 7.68	116%	$ 4.22	110%
Effects of derivative settlements	$ —		$ (0.14)		$ (0.02)	
Realized price with derivative settlements ($/Mcf)	$ 8.59	314%	$ 7.54	114%	$ 4.20	109%

(a) Calculated as a percentage of Brent.
(b) Calculated as a percentage of WTI.

Oil — Brent and realized prices excluding derivative settlements were lower for the year ended December 31, 2023 compared to 2022. The decrease was largely a result of reduced risk premiums associated with the conflict in Ukraine, Russian crude and refined products demonstrating that they could make it to market regardless of sanctions, and increasing production from OPEC producers, such as Iran and Venezuela, and non-OPEC producers including Brazil and the United States.

NGLs — Prices for NGLs decreased in the year ended December 31, 2023 compared to 2022 as prices for competing and complementary products (natural gas, crude oil) declined and as NGL production and inventories grew to near-record levels. For the year ended December 31, 2023, California continue to benefit from premium pricing for NGLs compared to other North American locations.

Natural Gas — California natural gas realized prices for the year ended December 31, 2023 averaged slightly above those for 2022 driven largely by price spikes during the first quarter of 2023 which exceeded the price spike experienced in the fourth quarter of 2022. For the balance of 2023, prices in California and nationally were generally weaker as storage inventories were restored and as North American natural gas production grew.

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 8 Divestitures and Acquisitions* and *Note 17 Subsequent Events* for more information on our transactions.

Carbon TerraVault Joint Venture

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our Carbon TerraVault JV.

Supply Chain and Inflation

We continued to experience relatively flat pricing from our suppliers in 2023 as compared to 2022. We have long term vendor relationships and have taken measures to limit the effects of inflation by entering into contracts for a significant majority of our materials and services with terms of one to three years. We have not experienced any meaningful inflation in connection with recent contract renewals. Overall, we continue to expect minimal inflation in our supply chain.

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 sell 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.

Income Taxes

All of our income is earned from domestic operations and is subject to tax in the United States. The following table sets forth our effective tax rate on income from continuing operations:

	Year ended December 31,		
	2023	**2022**	**2021**
U.S. federal statutory tax rate	21%	21%	21%
State income taxes, net	5	9	(81)
Exclusion of income attributable to noncontrolling interests	—	—	(1)
Changes in tax attributes	—	(2)	(8)
Executive compensation	1	—	2
Change in the U.S. federal valuation allowance	(2)	2	(106)
Other	—	1	—
Effective tax rate	25%	31%	(173)%

During the year ended December 31, 2023, we released a valuation allowance of $35 million for a portion of the tax loss on the sale of our Lost Hills assets after we jointly agreed to amend the original tax treatment with the buyer. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information on the Lost Hills transaction. This valuation allowance was initially recorded during the year ended December 31, 2022 for the realizability of a capital loss on the sale of Lost Hills, the deductibility of which was limited. During the year ended December 31, 2021, we released all of our valuation allowance recorded against our net deferred tax assets given our anticipated future earnings trend at that time.

During the years ended December 31, 2022 and 2021, we recognized a tax benefit for tax credits related to our oil and gas operations. The tax benefit of these credits is presented as changes in tax attributes in our effective tax rate reconciliations.

Management expects to realize the recorded deferred tax assets primarily 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 or three-years of cumulative income is no longer present. For additional information on tax-related items see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Income Taxes*.

Statement of Operations Analysis

Results of Oil and Natural Gas Operations

The following table includes key operating data for our oil and natural gas operations, excluding unallocated corporate expenses, on a per Boe basis for the years ended December 31, 2023, 2022 and 2021. 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.

	Year ended December 31,		
	2023	2022	2021
($ per Boe)			
Energy operating costs	$ 10.31	$ 9.76	$ 7.01
Gas processing costs	$ 0.58	$ 0.52	$ 0.54
Non-energy operating costs	$ 15.35	$ 13.47	$ 11.84
Operating costs	$ 26.24	$ 23.75	$ 19.39
Field general and administrative expenses(a)	$ 1.34	$ 1.09	$ 0.94
Field depreciation, depletion and amortization(b)	$ 6.61	$ 5.29	$ 5.23
Field taxes other than on income	$ 3.61	$ 3.36	$ 2.83
Field transportation expenses	$ 0.99	$ 0.85	$ 0.80

(a) Excludes unallocated general and administrative expenses.
(b) Excludes depreciation, depletion and amortization related to our corporate assets and Elk Hills power plant.

Energy operating costs were higher on a per Boe basis in 2023 compared to 2022 as a result of lower production volumes in 2023. Non-energy operating costs were higher in 2023 compared to 2022 on a per Boe basis due to higher compensation-related costs for field personnel and additional downhole maintenance activity in 2023.

Field depreciation, depletion and amortization increased in 2023 compared to the prior year primarily due to a change in our depreciation, depletion and amortization rates which are periodically adjusted to reflect an update of our SEC reserve estimates. Lower production volumes also contributed to the increase on a per Boe basis.

Field taxes other than on income were higher in 2023 on a per Boe basis due to lower production volumes in 2023.

Results of Operations

Reorganization

In 2023, we undertook initiatives to streamline our operations and implemented organizational changes. These actions were taken to better align our resources to our strategic priorities and improve operational efficiency. As a result, we recognized a severance charge of $10 million, included in other operating expenses, net on our consolidated statement of operations. In 2024, we expect to realize annualized savings of approximately $65 million, of which $50 million relates to operating costs, $10 million relates to general and administrative expenses, with the remainder reducing exploration expense and capital. Our results of operations for 2023 reflect partial savings achieved as actions were taken beginning in August 2023 and continuing into the fourth quarter.

Year Ended December 31, 2023 vs. 2022

The following table presents our total operating revenues:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Oil, natural gas and NGL sales	$ 2,155	$ 2,643
Net loss from commodity derivatives	(12)	(551)
Marketing of purchased natural gas	401	314
Electricity sales	211	261
Interest and other revenue	46	40
Total operating revenues	$ 2,801	$ 2,707

Oil, natural gas and NGL sales – Oil, natural gas and NGL sales, excluding the impact of payments on settled commodity derivatives, were $2,155 million for the year ended December 31, 2023, which is a decrease of $488 million, compared to $2,643 million for the year ended December 31, 2022. The decrease was primarily due to lower realized prices and lower production volumes for oil, as shown in the following table:

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2022	$ 1,968	$ 264	$ 411	$ 2,643
Changes in realized prices	(358)	(64)	49	(373)
Changes in production	(76)	(2)	(37)	(115)
Year ended December 31, 2023	$ 1,534	$ 198	$ 423	$ 2,155

Note: See *Production, Prices and Realizations* for volumes and realized prices by commodity type for each period.

The effect of cash settlements on our commodity derivative contracts is not included in oil, natural gas and NGL sales. Including the effect of net payments on settled commodity derivatives described below, our oil, natural gas and NGL sales decreased by $22 million in 2023 compared to the same prior year period.

Net loss from commodity derivatives – Net loss from commodity derivatives was $12 million for the year ended December 31, 2023 compared to a net loss of $551 million for the year ended December 31, 2022. The change primarily resulted from payments on settled commodity derivatives 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:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Non-cash commodity derivative gain	$ 260	$ 187
Settlements and amortized premiums	(272)	(738)
Net loss from commodity derivatives	$ (12)	$ (551)

Marketing of purchased natural gas – Marketing of purchased natural gas relates to natural gas acquired from third parties which is subsequently sold in connection with certain of our marketing activities. Marketing of purchased natural gas was $401 million during the year ended December 31, 2023, which is an increase of $87 million from $314 million during the same prior year period. The increase was primarily a result of higher prices for natural gas acquired for resale during 2023, which included unusually high prices in January 2023. As part of our marketing activities, we may purchase gas in producing areas and transport for sales to areas with higher pricing. Revenues from marketing purchased natural gas net of related purchased natural gas marketing expense increased $139 million from $180 million in 2023 compared to $41 million in 2022.

Electricity sales – Electricity sales decreased by $50 million to $211 million during the year ended December 31, 2023 compared to $261 million for the year ended December 31, 2022. The decrease was predominantly due to lower electricity prices in 2023.

The following table presents our consolidated operating expenses, non-operating expenses and income tax provision:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Operating expenses		
Energy operating costs	$ 323	$ 323
Gas processing costs	18	17
Non-energy operating costs	481	445
General and administrative expenses	267	222
Depreciation, depletion and amortization	225	198
Asset impairments	3	2
Taxes other than on income	165	162
Exploration expense	3	4
Purchased natural gas marketing expense	221	273
Electricity generation expenses	103	167
Transportation costs	67	50
Accretion expense	46	43
Carbon management business expenses	37	14
Other operating expenses, net	66	34
Total operating expenses	$ 2,025	$ 1,954
Net gain on asset divestitures	32	59
Operating income	808	812
Non-operating (expenses) income		
Interest and debt expense	(56)	(53)
Loss on early extinguishment of debt	(1)	—
Loss from investment in unconsolidated subsidiary	(9)	(1)
Other non-operating income, net	6	3
Income before income taxes	748	761
Income tax provision	(184)	(237)
Net income	$ 564	$ 524

Non-energy operating costs – Non-energy operating costs for the year ended December 31, 2023 were $481 million, which was an increase of $36 million from $445 million for the year ended December 31, 2022. The increase was primarily a result of higher compensation-related costs for field personnel as well as additional downhole and surface maintenance activity in 2023 as compared to 2022. These increases were partially offset by savings due to actions taken in August 2023 to align our workforce with our current activity level.

General and administrative expenses – General and administrative expenses were $267 million for the year ended December 31, 2023, which was an increase of $45 million from $222 million for the year ended December 31, 2022. The increase in G&A expenses was primarily attributable to compensation-related expenses (including stock-based compensation awards discussed further below) and higher spending to streamline our information technology infrastructure.

The table below shows the portion of total G&A expenses which are directly attributable to our carbon management business:

	Year ended December 31,	
	2023	2022
	(in millions)	
Exploration and production, corporate and other	$ 255	$ 210
Carbon management business	12	12
Total general and administrative expenses	$ 267	$ 222

Awards are granted under our stock-based compensation plans to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include performance stock units and restricted stock units that either cliff vest or vest ratably over a two- or three-year period. Grants of equity-settled awards in 2021 contemplated that no corresponding grants would be made in 2022. We resumed granting equity-settled awards in 2023. Our equity-settled awards granted to non-employee directors are restricted stock units that vest ratably over a three-year period. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduce volatility in our results of operations because we pay half of our cash-settled awards based on our stock price performance and we adjust our obligation for unvested cash-settled awards at the end of each reporting period. Equity-settled awards are not similarly adjusted for changes in our stock price.

Stock-based compensation included in G&A expense is shown in the table below:

	Year ended December 31,	
	2023	2022
	(in millions)	
Cash-settled awards	$ 13	$ 8
Stock-settled awards	27	18
Total included in general and administrative expenses	$ 40	$ 26

Depreciation, depletion and amortization – Depreciation, depletion and amortization increased $27 million to $225 million for the year ended December 31, 2023 from $198 million for the same prior year period. The increase was primarily the result of a change in our DD&A rates which are periodically adjusted to reflect an update of our SEC reserve estimates.

Purchased natural gas marketing expense – Purchased natural gas marketing expense was $221 million for the year ended December 31, 2023, which was a decrease of $52 million from $273 million for the year ended December 31, 2022 primarily due to lower natural gas prices partially offset by higher volumes.

Electricity generation expense – Electricity generation expenses decreased to $103 million for the year ended December 31, 2023 from $167 million for the year ended December 31, 2022. The decrease of $64 million was predominantly a result of lower prices for natural gas used in electricity generation.

Transportation costs – Transportation costs were $67 million for the year ended December 31, 2023 which was an increase of $17 million from $50 million for the prior year. The increase in transportation costs was predominately a result of higher rates for natural gas transportation capacity in 2023.

Carbon management business expenses – Carbon management business (CMB) expenses were $37 million for the year ended December 31, 2023 compared to $14 million for the year ended December 31, 2022. CMB expenses include lease cost for sequestration easements, advocacy, and other related costs. The increase in 2023 was predominately a result of higher costs for CO_2 injection easements and additional costs to evaluate certain projects.

Other operating expenses, net – Other operating expenses, net was $66 million for the year ended December 31, 2023, which was an increase of $32 million from $34 million for the year ended December 31, 2022. The increase was primarily a result of one-time costs, such as severance, that we incurred in connection with our reorganization in 2023.

Net gain on asset divestitures – Our net gain on asset divestitures for the year ended December 31, 2023 was $32 million primarily related the divestiture of our non-operated portion of the Round Mountain Unit. Net gain on asset divestitures for the year ended December 31, 2022 was $59 million primarily related to the sale of our 50% non-operated working interest in certain horizons within our Lost Hills field and certain Ventura basin assets. For more information on our asset divestitures, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions.*

Income tax provision – The income tax provision for the year ended December 31, 2023 was $184 million (effective tax rate of 25%) compared to $237 million (effective tax rate of 31%) for the year ended December 31, 2022. The income tax provision for 2022 included a provision for a valuation allowance recorded in the first quarter of 2022 at the time of our Lost Hills divestiture. This valuation allowance was released in the first quarter of 2023 after the Purchase and Sale Agreement was amended. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Income Taxes* for more information on a valuation allowance related to our Lost Hills divestiture.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity and capital resources are cash flows from our oil and gas operations, cash and cash equivalents on hand and available borrowing capacity under our Revolving Credit Facility which matures July 31, 2027. We generated additional cash flow of $32 million from divestitures of non-core assets during 2023. Our primary uses of operating cash flow for 2023 were for capital investments, repurchases of our outstanding debt and common stock and payment of dividends.

The following table summarizes our liquidity:

	December 31, 2023
	(in millions)
Cash and cash equivalents	$ 496
Revolving Credit Facility:	
Borrowing capacity	630
Outstanding letters of credit	(153)
Availability	$ 477
Liquidity	$ 973

As of December 31, 2023, we were in compliance with all of the covenants of our Revolving Credit Facility. For a description of the terms and conditions of our long-term debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt.*

Under the terms of the Merger Agreement, we are obligated to assume the Aera indebtedness at Closing. We have entered into a debt commitment letter with the Bank pursuant to which the Bank has committed, subject to satisfaction of customary conditions, to provide us with the Bridge Loan Facility. We currently intend to refinance the Aera indebtedness with cash on hand, borrowings under our revolving credit facility, through one or more debt capital markets transactions and, only to the extent necessary, borrowings under the Bridge Loan Facility. See *Part I, Item 1 and 2 – Business and Properties, Recent Developments – Pending Aera Merger* for more information on the Aera Merger and Bridge Loan Facility.

In connection with the Merger Agreement, on February 9, 2024, we entered into a second amendment to our Revolving Credit Facility to, among other things, permit us to incur indebtedness under the Bridge Loan Facility.

We are also currently in the process of seeking additional commitments from existing and new lenders to expand our borrowing capacity under the Revolving Credit Facility, as well as seeking an increase to our existing borrowing base of $1.2 billion. These changes would only become effective upon closing of the Aera Merger and there can be no assurances that we will be successful in these efforts.

At current commodity prices and based upon our planned 2024 capital program described below, we expect to generate operating cash flow to support and invest in our core assets and preserve financial flexibility. We regularly review our financial position and evaluate whether to (i) adjust our drilling program, (ii) return available cash to shareholders through dividends or stock buybacks to the extent permitted under our Revolving Credit Facility and Senior Notes indenture, (iii) repurchase outstanding indebtedness, (iv) advance carbon management activities, or (iv) maintain cash and cash equivalents on our balance sheet.

We believe we have sufficient sources of liquidity to meet our obligations for the next twelve months.

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, 2023.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Derivatives* for more information on our open derivative contracts as of December 31, 2023 and *Note 4 Debt* for more information on the hedging requirements included in our Revolving Credit Facility.

Dividend Policy

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. Post closing of the Aera Merger, and subject to Board approval, we expect to increase our fixed quarterly dividend.

On February 27, 2024, our Board of Directors declared a cash dividend of $0.31 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 6, 2024 and is expected to be paid on March 18, 2024.

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

	Total Dividend	Annual Rate Per Share
	(in millions)	($ per share)
Year ended December 31, 2021	$ 14	$ 0.17
Year ended December 31, 2022	59	$ 0.7925
Year ended December 31, 2023	81	$ 1.1575
	$ 154	

Share Repurchase Program

Our Board of Directors has authorized a Share Repurchase Program to acquire up to $1.35 billion of our common stock through December 31, 2025. This includes a recent increase of $250 million and extension approved by our Board of Directors on February 6, 2024. The repurchases may be affected 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. Shares repurchased are held as treasury stock.

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2021	4,089,988	$ 148	$ 36.08
Year ended December 31, 2022	7,366,272	$ 313	$ 42.47
Year ended December 31, 2023	3,407,655	$ 143	$ 41.69
Inception of Program (May 2021) through December 31, 2023	14,863,915	$ 604	$ 40.53

Note: The total value of shares purchased includes approximately $1 million related to excise taxes on share repurchases, which was effective beginning in 2023. Commissions paid were not significant in all periods presented.

Uses of Cash

2024 Capital Program

We expect our total 2024 capital program to range between $300 million and $340 million assuming normal operating conditions and excluding any additional capital which could result from the Aera Merger. Of this amount, $250 million to $260 million is related to oil and natural gas development, $30 million to $40 million is related to maintenance of one of our gas processing facilities and a power plant, both of which are located in our Elk Hills field, $15 million to $25 million is for carbon management projects and $5 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 3 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on our joint venture with Brookfield.

With respect to oil and natural gas development, we expect to run a one rig program executing projects using existing permits through 2024. Subject to the availability of well permits, we expect to increase to a four rig program in the second half of 2024. The actual amount of spending related to oil and gas development under our 2024 capital program will depend on a variety of factors. In particular, the rate and amount of this spending depends on our ability to obtain new well permits in the second half of the year. If we are not able to obtain these permits, we could reduce our capital program by up to $100 million. For more information on permitting, refer to *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

Our 2024 capital for carbon management projects includes approximately $5 million for the installation of carbon capture equipment at one of our gas processing facilities located at our Elk Hills field. We expect the total capital investment for this project will range between $15 million to $20 million and work will be completed in 2025. 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 Business*.

Other Uses of Cash

Other than our 2024 capital program, our expected material uses of cash during 2024 include: (1) dividends, share repurchases and payroll taxes on equity-settled compensation awards; (2) settlements on commodity derivative contracts; (3) income taxes; (4) settlement of asset retirement obligations; (5) operating expenses; (6) costs related to advancing our carbon management activities not included in our capital program, such as employee costs and engineering studies; (7) transaction costs related to the Aera merger, including advisory, legal and other third-party fees and (8) to the extent necessary, repayment of Aera indebtedness.

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

- repayment of principal and interest on our Senior Notes (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt*)
- operating lease liabilities including our drilling rigs, commercial office space, fleet vehicles, easements and certain facilities (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 12 Leases)*
- obligations associated with our defined benefit and post-employment benefit plans (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 13 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*)
- a contingent liability for put and call features related to Brookfield's initial investment in the Carbon TerraVault JV (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Investment in Unconsolidated Subsidiary and Related Party Transactions)*

We also 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 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, 2023.

	One Year or Less	More Than One Year	Total
		(in millions)	
Oil and gas leases, surface easements and pipeline right-of-way[(a)]	$ 1	$ 4	$ 5
Oil and gas transportation, throughput and storage arrangements[(b)]	51	97	148
Software licenses and other contracts	24	47	71
Total	$ 76	$ 148	$ 224

(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.

Our operating cash flow for the year ended December 31, 2023 was $653 million, which was a decrease of $37 million, or 5%, from $690 million for the year ended December 31, 2022. The decrease was largely driven by lower revenue from sales of the commodities we produce. Our production volume decreased by 5 MBoe per day, or 5%, from 91 MMBoe/d in 2022 to 86 MMBoe/d in 2023 predominantly as a result of natural decline. Additionally, average realized Brent prices decreased by $17.85 per barrel from $98.26 per barrel in 2022 to $80.41 per barrel in 2023. We earned a higher margin on our marketing activities in 2023 as compared to the same prior year period. For more information on our production and price changes, see *Production and Price* above.

Settlement payments from derivative contracts decreased $466 million from $738 million in 2022 to $272 million in 2023. Shortly after emergence from bankruptcy in 2020, we entered into derivative positions through September 2023 to meet the requirements of our Revolving Credit Facility at that time during a low commodity price environment. The percentage of our production that we were required to hedge was lower in 2023 as compared to 2022. The tenor of these derivative positions ended in the third quarter of 2023 which, along with lower Brent prices between comparative periods, resulted in a decrease in settlement payments in 2023 as compared to 2022. For more information on our existing hedges see, *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Derivatives.*

Cash paid for income taxes in 2023 was $121 million compared to $20 million in 2022. Our U.S. federal taxable income increased in 2023 primarily due to the use of remaining net operating loss and tax credit carryforwards available to us along with realizing tax losses on asset divestitures in 2022. Additionally, our capital program was lower in 2023 as compared to 2022 which, along with the phase out of bonus depreciation, also contributed to the increase. We continue to pay minimum taxes in California.

Operating costs and general and administrative expenses increased in 2023 as compared to 2022 primarily due to higher compensation related costs and additional downhole maintenance activity. In August 2023, we took actions to better align our resources to strategic priorities and improve operational efficiency. We realized approximately $15 million of savings in 2023 and expect these actions to result in approximately $65 million of savings in operating and overhead costs on an annualized basis.

Cash flows from investing activities – The table below summarizes net cash used in investing activities:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Capital investments	$ (185)	$ (379)
Changes in capital accruals	(13)	1
Proceeds from divestitures	32	80
Acquisitions	(5)	(17)
Distributions related to the Carbon TerraVault JV	—	12
Capitalized joint venture transaction costs	—	(12)
Other	(4)	(2)
Net cash used in investing activities	$ (175)	$ (317)

The decrease in cash used in investing activities primarily relates to a lower capital program in 2023 as compared to 2022. In the first quarter of 2023, we reduced our capital program to one rig to align with available permits. In comparison, we averaged 4 drilling rigs in 2022. Proceeds from asset divestitures for the year ended December 31, 2023 included the sale of our non-operated interest in the Round Mountain Unit. Proceeds from divestitures for the year ended December 31, 2022 included the sale of our 50% non-operated working interest in certain horizons within our Lost Hills field, certain of our Ventura basin assets and our commercial office building in Bakersfield, California. In each of the years ended December 31, 2023 and 2022, the acquisitions shown in the table above related to purchasing storage reservoirs for our carbon management business. *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Divestitures and Acquisitions* for more information on our divestitures and acquisitions.

Cash flows from financing activities – The table below summarizes net cash used by financing activities:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Repurchases of common stock	$ (143)	$ (313)
Issuance of common stock	2	1
Common stock dividends	(81)	(59)
Debt repurchases	(56)	—
Debt financing costs	(8)	—
Shares cancelled for taxes	(3)	—
Net cash used by financing activities	$ (289)	$ (371)

Cash used for repurchases of our common stock under our Share Repurchase Program decreased in 2023 as compared to 2022 in part due to adding optionality to repurchase long-term debt. Additionally, our Board of Directors increased the quarterly dividend rate on our common stock during 2023. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stockholders' Equity* for more information on our Share Repurchase Program and cash dividends and *Note 4 Debt* for more information on repurchases of our Senior Notes.

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, 2023 and 2022 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 now appealing the order from BSEE. We expect to enter into a cost sharing agreement with former lessees in the first half of 2024, and expect to pay $12 million to $15 million for our share of the maintenance costs at that time. We will share in on-going maintenance costs during the pendency of the challenge to the BSEE order.

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 5 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	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. 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. The estimated amount of proved reserve volumes are 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.	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. Several other factors could change our proved oil and gas reserves including changes in energy costs, inflation, deflation and the political and regulatory environment, all of which are beyond our control.	Our total proved reserves were 377 MMBoe and our total proved developed reserves were 331 MMBoe at December 31, 2023. We estimate our 2024 depletion rate for oil and natural gas producing properties using the unit-of-production method will be approximately $6/Boe. A 5% change in our reserves would increase or decrease this DD&A rate by approximately $0.30/Boe. If realized prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2023 would have increased by 6 MMBoe or decreased by 8 MMBoe, respectively.

Title	Description	Estimation and Uncertainties	Sensitivities
Asset Retirement Obligations	The majority of our asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells. We determine our asset retirement obligation for wells by calculating the present value of estimated future cash outflows related to the abandonment obligation. The asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. 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.	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.	As of December 31, 2023 and 2022, we had asset retirement obligations of $521 million and $491 million, respectively, excluding liabilities associated with assets held for sale. A 1% increase in the inflation rate would increase our liability by $37 million and a 1% decrease in the inflation rate would decrease our liability by $40 million as of December 31, 2023.

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;
- 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, Ukraine and Yemen and the Red Sea;
- the ability to successfully integrate the business of Aera once the Aera merger is completed;
- the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the Aera merger that could reduce anticipated benefits or cause the parties to abandon the Aera merger;
- the occurrence of any event, change or other circumstances that could give rise to the termination of the Merger Agreement;
- the possibility that the stockholders of CRC may not approve the issuance of new shares of common stock in the Aera merger;
- the ability to obtain the required debt financing pursuant to our commitment letters and, if obtained, the potential impact of additional debt on our business and the financial impacts and restrictions due to the additional debt;
- 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, permits and approvals necessary for drilling or development activities or our carbon management business; (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;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and our capital plan;
- 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 and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and our ability to convert our CDMAs to definitive agreements and enter into other offtake agreements;
- our ability to maximize the value of our carbon management business and operate it on a stand alone basis;
- 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 business;
- 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; 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 the volume changes under PSCs. We maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of crude oil 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, 2023, we had hedges on approximately 75% of our anticipated oil production through 2024 and approximately 45% through 2025, which are in line with the covenants of our Revolving Credit Facility.

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, 2023, we had net assets of $17 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 $29 million in 2024, limiting our upside. We estimate that a $10 decrease in Brent oil forward prices could decrease our settlement payments by $36 million in 2024, negating the downside price movement for hedged volumes.

A summary of our Brent-based crude oil derivative contracts at December 31, 2023 are included in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 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 60% of our production during 2023 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 allows 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. All of our counterparties in the hedging program have an investment grade credit rating. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

Interest-Rate Risk

We had no variable-rate debt outstanding as of December 31, 2023.

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, 2023 and December 31, 2022, 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, 2023, and the related notes and financial statement schedule II (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2023, 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, 2023 and December 31, 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, 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, 2023 based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 a critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $225 million for the year ended December 31, 2023. 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 inclusive of market differentials. The Company employs technical personnel, 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. Complex 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, future commodity prices inclusive of market differentials, 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 reservoir engineers, as well as the independent reservoir engineering specialists and external engineering firm, (2) the knowledge, skills, and ability of the Company’s internal and independent reservoir engineers, and (3) the relationship of the independent reservoir engineering specialist and external engineering firm to the Company. We assessed the methodology used by the technical personnel employed by the Company 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 compared the commodity prices used by the Company’s internal technical personnel to publicly available prices and recalculated the relevant market differentials based on actual price realizations. We read and considered the reports of the independent reservoir engineering specialist in connect with our evaluation of the Company’s proved oil and gas reserves estimates.

/s/ KPMG LLP

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

Los Angeles, California
February 28, 2024

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2023 and 2022
(in millions, except share data)

	2023	2022
CURRENT ASSETS		
Cash and cash equivalents	$ 496	$ 307
Trade receivables	216	326
Inventories	72	60
Assets held for sale	13	5
Receivable from affiliate	19	33
Other current assets, net	113	133
Total current assets	929	864
PROPERTY, PLANT AND EQUIPMENT	3,437	3,228
Accumulated depreciation, depletion and amortization	(667)	(442)
Total property, plant and equipment, net	2,770	2,786
INVESTMENT IN UNCONSOLIDATED SUBSIDIARY	19	13
DEFERRED TAX ASSETS	132	164
OTHER NONCURRENT ASSETS	148	140
TOTAL ASSETS	$ 3,998	$ 3,967
CURRENT LIABILITIES		
Accounts payable	245	345
Liabilities associated with assets held for sale	5	5
Fair value of derivative contracts	8	246
Accrued liabilities	358	298
Total current liabilities	616	894
NONCURRENT LIABILITIES		
Long-term debt, net	540	592
Asset retirement obligations	422	432
Other long-term liabilities	201	185
STOCKHOLDERS' EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2023 or 2022	—	—
Common stock (200 million shares authorized at $0.01 par value); (83,557,800 and 83,406,002 shares issued; 68,693,885 and 71,949,742 shares outstanding at December 31, 2023 and 2022, respectively)	1	1
Treasury stock (14,863,915 shares held at cost at December 31, 2023 and 11,456,260 shares held at December 31, 2022)	(604)	(461)
Additional paid-in capital	1,329	1,305
Retained earnings	1,419	938
Accumulated other comprehensive income	74	81
Total stockholders' equity	2,219	1,864
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,998	$ 3,967

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, 2023, 2022 and 2021
(in millions, except per share data)

	Year ended December 31,		
	2023	**2022**	**2021**
REVENUES			
Oil, natural gas and NGL sales	$ 2,155	$ 2,643	$ 2,048
Net loss from commodity derivatives	(12)	(551)	(676)
Marketing of purchased natural gas	401	314	312
Electricity sales	211	261	172
Interest and other revenue	46	40	33
Total operating revenues	2,801	2,707	1,889
OPERATING EXPENSES			
Operating costs	822	785	705
General and administrative expenses	267	222	200
Depreciation, depletion and amortization	225	198	213
Asset impairments	3	2	28
Taxes other than on income	165	162	145
Exploration expense	3	4	7
Purchased natural gas marketing expense	221	273	196
Electricity generation expenses	103	167	96
Transportation costs	67	50	51
Accretion expense	46	43	50
Carbon management business expenses	37	14	—
Other operating expenses, net	66	34	29
Total operating expenses	2,025	1,954	1,720
Net gain on asset divestitures	32	59	124
OPERATING INCOME	808	812	293
NON-OPERATING (EXPENSES) INCOME			
Reorganization items, net	—	—	(6)
Interest and debt expense	(56)	(53)	(54)
Loss on early extinguishment of debt	(1)	—	(2)
Loss from investment in unconsolidated subsidiary	(9)	(1)	—
Other non-operating income (expenses), net	6	3	(2)
INCOME BEFORE INCOME TAXES	748	761	229
Income tax (provision) benefit	(184)	(237)	396
NET INCOME	564	524	625
Net income attributable to noncontrolling interest	—	—	(13)
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 564	$ 524	$ 612
Net income attributable to common stock per share			
Basic	$ 8.10	$ 6.94	$ 7.46
Diluted	$ 7.78	$ 6.75	$ 7.37
Weighted-average common shares outstanding			
Basic	69.6	75.5	82.0
Diluted	72.5	77.6	83.0

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, 2023, 2022 and 2021
(in millions)

	Year ended December 31,		
	2023	2022	2021
Net income	$ 564	$ 524	$ 625
Net income attributable to noncontrolling interest	—	—	(13)
Other comprehensive income (loss):			
Actuarial (loss) gain associated with pension and postretirement plans[(a)(b)]	(1)	13	16
Prior service credit[(b)]	—	—	65
Recognition of prior service credit due to curtailment[(c)]	(2)	—	—
Amortization of prior service credit[(b)(d)]	(4)	(4)	(1)
Total other comprehensive (loss) income	(7)	9	80
Comprehensive income attributable to common stock	$ 557	$ 533	$ 692

(a) Net of tax benefit of $1 million in 2023 and expense $5 million in 2022.
(b) There were no tax effects in 2021.
(c) Net of tax benefit of $1 million in 2023.
(d) Net of tax benefit of a $1 million in both 2023 and 2022.

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, 2023, 2022 and 2021
(in millions)

	Common Stock	Treasury Stock	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, December 31, 2020	$ 1	$ —	$ 1,268	$ (123)	$ (8)	$ 1,138	$ 44	$ 1,182
Net income	—	—	—	612	—	612	13	625
Distributions to noncontrolling interest holder	—	—	—	—	—	—	(50)	(50)
Cash dividends ($0.17 per share)	—	—	—	(14)	—	(14)	—	(14)
Redemption of noncontrolling interest	—	—	7	—	—	7	(7)	—
Share-based compensation	—	—	13	—	—	13	—	13
Repurchases of common stock	—	(148)	—	—	—	(148)	—	(148)
Issuance of common stock	—	—	2	—	—	2	—	2
Other	—	—	(2)	—	—	(2)	—	(2)
Other comprehensive income	—	—	—	—	80	80	—	80
Balance, December 31, 2021	$ 1	$ (148)	$ 1,288	$ 475	$ 72	$ 1,688	$ —	$ 1,688
Net income	—	—	—	524	—	524	—	524
Cash dividends ($0.7925 per share)	—	—	—	(61)	—	(61)	—	(61)
Share-based compensation	—	—	19	—	—	19	—	19
Repurchases of common stock	—	(313)	—	—	—	(313)	—	(313)
Other	—	—	(2)	—	—	(2)	—	(2)
Other comprehensive income, net of tax	—	—	—	—	9	9	—	9
Balance, December 31, 2022	$ 1	$ (461)	$ 1,305	$ 938	$ 81	$ 1,864	$ —	$ 1,864
Net income	—	—	—	564	—	564	$ —	564
Cash dividends ($1.1575 per share)	—	—	—	(83)	—	(83)	$ —	(83)
Share-based compensation	—	—	28	—	—	28	$ —	28
Repurchases of common stock	—	(143)	—	—	—	(143)	$ —	(143)
Shares cancelled for taxes	—	—	(3)	—	—	(3)	$ —	(3)
Other	—	—	(1)	—	—	(1)	$ —	(1)
Other comprehensive income, net of tax	—	—	—	—	(7)	(7)	$ —	(7)
Balance, December 31, 2023	$ 1	$ (604)	$ 1,329	$ 1,419	$ 74	$ 2,219	$ —	$ 2,219

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, 2023, 2022 and 2021
(in millions)

	Year ended December 31,		
	2023	2022	2021
CASH FLOW FROM OPERATING ACTIVITIES			
Net income	$ 564	$ 524	$ 625
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	225	198	213
Deferred income tax provision (benefit)	35	226	(396)
Asset impairments	3	2	28
Net loss from commodity derivatives	20	551	676
Settlement payments from commodity derivatives	(272)	(738)	(319)
Loss on early extinguishment of debt	1	—	2
Net gain on asset divestitures	(32)	(59)	(124)
Other non-cash charges to income, net	103	43	62
Changes in operating assets and liabilities, net:			
Decrease (increase) in trade receivables	110	(81)	(68)
(Increase) in inventories	(12)	—	—
Decrease (increase) in other current assets, net	—	35	(47)
(Decrease) increase in accounts payable and accrued liabilities	(92)	(11)	8
Net cash provided by operating activities	653	690	660
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(185)	(379)	(194)
Changes in accrued capital investments	(13)	1	20
Proceeds from asset divestitures	32	80	67
Acquisitions	(5)	(17)	(52)
Distribution related to the Carbon TerraVault JV	—	12	—
Capitalized joint venture transaction costs	—	(12)	—
Other	(4)	(2)	(2)
Net cash used in investing activities	(175)	(317)	(161)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from Revolving Credit Facility	—	—	16
Repayments of Revolving Credit Facility	—	—	(115)
Proceeds from Senior Notes	—	—	600
Debt repurchases	(56)	—	—
Debt financing costs	(8)	—	(13)
Repayment of Second Lien Term Loan	—	—	(200)
Repayment of EHP Notes	—	—	(300)
Distributions to noncontrolling interest holders	—	—	(50)
Repurchases of common stock	(143)	(313)	(148)
Common stock dividends	(81)	(59)	(14)
Issuance of common stock	2	1	2
Shares cancelled for taxes and other	(3)	—	—
Net cash (used) provided by financing activities	(289)	(371)	(222)
Increase in cash	189	2	277
Cash and cash equivalents—beginning of period	307	305	28
Cash and cash equivalents—end of period	$ 496	$ 307	$ 305

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

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

Nature of Business

We are an independent oil and natural gas exploration and production and carbon management company operating properties exclusively within California. We are committed to energy transition and have some of the lowest carbon intensity production in the United States. We are in the early stages of permitting several carbon capture and storage projects in California. Our carbon management business, which we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and storage facilities in California. In December 2023, the U.S. Environmental Protection Agency released draft Class VI permits for a carbon storage project held by a joint venture we entered into with BGTF Sierra Aggregator LLC (Brookfield) to pursue carbon management and storage activities (Carbon TerraVault JV). See *Note 3 Investments and Related Party Transactions* for more information on the Carbon TerraVault JV.

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 subsidiaries.

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 significant 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.

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

Our revenue, profitability and future growth or our oil and natural gas operations are substantially dependent upon prevailing and future prices for oil and natural gas, which can be volatile and dependent on factors beyond our control including global production inventories, available storage and transportation capacities, government regulation, the military conflicts in Ukraine and Israel, instability in the Middle East and economic conditions. We are in the early stages of developing a carbon capture and sequestration business which is subject to risks as an emerging industry. We operate exclusively 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. In light of the ongoing energy deficit in California and strong demand for native crude oil production, 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, 2023, three California refineries each accounted for at least 10%, and collectively 44%, of our sales (before the effects of hedging). For the year ended December 31, 2022, three California refineries each accounted for at least 10%, and collectively accounted for 52%, of our sales (before the effects of hedging). For the year ended December 31, 2021, three California refineries each accounted for at least 10%, and collectively accounted for 51%, of our sales (before the effects of hedging).

Recently Issued but not Adopted Accounting and Disclosure Changes

In December 2023, the Financial Accounting Standards Board's (FASB) issued new disclosure requirements for *Income Taxes* (ASC 740). The rule is effective for fiscal years beginning after December 15, 2024, but early adoption is permitted. This rule is to be applied on a prospective basis, but a retrospective application is permitted. We do not expect the adoption of these rules to have a significant impact on our financial statements.

In November 2023, the FASB issued new segment disclosure requirements primarily to enhance disclosure of significant segment expenses. These new segment disclosure requirements will apply to us. The rules are effective for fiscal years beginning after December 15, 2023 and interim periods beginning on January 1, 2025, early adoption is permitted. The disclosure requirements will be applied retrospectively to all prior periods included in the financial statements. We do not expect the adoption of these rules to have a significant impact on our financial statements.

Significant Accounting Policies

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. These assumptions include estimates of future product prices, which we base on forward price curves and, when applicable, contractual prices, estimates of oil and natural gas reserves and estimates of future expected operating and development costs. 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 rate 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 depreciated 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 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.

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 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.

The carrying amounts of cash and other on-balance sheet financial instruments, other than fixed-rate debt, approximate fair value.

Revenue Recognition

We derive substantially all of our revenue from sales of oil, natural gas and NGLs and associated hedging activities, with the remaining revenue generated from sales of electricity and trading 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 14 Revenue* for more information on our revenue from contracts with customers.

Joint Ventures and Investments in Unconsolidated Subsidiaries

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 3 Investment in Unconsolidated Subsidiary and Related Party Transactions* for more information on the Carbon TerraVault JV. 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.

Inventories

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

	2023	2022
	(in millions)	
Materials and supplies	$ 68	$ 56
Finished goods	4	4
Total	$ 72	$ 60

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.

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 9 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 presents a rollforward of our ARO.

(in millions)	Year ended December 31, 2023	Year ended December 31, 2022
Beginning balance	$ 491	$ 489
Liabilities settled and divested	(60)	(57)
Accretion expense on discounted obligation	46	43
Revisions of estimated obligation	37	15
Additions	7	6
Other	—	(5)
Ending balance	$ 521	$ 491
Current portion (included in accrued liabilities)	$ 99	$ 59
Non-current portion	$ 422	$ 432

Note: The table excludes $5 million related to asset retirement obligations associated with assets held for sale.

Our liabilities settled and divested in 2023 of $60 million, included $51 million for settlement payments and $9 million of liabilities assumed related to our sale of our non-operated working interest in the Round Mountain Unit and a non-producing asset. Revisions of our estimated obligation increased $37 million, which reflected changes in the timing of settlement.

During 2022, our total asset retirement obligation increased by $2 million from 2021. Our liabilities settled and divested in 2022 of $57 million, included $40 million for settlement payments and $17 million of liabilities assumed related to our Lost Hills divestiture. Revisions of our estimated obligation increased $15 million, which reflect higher anticipated future abandonment costs, including inflation, and changes in the timing of settlement.

See *Note 8 Divestitures and Acquisitions* for more information on our sold properties and our liabilities reclassified as held for sale.

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 our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production 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 18% and 16% of our total production for the years ended December 31, 2023 and 2022, 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 employees participate in postretirement benefit plans we sponsor. These plans are primarily funded as benefits are paid. In addition, a small number 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. The majority of our leases are for commercial office space, fleet vehicles, drilling rigs, easements and facilities. 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 have not been retired and are displayed separately as treasury stock on our consolidated balance sheet.

Assets Held for Sale

We may market certain non-core oil and natural gas assets or other properties for sale. At the end of each reporting period, we evaluate if these assets should be classified as held for sale. The held for sale criteria includes the following: management commitment to a plan to sell, the asset is available for immediate sale, an active program to locate a buyer exists, the sale of the asset is probable and expected to be completed within one year, the asset is being actively marketed for sale and it is unlikely that significant changes will be made to the plan. If all of these criteria are met, the asset is presented as held for sale on our consolidated balance sheet and measured at the lower of the carrying amount or estimated fair vale less costs to sell. DD&A expense is not recorded on assets once classified as held for sale.

The assets classified as held for sale at December 31, 2023 include the remaining assets and the associated asset retirement obligations in the Ventura basin and properties acquired for our carbon management activities. See *Note 8 Divestitures and Acquisitions* for more information.

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

We capitalize the costs incurred to acquire or develop our oil and natural gas assets, including ARO and interest. For asset acquisitions, purchase price, including liabilities assumed, is allocated to acquired assets based on relative fair values at the acquisition date. We evaluate long-lived assets on a quarterly basis for possible impairment.

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

	December 31, 2023	December 31, 2022
	(in millions)	
Proved oil and natural gas properties	$ 3,156	$ 2,972
Unproved oil and natural gas properties	1	2
Facilities and other	280	254
Total property, plant and equipment	3,437	3,228
Accumulated depreciation, depletion and amortization	(667)	(442)
Total property, plant and equipment, net	$ 2,770	$ 2,786

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

	Year ended December 31,		
(in millions)	2023	2022	2021
Beginning balance	$ 1	$ 1	$ 3
Charged to expense	—	—	(2)
Ending balance	$ 1	$ 1	$ 1

There are not significant exploratory well costs in the periods presented that have been capitalized for a period greater than one year after the completion of drilling. Our capitalized exploratory well costs at December 31, 2023 are for wells that we intend to drill.

Asset Impairments

In 2023, we recognized an impairment of $3 million related to properties acquired for our carbon management activities. The fair value, using Level 3 inputs in the fair value hierarchy, declined during the first quarter of 2023 due to market conditions (including inflation and rising interest rates).

We recognized an asset impairment of $2 million for the year ended December 31, 2022 related to a write-down of CRC Plaza, a commercial office building located in Bakersfield, California to fair value. In 2022, we sold CRC Plaza for $13 million. See *Note 8 Divestitures and Acquisitions* for further information regarding the sale of CRC Plaza.

Asset impairments were $28 million for the year ended December 31, 2021, including $25 million related to the write-down of CRC Plaza to fair value and a $3 million write-off of capitalized costs related to projects which were abandoned. We valued our commercial office building based on a market approach (using Level 3 inputs in the fair value hierarchy). The decline in commercial demand for office space of this size and type in that market at each assessment resulted in an impairment.

NOTE 3 INVESTMENT IN UNCONSOLIDATED SUBSIDIARY AND RELATED PARTY TRANSACTIONS

In August 2022, our wholly-owned subsidiary Carbon TerraVault I, LLC 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. We determined that the Carbon TerraVault JV is a 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. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for more information on the VIE consolidation model.

Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through the Carbon TerraVault JV. As part of the formation of the Carbon TerraVault JV, we contributed rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage (26R reservoir) and Brookfield committed to make an initial investment of $137 million, payable in three installments with the last two installments subject to the achievement of certain milestones. The final installment will be sized based on permitted storage capacity.

Brookfield contributed the first $46 million installment of their initial investment to the Carbon TerraVault JV in 2022. This amount may, at our sole discretion, be distributed to us or used to satisfy our share of future capital contributions, among other items. 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 sheet. The contingent liability was $52 million and $48 million at December 31, 2023 and 2022, respectively, inclusive of accrued interest.

The tables below present the summarized financial information related to our equity method investment and related party transactions for the periods presented.

	December 31, 2023	December 31, 2022
	(in millions)	
Investment in unconsolidated subsidiary[(a)]	$ 19	$ 13
Receivable from affiliate[(b)]	$ 19	$ 33
Property, plant and equipment[(c)]	$ 6	$ —
Contingent liability (related to Carbon TerraVault JV put and call rights)	$ 52	$ 48

(a) Reflects our investment less losses allocated to us of $9 million and $1 million for the year ended December 31, 2023 and 2022, respectively.

(b) The contribution of the injection rights at the Carbon TerraVault JV formation was accounted for as a financing activity. The amount of Brookfield's initial contribution available to us and amounts due to us under the MSA are reported as receivable from affiliate. At December 31, 2023, the amount of $19 million includes $17 million remaining of Brookfield's initial contribution available to us and $2 million related to the MSA and vendor reimbursements. At December 31, 2022, the amount of $33 million includes $32 million remaining of Brookfield's initial contribution available to us and $1 million related to the MSA and vendor reimbursements.

(c) This amount includes the reimbursement to us for plugging and abandonment activities at the 26R reservoir, which is recorded as a reduction to the net book value of our proved oil and gas properties.

	Year Ended December 31,	
	2023	2022
	(in millions)	
Loss from investment in unconsolidated subsidiary	$ 9	$ 1
General and administrative expenses[a]	$ 8	$ —

(a) General and administrative expenses on our condensed consolidated statement of operations are net of this amount invoiced by us under the MSA for back-office operational and commercial services.

The underlying net assets of the Carbon TerraVault JV were $310 million and $314 million as of December 31, 2023 and 2022, respectively, which includes cash on hand and PP&E, net of current liabilities. The difference between the carrying value of our investment of $19 million and $13 million at December 31, 2023 and 2022, 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.

The Carbon TerraVault JV has an option to participate in certain projects that involve the capture, transportation and storage of CO_2 in California. This option expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by 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).

We entered into 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.

NOTE 4 DEBT

As of December 31, 2023 and 2022, our long-term debt consisted of the following:

	2023	2022	Interest Rate	Maturity
	(in millions)			
Revolving Credit Facility	$ —	$ —	SOFR plus 2.50%-3.50% ABR plus 1.50%-2.50%[a]	July 31, 2027[b]
Senior Notes	545	600	7.125%	February 1, 2026
Principal amount of debt	$ 545	$ 600		
Unamortized debt issuance costs	(5)	(8)		
Long-term debt, net	$ 540	$ 592		

(a) At our election, borrowings under the amended Revolving Credit Facility may be alternate base rate (ABR) loans or term SOFR loans, plus an applicable margin. ABR loans bear interest at a rate 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%. Term SOFR loans bear interest at term SOFR, plus an additional 10 basis points per annum credit spread adjustment. The applicable margin is adjusted based on the commitment utilization percentage and will vary from (i) in the case of ABR loans, 1.50% to 2.50% and (ii) in the case of term SOFR loans, 2.50% to 3.50%.

(b) The Revolving Credit Facility is subject to a springing maturity to August 4, 2025 if any of our Senior Notes, defined below, are outstanding on that date.

Fair Value

The estimated fair value of our debt at December 31, 2023 and 2022 was approximately $554 million and $574 million, respectively. We estimate the fair value of our fixed-rate debt based on prices from known market transactions (Level 1 inputs on the fair value hierarchy).

Repurchases

For the year ended December 31, 2023, we repurchased $55 million in principal amount of our Senior Notes at par resulting in an extinguishment loss of $1 million for the write-off of unamortized debt issuance costs.

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. Our Revolving Credit Facility consists of a senior revolving loan facility with an aggregate commitment of $630 million, which we are permitted to increase if we obtain additional commitments from new or existing lenders. Our Revolving Credit Facility also includes a sub-limit of $250 million for the issuance of letters of credit. As of December 31, 2023, we had approximately $477 million available for borrowing under the Revolving Credit Facility after taking into account $153 million of outstanding letters of credit.

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. For information on an amendment to our Revolving Credit Facility, see *Note 17 Subsequent Events*.

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 $1.2 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, has a maturity date of July 31, 2027 (subject to a springing maturity of August 4, 2025 if any of our Senior Notes are outstanding on that date); permits us to make certain restricted payments (such as dividends and share repurchases) and certain investments (including in our carbon management business); 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; and provides for our capacity to issue letters of credit of $250 million. 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.

Senior Notes

On January 20, 2021, we completed an offering of $600 million in aggregate principal amount of our 7.125% senior unsecured notes due 2026 (Senior Notes). The net proceeds of $587 million, after $13 million of debt issuance costs, were used to repay in full our Second Lien Term Loan and EHP Notes, with the remainder used to repay substantially all of the then outstanding borrowings under our Revolving Credit Facility. We recognized a $2 million loss on extinguishment of debt, including unamortized debt issuance costs, associated with these repayments.

Security – Our Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by certain of our material subsidiaries.

Redemption – We may redeem the Senior Notes at any time prior to the maturity date at a redemption price equal to (i) 102% of the principal amount if redeemed in the twelve months beginning February 1, 2024 and (ii) 100% of the principal amount if redeemed after February 1, 2025, in each case plus accrued and unpaid interest.

Other Covenants – Our 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 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 Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Other

At December 31, 2023, all obligations under our Revolving Credit Facility and Senior Notes are guaranteed by certain of our material wholly owned subsidiaries. See *Note 16 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, 2023, we were in compliance with all debt covenants under our Revolving Credit Facility.

Principal maturities of debt outstanding at December 31, 2023 are as follows:

	As of December 31, 2023
	(in millions)
2024	$ —
2025	—
2026	545
2027	—
2028	—
Thereafter	—
Total	$ 545

NOTE 5 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, 2023 and 2022 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 we are now appealing the order from BSEE. Upon execution of a cost sharing agreement with former lessees, we will share in on-going maintenance costs during the pendency of the challenge to the BSEE order and have recognized a liability of $12 million included in accrued liabilities at December 31, 2023.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, easements related to oil and natural gas operations, obligations under long-term service agreements and field equipment.

At December 31, 2023, total purchase obligations on a discounted basis were as follows:

	December 31, 2023
	(in millions)
2024	$ 76
2025	60
2026	41
2027	7
2028	7
Thereafter	33
Total	224
Less: Interest	(38)
Present value of purchase obligations	$ 186

NOTE 6 DERIVATIVES

We continue to maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices. We also enter into natural gas swaps for the purpose of hedging our fuel consumption at one of our steamfloods as well as swaps for natural gas purchases and sales 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, 2023, 2022 and 2021*.* 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. Our Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges unless the ratio of our indebtedness to Consolidated EBITDAX is less than or equal to 1.5:1.0. We have also entered into a limited number of hedges above and beyond these requirements and will continue to evaluate our hedging strategy based on prevailing market prices and conditions. For more information on the requirements of our Revolving Credit Facility, see *Note 4 Debt.*

Summary of Derivative Contracts

We held the following Brent-based crude oil contracts as of December 31, 2023:

	Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025
Sold Calls:					
Barrels per day	23,650	30,000	30,000	29,000	19,748
Weighted-average price per barrel	$ 90.00	$ 90.07	$ 90.07	$ 90.07	$ 85.63
Purchased Puts					
Barrels per day	30,584	30,000	30,000	29,000	19,748
Weighted-average price per barrel	$ 67.27	$ 65.17	$ 65.17	$ 65.17	$ 60.00
Swaps					
Barrels per day	9,500	8,875	7,750	5,500	3,374
Weighted-average price per barrel	$ 79.81	$ 79.28	$ 79.64	$ 77.45	$ 72.66

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 – 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.

At December 31, 2023, we also held the following swaps to hedge purchased natural gas used in our operations as shown in the table below.

	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Swaps:				
MMBtu per day	10,000	10,000	10,000	10,000
Weighted-average price per MMBtu	$ 5.65	$ 5.65	$ 5.65	$ 5.65

The derivative contracts entered into related to our natural gas marketing activities are intended to lock in locational price spreads.

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,		
	2023	2022	2021
(in millions)			
Non-cash commodity derivative gain (loss)	$ 260	$ 187	$ (357)
Settlements and amortized premiums	(272)	(738)	(319)
Net loss from commodity derivatives	$ (12)	$ (551)	$ (676)

We report gains and losses on our derivative contracts for purchased natural gas used in our steamflood operations as a component of operating expense on our consolidated statement of operations. For the year ended December 31, 2023, we recognized a non-cash loss of $8 million which was included in other operating expenses, net on our consolidated statement of operations.

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:

December 31, 2023

Classification	Gross Amounts Recognized	Gross Amounts Offset on the Consolidated Balance Sheet	Net Amounts Presented on the Consolidated Balance Sheet
Assets:		(in millions)	
Other current assets, net	$ 39	$ (18)	$ 21
Other noncurrent assets	38	(32)	6
Liabilities:			
Current - Fair value of derivative contracts	(26)	18	(8)
Other long-term liabilities	(34)	32	(2)
	$ 17	$ —	$ 17

December 31, 2022

Classification	Gross Amounts Recognized	Gross Amounts Offset on the Consolidated Balance Sheet	Net Amounts Presented on the Consolidated Balance Sheet
Assets:		(in millions)	
Other current assets, net	$ 51	$ (12)	$ 39
Other noncurrent assets	7	—	7
Liabilities:			
Current - Fair value of derivative contracts	(258)	12	(246)
	$ (200)	$ —	$ (200)

Counterparty Credit Risk

As of December 31, 2023, all of our derivative financial instruments were 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, 2023, and 2022, we did not have collateral posted for financial instruments.

NOTE 7 INCOME TAXES

Net income before income taxes, for all periods presented, was generated from domestic operations. We recognized an income tax provision (benefit) for the periods presented as follows:

	Year ended December 31,		
(in millions)	2023	2022	2021
Federal	$ 146	$ 10	$ —
State	3	1	—
Current	149	11	—
Federal	(12)	141	(161)
State	47	85	(235)
Deferred	35	226	(396)
Total income tax provision (benefit)	$ 184	$ 237	$ (396)

Our income tax provision (benefit) differs from the amounts computed by applying the U.S. federal income tax statutory rate to income before income taxes as follows:

	Year ended December 31,		
	2023	2022	2021
U.S. federal statutory tax rate	21 %	21 %	21 %
State income taxes, net	5	9	(81)
Exclusion of income attributable to noncontrolling interest	—	—	(1)
Changes in tax attributes	—	(2)	(8)
Executive compensation	1	—	2
Change in the U.S. federal valuation allowance	(2)	2	(106)
Other	—	1	—
Effective tax rate	25 %	31 %	(173)%

During the year ended December 31, 2023, we released a valuation allowance of $35 million for a portion of the tax loss on the sale of our Lost Hills assets after we jointly agreed to amend the original tax treatment with the buyer. See *Note 8 Divestitures and Acquisitions* for more information on the Lost Hills transaction. This valuation allowance was initially recorded during the year ended December 31, 2022 for the realizability of a capital loss on the sale of Lost Hills, the deductibility of which was limited. During the year ended December 31, 2021, we released all of our valuation allowance recorded against our net deferred tax assets given our anticipated future earnings trend at that time.

During the years ended December 31, 2022 and 2021, we recognized a tax benefit for tax credits related to our oil and gas operations. The tax benefit of these credits is presented as changes in tax attributes in our effective tax rate reconciliations.

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2023 and 2022 were as follows:

	2023		2022	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Property, plant and equipment	$ 19	$ (286)	$ 47	$ (267)
Deferred compensation and benefits	40	—	27	—
Asset retirement obligations	157	—	148	—
Net operating loss and tax credit carryforwards	15	—	85	—
Business interest expense carryforward	161	—	167	—
Federal benefit of state income taxes	—	(21)	—	(31)
Other	81	(34)	60	(37)
Subtotal	473	(341)	534	(335)
Valuation allowance	—	—	(35)	—
Total deferred taxes	$ 473	$ (341)	$ 499	$ (335)

Management expects to realize the recorded deferred tax assets primarily 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 or three-years of cumulative income is no longer present.

Carryforwards

As of December 31, 2023, we had U.S. federal net operating loss carryforwards of $29 million, which begin to expire in 2037. Our carryforward for disallowed business interest of $765 million does not expire.

As of December 31, 2023, we had California net operating loss carryforwards of $2 billion, which begin to expire in 2026, and $20 million of tax credit carryforwards, which begin to expire in 2041.

Our ability to utilize a portion of our net operating loss, tax credit and interest expense carryforwards is subject to an annual limitation since we experienced an ownership change in connection with our emergence from bankruptcy. We recognized a tax benefit for $11 million of U.S. federal net operating loss carryforwards (that do not expire) and approximately $75 million for California net operating loss carryforwards. We expect our remaining carryforwards will expire unused. Additionally, we recognized a tax benefit for $6 million of California tax credit carryforwards.

Other

We did not record a liability for unrecognized tax benefits as of December 31, 2023 and 2022.

We remain subject to audit by the Internal Revenue Service for calendar years 2020 through 2022 as well as 2019 through 2022 by the state of California.

NOTE 8 DIVESTITURES AND ACQUISITIONS

Divestitures

Round Mountain Unit

On December 29, 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 CO_2 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.

Ventura Basin

During 2021 and 2022, we entered into transactions to sell our Ventura basin assets. The transaction contemplates multiple closings that are 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. We recognized a gain of $120 million on the Ventura divestiture during the year ended December 31, 2021.

During the year ended December 31, 2022, we recognized a gain of $11 million related to the sale of additional Ventura basin assets.

The closing of our remaining assets in the Ventura basin is subject to final approval from the State Lands Commission, we expect could occur in 2024. These remaining assets, consisting of property, plant and equipment and associated asset retirement obligations, are classified as held for sale on our consolidated balance sheet as of December 31, 2023.

Lost Hills

On February 1, 2022, we sold our 50% non-operated working interest in certain horizons within our Lost Hills field, located in the San Joaquin basin, recognizing a gain of $49 million. We retained an option to capture, transport and store 100% of the CO_2 from steam generators across the Lost Hills field for future carbon management projects. This option can be terminated by the buyer after January 1, 2026. We also retained 100% of the deep rights and related seismic data.

CRC Plaza

In 2022, we sold our commercial office building located in Bakersfield, California for net proceeds of $13 million, recognizing no gain or loss on the sale following recognition of impairment charges in 2021 and 2022. We also leased back a portion of the building with a term of 18 months. See *Note 2 Property, Plant and Equipment* for details of impairment charges we recognized prior to the sale of this property.

Other Divestitures

In 2023, we sold a non-producing asset in exchange for the assumption of liabilities recognizing a $7 million gain. In 2022, we sold non-core assets recognizing a $1 million loss. In 2021, we also sold unimproved land and other non-core assets for $13 million in proceeds recognizing a $4 million gain.

Acquisitions

MIRA JV

Our development joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA JV) contemplated that MIRA would fund the development of certain of our oil and natural gas properties in exchange for a 90% working interest. In August 2021, we purchased MIRA's entire working interest share for $52 million. We accounted for this transaction as an asset acquisition. Prior to the acquisition, our consolidated results reflect only our 10% working interest share in the productive wells.

Other Acquisitions

In 2023, we acquired properties for our carbon management business for approximately $5 million.

In 2022, we acquired properties for our carbon management business for approximately $17 million. In 2023, we recognized an impairment of $3 million to write these assets down to fair value (using Level 3 inputs in the fair value hierarchy) due to market conditions at that time (including inflation and rising interest rates). We intend to divest a portion of these assets, which are classified as held for sale as of December 31, 2023 on our consolidated balance sheet.

NOTE 9 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,		
	2023	2022	2021
		(in millions)	
General and administrative expenses	$ 40	$ 26	$ 17
Operating costs	7	4	2
Carbon management business expenses	1	—	—
Total stock-based compensation expense	$ 48	$ 30	$ 19
Income tax benefit	$ 9	$ 6	$ —

We paid $11 million and $6 million for our long-term cash incentive awards for the year ended December 31, 2023 and December 31, 2022, respectively. No payments were made during the year ended December 31, 2021.

Stock Settled Awards

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 from two to three 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, 2023:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2022	1,121	$ 25.64
Granted	416	$ 39.95
Vested	(81)	$ 30.53
Forfeited or Cancelled	(168)	$ 29.28
Unvested at December 31, 2023	1,288	$ 29.49

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, 2023, the unrecognized compensation expense for our unvested RSUs was approximately $10 million and is expected to be recognized over a weighted-average remaining service period of approximately two years.

Performance Stock Units

In 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.

In 2021 and 2022, executives were granted PSUs which are earned upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock generally during a three-year service period commencing on the grant date. Once units are earned, the earned units are not reduced for subsequent decreases in stock price. For the duration of the three-year period, a minimum of 0% and a maximum of 100% of the PSUs granted could be earned. 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. PSU grants made to certain executives in 2021 have been fully earned.

The following table sets forth PSU activity for the year ended December 31, 2023:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2022	947	$ 20.19
Granted	559	$ 43.03
Vested	(30)	$ 25.93
Forfeited or Cancelled	(103)	$ 36.68
Unvested at December 31, 2023	1,373	$ 28.13

The range of assumptions used in the valuation of PSUs granted during 2023, 2022 and 2021 were as follows:

	2023	2022	2021
Expected volatility[(a)]	42.36% - 55.00%	60.00%	60.00% - 65.00%
Risk-free interest rate[(b)]	3.81% - 4.95%	1.59% - 2.55%	0.16% - 0.60%
Dividend yield[(c)]	— %	— %	— %
Forecast period (in years)	1.5 - 3	2 - 3	2 - 3

(a) Expected volatility was calculated using the historic volatility of a peer group due to our limited trading history since our emergence from bankruptcy. For awards granted after June 2021, we included the historic volatility of our stock, excluding our first two trading months, in the peer group.

(b) Based on the U.S. Treasury yield for a two- or 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, 2023, the unrecognized compensation expense for our unvested PSUs was approximately $14 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 2023, 2022 and 2021, we granted performance cash-settled awards to approximately 500 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, 2023 were as follows:

	2023 Awards	2022 Awards	2021 Awards
Expected volatility[(a)]	40 %	36 %	25 %
Risk-free interest rate[(b)]	4.20 %	4.51 %	5.26 %
Dividend yield[(c)]	— %	— %	— %
Forecast period (in years)	2.15	1.5	0.5

(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, 2023, 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, 2023 was approximately $4 million.

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, 2023, a total of 57,493 common shares were issued under our ESPP.

NOTE 10 STOCKHOLDERS' EQUITY

The following is a summary of changes in our common shares outstanding:

	Common Shares Outstanding
Balance, December 31, 2021	79,299,222
Shares issued for warrant exercises	312
Shares issued under ESPP	16,480
Treasury stock - shares repurchased	(7,366,272)
Balance, December 31, 2022	71,949,742
Shares issued for warrant exercises	35,441
Shares issued under ESPP	41,013
Shares issued under stock-based compensation arrangements	75,344
Treasury stock - shares repurchased	(3,407,655)
Balance, December 31, 2023	68,693,885

Share Repurchase Program

Our Board of Directors authorized a Share Repurchase Program to acquire up to $1.1 billion of our common stock through June 30, 2024. The repurchases may be affected 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:

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2021	4,089,988	$148	$36.08
Year ended December 31, 2022	7,366,272	$313	$42.47
Year ended December 31, 2023	3,407,655	$143	$41.69
Total	14,863,915	$604	$40.53

Note: The total value of shares purchased includes approximately $1 million related to excise taxes on share repurchases, which was effective beginning in 2023. Commissions paid were not significant in all periods presented.

See *Note 17 Subsequent Events* for information on an increase and extension to our Share Repurchase Program.

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 17 Subsequent Events* for information on future cash dividends.

Our Board of Directors declared quarterly cash dividends of $0.17 per share of common stock for the fourth quarter of 2021 and each of the first three quarters of 2022. On November 2, 2022, our Board of Directors approved an increase in our dividend policy to an expected total annual dividend of $1.13 per share. On November 1, 2023, our Board of Directors increased our dividend policy to an expected total annual dividend of $1.24 per share. Cash dividends paid for each period is presented in the table below (excluding amounts accrued on share-based compensation awards).

	Total Dividend	Annual Rate Per Share
	(in millions)	($ per share)
Year ended December 31, 2021	$ 14	$ 0.17
Year ended December 31, 2022	59	$ 0.7925
Year ended December 31, 2023	81	$ 1.1575
	$ 154	

Noncontrolling Interests

BSP JV

Our development joint venture with Benefit Street Partners (BSP JV) contemplated that BSP contributed funds to the development of our oil and natural gas properties in exchange for preferred interests in the BSP JV. In September 2021, BSP's preferred interest was automatically redeemed in full under the terms of the joint venture agreement. Prior to the redemption, we made aggregate distributions to BSP of $50 million in 2021 which reduced noncontrolling interest on our consolidated balance sheet and was reported as a financing cash outflow on our consolidated statement of cash flows.

BSP's preferred interest was reported in equity on our consolidated balance sheets and BSP's share of net income (loss) was reported in net income attributable to noncontrolling interests in our consolidated statements of operations for all periods prior to redemption. Upon redemption, we reallocated the remaining balance of $7 million in noncontrolling interest and increased our additional paid-in capital by the same amount.

Warrants

As of December 31, 2023, we had outstanding warrants exercisable into 4,182,521 shares of our common stock.

These warrants are exercisable at an exercise price of $36 per share until October 2024. The Warrant Agreement contains customary anti-dilution adjustments in the event of any stock split, reverse stock split, stock dividend, equity awards under our Management Incentive Plan or other distributions. The warrant holder may elect, in its sole discretion, to pay cash or to exercise on a cashless basis, pursuant to which the holder will not be required to pay cash for shares of common stock upon exercise of the warrant but will instead receive fewer shares.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of after-tax amounts for our pension and postretirement benefit plans. See *Note 13 Pension and Postretirement Benefit Plans* for further information.

	Year ended December 31,		
	2023	2022	2021
		(in millions)	
Beginning accumulated other comprehensive income (loss)	$ 81	$ 72	$ (8)
Actuarial (loss) gain associated with pension and postretirement	(2)	18	16
Prior service credit	—	—	65
Recognition of prior service credit due to curtailment	(3)	—	—
Amortization of prior service credit	(5)	(5)	(1)
Other comprehensive (loss) income	(10)	13	80
Total recorded in accumulated other comprehensive income, before tax	71	85	72
Income tax benefit (provision)	3	(4)	—
Total recorded in accumulated other comprehensive loss, net of tax	$ 74	$ 81	$ 72

NOTE 11 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 9 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 use the 60-trading day volume weighted-average prices of our common stock 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, 2023.

The following table presents the calculation of basic and diluted EPS.

	Year ended December 31,		
	2023	2022	2021
(in millions, except per share amounts)			
Numerator for Basic and Diluted EPS			
Net income	$ 564	$ 524	$ 625
Less: Net income attributable to noncontrolling interests	—	—	(13)
Net income available to common stockholders	$ 564	$ 524	$ 612
Denominator for Basic EPS			
Weighted-average common shares	69.6	75.5	82.0
Potential dilutive common shares:			
Restricted Stock Units	1.0	0.7	0.5
Performance Stock Units	0.9	0.7	0.5
Warrants	1.0	0.7	—
Denominator for Diluted Earnings per Share			
Weighted-average shares - diluted	72.5	77.6	83.0
EPS			
Basic	$ 8.10	$ 6.94	$ 7.46
Diluted	$ 7.78	$ 6.75	$ 7.37

There were no potentially dilutive common shares for warrants in 2021 since the average market prices of our common stock at that time was below the warrant exercise price. See *Note 10 Stockholders' Equity* for a description of our warrants.

NOTE 12 LEASES

We have operating leases primarily for carbon sequestration easements, drilling rigs, vehicles and commercial office space. We have recorded the following amounts on our balance sheet as of December 31, 2023 and 2022:

	Classification	2023	2022
		(in millions)	
Right-of-use assets	*Other noncurrent assets*	$ 73	$ 73
Lease liabilities	*Accrued liabilities*	$ 15	$ 18
Lease liabilities	*Other long-term liabilities*	$ 55	$ 52

We determine if our arrangements contain a lease at inception.

We combine lease and nonlease components in determining fixed minimum lease payments for our drilling rigs and commercial office space. If applicable, fixed minimum lease payments are reduced by lease incentives for our commercial office space and increased by mobilization and demobilization fees for our drilling rigs. 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 our drilling rigs include costs to operate, move and repair the rigs. Variable lease costs for commercial office space includes 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, 2023	Year ended December 31, 2022
	(in millions)	
Operating lease costs	$ 23	$ 17
Short-term lease costs[a]	52	59
Variable lease costs	2	6
Total operating lease costs	77	82
Sublease income	(2)	(1)
Total lease costs	$ 75	$ 81

(a) Contracts with terms of less than one month or less are excluded from our disclosure of short-term lease costs.

We had two contracts treated as finance leases, where the terms ended in 2022. These leases were not material to our consolidated results of operations for the periods presented.

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, 2023 and 2022 is provided below:

	Year ended December 31, 2023	Year ended December 31, 2022
	(in millions)	
Cash paid for lease liabilities		
Lease liabilities associated with operating activities	$ 28	$ 14
Lease liabilities associated with investing activities	$ 2	$ 6
ROU assets obtained in exchange for new operating lease liabilities	$ 32	$ 35

	2023	2022
Operating Leases		
Weighted-average remaining lease term (in years)	7.34	6.43
Weighted-average discount rate	6.7 %	6.1 %

Our operating lease payments are as follows:

	As of December 31, 2023
	(in millions)
2024	$ 18
2025	14
2026	12
2027	10
2028	9
Thereafter	27
Less: Interest	(20)
Present value of lease liabilities	$ 70

NOTE 13 PENSION AND POSTRETIREMENT BENEFIT PLANS

We have various qualified and non-qualified benefit plans for our salaried and union and nonunion hourly employees.

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 supplemental plans that restore benefits lost due to government limitations on qualified plans. We recognized $24 million in other long-term liabilities for each of the years ended December 31, 2023 and 2022 related to these supplemental plans.

We expensed $19 million in 2023, $18 million in 2022, $19 million in 2021 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 2023, approximately 60 employees accrued benefits under these plans, 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.

In 2021, we adopted a postretirement benefit design change, which terminated the employer cost sharing for post age 65 retiree health benefits effective as of January 1, 2022. Our retiree health care benefits provided up to age 65 to current and future retirees who meet certain eligibility requirements were not affected by this change. As a result of this change, our postretirement medical benefit obligation was remeasured as of September 30, 2021. The remeasurement resulted in a decrease to the benefit obligation of $65 million with a corresponding increase to accumulated other comprehensive income. The benefit from the change in plan design is recognized in our statements of operations over the average remaining years of future service for active employees as a component of other non-operating expenses, net. In 2023, we reduced our workforce and accelerated $3 million of the unrecognized prior service cost credit in the third quarter of 2023.

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 (in millions):

	December 31, 2023		December 31, 2022	
	Pension	**Postretirement**	**Pension**	**Postretirement**
Amounts recognized on the balance sheet				
Other assets	$ 2	$ —	$ 2	$ —
Accrued liabilities	—	(3)	—	(4)
Other long-term liabilities	(3)	(33)	—	(33)
	$ (1)	$ (36)	$ 2	$ (37)
Accumulated other comprehensive income, net of tax	$ 2	$ 72	$ 2	$ 79

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 (in millions):

	Year ended December 31, 2023	Year ended December 31, 2022
Pension		
Changes in the benefit obligation		
Benefit obligation - beginning of year	$ 30	$ 44
Service cost - benefits earned during the period	1	1
Interest cost on projected benefit obligation	1	1
Actuarial loss (gain)[(a)]	3	(12)
Benefits paid	(1)	(4)
Benefit obligation - end of year	$ 34	$ 30
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 32	$ 29
Actual return on plan assets	3	(5)
Employer contributions	—	12
Benefits paid	(1)	(4)
Fair value of plan assets - end of year	$ 34	$ 32
Net benefit asset (liability)	$ —	$ 2
Postretirement		
Changes in the benefit obligation		
Benefit obligation - beginning of year	$ 38	$ 49
Service cost - benefits earned during the period	2	2
Interest cost on projected benefit obligation	2	1
Actuarial gain[(b)]	(2)	(12)
Benefits paid	(3)	(2)
Benefit obligation - end of year	$ 37	$ 38
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 1	$ 1
Employer contributions	3	2
Benefits paid	(3)	(2)
Fair value of plan assets - end of year	$ 1	$ 1
Net benefit liability	$ (36)	$ (37)

(a) The loss reflected in the changes in the pension benefit obligation for the year ended December 31, 2023 was primarily due to the decrease in the discount rate from 5.19% to 4.98% and other valuation assumption changes.

(b) The gain reflected in the changes in the postretirement benefit obligation for the year ended December 31, 2023 was primarily due to lower than expected benefit payments during 2023.

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:

(in millions)	2023	2022
Projected benefit obligation	$ 34	$ 30
Accumulated benefit obligation	$ 30	$ 27
Fair value of plan assets	$ 34	$ 32

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 (in millions):

	Year ended December 31,		
	2023	2022	2021
Pension			
Net periodic benefit costs			
Service cost - benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	1
Expected return on plan assets	(2)	(1)	(1)
Net periodic benefit costs	$ —	$ 1	$ 1
Postretirement			
Net periodic benefit costs			
Service cost - benefits earned during the period	$ 2	$ 2	$ 4
Interest cost on projected benefit obligation	2	1	3
Amortization of prior service cost credit	(5)	(5)	(1)
Amortization of net actuarial gain/loss	(2)	—	—
Curtailment gain	(3)	—	—
Net periodic benefit costs	$ (6)	$ (2)	$ 6

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 attributable to common stock (in millions):

	Year ended December 31,		
	2023	2022	2021
Pension			
Net actuarial (loss) gain	$ (1)	$ 4	$ (1)
Total	$ (1)	$ 4	$ (1)
Postretirement			
Net actuarial gain	$ 1	$ 9	$ 17
Prior service credit	—	—	65
Amortization of prior service credit due to curtailment	(2)	—	—
Amortization of prior service credit	(4)	(4)	(1)
Amortization net actuarial gain/loss	(1)	—	—
Total	$ (6)	$ 5	$ 81

The following tables 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, 2023	Year ended December 31, 2022
Pension		
Benefit Obligation Assumptions		
Discount rate	4.98 %	5.19 %
Rate of compensation increase	4.00 %	4.00 %
Net Periodic Benefit Cost Assumptions		
Discount rate	5.19 %	2.79 %
Expected return on assets	6.98 %	5.50 %
Rate of compensation increase	4.00 %	4.00 %
Postretirement		
Benefit Obligation Assumptions		
Discount rate	4.99 %	5.20 %
Net Periodic Benefit Cost Assumptions		
Discount rate	5.20 %	2.75 %
Expected return on assets	6.50 %	5.50 %

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the FTSE Above Median yield curve in 2023 and in 2022. 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 2023 and 2022, 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 2.38% and 2.52% as of December 31, 2023 and 2022, 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, 2023, health care cost trend rates would be 6.75% in 2024 decreasing until they reach 4.50% in 2033 and remain at 4.50% thereafter. For those union employees, we projected that, as of December 31, 2022, health care cost trend rates would be 7.00% in 2023 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 2023 and 2022, the target allocation of plan assets was 50% and 50% equity securities and 50% and 50% debt securities, respectively. 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. Our postretirement benefit plan assets of $1 million are invested in mutual funds (Level 1 on the fair value hierarchy) with target allocations of 40% equities and 60% debt securities.

The fair values of our pension plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2023			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class	(in millions)			
Comingled funds				
Bonds	—	18	—	18
Commodities	—	—	—	—
U.S. equity	—	6	—	6
International equity	—	10	—	10
Total pension plan assets	$ —	$ 34	$ —	$ 34

	Fair Value Measurements at December 31, 2022			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class	(in millions)			
Commingled funds				
Bonds	—	17	—	17
Commodities	—	1	—	1
U.S. equity	—	4	—	4
International equity	—	10	—	10
Total pension plan assets	$ —	$ 32	$ —	$ 32

Expected Contributions and Benefit Payments

In 2024, we do not expect to contribute to our pension plans and expect to contribute $4 million to our postretirement benefit plan. 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)	
2024	$ 7	$ 4
2025	$ 3	$ 4
2026	$ 2	$ 3
2027	$ 2	$ 3
2028	$ 2	$ 3
2029 - 2033	$ 12	$ 12

NOTE 14 REVENUE

Revenue from customers is recognized when 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. Disaggregated revenue for sales of oil, natural gas and natural gas liquids (NGLs) to customers includes the following:

	Year ended December 31,		
	2023	2022	2021
(in millions)			
Oil	$ 1,534	$ 1,968	$ 1,555
NGLs	198	264	250
Natural gas	423	411	243
Oil, natural gas and NGL sales	$ 2,155	$ 2,643	$ 2,048

We also process third-party wet gas at one of our gas processing facilities, which is sold to customers. We recognized $15 million, $14 million and $10 million included in other revenue on our consolidated statements of operations for the years ended December 31, 2023, 2022 and 2021, respectively.

Electricity Sales

The electrical output of our Elk Hills power plant that is not used in our operations is primarily sold to the wholesale power market and a 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. The PPA terminated in December 2023. 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 the California Independent System Operator (CAISO) market pricing with payment due the month following delivery. Payments under our PPA are settled monthly. We recognize revenue using the output method and consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments.

Marketing of Purchased Natural Gas

To transport our natural gas as well as third-party volumes, we have entered into firm pipeline commitments. In addition, we may from time-to-time enter into natural gas purchase and sale agreements with third parties to move natural gas to areas with higher demand. We report sales of purchased natural gas in total operating revenues and associated purchased natural gas expense related to our marketing activities in total operating expenses on our consolidated statements of operations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

NOTE 15 SUPPLEMENTAL ACCOUNT BALANCES AND CASH FLOW INFORMATION

Other Current Assets

Other current assets, net consisted of the following:

	December 31, 2023	December 31, 2022
	(in millions)	
Net amounts due from joint interest partners[(a)]	$ 43	$ 39
Fair value of derivative contracts	21	39
Prepaid expenses	19	17
Prepaid greenhouse gas allowances, net[(b)]	12	—
Natural gas margin deposits	—	16
Income tax receivable	—	10
Other	18	12
Other current assets, net	$ 113	$ 133

(a) Included in the net amounts due from joint interest partners are allowances of $3 million and $1 million for December 31, 2023 and 2022, respectively.
(b) Greenhouse gas allowances are purchased to meet California's cap-and-trade obligations. Our obligations are determined based on reported greenhouse gas emissions. As of December 31, 2023, we were in a net prepaid position due to the timing of the allowance purchases.

Other Noncurrent Assets

Other noncurrent assets consisted of the following:

	December 31, 2023	December 31, 2022
	(in millions)	
Right-of-use assets	$ 73	$ 73
Deferred financing costs related to our Revolving Credit Facility	11	6
Emission reduction credits	11	11
Prepaid power plant maintenance	34	28
Fair value of derivative contracts	6	7
Deposits and other	13	15
Other noncurrent assets	$ 148	$ 140

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31, 2023	December 31, 2022
	(in millions)	
Accrued employee-related costs	$ 82	$ 49
Accrued taxes other than on income	35	32
Current portion - asset retirement obligations	99	59
Accrued interest	18	19
Current portion - operating lease liability	15	18
Premiums due on derivative contracts	21	58
Liability for settlement payments on derivative contracts	8	33
Income tax payable	18	1
Signal Hill (maintenance expense)	12	8
Other	50	21
Accrued liabilities	$ 358	$ 298

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	December 31, 2023	December 31, 2022
	(in millions)	
Compensation-related liabilities	$ 38	$ 36
Pension and postretirement benefit plans	36	33
Lease liability	55	52
Premiums due on derivative contracts	10	8
Contingent liability related to Carbon TerraVault JV put and call rights	52	48
Other	10	8
Other long-term liabilities	$ 201	$ 185

Supplemental Cash Flow Information

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

	Year ended December 31,		
	2023	2022	2021
(in millions)			
Supplemental Cash Flow Information			
Interest paid, net of amount capitalized	$ (44)	$ (43)	$ (28)
Income taxes paid	$ 121	$ 20	$ —
Supplemental Disclosure of Non-cash Investing and Financing Activities			
Derivative related to additional earn-out consideration for the Ventura divestiture	$ —	$ —	$ 3
Receivable from affiliate	$ —	$ 32	$ —
Dividends accrued for stock-based compensation awards	$ 3	$ 2	$ —
Contribution to the Carbon TerraVault JV	$ 15	$ 2	$ —

NOTE 16 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

We have designated certain of our subsidiaries as Unrestricted Subsidiaries under the indenture governing our Senior Notes (Senior Notes Indenture). Unrestricted Subsidiaries (as defined in the Senior Notes Indenture) are subject to fewer restrictions under the Senior Notes Indenture. We are required under the Senior Notes indenture to present the financial condition and results of operations of CRC and its Restricted Subsidiaries (as defined in the 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, 2023 and 2022 and the consolidating statements of operations for the year ended December 31, 2023, 2022 and 2021, as applicable, reflect the consolidating financial information of our parent company, 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, 2023 and 2022

	As of December 31, 2023				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total current assets	$ 511	$ 20	$ 398	$ —	$ 929
Total property, plant and equipment, net	14	12	2,744	—	2,770
Investments in consolidated subsidiaries	2,311	(11)	1,347	(3,647)	—
Deferred tax asset	132	—	—	—	132
Investment in unconsolidated subsidiary	—	19	—	—	19
Other assets	12	36	100	—	148
TOTAL ASSETS	$ 2,980	$ 76	$ 4,589	$ (3,647)	$ 3,998
Total current liabilities	142	13	461	—	$ 616
Long-term debt	540	—	—	—	540
Asset retirement obligations	—	—	422	—	422
Other long-term liabilities	79	73	49	—	201
Total equity	2,219	(10)	3,657	(3,647)	2,219
TOTAL LIABILITIES AND EQUITY	$ 2,980	$ 76	$ 4,589	$ (3,647)	$ 3,998

	As of December 31, 2022				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total current assets	$ 329	$ 33	$ 502	$ —	$ 864
Total property, plant and equipment, net	13	6	2,767	—	2,786
Investments in consolidated subsidiaries	2,096	—	1,512	(3,608)	—
Deferred tax asset	164	—	—	—	164
Investment in unconsolidated subsidiary	—	13	—	—	13
Other assets	8	33	99	—	140
TOTAL ASSETS	$ 2,610	$ 85	$ 4,880	$ (3,608)	$ 3,967
Total current liabilities	76	7	811	—	$ 894
Long-term debt	592	—	—	—	592
Asset retirement obligations	—	—	432	—	432
Other long-term liabilities	78	67	40	—	185
Total equity	1,864	11	3,597	(3,608)	1,864
TOTAL LIABILITIES AND EQUITY	$ 2,610	$ 85	$ 4,880	$ (3,608)	$ 3,967

Condensed Consolidating Statement of Operations
For the year ended December 31, 2023 and 2022

	Year ended December 31, 2023				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total 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	$ (453)	$ (63)	$ 1,080	$ —	$ 564

	Year ended December 31, 2022				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues	$ 4	$ —	$ 2,703	$ —	$ 2,707
Total costs and other	177	37	1,740	—	1,954
Gain on asset divestitures	—	—	59	—	59
Non-operating (loss) income	(55)	(3)	7	—	(51)
(LOSS) INCOME BEFORE INCOME TAXES	(228)	(40)	1,029	—	761
Income tax provision	(237)	—	—	—	(237)
NET (LOSS) INCOME	$ (465)	$ (40)	$ 1,029	$ —	$ 524

	Year ended December 31, 2021				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues	$ (55)	$ 57	$ 1,887	$ —	$ 1,889
Total costs and other	158	30	1,532	—	1,720
Gain on asset divestitures	—	—	124	—	124
Non-operating (loss) income	(66)	—	2	—	(64)
(LOSS) INCOME BEFORE INCOME TAXES	(279)	27	481	—	229
Income tax provision	396	—	—	—	396
NET INCOME (LOSS)	117	27	481	—	625
Net (income) loss attributable to noncontrolling interest	—	(13)	—	—	(13)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 117	$ 14	$ 481	$ —	$ 612

NOTE 17 SUBSEQUENT EVENTS

Pending Aera Merger

On February 7, 2024, we entered into a definitive agreement and plan of merger (Merger Agreement) to combine with Aera Energy, LLC (Aera) in an all-stock transaction (Aera Merger) with an effective date of January 1, 2024. Aera is a leading operator of mature fields in California, primarily in the San Joaquin and Ventura basins, with high oil-weighted production.

Pursuant to the Merger Agreement, we have agreed to issue 21,170,357 shares of common stock (subject to customary adjustments in the event of stock splits, dividend paid in stock and similar items) plus an additional number of shares determined by reference to the dividends declared by us having a record date between the effective date and closing as more fully described in the Merger Agreement. Under the terms of the Merger Agreement, we have also agreed to assume Aera's outstanding long-term indebtedness of $950 million at closing. We expect to repay a significant portion of this indebtedness with cash on hand and borrowings under our Revolving Credit Facility. We intend to refinance the balance through one or more debt capital markets transactions and, only to the extent necessary, borrowings under a bridge loan facility provided by Citigroup Global Markets, Inc. (the Bank). Under the terms of our debt commitment letter with the Bank, it has committed, subject to satisfaction of customary conditions, to provide us with an unsecured 364-day bridge loan facility in an aggregate principal amount of $500 million (Bridge Loan Facility).

Closing of the Aera Merger is subject to certain conditions, including, among others, approval of the stock issuance by our stockholders, expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, prior authorization by the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act and other customary closing conditions.

Upon completion of the transaction, we currently expect our existing stockholders to own approximately 77.1% of the combined company and the existing Aera owners to own approximately 22.9% of the combined company, on a fully diluted basis. The Aera Merger is expected to close in the second half of 2024.

Share Repurchase Program

On February 6, 2024 our Board of Directors increased the Share Repurchase Program by $250 million to $1.35 billion and extended the program through December 31, 2025.

Amendment to our Revolving Credit Facility

In connection with the Merger Agreement, on February 9, 2024, we entered into a second amendment to our Revolving Credit Facility to permit us to incur indebtedness under the Bridge Loan Facility.

Dividends

On February 27, 2024, our Board of Directors declared a cash dividend of $0.31 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 6, 2024 and is expected to be paid on March 18, 2024.

Stock-Based Compensation

In February 2024, certain of our executives were granted an aggregate of approximately 182,000 RSUs and 273,000 PSUs. The PSUs cliff vest on the third anniversary of the grant date. The RSUs vest ratably over three years, with units vesting on the anniversary date of each grant, generally subject to continued employment through the applicable vesting dates.

Sale of Fort Apache in Huntington Beach

In February 2024, we entered into an agreement to sell our 0.9-acre Fort Apache real estate property in Huntington Beach, California for approximately $10 million.

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. All of our proved reserves are located within the state of California.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil[(a)]	NGLs	Natural Gas	Total[(b)]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBoe)
Balance at December 31, 2020	313	41	527	442
Revisions of previous estimates[(c)]	50	5	108	73
Improved recovery	1	—	—	1
Extensions and discoveries	4	—	6	5
Acquisitions and divestitures	(3)	(1)	(7)	(5)
Production	(22)	(4)	(58)	(36)
Balance at December 31, 2021	343	41	576	480
Revisions of previous estimates[(c)]	(38)	—	(36)	(44)
Improved recovery	6	—	—	6
Extensions and discoveries	11	1	26	16
Acquisitions and divestitures	(8)	—	(1)	(8)
Production	(20)	(4)	(54)	(33)
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
PROVED DEVELOPED RESERVES				
December 31, 2020	266	39	460	382
December 31, 2021	282	38	510	405
December 31, 2022	251	36	458	363
December 31, 2023[(d)]	223	34	445	331
PROVED UNDEVELOPED RESERVES				
December 31, 2020	47	2	67	60
December 31, 2021	61	3	66	75
December 31, 2022	43	2	53	54
December 31, 2023	33	1	73	46

(a) Includes proved reserves related to economic arrangements similar to PSCs of 76 MMBbl, 92 MMBbl, 111 MMBbl and 85 MMBbl at December 31, 2023, 2022, 2021 and 2020, 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 18% of proved developed oil reserves, 7% of proved developed NGLs reserves, 10% of proved developed natural gas reserves and, overall, 15% of total proved developed reserves at December 31, 2023 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.

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 & 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions – 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 8 Divestitures and Acquisitions* for more information on this transaction.

2022

Revisions of previous estimates – We had net positive price-related revisions of 6 MMBoe primarily resulting from a higher commodity price environment in 2022 compared to 2021. The price revision reflects the extended economic lives of our fields, estimated using 2022 SEC pricing. Additionally, we have experienced higher vendor-related pricing and compensation-related cost increases due to inflation.

We had 16 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 31 MMBoe and positive 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 and addition of proved undeveloped locations due to positive drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

We had 34 MMBoe of negative revisions to our proved reserves due to the impact of California regulatory changes and court challenges on our development plans. Of this amount, negative revisions of 20 MMBoe of proved reserves were 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 LA Basin. Negative revisions of 14 MMBoe to our proved reserves were due to challenges to Kern County's ability to issue well permits in reliance on an existing EIR for CEQA purposes. The volumes affected by these court challenges are in Kern County. See *Part I, Item 1 & 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions and discoveries – We added 16 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 8 MMBoe which primarily related to our Lost Hills divestiture. See *Note 8 Divestitures and Acquisitions* for more information on these transactions.

2021

Revisions of previous estimates – We had positive price-related revisions of 64 MMBoe primarily resulting from a higher commodity price environment in 2021 compared to 2020. The net price revision reflects the extended economic lives of our fields, estimated using 2021 SEC pricing, partially offset by higher operating costs.

We had 9 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 21 MMBoe and negative performance-related revisions of 12 MMBoe. Our positive performance-related revisions of 21 MMBoe primarily related to better-than-expected well performance and adding proved undeveloped locations due to positive drilling results in certain areas. The positive revision also included proved undeveloped reserves added to our five-year development plans in 2021. Our negative performance-related revisions primarily relate to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Extensions and discoveries – We added 5 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 11 MMBoe in connection with our Ventura divestiture and added 6 MMBoe in connection with our acquisition of the working interest in certain wells from MIRA. See *Note 8 Divestitures and Acquisitions* for more information on these transactions.

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, 2023	December 31, 2022
	(in millions)	(in millions)
Proved properties	$ 3,156	$ 2,972
Unproved properties	1	2
Total capitalized costs	3,157	2,974
Accumulated depreciation, depletion and amortization	(601)	(394)
Net capitalized costs	$ 2,556	$ 2,580

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, 2023	2022	2021
		(in millions)	
Property acquisition costs			
Proved properties(a)	$ —	$ —	$ 53
Unproved properties	—	—	—
Exploration costs	3	4	7
Development costs(b)	198	389	210
Costs incurred	$ 201	$ 393	$ 270

(a) Acquisition costs relates to our acquisition of MIRA's working interests in certain wells in 2021.
(b) Development costs include a $44 million increase, $24 million increase and $19 million increase in ARO (including assets held for sale) in 2023, 2022 and 2021, respectively.

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, 2023		2022		2021	
	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)
Revenues(a)	$ 1,879	$ 59.98	$ 1,901	$ 57.51	$ 1,729	$ 47.55
Operating costs(b)	822	26.24	785	23.75	705	19.39
General and administrative expenses	42	1.34	36	1.09	34	0.94
Other operating expenses(c)	32	1.01	21	0.64	25	0.68
Depreciation, depletion and amortization	207	6.61	175	5.29	190	5.23
Taxes other than on income	113	3.61	111	3.36	103	2.83
Accretion expense	46	1.47	43	1.30	50	1.38
Exploration expenses	3	0.10	4	0.12	7	0.19
Pretax income	614	19.60	726	21.96	615	16.91
Income tax provision(d)	(171)	(5.45)	(189)	(5.72)	(144)	(3.96)
Results of operations	$ 443	$ 14.15	$ 537	$ 16.24	$ 471	$ 12.95

(a) Revenues include oil, natural gas and NGL sales, cash settlements on our commodity derivatives and other revenue related to our oil and natural gas operations.
(b) Operating costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties.
(c) Other operating expenses primarily include transportation costs.
(d) 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 28%. The effective tax rate for 2022 and 2021 includes the benefit of enhanced oil recovery and 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, 2023, 2022 and 2021, 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, 2023, 2022 and 2021. 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

(in millions)	December 31, 2023	December 31, 2022	December 31, 2021
Future cash inflows	$ 24,813	$ 35,190	$ 28,031
Future costs			
Operating costs[(a)]	(12,479)	(15,294)	(13,508)
Development costs[(b)]	(1,805)	(1,973)	(2,607)
Future income tax expense	(2,784)	(4,843)	(3,124)
Future net cash flows	7,745	13,080	8,792
Ten percent discount factor	(3,676)	(6,354)	(4,243)
Standardized measure of discounted future net cash flows	$ 4,069	$ 6,726	$ 4,549

(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

(in millions)	2023	2022	2021
Beginning of year	$ 6,726	$ 4,549	$ 1,932
Sales of oil and natural gas, net of production and other operating costs	(1,604)	(1,156)	(543)
Changes in price, net of production and other operating costs	(2,829)	3,814	3,414
Previously estimated development costs incurred	164	228	185
Change in estimated future development costs	(47)	306	(401)
Extensions, discoveries and improved recovery, net of costs	99	509	115
Revisions of previous quantity estimates[(a)]	(103)	(1,041)	1,114
Accretion of discount	853	573	226
Net change in income taxes	1,029	(869)	(1,131)
Purchases and sales of reserves in place	(270)	(141)	(15)
Change in timing of estimated future production and other	51	(46)	(347)
Net change	(2,657)	2,177	2,617
End of year	$ 4,069	$ 6,726	$ 4,549

(a) Includes revisions related to performance and price changes.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Charged (Credited) to Costs and Expenses	Charged (Credited) to Other Accounts	Deductions	Balance at End of Period
2023					
Deferred tax valuation allowance	$ 35	$ (35)	$ —	$ —	$ —
Other asset valuation allowance	$ 1	$ 2	$ —	$ —	$ 3
2022					
Deferred tax valuation allowance	$ —	$ 35	$ —	$ —	$ 35
Other asset valuation allowance	$ —	$ 1	$ —	$ —	$ 1
2021					
Deferred tax valuation allowance	$ 549	$ (526)	$ (23)	$ —	$ —
Other asset valuation allowance	$ —	$ —	$ —	$ —	$ —

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, 2023 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, 2023, our system of internal control over financial reporting is effective.

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 management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), has evaluated the effectiveness 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 amended (Exchange Act)), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our CEO and CFO have concluded that, as of December 31, 2023, our disclosure controls and procedures are effective and are 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 CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act of 1934) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the three months ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control 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

Director Departure

On February 23, 2024, Julio M. Quintana informed the Board of Directors of his decision not to seek reelection as a director at the Company's 2024 Annual Meeting of Stockholders (the "2024 Annual Meeting"). Mr. Quintana will continue to serve on the Board of Directors and applicable committees thereof for the remainder of his term as a director until the 2024 Annual Meeting. Mr. Quintana's decision not to stand for reelection was not due to any disagreements with the Company on any matter regarding its operations, policies or practices. The Board thanks Mr. Quintana for his board service.

Rule 10b5-1 Trading Arrangements

During the year ended December 31, 2023, none of our 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.

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 2024 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2023 (2024 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:

Name	Employment History	Age at February 28, 2024
Francisco J. Leon	President, Chief Executive Officer and Director since 2023; Executive Vice President and Chief Financial Officer 2020-2023; 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.	47
Manuela (Nelly) Molina	Executive Vice President and Chief Financial Officer since 2023; Sempra Energy Vice President of Audit Services 2022 to 2023 and Vice President Investor Relations 2020 to 2022; IEnova (a Sempra company) Chief Financial Officer 2017 to 2020 and Vice President Finance 2010 to 2017; El Paso Corp. Vice President Finance and Controller 2001 to 2010; Gas Natural de Noroeste General Manager 1999 to 2001 and Controller 1997 to 1999.	51
Omar Hayat	Executive Vice President Operations since 2023; Senior Vice President Operations 2023; Vice President of Operations for Elk Hills production complex from 2021 - 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 - 2019.	48
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.	59
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.	59
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.	53

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2024 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 2024 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 2024 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 2024 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).
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).
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).

Exhibit Number	Exhibit Description
3.4	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 3.2 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
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, 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).
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).
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 October 27, 2020, 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-A filed October 27, 2020 and incorporated herein by reference).
10.9	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).
10.10**	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).

Exhibit Number	Exhibit Description
10.11	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).
	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.
10.12	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).
10.13	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).
10.14	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).
10.15	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.46 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.16	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.47 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.17	Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Term and Conditions (filed as Exhibit 10.48 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.18	Employment Agreement by and between Mark A. McFarland and California Resources Corporation, dated March 22, 2021 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 22, 2021 and incorporated herein by reference).
10.19	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 5, 2021 and incorporated herein by reference).
10.20	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).
10.21	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).
10.22**	Employment Agreement by and between Manuela Molina and California Resources Corporation, dated May 8, 2023 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 1, 2023 and incorporated herein by reference).
10.23**	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).
10.24**	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).
10.25	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).
10.26	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).
10.27	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).

Exhibit Number	Exhibit Description
10.28	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).
10.29*	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions.
10.30*	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions.
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.
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.
99.1*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2023.
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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CALIFORNIA RESOURCES CORPORATION

February 28, 2024

By: /s/ Francisco J. Leon

Francisco J. Leon
President,
Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Francisco J. Leon Francisco J. Leon	President, Chief Executive Officer and Director	February 28, 2024
/s/ Manuela (Nelly) Molina Manuela (Nelly) Molina	Executive Vice President and Chief Financial Officer	February 28, 2024
/s/ Noelle M. Repetti Noelle M. Repetti	Senior Vice President and Controller and Principal Accounting Officer	February 28, 2024
/s/ Tiffany (TJ) Thom Cepak Tiffany (TJ) Thom Cepak	Chair of the Board	February 28, 2024
/s/ Andrew B. Bremner Andrew B. Bremner	Director	February 28, 2024
/s/ James N. Chapman James N. Chapman	Director	February 28, 2024
/s/ Mark A. (Mac) McFarland Mark A. (Mac) McFarland	Director	February 28, 2024
/s/ Nicole Neeman Brady Nicole Neeman Brady	Director	February 28, 2024
/s/ Julio M. Quintana Julio M. Quintana	Director	February 28, 2024
/s/ William B. Roby William B. Roby	Director	February 28, 2024
/s/ A. Alejandra Veltmann A. Alejandra Veltmann	Director	February 28, 2024

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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 May 3, 2024. 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

American Stock Transfer and Trust Company, LLC
Shareholder Services
6201 15th Avenue, Brooklyn, New York 11219
(866) 659-2647
crc@astfinancial.com
www.astfinancial.com

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

Chris D. Gould
Executive Vice President, Chief Sustainability Officer and Managing Director, Carbon TerraVault Holdings, LLC

Omar Hayat
Executive Vice President, Operations

Manuela (Nelly) Molina
Executive Vice President
and Chief Financial 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 Special Committee on Finance and Director since 2020

Andrew B. Bremner
Member of the Compensation Committee, Sustainability Committee, Special Committee on Finance and Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2021

James N. Chapman
Chair of the Compensation Committee and Special Committee on Finance, Member of the Nominating and Governance Committee and Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2020

Francisco J. Leon
President, Chief Executive Officer and Director since 2023

Mark A. (Mac) McFarland
Chair of the Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2020

Nicole Neeman Brady
Member of the Sustainability Committee and Compensation Committee and Director since 2021

Julio M. Quintana
Chair of the Nominating and Governance Committee, Member of the Audit Committee and Director since 2020

William B. Roby
Chair of the Sustainability Committee, Member of the Audit 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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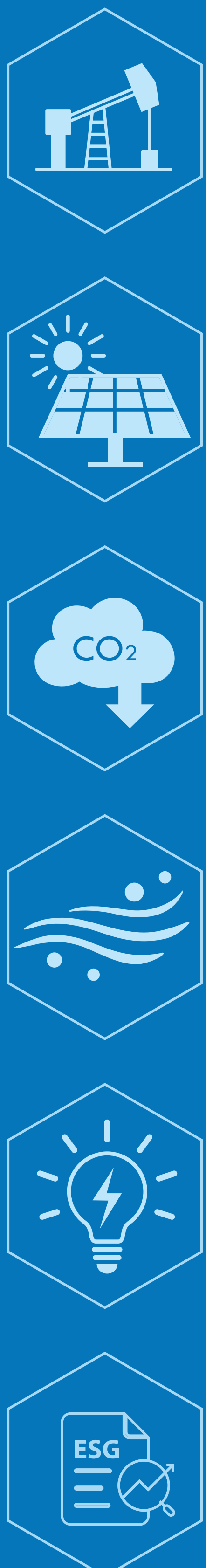
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