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, 2021
☐ **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.)

27200 Tourney Road, Suite 200
Santa Clarita, California 91355
(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. ☑

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, 2021: $2,467,158,949.

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, 2022, there were 78,744,340 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2021 with the Securities and Exchange Commission in connection with the registrant's 2022 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

GLOSSARY AND SELECTED ABBREVIATIONS

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

- ***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 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.
- ***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.
- ***GHG*** - Greenhouse gases.
- ***JV*** - Joint venture.
- ***LCFS*** - Low Carbon Fuel Standard.
- ***LIBOR*** - London Interbank Offered Rate.
- ***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.
- ***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.
- ***OPEC*** - Organization of the Petroleum Exporting Countries.
- ***PHMS*** - 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.
- ***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.
- ***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 company operating properties exclusively within California. We provide ample, affordable and reliable energy in a safe and responsible manner, to support and enhance the quality of life of Californians and the local communities in which we operate. We do this through the development of our broad portfolio of assets while adhering to our commitment to making value-based capital investments. Further, we are committed to energy transition and have some of the lowest carbon intensity production in the United States. Through our subsidiary, Carbon TerraVault, we are in the early stages of developing several carbon capture and sequestration projects in California. Separately, we are evaluating the feasibility of a carbon capture system to be located at our Elk Hills power plant (CalCapture). We are also pursuing multiple solar projects for supplying the grid (front-of-the-meter solar) and powering our operations (behind-the-meter solar). 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.

We qualified for and adopted fresh start accounting in connection with our emergence from bankruptcy on October 27, 2020, at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting. As a result of the application of fresh start accounting and the effects of the implementation of our joint plan of reorganization (the Plan), the financial statements after October 31, 2020 may not be comparable to the financial statements prior to that date. Accordingly, "black-line" financial statements are presented to distinguish between Predecessor and Successor companies. References to "Predecessor" refer to the Company for periods ending on or prior to October 31, 2020 and references to "Successor" refer to the Company for periods subsequent to October 31, 2020.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Chapter 11 Proceedings* and *Note 15 Fresh Start Accounting* for additional information on the terms of the Plan, our emergence from bankruptcy and application of fresh start accounting.

Business Strategy

Our strategy is to continue to develop our oil and natural gas assets and while pursuing opportunities in the emerging industries of decarbonization and energy transition. To accomplish our strategy, we have developed the following key priorities:

- **Maintain our oil production with a self-funded capital program focused on low-risk, high return investments.** The lower base decline of our conventional assets and more efficient capital requirements compared to many of our peers provides us with a significant advantage. We are targeting investing up to approximately 50% of our operating cash flow back into our exploration and production business over the next several years. Our capital allocation priorities focus on enhancing the value of our oil and gas assets while protecting our balance sheet, maintaining mechanical integrity of our infrastructure and sustaining our base oil production. With the premium Brent-based pricing for our oil, we intend to continue our focus on crude oil projects which have a higher return than our natural gas projects.

- **Preserve balance sheet strength and return capital to our shareholders.** We maintain a robust hedging strategy to help protect our cash flow from operations from volatility in the commodities market. Additionally, we are committed to maintaining low leverage and a strong liquidity position. Over the next several years, we are targeting investing approximately 25% of our operating cash flow for shareholder returns and other strategic opportunities. In 2021, we adopted a dividend policy by which we expect to pay a quarterly dividend of $0.17 per share of our common stock, subject to final quarterly approval by our Board of Directors. We have also adopted a $350 million share repurchase program that is expected to run through December 31, 2022. We have repurchased 4,089,988 shares as of December 31, 2021 at an average price of $36.08 per share.

- **Maintain our commitment to safety and sustainability and demonstrate leadership on ESG practices in the E&P space**. We are committed to exceptional environmental and safety performance and have some of the lowest carbon intensity production among oil and natural gas producers in the United States. We recently announced a Full-Scope Net Zero goal and are seeking to permanently store captured or removed carbon emissions equal to our Scope 1, 2 and 3 emissions by 2045, which aligns us with the state of California's 2045 net zero ambitions and puts us ahead of the net zero goals in the Paris Agreement. We intend to achieve this goal through our existing and future decarbonization projects, including Carbon TerraVault. We strive to create a culture of safety and achieved a 99.9997% oil spill prevention rate in 2021 and registered a workforce total recordable incident rate of 0.43 per 100 employees and contractors. As part of our commitment to this priority, our annual incentive compensation metrics for our management team include specific ESG targets for safety, environmental stewardship and sustainability project milestones. For 2022, 30% of our management team's annual incentive related to company performance is tied to ESG related metrics.

- **Advancing decarbonization and other emissions reducing projects.** Over the next several years, we are targeting investing approximately 25% of our operating cash flows in carbon management projects. These projects include Carbon TerraVault, which is in the early stages of permitting and developing several carbon capture and permanent storage projects in suitable reservoirs. Separately, we are evaluating the feasibility of our CalCapture project which utilizes the Elk Hills power plant as the emissions source for CO_2 EOR in our Elk Hills field. We are also pursuing multiple front-of-the-meter and behind-the-meter solar projects.

Operations

As of December 31, 2021, our proved reserves totaled an estimated 480 MMBoe, of which 343 MMBbl were crude oil and condensate reserves, 41 MMBbl were NGL reserves and 576 BcF, or 96 MMBoe, were natural gas reserves.

As of December 31, 2021, we held approximately 1.9 million net mineral acres, the largest non-governmental mineral acreage position in California. Our operated asset base spans 99 distinct fields with approximately 10,000 operated wells. We had average net production of approximately 100 MBoe/d (60% oil) for the year ended December 31, 2021. Our average net revenue interest was 85% as of December 31, 2021. From time to time, we will assess our robust portfolio of assets for divestitures.

The following table highlights key information about our operations as of and for the year ended December 31, 2021:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Other[(a)]	Total Operations
Mineral Acreage						
Net mineral acreage (thousands)	1,260	30	11	472	118	1,891
Average net mineral acreage held in fee (%)	78 %	45 %	3 %	40 %	97 %	69 %
Number of producing fields we operate	42	5	2	50	—	99
Average net revenue interest (%)[(b)]	91 %	69 %	85 %	81 %	100 %	85 %
Average drilling rigs[(c)]	2	—	—	—	—	2
Net wells drilled and completed	109.4	6.5	—	—	—	115.9
Proved reserves						
Oil (MMBbl)	203	138	2	—	—	343
NGLs (MMBbl)	41	—	—	—	—	41
Natural gas (Bcf)	481	11	1	83	—	576
Total (MMBoe)	324	140	2	14	—	480
Oil percentage of proved reserves	63 %	99 %	100 %	— %	— %	71 %
Production						
Total net production (MMBoe)	27	7	1	1	—	36
Average daily net production (MBoe/d)	75	19	3	3	—	100

(a) Reflects retained non-operating interest in the Ventura Basin and nearby areas. Our other interests include unproved locations. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on our Ventura Basin divestiture.

(b) The average net revenue interest represents our interest in oil, natural gas and NGL production as a percentage of gross production. Our revenue interest considers royalties and similar burdens and third-party working interests.

(c) We operated three drilling rigs in the San Joaquin basin and one drilling rig in the Los Angeles basin at December 31, 2021.

San Joaquin Basin

The San Joaquin basin contains some of the largest oil fields in the United States based on cumulative production and proved oil and natural gas reserves. Commercial petroleum development 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 one of the largest fields in the continental United States.

At Elk Hills we operate efficient natural gas processing facilities, including a state-of-the-art cryogenic gas plant, with a combined gas processing capacity of over 520 MMcf/d. Additionally, our Elk Hills power plant generates sufficient electricity to operate the field, and sells excess power to the wholesale market and a utility. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of the producing wells.

We have a large ownership interest in several of the largest existing oil fields in the San Joaquin basin including Buena Vista and Coles Levee. We have also been successfully developing steamfloods in our Kern Front operations.

We believe our extensive 3D seismic library, which covers approximately 800,000 acres in the San Joaquin basin, or approximately 50% of our gross mineral acreage in this basin, gives us a competitive advantage in field development and further exploration.

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. The basin contains multiple stacked formations throughout its depths, and we believe that the Los Angeles basin provides a considerable inventory of existing field re-development opportunities as well as new play discovery potential. 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.

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. Our significant mineral acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment.

Ventura Basin

During the fourth quarter of 2021, we divested a vast majority of our assets in the Ventura basin. Other than a de minimis non-operated asset, our remaining Ventura basin assets are expected to be sold in the first half of 2022.

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, 2021.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Other[(a)]	Total
	(in thousands)					
Developed[(b)]						
Gross[(c)]	462	21	10	267	2	762
Net[(d)]	422	16	10	250	1	699
Undeveloped[(e)]						
Gross[(c)]	1,027	17	2	270	144	1,460
Net[(d)]	838	14	1	222	117	1,192
Total						
Gross[(c)]	1,489	38	12	537	146	2,222
Net[(d)]	1,260	30	11	472	118	1,891

(a) Reflects remaining mineral acreage to be retained in the Ventura Basin and nearby areas. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 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, 2021, 69% of our total net mineral interest position was held in fee and the remainder was leased. Of our leased acreage, approximately 59% 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 72,000 net mineral acres will expire in 2022, 46,000 net mineral acres will expire in 2023 and 34,000 net mineral acres will expire in 2024. These leases represent 13% of our total net undeveloped acreage and 8% of our total net acreage as of December 31, 2021 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.

For additional information on production and prices, see information set forth in *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Production, Prices and Realizations*.

	Successor		Predecessor	
	Year Ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year Ended December 31, 2019
Average daily production				
Oil (MBbl/d)	60	63	70	80
NGLs (MBbl/d)	13	12	13	15
Natural gas (MMcf/d)	159	165	174	197
Total daily production (MBoe/d)[(a)]	100	103	112	128
Total production (MMBoe)[(a)]	36	6	34	47
Average realized prices				
Oil with hedge ($/Bbl)	$ 56.05	$ 45.37	$ 43.19	$ 68.65
Oil without hedge ($/Bbl)	$ 70.43	$ 45.65	$ 41.21	$ 64.83
NGLs ($/Bbl)	$ 53.62	$ 38.00	$ 25.70	$ 31.71
Natural gas without hedge ($/Mcf)	$ 4.22	$ 3.21	$ 2.11	$ 2.87
Average benchmark prices				
Brent oil ($/Bbl)	$ 70.79	$ 47.10	$ 42.43	$ 64.18
WTI oil ($/Bbl)	$ 67.91	$ 44.21	$ 38.44	$ 57.03
NYMEX gas ($/MMBtu)	$ 3.61	$ 2.86	$ 1.95	$ 2.67
Operating costs per Boe				
Operating costs	$ 19.39	$ 18.19	$ 14.95	$ 19.16

(a) See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Production, Prices and Realizations* for more information on our production activity.

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

	Elk Hills			Wilmington		
	2021	2020	2019	2021	2020	2019
Average daily production						
Oil (MBbl/d)	17	18	22	16	21	20
NGLs (MBbl/d)	10	10	12	—	—	—
Natural gas (MMcf/d)	81	90	103	—	1	1
Total daily production (MBoe/d)	40	43	51	16	21	20

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 15% of our total production for the year ended December 31, 2021.

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:

	Successor				**Predecessor**			
	Year ended December 31, 2021		**November 1, 2020 - December 31, 2020**		**January 1, 2020 - October 31, 2020**		**Year ended December 31, 2019**	
	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)
Operating costs	$ 705	$ 19.39	$ 114	$ 18.19	$ 511	$ 14.95	$ 895	$ 19.16
Excess costs attributable to PSCs	(66)	$ (1.83)	$ (8)	$ (1.33)	(28)	$ (0.81)	(68)	$ (1.46)
Operating costs, excluding effects of PSCs[(a)]	$ 639	$ 17.56	$ 106	$ 16.86	$ 483	$ 14.14	$ 827	$ 17.70

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

Estimated Proved Reserves, Future Net Cash Flows and Drilling Locations

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC).

The following tables summarize our estimated proved oil (including condensate), NGLs and natural gas reserves and PV-10 as of December 31, 2021. Our estimated volumes and cash flows were calculated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Prices), unless prices were defined by contractual arrangements. For oil volumes, the average Brent spot price of $69.47 per barrel was adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of $3.60 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, 2021 were $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 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, 2021				
	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Proved developed reserves					
Oil (MMBbl)	171	109	2	—	282
NGLs (MMBbl)	38	—	—	—	38
Natural Gas (Bcf)	418	8	1	83	510
Total (MMBoe)[a]	279	110	2	14	405
Proved undeveloped reserves					
Oil (MMBbl)	32	29	—	—	61
NGLs (MMBbl)	3	—	—	—	3
Natural Gas (Bcf)	63	3	—	—	66
Total (MMBoe)	45	30	—	—	75
Total proved reserves					
Oil (MMBbl)	203	138	2	—	343
NGLs (MMBbl)	41	—	—	—	41
Natural Gas (Bcf)	481	11	1	83	576
Total (MMBoe)	324	140	2	14	480
Reserves to production ratio (years)[b]	12	20	2	14	13

(a) As of December 31, 2021, approximately 22% of proved developed oil reserves, 8% of proved developed NGLs reserves, 16% of proved developed natural gas reserves and, overall, 19% 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, 2021 divided by total production for the year ended December 31, 2021.

Changes to Proved Reserves

The components of the changes to our proved reserves during the year ended December 31, 2021 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2020	317	105	12	8	442
Revisions related to price	30	25	2	7	64
Revisions related to performance	(8)	17	—	—	9
Extensions and discoveries	5	—	—	—	5
Improved recovery	1	—	—	—	1
Acquisitions and divestitures	6	—	(11)	—	(5)
Production	(27)	(7)	(1)	(1)	(36)
Balance at December 31, 2021	324	140	2	14	480

(a) Includes proved reserves related to PSCs of 111 MMBoe and 85 MMBoe at December 31, 2021 and 2020, respectively.

Revisions related to price – 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 our higher operating costs.

Revisions related to performance – 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 addition of 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 plan 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. We added 6 MMBoe in connection with our acquisition of the working interest in certain wells from Macquarie Infrastructure and Real Assets Inc. (MIRA). See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on these transactions.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2021 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBoe)		
Balance at December 31, 2020	39	19	—	2	60
Revisions related to price	2	(1)	—	—	1
Revisions related to performance	6	13	—	(2)	17
Extensions and discoveries	3	—	—	—	3
Improved recovery	—	—	—	—	—
Transfers to proved developed reserves	(5)	(1)	—	—	(6)
Balance at December 31, 2021	45	30	—	—	75

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

Revisions related to performance – We had 17 MMBoe of net positive performance-related revision which included 19 MMBoe positive performance-related revisions and negative performance-related revisions of 2 MMBoe. Our positive performance-related revisions of 19 MMBoe primarily related to better-than-expected well performance and the addition of proved undeveloped locations due to positive drilling results in certain areas. The positive revision also included proved undeveloped reserves which were added to our five-year development plan in 2021. Our negative performance-related revisions primarily related 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 3 MMBoe of proved undeveloped reserves through extensions and discoveries, as a result of successful drilling and workover programs in the San Joaquin and Los Angeles basins.

Transfers to proved developed reserves – We converted 6 MMBoe of proved undeveloped reserves to proved developed reserves in the San Joaquin and Los Angeles basins. This resulted in a conversion rate of approximately 10% of our beginning-of-year proved undeveloped reserves, with an investment of approximately $64 million of drilling and completion capital. We believe we will have sufficient capital to develop all year end 2021 proved undeveloped reserves within five years of their original booking date.

PV-10, Standardized Measure and Reserve Replacement Ratio

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, 2021
	(in millions)
Standardized measure of discounted future net cash flows	$ 4,549
Present value of future income taxes discounted at 10%	1,624
PV-10 of cash flows[(a)]	$ 6,173

(a) The average realized prices for estimating our PV-10 of cash flow as of December 31, 2021 were $68.73 per barrel for oil, $52.81 per barrel for NGLs and $3.99 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, 2021 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 Vice President of Reserves has primary responsibility for overseeing the preparation of our reserves estimates. With over 25 years of technical and leadership experience in the oil and gas industry, she has been involved with all stages of petroleum exploration and development from appraisal of new discoveries to enhanced recovery methods in mature fields. She holds a Master of Business Administration from Pepperdine University, as well as bachelor’s and master’s degrees in Geology from the University of California, Santa Barbara.

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 2021. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Ryder Scott and Netherland, Sewell & Associates, Inc. (NSAI) were engaged to provide independent audits of our reserves estimates for our fields. For the year ended December 31, 2021, Ryder Scott audited 47% of our total proved reserves. NSAI audited 35% 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. Both of our independent reserve engineers issued an unqualified audit opinion on the applicable portions of our proved reserves as of December 31, 2021, which are attached as Exhibit 99.1 and 99.2, respectively, to this Form 10-K and incorporated herein by reference.

Ryder Scott qualifications – The primary technical engineer responsible for our audit has more than 44 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Executive Committee and the Board of Directors and is a registered Professional Engineer in the state of Texas.

NSAI qualifications – The primary technical engineer primarily responsible for our audit has more than 20 years of petroleum engineering experience, with the majority spent evaluating California properties, and is a registered Professional Engineer in the state of Texas.

Drilling Locations

The table below sets forth our total gross identified drilling locations by basin for our proved undeveloped reserves as of December 31, 2021, excluding injection wells.

	Proved Drilling Locations
San Joaquin Basin	401
Los Angeles Basin	262
Total	663

We use production data and experience gained from our development programs to identify and prioritize our drilling inventory. Drilling locations are included in our reserves only after we have adopted a development plan to drill them within a five-year time frame of the original reserve booking. As a result of rigorous technical evaluation of geologic and engineering data, we can estimate with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations. Our year-end development plans and associated proved undeveloped reserves are consistent with SEC guidelines for development within five years. We believe we will have sufficient capital to develop all year-end 2021 proved undeveloped reserves within five years of their original booking date.

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
2021					
Productive					
Exploratory	—	—	—	—	—
Development	109.4	6.5	—	—	115.9
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2020					
Productive					
Exploratory	—	—	—	—	—
Development	4.0	4.5	—	0.4	8.9
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2019					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	117.5	25.2	2.0	2.4	147.1
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, 2021.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
Gross	15.0	1.0	—	—	16.0
Net	12.3	1.0	—	—	13.3

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 89% as of December 31, 2021. 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, 2021, excluding wells that have been idle for more than five years:

	As of December 31, 2021			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	7,577	6,732	152	141
Los Angeles Basin	1,725	1,635	—	—
Ventura Basin	56	56	—	—
Sacramento Basin	—	—	755	696
Total	9,358	8,423	907	837
Multiple completion wells included in the total above	44	51	8	5

(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 2022 capital plan does not allocate any capital towards exploration drilling. Although we do not anticipate exploration drilling in the near term, we do have a portfolio of 65 exploration prospects in the San Joaquin and Sacramento basins that we may pursue in the future. We also have an extensive 3D and 2D seismic library that we use to develop and refine exploration prospects.

Carbon Management Business

In November 2021, our Board of Directors announced a Full Scope Net Zero Goal. As part of this strategy, we intend to pursue CCS projects and believe our existing assets are well positioned to support the development of these projects. In addition, our operations are in close proximity to significant sources of carbon dioxide (CO_2) emissions in California.

Through our subsidiary, Carbon TerraVault, we are in the early stages of developing several CCS projects in California. Currently, we have applied for permits for two initial permanent CCS projects at the Elk Hills Field. We are also in discussions with potential emitters to enter into joint venture or other commercial arrangements with respect to Carbon TerraVault. Once completed, we expect that our Carbon TerraVault CCS projects will inject CO_2 captured from industrial sources into depleted underground oil and natural gas reservoirs and permanently store CO_2 deep underground. Separately, we are also evaluating the feasibility of a carbon capture system to be located at our Elk Hills power plant.

While all of these projects are in early stages and we do not consider the financial impact of our carbon sequestration activities to be material to our operating and financial results for the year ended December 31, 2021, 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. For more information about the risks involved in our CCS projects, see *Part I, Item 1A – Risk Factors.*

Human Capital

Our employees are our most important asset and we strive to provide a safe and healthy workplace, development opportunities and financial rewards so that our employees remain engaged and focused on providing safe, affordable and abundant energy for the communities in California.

Employee development opportunities are provided to enhance leadership development and expand career opportunities. A copy of our policies are provided to all employees, who also undergo mandatory annual training on the policies. Employer sponsored 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 our employees and those of our suppliers, vendors and joint ventures. We provide our employees industry competitive base wages and incentive compensation opportunities, as well as comprehensive health and retirement benefits; life, disability and accident insurance coverages; and employee assistance and wellness programs to promote financial stability and healthy lifestyles. We promote the health and well-being of our employees by providing these comprehensive health benefits and time off for maternity and parental leave for the adoption or birth of a child, illness and vacation. We also provide options for alternate work schedules, flexible work hours, part-time work options and telecommuting.

As of December 31, 2021, we had approximately 970 employees, all in the United States. Approximately 50 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third-party contractors throughout our operations.

Core Values

We believe our core values of Character, Responsibility and Commitment and our comprehensive business and ethical conduct policies sustain and enhance 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.

Diversity, Equity and Inclusion

Our goal is to foster a strong culture that promotes diversity, equity and inclusion and are committed to advancing women and minorities in our workplace. We believe increasing diversity, equity and inclusion will improve financial performance through better retention rates, higher innovation, and increased productivity. Beginning in 2022, we plan to establish a diversity, equity and inclusion executive council to oversee our initiatives and incorporate a quantitative metric that directly impacts incentive compensation for all of our employees.

As of December 31, 2021, 19% of our employees and 18% of our senior managers were female. Additionally, 38% of our employees and 21% of our senior managers were ethnically diverse. Currently, 33% of our Board of Directors are female.

Employee Safety

Our unwavering commitment to safety and the environment defines how we operate our business. We prepare our workforce to work safely through comprehensive training, on-the-job guidance and tools and safety meetings. Each year, we set a threshold injury and illness incidence rate as a quantitative metric that directly impacts incentive compensation for all of our employees. 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 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. The tightening labor market has not adversely affected our operations and we continue to attract the talent needed to support our operations.

Marketing Arrangements

Crude Oil – We sell nearly all of our crude oil into the California refining markets. Substantially all 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 indices that are closely tied to Brent prices. International waterborne-based Brent prices are used 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 markets on a daily basis at average monthly index pricing. 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 enjoy 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 pipeline transportation contract for 6,500 barrels per day of NGLs. 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.

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 wholesale power market and a local utility. We also sell the remaining capacity to community choice aggregates and local utilities.

Delivery Commitments

We have short-term commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2021, we had oil delivery commitments of 52 MBbl/d through March 2022, NGL delivery commitments of 12 MBbl/d through March 2022 and natural gas delivery commitments of 32 MMcf/d through October 2022. 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.

Hedging

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 Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges over our reasonably anticipated oil production from our proved reserves. We have also entered into incremental hedges above and beyond these requirements for some time periods and will continue to evaluate our hedging strategy based on prevailing market prices and conditions.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our commodity contracts.

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.

We had three customers that individually accounted for at least 10%, and collectively accounted for 51%, of our sales (before the effects of hedging). These purchasers are in the crude oil refining industry. In light of the ongoing energy deficit in California and the strong demand for native crude oil production, we do not believe that the exit of any single customer from the market would have a material adverse effect on our financial condition or results of operations at this time.

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 small independent producers and major international oil companies who operate in California. We also compete with foreign oil and gas companies because California imports approximately 70% of the oil it consumes and virtually all of that arrives from waterborne sources. 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 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. At current commodity price levels, we have experienced modest price increases for materials and services as contracts are renewed. We believe our relative size and activity levels, compared to other in-state producers, favorably influences the pricing we receive from third-party providers in the markets in which we operate.

We face competition from other sources of energy, including wind and solar power. These products compete directly with the electricity we generate from our power plants 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.

Infrastructure

Our infrastructure, including plants and facilities owned by the Wilmington field and used in our operations, is presented below:

Description	Quantity	Unit	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants[(a)]	6	MMcf/d	525	18	543
Power Plants[(b)]	3	MW	595	48	643
Steam Generators/Plants[(c)]	>30	MBbl/d	150	—	150
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
Gathering Systems[(e)]		Miles			>8,000

(a) Includes the Elk Hills cryogenic gas plant with a capacity of 200 MMcf/d of inlet gas and two low temperature separation plants used as backup facilities. 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 contiguous operations in the San Joaquin basin. We utilize approximately a third of its capacity for operations and our subsidiary sells the excess to the grid and to a local utility. Also included is a 45-megawat cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations and a 48-megawatt power generating facility within our Long Beach operations 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 gathering lines 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 gathering systems 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.

Regulation of the Oil and Natural Gas Industry

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 are described in this section.

Regulation of Exploration and Production

CalGEM is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission's administration of state surface and mineral interests. The Bureau of Land Management (BLM) of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California, on which CalGEM also asserts jurisdiction over certain activities. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. CalGEM currently requires an operator to identify the manner in which 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 gas ordinance, which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015. A group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR. Kern County circulated and certified a supplementary EIR to address the ruling from the court and, thereafter, resumed issuing local permits relying on the revised Kern County EIR. However, the trial court required that Kern County pause its local permitting system until the trial court has reviewed the supplementary EIR and confirmed that it satisfied the concerns raised by the Court of Appeal. A hearing is scheduled for April 2022. If the Kern County EIR is not reinstated or adequately modified following resolution of the litigation described above, obtaining drilling permits for our operations in areas where we do not have field or project specific CEQA coverage could be delayed or become more costly as a result of compliance with CEQA. We believe that we currently have a sufficient inventory of drilling permits for our anticipated operations; however, we cannot guarantee our ability to timely obtain additional permits in the future.

The California Legislature has 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. 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. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

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 October 2021, CalGEM released for public comment public health regulations, which include expanded land use setbacks of up to 3,200 feet from new wells in new surface locations. The proposed regulation would also require pollution controls for existing wells and facilities within the same 3,200-foot setback area. CalGEM is currently in the process of conducting an economic analysis of the proposed rule. Following this analysis, CalGEM will submit the proposed rule to the Office of Administrative Law and begin an additional process of receiving comments and refinement of the proposal as needed before a final rule can be issued. Litigation regarding any final rulemaking is also expected.

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 approximately 400,000 miles of previously unregulated onshore gas gathering lines 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.

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 gas wells and phase out existing wells over a number of years. These bans do not apply to our operations in unincorporated areas of Los Angeles, 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. For example, a similar ban was previously proposed in Monterey County, where we own mineral rights but have no production, before being declared to be preempted by state and federal regulation. Other local governments have sought to ban natural gas or the transportation of natural gas through their cities. The City of Antioch declined to extend our franchise agreement for a natural gas pipeline through its city. Several companies, including CRC, have challenged the city's inconsistent and arbitrary approach to natural gas approvals.

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.

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.

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, and 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.

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. Since the state and the EPA did not complete their review before the state’s deadlines, the state announced that it will not rescind permits or enforce the deadlines with respect to many of the formations pending completion of the review but has applied the deadlines to others. Several industry groups and operators challenged CalGEM’s implementation of its aquifer exemption regulations. In March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcement of CalGEM’s aquifer exemption regulations. The court found that CalGEM must find actual harm results from an injection well’s operations and go through a hearing process before the agency can issue fines or shut down operations. 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. We are coordinating with the state to change injection zones in certain fields to facilitate disposal of produced water in deeper formations where feasible or to increase recycling of produced water in pressure maintenance or waterfloods in lieu of disposal. In September 2021, the EPA issued a letter to the California Natural Resources Agency and the State Water Resources Control Board regarding the state's compliance with the 2015 compliance plan relating to the state's process for approving aquifer exemptions under the SDWA. The letter requested that California take appropriate action by September 2022, or the EPA would consider taking additional action to impose limits on California's administration of the UIC program, withhold federal funds for the administration of the UIC program, and direct orders to oil and gas operators injecting into formations not authorized by EPA, among other measures. The state responded in October 2021 with a proposed compliance plan but, to date, EPA has not yet responded.

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 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 announced that climate change will be a focus of his administration, and he has issued several executive orders on the subject, which, among other things, recommitted the United States to the Paris Agreement, called for the reinstatement or issuance of methane emissions standards for new, modified and existing oil and gas facilities and called for 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.

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 2020, the Governor of California 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.*

The EPA and the California Air Resources Board (CARB) have also expanded direct regulation of methane as a contributor to GHG emissions. In 2016, the EPA adopted regulations to require additional emission controls for methane, volatile organic compounds and certain other substances for new or modified oil and natural gas facilities. Although the EPA rescinded the methane-specific requirements for production and processing facilities in September 2020, the U.S. Congress subsequently approved, and President Biden signed into a law, a resolution to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, the EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. The EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of a final rule by the end of the year. Moreover, CARB has implemented more stringent regulations that require monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and natural gas production, pipeline gathering and boosting facilities and natural gas processing plants, as well as additional controls such as tank vapor recovery to capture methane emissions.

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 Business

- Prices for our products can fluctuate widely and an extended period of low prices could materially and adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.
- We are subject to economic downturns and the effects of public health events, such as the COVID-19 pandemic, which may materially and adversely affect the demand and the market prices for our products.
- Our aspirations, goals and initiatives related to carbon management activities and our Full Scope Net Zero target and our public statements and disclosures regarding them expose us to numerous risks.
- Our ability to establish a large-scale carbon capture and sequestration project is subject to numerous risks and uncertainties. If we are unable to successfully execute our carbon capture and sequestration strategy, it could have a material adverse effect on our business, results of operations and financial condition and our ability to achieve our Full-Scope Net Zero goals.
- Drilling for and producing oil and natural gas carry significant operational and financial 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 can involve substantial capital investments. We may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.
- From time to time we may engage in exploratory drilling, including drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.
- Our producing properties are located exclusively in California, making us vulnerable to economic and regulatory factors associated with having operations concentrated in this geographic area.
- Many of our current and potential competitors have or may potentially have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties.
- Our hedging activities may limit our ability to realize the full benefits of increases in commodity prices.
- Our level of hedging activities 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 lower than estimated.

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.
- Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations any of which could increase costs, restrict operations and change or delay the implementation of our business plans.
- Concerns about climate change and other air quality issues may prompt governmental action that could materially affect our operations or results.
- Adverse tax law changes may affect our operations.

Risks Related to our Indebtedness

- 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 prices 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.

General Risk Factors

- Increasing attention to ESG matters may adversely impact our business.
- Acquisition and disposition activities involve substantial risks.
- 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 Our Business

Prices for our products can fluctuate widely and an extended period of low prices 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 sustained period of low prices for oil, natural gas and NGLs 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 supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- changes in domestic and global supply and demand;
- domestic and global inventory levels;
- political and economic conditions, including international disputes such as the conflict between Ukraine and Russia;
- 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;
- 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 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 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;
- affecting our ability to attract counterparties and enter into commercial transactions, including hedging, surety or insurance transactions; 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.

We are subject to economic downturns and the effects of public health events, such as the COVID-19 pandemic, which may materially and adversely affect the demand and the market price for our products.

The COVID-19 pandemic has adversely affected the global economy, and has resulted in, among other things, travel restrictions, business closures and the institution of quarantining and other mandated and self-imposed restrictions on movement. We do not know how long these conditions will last. The severity, magnitude and duration of COVID-19 or another pandemic, the extent of actions that have been or 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 the 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 the pandemic's adverse impact on our operating results.

Additionally, to the extent the COVID-19 pandemic or any resulting worsening of the global business and economic environment 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.

Our aspirations, goals, and initiatives related to carbon management activities and our Full Scope Net Zero target, and our public statements and disclosures regarding them, expose us to numerous risks.

We have developed, and will continue to develop and set, goals, targets, and other objectives related to sustainability matters, including our Full Scope Net Zero target and our energy transition strategy. Statements related to these goals, targets and objectives reflect our current plans and do not constitute a guarantee that they will be achieved. Our efforts to research, establish, accomplish, and accurately report on these goals, targets, and objectives expose us to numerous operational, reputational, financial, legal, and other risks. Our ability to achieve any stated goal, target, or objective, including with respect to emissions reduction, 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 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.

Our ability to establish a large scale carbon capture and sequestration project is subject to numerous risks and uncertainties. If we are unable to successfully execute our CCS strategy, it could have a material adverse effect on our business, results of operations and financial condition and our ability to achieve our Full-Scope Net Zero goals.

We have announced a strategy to pursue various carbon emissions reduction efforts, including CCS projects such as Carbon TerraVault. To our knowledge, there are no existing large scale carbon capture projects in California of the type contemplated by Carbon TerraVault or CalCapture. These projects face operational, technological and regulatory risks that could be considerable due to 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:

- Large scale carbon capture is an emerging sector and there are not substantial precedents to gauge the likely range of structures or economic terms that will be necessary to reach agreeable terms.
- The development of a CCS project may require us to enter into long term joint ventures with large carbon emitters and operators of infrastructure for transporting CO_2 (or other GHGs) and we may not be able to do so on agreeable terms or at all.
- Not all facilities 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 usable in one or more of our CCS projects.
- Our CCS projects are expected to have material capital requirements and there is no certainty that we will be able to finance these projects on reasonable terms.
- To the extent CO_2 transportation pipelines are not present in proposed project areas, or if they do not extend to one or more of our project sites, we may be required to convert existing pipelines, or build new CO_2 pipelines or lateral connections, which will require much larger capital expenditures and may be subject to various environmental and other permitting requirements as well as third party easements that could be difficult to obtain, which may render one or more projects uneconomical or impractical. Additionally, even in areas where such pipelines are in place, our use of them may require reaching agreements on CO_2 transportation with operators of the pipelines.
- The economics of CCS projects depend on financial and tax incentives that may not currently be sufficient for our CCS projects to be economical or could be changed or terminated. Congress has incentivized the development of carbon capture projects through the establishment of the Internal Revenue Code Section 45Q tax credit (45Q) for carbon sequestration. Recent Internal Revenue Service guidance and regulations on this tax credit are intended to provide increased certainty for the industry by establishing processes and standards to secure geologic storage of CO_2. However, additional financial incentives may be required for our 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 45Q or LCFS are subsequently amended in a manner that such incentives no longer apply or are restricted in application to our projects, we may not be able to successfully achieve an economic return from our CCS business or, alternatively, the construction of operation of applicable projects may be substantially delayed such that one or more projects is unprofitable or otherwise infeasible.
- CCS projects will require storage of CO_2 in subterranean reservoirs over long periods of time. If accidental releases or subsurface migration of CO_2 from our CCS activities were to occur in the course of operating one or more of our CCS sites, there is the risk of recapture of 45Q tax credits or LCFS credits from us by the government, as well as a risk of trespass or other tort claims related to the accidental release or migration of CO_2 beyond the boundaries of any anticipated project's approved area and potential for fines and penalties for violations of environmental requirements.
- 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 is no assurance that we will be successful in obtaining 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 all applicable permits for CCS activities on a timely basis or on favorable terms.
- As CCS and carbon management represent an emerging sector, regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent 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.
- We may not own the pore space at all of our CCS project sites, which may require us to enter into agreements with a group of owners for the real estate covering the extent of the project.
- 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, notwithstanding that CO_2 emissions are intended to be captured, there may be organized opposition to carbon capture, including our projects, from certain environmental groups.

There can be no assurances that we will successfully develop our CCS projects, including Carbon Terravault and CalCapture, and such failure could have a material adverse effect on our liquidity, financial condition and results of operations. If we are not able to successfully develop these projects, our ability to achieve our 2045 Full-Scope Net Zero goal for Scope 1, 2 and 3 emissions would also be materially and adversely affected.

Drilling for and producing oil and natural gas carry significant operational and financial 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 exploration and development of oil and natural gas properties 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. We also bear the risks of equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts) and other associated risks.

Our decisions and ultimate profitability are also affected by commodity prices, the availability of capital, regulatory approvals, available transportation and storage capacity, the political environment and other factors. Our cost of drilling, completing, stimulating, equipping, operating, inspecting, maintaining and abandoning wells is also often uncertain.

Any of the forgoing operational or financial 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 represent a significant part of our long-term growth 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 13% of our total net undeveloped acreage at December 31, 2021.

Our business involves substantial capital investments, which may include acquisitions, partnerships or joint venture arrangements with other oil and gas exploration and production companies or financial investors. We may be unable to fund our capital program, or reach satisfactory terms for other future capital requirements, which could lead to a decline in our oil and natural gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.

Our exploration, development and acquisition activities can involve substantial capital investments. We intend to fund our 2022 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
- the availability under our Revolving Credit Facility and external sources of financing.

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.

From time to time we may engage in exploratory drilling, including 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 our exploration drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular for those exploration drilling locations 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.

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 include local price fluctuations, changes in state or regional laws and regulations affecting our operations 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 and earthquakes. 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.

Many of our current and potential competitors have or may potentially have greater resources than we have and we may not be able to successfully compete in acquiring, exploring 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 multinational oil companies, 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 covenants that require us to maintain a certain level of hedges and we currently have 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.

Our level of hedging activities may be impacted by financial regulations that could increase our costs of hedging and/or limit the number of hedging counterparties available to us.

U.S. financial regulations can impact both our level of hedging activity as well as the potential cost of entering into hedges. In particular, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, established federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the U.S. Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions. These regulations can affect both the size of positions that we may enter and the ability or willingness of counterparties to trade opposite us.

In addition, U.S. regulators adopted a final rule in November 2019 implementing a new approach for calculating the exposure amount of derivative contracts under the applicable agencies’ regulatory capital rules, referred to as the standardized approach for counterparty credit risk (SA-CCR). Certain financial institutions are required to comply with the new SA-CCR rules beginning on January 1, 2022. The new rules could significantly increase the capital requirements for some of our hedge counterparties in the OTC derivatives market. These increased capital requirements could result in significant additional costs being passed through to end users like us or reduce the number of participants or products available to us in the OTC derivatives market.

The European Union and other non-U.S. jurisdictions may implement regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations, which could also adversely affect our hedging opportunities.

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 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 a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although over 80% of our estimated proved reserve volumes as of December 31, 2021 were audited by our independent petroleum engineers, Ryder Scott and 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, including:

- historical production from the area compared with production from similar areas;
- the quality, quantity and interpretation of available relevant data;
- commodity prices;
- production and operating costs;
- ad valorem, excise and income taxes;
- development costs;
- the effects of government regulations; and
- future workover and facilities costs.

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 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.

In September 2020, Governor Gavin Newsom of California issued an executive order (Order) that seeks to reduce both the demand for and supply of petroleum fuels in the state. The Order establishes several goals and directs several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of new emissions-producing passenger vehicles, drayage trucks and off-road vehicles by 2035 and, to the extent feasible, medium and heavy duty trucks by 2045; developing strategies for the closure and repurposing of oil and gas facilities in California; and proposing legislation to end the issuance of new hydraulic fracturing permits in the state by 2024.

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. 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. Beginning in 2021, CalGEM ceased issuing new well stimulation permits and has slowed the approval of new drill permits even as it continues approving plugging and workovers. In addition, a group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR that Kern County had typically relied on to satisfy CEQA in order to issue permits in Kern County. Kern County circulated and certified a supplementary EIR. However, the trial court required that Kern County pause its local permitting system until the trial court has reviewed the supplementary EIR and confirmed that it satisfied the concerns raised by the Court of Appeal. A hearing is scheduled for April 2022. If the Kern County EIR is not reinstated or adequately modified following resolution of the litigation described above, obtaining drilling permits for our operations in areas where we do not have field or project specific CEQA coverage could be delayed or become costly as a result of compliance with CEQA.

While we have a new drill permit inventory and believe we will be able to continue to maintain oil production in 2022, we cannot guarantee that we will indefinitely continue to receive new drill permits in a sufficient number to offset oil production decline.

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. We cannot predict the actions the Governor of California or the California legislature may take with respect to the regulation of our business, the oil and natural gas industry or the state’s economic, fiscal or environmental policies, nor can we predict what actions may be taken at the federal level with respect to health, environmental safety, climate, labor or energy laws, regulations and policies, including those that may directly or indirectly impact our operations.

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 recent years, the regulation of methane emissions from oil and gas facilities has been subject to uncertainty. In September 2020, the Trump Administration revised prior regulations to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations. However, the U.S. Congress subsequently approved and President Biden signed into a law, a resolution to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, the EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. The EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of a final rule by the end of the year. Additionally, at the 26th Conference of the Parties of the United Nations Framework Convention on Climate Change (COP26) in Glasgow in November 2021, the United States and the European Union jointly announced the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. The full impact of these actions is uncertain at this time and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects 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 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 gas companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (GFANZ) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. 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. The Federal Reserve announced in late 2020 that it has joined the Network for Greening the Financial System (NGFS), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Subsequently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenged most relevant to central banks and supervisory authorities. Although we cannot predict the effects of these actions, such limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities. Additionally, the Securities and Exchange Commission announced its intention to promulgate rules requiring climate disclosures. Although the form and substance of these requirements is not yet known, this may result in additional costs to comply with any such disclosure requirements.

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.

Adverse tax law changes may affect our operations.

We are subject to taxation by various tax authorities at the federal, state and local levels where we do business. New legislation could be enacted by any of these government authorities that could adversely affect our business. Legislation has been previously 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 gas exploration and production companies. Such changes include, but are not 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; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. 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.

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. Although such proposals targeting our industry have not become law, campaigns by various interest groups could lead to additional future taxes.

Risks Related to our Indebtedness

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

As of December 31, 2021, we had $600 million of total long-term debt, and additional borrowing capacity of $367 million under the Revolving Credit Facility (after taking into account $125 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 operations 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;
- 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, 2022 was set at $492 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, limiting our ability, among other things, to:

- incur additional indebtedness;
- incur additional liens;
- pay dividends or make other distributions;
- make investments, loans or advances;
- sell or discount receivables;
- enter into mergers;
- sell properties;
- enter into or terminate hedge agreements;
- enter into transactions with affiliates;
- maintain gas imbalances;
- enter into take-or-pay contracts or make other prepayments;
- enter into sale and leaseback agreements;
- prepay or modify the terms of junior debt;
- enter into negative pledge agreements;
- enter into production sharing contracts;
- amend our organizational documents; and
- make capital investments.

The Revolving Credit Agreement 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 such, our results of operations are 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 a certain portion of our debt. 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.

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 $0.68, payable to shareholders in quarterly increments of $0.17 per share of common stock, subject to board authorization and declaration each quarter. In addition, as of December 31, 2021, we had remaining authorization under our Share Repurchase Program to repurchase up to $102 million of shares of our common stock. 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, 2021, we had 79,299,222 outstanding shares of common stock and 4,296,055 shares of common stock issuable upon exercise of outstanding warrants. We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that 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 January 31, 2022, four of our shareholders owned at least 10% and collectively approximately 46% 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.

General Risk Factors

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. 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.

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

Acquisition and disposition activities involve substantial risks.

Our acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs 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. If we are not able to make acquisitions, we may not be able to grow our reserves or develop our properties in a timely manner or at all.

Part of our business strategy involves divesting non-core assets. 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.

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 oil and natural gas exploration and production activities and our assets are subject to risks such as fires, explosions, releases, discharges, power outages, equipment or information technology failures and industrial accidents, as are the assets and properties of third parties who supply us with energy, equipment and services or who purchase, transport or use our products. 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. In addition, events such as earthquakes, floods, mudslides, wildfires, power outages, high winds, droughts, cybersecurity, vandalism or terrorist attacks and other events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. Further, recent wildfires experienced in California have limited the availability and increased the cost of obtaining insurance against certain natural disasters. 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.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3 LEGAL PROCEEDINGS

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

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information for Common Stock

Since our emergence from bankruptcy on October 27, 2020, our common stock has been listed under the symbol "CRC" on the New York Stock Exchange (NYSE). During the period from July 16, 2020 through October 26, 2020, the Predecessor company’s common stock was quoted on the OTC Pink Market under the symbol “CRCQQ”. Prior to July 16, 2020, the Predecessor company’s common stock was listed on the NYSE under the symbol “CRC”.

Holders of Record

Our common stock was held by 3 stockholders of record at December 31, 2021.

Dividend Policy

In the fourth quarter of 2021, our Board of Directors declared a quarterly cash dividend of $0.17 per share of common stock. The dividend was paid on December 16, 2021 to shareholders of record at the close of business on December 1, 2021. On February 23, 2022, our Board of Directors declared a quarterly cash dividend of $0.17 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 7, 2022 and is expected to be paid on March 16, 2022. All dividends are subject to quarterly approval by our Board of Directors and will be determined based on conditions including, our earnings, financial condition, restrictions from our Revolving Credit Facility, business conditions and other factors. Based on current conditions, we expect to continue paying regular quarterly dividends of $0.17 per share through 2022.

Share Repurchases

In May 2021, our Board of Directors authorized a Share Repurchase Program. We increased our Share Repurchase Program in February 2022 by $100 million to $350 million in aggregate and extended the term of the program until December 31, 2022. 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, 2021 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)]
April 1, 2021 - June 30, 2021	1,440,203	$ 31.56	1,440,203	$ —
July 1, 2021 - September 30, 2021	1,151,596	$ 33.42	1,151,596	—
October 1, 2021 - October 31, 2021	384,605	$ 42.23	384,605	—
November 1, 2021 - November 30, 2021	491,331	$ 43.57	491,331	—
December 1, 2021 - December 31, 2021	622,253	$ 41.75	622,253	—
Total	4,089,988	$ 36.08	4,089,988	$ —

(a) The dollar value of shares that may yet be purchased under the Share Repurchase Program totaled $102 million as of December 31, 2021.

Securities Authorized for Issuance Under Equity Compensation Plans

A description of stock-based compensation plans can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Stock-Based Compensation*. The aggregate number of shares of our common stock authorized for issuance under our stock-based compensation plans for our executives, employees and non-employee directors, approved as part of the Plan upon our emergence from bankruptcy, is 9,257,740. Approximately 2,092,318 has been issued or reserved through December 31, 2021. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Chapter 11 Proceedings* for more information on the Plan.

The following is a summary of the securities available for issuance as of December 31, 2021:

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	—	—	—
Equity compensation plan not approved by security holders	2,074,145 (1)	—	7,165,422 (2)
Total	2,074,145		7,165,422

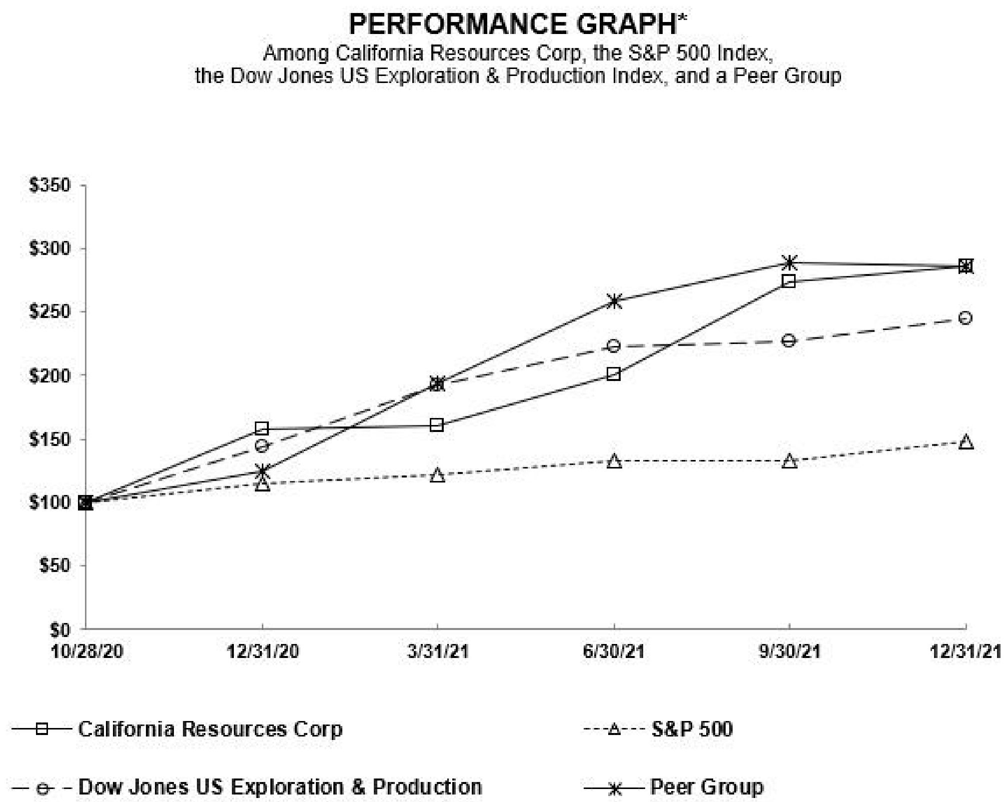
(1) The number of securities to be issued upon vesting of performance stock units assumes all units are earned upon achieving the specified 60-trading day volume weighted average prices for shares of our common stock. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Stock-Based Compensation* for more information on these awards.

(2) Relates to remaining shares available for issuance under our stock-based compensation plans for our executives, employees and non-employee directors.

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 groups. 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 peer group consisted of Antero Resources Corporation; Berry Petroleum; Callon Petroleum Company; Comstock Resources Inc.; Coterra Energy Inc.; Denbury Inc.; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; Oasis Petroleum Inc.; PDC Energy, Inc.; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; Vermilion Energy Inc.; and Whiting Petroleum Corporation



	10/28/20	12/31/20	3/31/21	6/30/21	9/30/21	12/31/21
CRC	**100.00**	**157.27**	**160.40**	**200.93**	**273.33**	**285.97**
S&P 500	**100.00**	**115.21**	**122.33**	**132.78**	**133.56**	**148.28**
Dow Jones US Exploration & Production	**100.00**	**143.37**	**192.09**	**221.97**	**226.75**	**245.05**
Peer Group	**100.00**	**125.21**	**193.92**	**258.98**	**289.09**	**285.45**

* 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.*

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.

On July 15, 2020, we filed voluntary petitions for relief under Chapter 11 of Title 11 of the Bankruptcy Code. On October 13, 2020, the Bankruptcy Court confirmed our joint plan of reorganization (the Plan) and we subsequently emerged from Chapter 11 on October 27, 2020 with a new Board of Directors, new equity owners and a significantly improved financial position.

We qualified for and adopted fresh start accounting upon emergence from bankruptcy at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the financial statements after October 31, 2020 may not be comparable to the financial statements prior to that date. References to "Predecessor" refer to the Company for periods ended on or prior to October 31, 2020 and references to "Successor" refer to the Company for periods subsequent to October 31, 2020. See *Part II, Item 8 – Financial Statements and Supplementary Data – Note 14 Chapter 11 Proceedings* and *Note 15 Fresh Start Accounting* for more information.

The periods November 1, 2020 through December 31, 2020 (Successor period) and January 1, 2020 through October 31, 2020 (Predecessor period) are distinct reporting periods as a result of the adoption of fresh start accounting. Certain operating results and performance measures were not significantly impacted by the reorganization. Accordingly, we believe that discussing the combined results for the two periods in 2020 is relevant and useful when making comparisons between periods for certain items such as production, realized prices, production costs and general and administrative expenses. While this combined presentation is not in accordance with generally accepted accounting principles in the United States (GAAP) and no comparable GAAP measures are presented, management believes that providing this information supplements the discussion of our results. For items that are not comparable (for example depreciation, depletion and amortization, interest expense and noncontrolling interest), our discussion addresses Predecessor and Successor results separately.

COVID-19 Pandemic

The COVID-19 pandemic has continued to create challenges including disrupting global supply chains. In early 2021, health agencies approved vaccines for combating the COVID-19 virus. However, actual vaccination results are ultimately dependent on, among other factors, vaccine availability and their acceptance by individuals. Variants of COVID-19 have become the dominant strain and have begun to spread resulting in pandemic restrictions being reinstated. Accordingly, the continued pace of recovery from the COVID-19 pandemic is not currently known.

Global commodity prices increased during 2021 amid strong demand recovery from the economic impacts of COVID-19. We maintain various measures, primarily implemented during 2020, to protect the health of our workforce and to support the prevention of COVID-19 at our plants, rigs, fields and administrative offices. We have not experienced any operational slowdowns due to COVID-19 among our workforce.

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, 2021, the period from November 1, 2020 through December 31, 2020, the period from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019:

	Successor		Predecessor	
	2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	2019
Oil (MBbl/d)				
San Joaquin Basin	39	38	42	52
Los Angeles Basin	19	23	25	24
Ventura Basin	2	2	3	4
Total	60	63	70	80
NGLs (MBbl/d)				
San Joaquin Basin	13	12	13	15
Total	13	12	13	15
Natural gas (MMcf/d)				
San Joaquin Basin	135	138	147	162
Los Angeles Basin	1	1	2	2
Ventura Basin	4	3	4	5
Sacramento Basin	19	23	21	28
Total	159	165	174	197
Total Production (MBoe/d)	100	103	112	128

Total daily production volumes was 100 MBoe/d for the year ended December 31, 2021, a decrease of 10% from 111 MBoe/d for the combined year ended December 31, 2020. The decrease was largely a result of natural production declines. We suspended our drilling activity in the first quarter of 2020 and temporarily shut-in production in the second quarter of 2020 in response to the economic conditions at that time. We increased our capital investment and re-started our drilling program during 2021. Our capital program for 2022 aims to maintain oil production by investing in shallower, oil projects with faster payouts to offset natural oil decline. PSCs negatively impacted our production in 2021 by approximately 3 MBoe/d compared to the combined year ended December 31, 2020. We divested the vast majority of our assets in the Ventura basin which resulted in a decrease of 2 MBoe/d beginning in the fourth quarter of 2021. This decrease was partially offset by improved operational results from our 2021 drilling program and our acquisition of MIRA's working interest in certain wells in the third quarter of 2021 which increased oil production by 1 MBbl/d.

In the first quarter of 2022, we expect to conduct regular maintenance at our Elk Hills cryogenic gas plant that will result in a shut down for approximately six to eight weeks. We estimate a decrease in production of approximately 6 MBoe/d in the first quarter of 2022, returning to pre-turnaround production levels in the second quarter of 2022.

We temporarily shut-in production of 3 MBoe/d in 2020, which negatively impacted our production compared to 2019. Additionally, our divestiture of a 50% working interest in certain zones within our Lost Hills Field resulted in a decrease of approximately 2 MBoe/d beginning in the second quarter of 2019. Our PSCs positively impacted our oil production in the combined year ended December 31, 2020 by approximately 3 MBoe/d compared to 2019.

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

	Successor			
	2021		November 1, 2020 - December 31, 2020	
	Price	Realization	Price	Realization
Oil ($ per Bbl)				
Brent	$ 70.79		$ 47.10	
Realized price without derivative settlements	$ 70.43	99%	$ 45.65	97%
Effects of derivative settlements	(14.38)		(0.28)	
Realized price with derivative settlements	$ 56.05	79%	$ 45.37	96%
WTI	$ 67.91		$ 44.21	
Realized price without derivative settlements	$ 70.43	104%	$ 45.65	103%
Realized price with derivative settlements	$ 56.05	83%	$ 45.37	103%
NGLs ($ per Bbl)				
Realized price[(a)]	$ 53.62	76%	$ 38.00	81%
Realized price[(b)]	$ 53.62	79%	$ 38.00	86%
Natural gas				
NYMEX ($/MMBTU)	$ 3.61		$ 2.86	
Realized price without derivative settlements ($/Mcf)	$ 4.22	117%	$ 3.21	112%
Effects of derivative settlements	(0.02)		(0.07)	
Realized price with derivative settlements ($/Mcf)	$ 4.20	116%	$ 3.14	110%

(a) Realization is calculated as a percentage of Brent.
(b) Realization is calculated as a percentage of WTI.

	Predecessor			
	January 1, 2020 - October 31, 2020		2019	
	Price	Realization	Price	Realization
Oil ($ per Bbl)				
Brent	$ 42.43		$ 64.18	
Realized price without derivative settlements	$ 41.21	97%	$ 64.83	101%
Effects of derivative settlements	1.98		3.82	
Realized price with derivative settlements	$ 43.19	102%	$ 68.65	107%
WTI	$ 38.44		$ 57.03	
Realized price without derivative settlements	$ 41.21	107%	$ 64.83	114%
Realized price with derivative settlements	$ 43.19	112%	$ 68.65	120%
NGLs ($ per Bbl)				
Realized price[(a)]	$ 25.70	61%	$ 31.71	49%
Realized price[(b)]	$ 25.70	67%	$ 31.71	56%
Natural gas				
NYMEX ($/MMBTU)	$ 1.95		$ 2.67	
Realized price without derivative settlements ($/Mcf)	$ 2.11	108%	$ 2.87	107%
Effects of derivative settlements	0.06		(0.01)	
Realized price with derivative settlements ($/Mcf)	$ 2.17	111%	$ 2.86	107%

(a) Realization is calculated as a percentage of Brent.
(b) Realization is calculated as a percentage of WTI.

Oil — Brent index and realized prices excluding hedge settlements were higher for the year ended December 31, 2021 compared to 2020 as oil demand was bolstered by the re-opening of economies and easing of mobility restrictions related to the COVID-19 pandemic. Prices also increased due to a rise in domestic demand and lower supply caused by reduced investment in the U.S. upstream oil and gas sector during 2020 as well as supply management by OPEC members.

NGLs — Prices for NGLs increased in the year ended December 31, 2021 compared to 2020. Higher prices were primarily the result of increased demand in the U.S. and abroad.

Natural Gas — In 2021, natural gas prices increased both across the United States and within California compared to 2020 primarily due to concerns that low storage levels combined with anticipated demand returning to pre-COVID-19 levels would not be sufficient to meet domestic and growing export demand.

Divestitures

Ventura Transactions

During the second quarter of 2021, we entered into transactions to sell our Ventura basin assets. These transactions contemplate multiple closings that are subject to customary closing conditions. In total, we will receive cash consideration of up to $102 million, before purchase price adjustments, plus additional earn-out consideration that is linked to future commodity prices. The consideration, exclusive of the earn-out, includes $82 million of total cash consideration (subject to purchase price adjustments) and up to $20 million of potential additional consideration if the buyer does not perform certain abandonment obligations with respect to the divested properties. The additional consideration is secured by production payments of $20 million over a five-year period. To the extent the buyer satisfies all of the required abandonment obligations within a five-year period following the initial close date, none of the $20 million of potential additional consideration will be paid to us.

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. We expect to divest our remaining assets in the Ventura basin during the first half of 2022. These remaining assets, consisting of property, plant and equipment and the associated asset retirement obligations, are classified as held for sale on our consolidated balance sheet as of December 31, 2021.

Lost Hills Transaction

In February 2022, we sold our 50% non-operated working interest in certain horizons within our Lost Hills field, located in the San Joaquin basin, for proceeds of $55 million (before transaction costs and purchase price adjustments). 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. We also retained 100% of the deep rights and related seismic data.

Other Divestitures

In 2021, we also sold unimproved land and other non-core assets for $13 million of proceeds recognizing a $4 million gain.

In January 2020, we sold royalty interests and divested non-core assets resulting in $41 million of proceeds. The divestitures were treated as normal retirements and no gain or loss was recognized.

Acquisitions and Joint Ventures

During the second half of 2021, we completed our development joint venture (JV) with MIRA, our development joint venture with Benefit Street Partners (BSP) and our development joint venture with Royale Energy Inc. (Royale JV).

The MIRA JV contemplated that MIRA would fund the development of certain of our oil and natural gas properties in the San Joaquin basin in exchange for a 90% working interest in the related properties. In August 2021, we purchased MIRA’s entire working interest share in the conveyed assets for a net cash payment of $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.

The BSP JV contemplated that BSP would contribute funds for the development of our oil and natural gas properties in exchange for preferred interests in a joint venture entity. 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 recorded as a financing cash outflow on our consolidated statement of cash flows. Our consolidated results reflect the full operations of the BSP JV, with BSP's share of net income reported in net income attributable to noncontrolling interests on our consolidated statements of operations through the redemption date.

The Royale JV contemplated that Royale would fund the development of certain of our natural gas properties in Sacramento Valley. In December 2021, the Royale JV was mutually terminated by both parties.

The development joint venture with Alpine Energy Capital, LLC (Alpine) contemplated that Alpine would fund the drilling of certain wells within the Elk Hills field. The development agreement with Alpine was terminated in October 2021. The termination of the development plan does not affect the 90% working interest earned by Alpine in wells previously drilled. Our consolidated results reflect only our working interest share in the productive wells.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Joint Ventures* in our 2020 Form 10-K for more information on the history of our joint ventures.

Dividend Payment

On December 16, 2021, we paid a $0.17 per share dividend on our common stock in the aggregate amount of $14 million to shareholders of record at the close of business on December 1, 2021.

On February 23, 2022, our Board of Directors declared a cash dividend of $0.17 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 7, 2022 and is expected to be paid on March 16, 2022. This quarterly dividend is made pursuant to a cash dividend policy approved by the Board of Directors in November 2021.

Share Repurchase Program

During 2021, our Board of Directors authorized a Share Repurchase Program for up to $250 million of our common stock through June 30, 2022. As of December 31, 2021, we repurchased 4,089,988 shares of our common stock, at an average price of $36.08 per share, through either open market purchases or a Rule 10b5-1 plan for $148 million. Shares repurchased are held as treasury stock as of December 31, 2021.

In February 2022, the Share Repurchase Program was increased by $100 million to $350 million in aggregate and we extended the term of the program until December 31, 2022. For the period January 1, 2022 through February 18, 2022, we repurchased an additional 933,200 shares of our common stock, at an average price of $42.57 per share, through either open market purchases or a Rule 10b5-1 plan for approximately $40 million. After these repurchases and the $100 million increase in our Share Repurchase Program, we have approximately $162 million of remaining capacity available for future repurchases.

Seasonality

While certain aspects of our operations are affected by seasonal factors, such as energy costs, overall, seasonality has not been a material driver of changes in our earnings during the year.

Income Taxes

Management assesses the realizability of deferred tax assets each period by considering whether it is more-likely-than-not that all or a portion of our deferred tax assets will be realized. At each reporting date new evidence is considered, both positive and negative, including whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. For the assessment period ended December 31, 2021, management concluded that it was more-likely-than-not that all of our existing deferred tax assets would be realized. This determination was based, in part, on our three-year cumulative income position, the profitability of our core business activities in recent periods and our projections of future taxable income at current commodity prices and our current cost structure. We also considered our ability to generate future taxable income in a lower commodity price environment as a potential source of negative evidence. Based on our assessment, we determined there is sufficient positive evidence to conclude that it is more-likely-than-not that our deferred tax assets of $396 million at December 31, 2021 are realizable and we released all of our valuation allowance in the fourth quarter of 2021.

For additional information on tax-related items, see information set forth in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Income Taxes*.

Statement of Operations Analysis

Results of Oil and Natural Gas Operations

The following table presents key operating data for our oil and natural gas operations, on a per Boe basis for the year ended December 31, 2021, the Successor period from November 1, 2020 through December 31, 2020 and the Predecessor period from January 1, 2020 through October 31, 2020 along with supplemental information for the combined year ended December 31, 2020. Energy operating costs consist of purchases of natural gas used to generate electricity, purchased electricity and internal costs used to generate electricity used in our operations. Non-energy operating costs equal total operating costs less energy and gas processing costs. However, non-energy operating costs include the costs of purchasing natural gas used to generate steam for our steamfloods.

	Successor		Predecessor	Combined
	Year ended December 31,	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31,
	2021			2020
Energy operating costs	$ 5.09	$ 4.46	$ 3.86	$ 3.95
Gas processing costs	$ 0.54	$ 0.55	$ 0.55	$ 0.55
Non-energy operating costs	$ 13.76	$ 13.18	$ 10.54	$ 10.95
Operating costs	$ 19.39	$ 18.19	$ 14.95	$ 15.45
Field general and administrative expenses	$ 0.94	$ 1.12	$ 1.11	$ 1.11
Field depreciation, depletion and amortization	$ 5.23	$ 4.95	$ 8.75	$ 8.16
Field taxes other than on income	$ 2.83	$ 0.64	$ 3.10	$ 2.72

Operating costs per Boe in 2021 were higher than the combined period of 2020 primarily as a result of higher natural gas and electricity prices and increased downhole maintenance activity. Partially offsetting these increases are reduced labor-related expenses from actions taken to reduce our headcount in late 2020 and early 2021 and reduced employee benefits beginning in the second quarter of 2021. Further, our management team's annual incentive for 2021 included a performance metric tied to cost savings. Operating costs in the Predecessor period of 2020 reflect cost savings for shut-in wells and lower activity in response to the lower commodity price environment as well as reduced work hours in the second quarter of 2020. We continue to focus on achieving recurring cost savings.

Field depreciation, depletion and amortization in the Successor periods of 2021 and 2020 was lower than the Predecessor period of 2020 primarily as a result of a lower depletable basis resulting from our fresh start fair value adjustments.

Field general and administrative expenses were lower in 2021 primarily due to actions taken to reduce costs which included headcount reductions in the third quarter of 2020 and first quarter of 2021.

Field taxes other than on income on a per Boe basis were higher in 2021 as compared to the combined period of 2020 due to lower production volumes in 2021. However, the total amount paid on field taxes other than on income was lower in 2021 as compared to the combined period of 2020 due to a decrease in ad valorem and production taxes, partially offset by higher greenhouse gas taxes due to emission levels as we increased activity and market prices.

Consolidated Results of Operations

Year Ended December 31, 2021 vs. the Successor and Predecessor Periods of 2020

The following table presents our consolidated revenue for the year ended December 31, 2021 and the Successor and Predecessor periods of 2020 along with supplemental information for the combined year ended December 31, 2020 (in millions):

	Successor		Predecessor	Combined
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020
Revenue				
Oil, natural gas and NGL sales	$ 2,048	$ 237	$ 1,092	$ 1,329
Net (loss) gain from commodity derivatives	(676)	(141)	91	(50)
Sales of purchased natural gas	312	38	124	162
Electricity sales	172	15	86	101
Other revenue	33	3	14	17
Total operating revenues	$ 1,889	$ 152	$ 1,407	$ 1,559

Oil, natural gas and NGL sales – Oil, natural gas and NGL sales, excluding the impact of settled hedges, were $2,048 million for the year ended December 31, 2021, which is an increase of 54% or $719 million, compared to $1,329 million for the combined year ended December 31, 2020. The increase was primarily due to higher realized prices as shown in the following table:

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2020 (Combined)	$ 1,050	$ 135	$ 144	$ 1,329
Changes in realized prices	715	127	122	964
Changes in production	(210)	(12)	(23)	(245)
Year ended December 31, 2021	$ 1,555	$ 250	$ 243	$ 2,048

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

The effect of settled hedges is not included in the table above. Payments on commodity derivatives were $319 million for the year ended December 31, 2021 compared to proceeds of $107 million for the combined year ended December 31, 2020. Including the effect cash settlements on commodity derivatives, our oil, natural gas and NGL sales increased by $293 million or 20% in 2021 compared to the same prior year period. A majority of our cash settlements on commodity derivatives during 2021 were related to contracts entered into shortly after our emergence from bankruptcy in order to comply with debt covenants in our Revolving Credit Facility.

Net (loss) gain from commodity derivatives – Gains and losses from our commodity derivative contracts primarily relate to the non-cash changes in the fair value of our outstanding derivatives resulted from the positions held at the end of each measurement period as well as the relationship between contract prices and the associated forward curves. Gains and losses from our commodity derivative contracts are shown in the table below:

	Successor		Predecessor	Combined
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020
(in millions)				
Non-cash commodity derivative loss, excluding noncontrolling interest	$ (357)	$ (138)	$ (19)	$ (157)
Non-cash commodity derivative (loss) gain, attributable to noncontrolling interest	—	(2)	2	—
Total non-cash changes	(357)	(140)	(17)	(157)
Net (payments) proceeds on settled commodity derivatives	(319)	(1)	108	107
Net (loss) gain from commodity derivatives	$ (676)	$ (141)	$ 91	$ (50)

Sales of purchased natural gas – Sales of purchased natural gas were $312 million for the year ended December 31, 2021, compared to $162 million for the combined year ended December 31, 2020, which is an increase of $150 million, or 93%. The increase was due to higher natural gas prices in 2021 partially offset by decreased volumes. Our natural gas sales net of related purchases were $116 million for the year ended December 31, 2021 compared to $60 million for the combined year ended December 31, 2020.

Electricity sales — Electricity sales increased by $71 million to $172 million during the year ended December 31, 2021 compared to $101 million for the combined year ended December 31, 2020. The increase was predominantly due to higher electricity prices in 2021 resulting from higher natural gas prices as well as reduced hydroelectric generation in California. Additionally, electric power generation was higher in 2021 due to planned maintenance and an outage at the Elk Hills power plant in 2020.

Other revenue — Other revenue primarily includes fees and sales from processing third party gas. Other revenue increased by $16 million to $33 million for the year ended December 31, 2021, compared to $17 million for the combined year ended December 31, 2020 primarily due to higher natural gas prices.

The following table presents our operating and non-operating expenses (income) for the year ended December 31, 2021 and the Successor and Predecessor periods of 2020 along with supplemental information for the combined year ended December 31, 2020 (in millions):

	Successor		Predecessor	Combined
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020
Operating expenses				
Energy operating costs	$ 185	$ 28	$ 132	$ 160
Gas processing costs	20	3	19	22
Non-energy operating costs	500	83	360	443
General and administrative expenses	200	40	212	252
Depreciation, depletion and amortization	213	34	328	362
Asset impairments	28	—	1,736	1,736
Taxes other than on income	145	10	134	144
Exploration expense	7	1	10	11
Purchased natural gas expense	196	24	78	102
Electricity generation expenses	96	10	53	63
Transportation costs	51	8	35	43
Accretion expense	50	8	33	41
Other operating expenses, net	29	9	56	65
Total operating expenses	$ 1,720	$ 258	$ 3,186	$ 3,444
Gain on asset divestitures	124	—	—	—
Operating income (loss)	293	(106)	(1,779)	(1,885)
Non-operating (expenses) income				
Reorganization items, net	(6)	(3)	4,060	4,057
Interest and debt expense, net	(54)	(11)	(206)	(217)
Net (loss) gain on early extinguishment of debt	(2)	—	5	5
Other non-operating expenses, net	(2)	(5)	(84)	(89)
Income (loss) before income taxes	229	(125)	1,996	1,871
Income tax benefit	396	—	—	—
Net income (loss)	$ 625	$ (125)	$ 1,996	$ 1,871
Net (income) loss attributable to noncontrolling interests	$ (13)	$ 2	$ (107)	$ (105)

Energy operating costs – Energy operating costs were $185 million for the year ended December 31, 2021, which was an increase of 16% or $25 million compared to $160 million for the combined year ended December 31, 2020. The increase was predominantly a result of higher prices for purchased natural gas, which we use to generate electricity for our operations, and for purchased electricity.

Non-energy operating costs – Non-energy operating costs for the year ended December 31, 2021 were $500 million, which was an increase of $57 million or 13% from $443 million for the combined year ended December 31, 2020. This increase was primarily a result of higher downhole maintenance activity in 2021 which was deferred from 2020 as we shut-in wells and suspended surface maintenance activity due to the COVID-19 pandemic. Additionally, non-energy operating costs increased in 2021 due to higher prices for natural gas, which we use to generate steam for our steamfloods. Partially offsetting these increases were lower labor-related costs from headcount reductions in late 2020 and early 2021 and reduced employee benefits beginning in the second quarter of 2021. Although higher natural gas prices in 2021 increased our operating costs, higher prices have a net positive effect on our operating results due to higher revenue from sales of this commodity which we also produce.

General and administrative expenses – Our general and administrative expenses (G&A) were $200 million for the year ended December 31, 2021, which was a decrease of $52 million from $252 million for the combined year ended December 31, 2020. The decrease in G&A expenses was primarily attributable to lower labor-related costs as a result of workforce reductions that occurred in the second half of 2020 and the first quarter of 2021 as well as employee benefit reductions in the second quarter of 2021. The remaining decrease was also due to lower spending across a number of cost categories. The decrease was partially offset by an increase in compensation expense related to equity-settled awards granted to executives and directors in 2021.

Depreciation, depletion and amortization – Depreciation, depletion and amortization in each of the Successor periods was lower than the Predecessor period of 2020 primarily due to a decrease in the carrying value of our property as a result of fair value adjustments recorded as part of fresh start accounting on our emergence date. For further detail about our fair value adjustments see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Fresh Start Accounting*.

Asset impairments – Asset impairments were $28 million for the year ended December 31, 2021 compared to $1.7 billion for the combined year ended December 31, 2020. The asset impairment charges in 2021 included $25 million related to a commercial office building located in Bakersfield, California due to the decline in commercial demand for office space of this size and type in that market. The impairment charge of $1.7 billion in 2020 was due to the sharp drop in commodity prices at the end of the first quarter of 2020. Approximately $1.5 billion of this charge related to certain of our proved properties and $228 million related to unproved acreage that was no longer included in our development plans at that time. For further detail about our first quarter 2020 asset impairment, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Property, Plant and Equipment*.

Taxes other than on income – Taxes other than on income were $145 million for the year ended December 31, 2021, which was an increase of $1 million from $144 million for the combined year ended December 31, 2020. In 2021, we paid higher greenhouse gas taxes due to emission levels as we increased activity and increased market prices, which was partially offset by a decrease in ad valorem and production taxes.

Purchased natural gas expense – Purchased natural gas expense was $196 million for the year ended December 31, 2021, which was an increase of $94 million or 92% from $102 million for the combined year ended December 31, 2020 primarily due to higher prices in 2021 for purchased natural gas related to our trading activities.

Electricity generation expense – Electricity generation expenses increased to $96 million for the year ended December 31, 2021 from $63 million for the combined year ended December 31, 2020. The increase of $33 million was predominantly a result of higher pricing in 2021 on purchased natural gas used in electricity generation.

Other operating expenses, net – Other operating expenses, net was $29 million for the year ended December 31, 2021, which was a decrease of $36 million or 55% from $65 million for the combined year ended December 31, 2020. In 2020, other operating expenses, net included a one-time payment of $20 million made in connection with an expiring pipeline delivery contract and $7 million related to an outage at the Elk Hills power plant. Both of the years ended December 31, 2021 and the combined year ended December 31, 2020 include $15 million of severance costs related to the reduction in our workforce and the departure of certain executive and other senior officers.

Gain on asset divestitures – Gain on asset divestitures for the year ended December 31, 2021 was $124 million related to the sale of the majority of our Ventura basin operations, unimproved land and other non-core assets. No gain or loss was recognized in 2020 on the sale of royalty interests and a non-core asset since we accounted for these transactions as normal retirements. For more information on our asset divestitures, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions.*

Reorganization items, net – Reorganization items, net was $6 million for the year ended December 31, 2021, all of which related to legal, professional and other fees related to our bankruptcy, compared to a $4.1 billion net gain for the combined year ended December 31, 2020. Reorganization items, net for the combined periods of 2020 includes legal, professional and other fees related to our bankruptcy, a net gain from the cancellation of our pre-emergence debt and the associated write-off of the unamortized balance of deferred gain, original issue discounts and deferred issuance costs and debtor-in-possession financing costs which were incurred during our bankruptcy proceedings. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Chapter 11 Proceedings* for additional information about reorganization items, net.

Interest and debt expense, net – Interest and debt expense, net was $54 million for the year ended December 31, 2021 compared to $11 million for the Successor period of 2020 and $206 million for the Predecessor period of 2020. Interest and debt expense, net during 2021 primarily consists of interest on our Senior Notes. Interest and debt expense, net for the Successor period of 2020 primarily includes interest on our Revolving Credit Facility, Second Lien Notes and EHP Notes as well as amortization of debt issuance costs and deferred gain as shown in the table below. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt* for additional information on our credit agreements and January 2021 Senior Notes offering.

Interest and debt expense, net decreased in the Successor period of 2020 as compared to the Predecessor period of 2020 primarily due to the discharge of our debt upon emergence from bankruptcy.

The table below shows interest and debt expense, net for the Successor and Predecessor periods (in millions):

	Successor		Predecessor
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Interest expense on debt	$ 49	$ 10	$ 223
Amortization of deferred gain	—	—	(39)
Amortization of debt issuance	7	1	29
Other interest	1	—	1
Capitalized interest	(3)	—	(8)
Interest and debt expense, net	$ 54	$ 11	$ 206

Other non-operating expense, net – Other non-operating expenses, net for the year ended December 31, 2021 was $2 million compared to $89 million in the combined period of 2020. Other non-operating expense includes pension cost, other than the service cost component, related to our pension and postretirement benefit plans. The higher expense in 2020 was primarily a result of legal, professional and other fees in preparation for our bankruptcy filing and an abandoned financing transaction.

Income tax benefit – We released our valuation allowance in the fourth quarter of 2021. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Income Tax* for more information on the realizability of our deferred tax assets.

Net income attributable to noncontrolling interests – Upon emergence from bankruptcy, we acquired all third-party membership interests in the Ares JV. As a result, the allocation of net loss (income) to noncontrolling interest holders in the Successor period not comparable to the Predecessor periods.

The net loss allocated to the noncontrolling interest holder, BSP, in the Successor period of 2020 primarily related to non-cash losses on derivatives. BSP's preferred interest in the BSP JV was automatically redeemed in full in September 2021 and income was allocated to BSP up to the redemption date.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Chapter 11 Proceedings* for additional information on the Ares JV and *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Equity* for more information on the redemption of the preferred member interest from BSP.

<u>*The Successor and Predecessor Periods of 2020 vs. 2019*</u>

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Statement of Operations Analysis* in our 2020 Form 10-K for our analysis of the changes in our consolidated statements of operations for the Successor period from November 1, 2020 through December 31, 2020 and the Predecessor periods from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations, cash on hand and available borrowing capacity under our Revolving Credit Facility. As of December 31, 2021, we had liquidity of $672 million, which consisted of $305 million in cash and $367 million of available borrowing capacity under our Revolving Credit Facility. In February 2022, we obtained $60 million of additional commitments from new lenders increasing our liquidity due to our available borrowing capacity under our Revolving Credit Facility increasing to $427 million from $367 million. As of December 31, 2021, 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.*

We consider our low leverage and ability to control costs to be a core strength and strategic advantage, which we are focused on maintaining. At current commodity prices, 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 we may (i) increase investments in our drilling program to accelerate value, (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) advance carbon management activities, or (iv) maintain cash on our balance sheet. We expect to begin paying cash income taxes in 2022. Our tax paying status depends on a number of factors, including the amount and type of our capital spend, cost structure and activity levels. We expect to focus on asset retirement activities over the next several years to reduce our idle well inventory. 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. Our Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges. We have also entered into incremental hedges above and beyond these requirements for some time periods and will continue to evaluate our hedging strategy based on prevailing market prices and conditions. In some circumstances, these hedges (including hedges entered into by us in 2020 to comply with covenants in our Revolving Credit Facility) may prevent us from realizing the full benefits of price increases.

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 during the year ended December 31, 2021.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our open derivative contracts as of December 31, 2021.

Uses of Cash

2022 Capital Program

We have increased our 2022 capital program from our 2021 level and target a range of $330 to $375 million. The program includes $300 to $335 million for oil and gas development and $30 to $40 million for carbon management projects. This level of expected spending is consistent with our strategy of investing up to 50% of our operating cash flow back into our oil and gas operations.

We prioritize high oil mix projects that provide high margins and low decline rates to maximize our cash flow from operations. Our technical teams are consistently working to enhance value by improving the economics of our inventory through detailed geologic studies as well as application of more effective and efficient drilling and completion techniques. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our asset portfolio.

The actual amount of spending under our 2022 capital program will depend on a variety of factors, including commodity prices, the success of our drilling program, operating costs and other general market conditions. Because we own and operate substantially all of our assets, the amount and timing of our capital spending is largely within our control. Any curtailment of the development of our properties will lead to a decline in our production and may lower our reserves. A continued decline in our production and reserves would negatively impact our cash flow from operations and the value of our assets.

Other Uses of Cash

Other than our 2022 capital program and hedging activity, our expected material uses of cash during 2022 include, among other possible uses: (1) cash settlements on commodity derivative contracts and premiums for entering into new contracts (2) payments to service our debt; (3) domestic income taxes; (4) asset retirement obligations; and (5) advancing carbon management activities. After these material uses, we intend to return cash to shareholders through either future dividends or share repurchases.

The table below summarizes our current and long-term material cash requirements as of December 31, 2021 that we expect to fund with operating cash flow (in millions):

	Payments Due by Year				
	Total	**Less than 1 Year**	**Years 2 and 3**	**Years 4 and 5**	**More than 5 Years**
On-Balance Sheet	(in millions)				
Long-term debt[(a)]	$ 600	$ —	$ —	$ 600	$ —
Interest on long-term debt	177	43	87	47	—
Pension and postretirement[(b)]	108	17	19	15	57
Operating and finance leases[(c)]	62	12	16	11	23
Off-Balance Sheet					
Purchase obligations[(d)]	136	54	42	10	30
Total	$ 1,083	$ 126	$ 164	$ 683	$ 110

(a) Represents the outstanding long-term debt balance as of December 31, 2021. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Debt* for more information on our long-term debt agreements.
(b) Represents undiscounted future obligations for defined benefit and supplemental plans.
(c) Our operating leases include drilling rigs, commercial office space, fleet vehicles and certain facilities. Our finance leases include information technology equipment and are not material to our consolidated financial statements taken as a whole.
(d) Amounts include payments that will become due under long-term agreements to purchase goods and services used in the normal course of business primarily including pipeline capacity and land leases. Purchase obligations for pipeline capacity are based on contractual volumes and current market rates for that firm transportation capacity during the contract period. Land leases reflect obligations for fixed payments under our term contracts. Also included is a commitment to invest approximately $12 million in evaluation and development activities at one of our oil and natural gas properties prior to January 1, 2023. During 2021, we entered into an amendment allowing us to accept certain land use requirements which, at the time of acceptance on or before May 2022, will relieve us from our remaining obligation.

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, 2021 was $660 million, which was an increase of $554 million, or 523%, from $106 million for the combined year ended December 31, 2020. The increase was primarily related to higher average realized prices (including the effects of settlements on our commodity derivatives) partially offset by declining production and increased costs from higher activity levels in 2021 as compared to 2020. Further, in 2021, we realized cost savings from actions taken to reduce the size of our workforce and employee benefits along with other cost savings measures. Our improved operating cash flow in 2021 reflects lower interest payments and professional fees compared to 2020 when we restructured our balance sheet through bankruptcy proceedings. With improved operating cash flow in 2021, we took additional steps to protect our downside commodity price risk by entering into derivative contracts, perform asset retirement activities and build our inventory of greenhouse gas allowances.

Cash flows from investing activities – Our net cash used in investing activities was $161 million for the year ended December 31, 2021, which was an increase of $124 million from $37 million in the combined year ended December 31, 2020. This use of cash primarily related to a higher capital program in 2021 as compared to 2020 when we reduced our capital investment to a level necessary to maintain the mechanical integrity of our facilities. We sold the majority of our Ventura basin operations in 2021 and the cash from this divestiture was partially offset by the cash paid for the acquisition of working interests in certain joint venture wells held by MIRA. During the combined period ended December 31, 2020, we realized cash proceeds of $41 million from the sale of royalty interests and non-core assets.

The table below summarizes net cash used in investing activities (in millions):

	Successor		Predecessor	Combined
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2020
Capital investments	$ (194)	$ (7)	$ (40)	$ (47)
Changes in capital investment accruals	20	(1)	(24)	(25)
Acquisitions, divestitures and other	13	1	34	35
Net cash used in investing activities	$ (161)	$ (7)	$ (30)	$ (37)

Cash flows from financing activities – Our net cash used in financing activities was $222 million for the year ended December 31, 2021 and primarily related to distributions to BSP as well as repurchases of our common stock under our Share Repurchase Program. During the year ended December 31, 2021, we issued Senior Notes, the proceeds of which were used to repay our EHP Notes and our Second Lien Term Loan with the remainder used to paydown our Revolving Credit Facility. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt* for additional information on our credit agreements.

Our net cash used in financing activities was $58 million for the combined year ended December 31, 2020. Uses of cash in 2020 primarily related to our debt transactions as a result of our bankruptcy proceedings and a payoff of $100 million of existing debt in January 2020. We also made $134 million of distributions to noncontrolling interest holders in the combined period of 2020, which included payments of $70 million to our former noncontrolling interest holder, ECR and $64 million to BSP. We raised proceeds of $446 million from an equity issuance at the time of our emergence from bankruptcy.

The table below summarizes net cash (used) provided by financing activities for the years ended December 31, 2021 and 2020 (in millions):

	Successor		Predecessor	Combined
	Year ended December 31,	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31,
	2021			2020
Debt transactions	$ (12)	$ (126)	$ (241)	$ (367)
Distributions to noncontrolling interest holders	(50)	(30)	(104)	(134)
Repurchases of common stock	(148)	—	—	—
Issuance of common stock	2	—	446	446
Common stock dividends	(14)	—	—	—
Other	—	—	(3)	(3)
Net cash (used) provided by financing activities	$ (222)	$ (156)	$ 98	$ (58)

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, 2021 and 2020 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 is challenging 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 also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

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

Critical Accounting Estimates

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

Title	Description	Judgments and Uncertainties	Sensitivities
Reserves	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 and impairment charges, if any. We use the successful efforts method of accounting for our oil and gas producing activities. Under this method, we capitalize the costs 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. Future cash flows from expected reserve volumes for producing properties may be used in an impairment analysis or a determination of whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. We also use reserves to predict when a producing well will become inactive, and then idle, to schedule the timing of abandonment in estimating our asset retirement obligations.	The determination of quantities of proved reserves is a highly technical process performed by our petroleum engineers and geoscientists. The analysis is based on drilling results, reservoir performance, subsurface interpretation and future development plans. Production rate forecasts are derived using a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes, 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.	Our total proved reserves were 480 MMBoe and our total proved developed reserves were 405 MMBoe at December 31, 2021. We estimate our 2022 DD&A rate for our oil and natural gas producing properties using the unit-of-production method will be approximately $4.50/Boe. A 5% change in our reserves would increase or decrease this DD&A rate by approximately $0.25/Boe. If realized prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2021 would have increased by 4 MMBoe or decreased by 8 MMBoe, respectively.

Title	Description	Judgments and Uncertainties	Sensitivities
Realizability of Deferred Tax Assets	We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more-likely-than-not that some portion or all of our deferred tax assets will not be realized, the deferred tax asset is reduced to the amount realizable by a valuation allowance.	In making such assessments regarding the realizability of our deferred tax assets, numerous judgments and assumptions are inherent in the determination of whether sufficient future taxable income will be generated to permit realization of existing deferred tax assets. Significant assumptions include commodity price curves and estimates of future expected operating, development and abandonment costs. We also evaluate whether we are in a three-year cumulative income position and our historic earnings trends which may support our ability to protect future taxable income.	At December 31, 2020, we had a tax valuation allowance of $549 million against our entire U.S. federal and state deferred tax assets. During 2021, we realized substantial improvements in commodity prices and have an improved financial position. At December 31, 2021, we assessed the realizability of our deferred tax assets and determined that all our deferred tax assets are more-likely-than-not realizable. Changes in assumptions or changes in tax laws and regulations could materially affect the recognized amount of valuation allowance.

Significant Accounting and Disclosure Changes

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for a discussion of new accounting standards.

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.

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 and the potential for sustained low oil, natural gas and natural gas liquids prices;
- legislative or regulatory changes, including those related to (i) drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, (ii) managing energy, water, land, greenhouse gases (GHGs) or other emissions, (iii) protection of health, safety and the environment, (iv) tax credits or other incentives, or (v) transportation, marketing and sale of our products;
- availability or timing of, or conditions imposed on, permits and approvals necessary for drilling or development projects;
- changes in business strategy and our capital plan;
- lower-than-expected production, reserves or resources from development projects or acquisitions, or higher-than-expected decline rates;
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves;
- the recoverability of resources and unexpected geologic conditions;
- our ability to realize the benefits of business strategies and initiatives related to energy transition, including carbon capture and storage projects and other renewable energy efforts;
- our ability to finance and implement our carbon capture and storage projects;
- global geopolitical, socio-demographic and economic trends and technological innovations;
- changes in our dividend policy and our ability to declare future dividends;
- production-sharing contracts' effects on production and operating costs;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund planned investments, interest payments on our debt, stock repurchases or changes to our capital plan;
- insufficient capital or liquidity unavailability of capital markets or inability to attract potential investors;
- limitations on transportation or storage capacity and the need to shut-in wells;
- inability to enter into desirable transactions, including acquisitions, asset sales and joint ventures;
- joint ventures and acquisitions and our ability to achieve expected synergies;
- our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- our ability to successfully gather and verify data regarding emissions, our environmental impacts and other initiatives;
- the compliance of various third parties with our policies and procedures and legal requirements as well as contracts we enter into in connection with our climate-related initiatives;
- the effect of our stock price on costs associated with incentive compensation;
- changes in the intensity of competition in the oil and gas industry;
- effects of hedging transactions;
- equipment, service or labor price inflation or unavailability;
- climate-related conditions and weather events;
- disruptions due to accidents, mechanical failures, power outages, transportation or storage constraints, natural disasters, labor difficulties, cyber-attacks or other catastrophic events;

- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19; 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 term as a result of our current hedges in place. As of December 31, 2021, we had hedges on approximately 80% of our anticipated oil production through 2022 and approximately 50% through 2023, 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, 2021, we had net liabilities of $395 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 $165 million in 2022 and $101 million in 2023, limiting our upside. We estimate that a $10 decrease in Brent oil forward prices could decrease our settlement payments by $162 million in 2022 and $101 million in 2023, negating the downside price movement for hedged volumes.

A summary of our Brent-based crude oil derivative contracts at December 31, 2021 are included in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

Counterparty Credit Risk

Our counterparty credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer 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 and accelerate payment dates. Approximately 60% of our production during 2021 was oil which was sold predominately to refineries in California. As of December 31, 2021, trade receivables for all commodities were collected within 30 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. 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

As discussed in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Debt,* we issued $600 million of Senior Notes in January 2021 the net proceeds of which were used to repay in full our Second Lien Term Loan and repay all the outstanding EHP Notes with the remainder used to repay substantially all of the then outstanding borrowings under our Revolving Credit Facility. Our new Senior Notes bear interest at a fixed rate of 7.125% per annum. We had no variable-rate debt outstanding as of December 31, 2021.

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021. The contracts expired on May 4, 2021. We did not report any gains or losses on these contracts for the years ended December 31, 2021 or 2020. No settlement payments were received in either 2021 or 2020.

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, 2021 and 2020, the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity (deficit), and cash flows for the year ended December 31, 2021 (Successor), for the periods from November 1, 2020 to December 31, 2020 (Successor) and January 1, 2020 to October 31, 2020 (Predecessor), and for the year ended December 31, 2019 (Predecessor), 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, 2021, 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 present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the year ended December 31, 2021 (Successor), for the periods ended November 1, 2020 to December 31, 2020 (Successor) and January 1, 2020 to October 31, 2020 (Predecessor), and for the year ended December 31, 2019 (Predecessor), 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, 2021 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

New Basis of Presentation

As discussed in Notes 1 and 15 to the consolidated financial statements, the Company emerged from Chapter 11 bankruptcy on October 27, 2020 with a reporting date of October 31, 2020. Accordingly, the accompanying consolidated financial statements as of December 31, 2021 and 2020 and for the Successor period have been prepared in conformity with Accounting Standards Codification Topic 852, Reorganizations, with the Company's assets, liabilities and capital structure having carrying amounts that are not comparable with prior periods.

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 $213 million for the year ended December 31, 2021 (Successor). 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 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 specialists and external engineering firms to the Company. We assessed the methodology used by the technical personnel employed by the Company and the independent reservoir engineering specialists 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 specialists in connection 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 25, 2022

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2021 and 2020
(in millions, except share data)

	2021	2020
CURRENT ASSETS		
Cash	$ 305	$ 28
Trade receivables	245	177
Inventories	60	61
Assets held for sale	22	—
Other current assets	121	63
Total current assets	753	329
PROPERTY, PLANT AND EQUIPMENT	2,845	2,689
Accumulated depreciation, depletion and amortization	(246)	(34)
Total property, plant and equipment, net	2,599	2,655
DEFERRED TAX ASSET	396	—
OTHER NONCURRENT ASSETS	98	90
TOTAL ASSETS	$ 3,846	$ 3,074
CURRENT LIABILITIES		
Accounts payable	266	212
Liabilities associated with assets held for sale	21	—
Fair value of derivative contracts	270	50
Accrued liabilities	297	211
Total current liabilities	854	473
NONCURRENT LIABILITIES		
Long-term debt, net	589	597
Fair value of derivative contracts	132	6
Asset retirement obligations	438	547
Other long-term liabilities	145	269
STOCKHOLDERS' EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value); no shares outstanding at December 31, 2021 or 2020	—	—
Common stock (200 million shares authorized at $0.01 par value); (83,389,210 and 83,319,660 shares issued; 79,299,222 and 83,319,660 shares outstanding at December 31, 2021 and 2020, respectively)	1	1
Treasury stock (4,089,988 shares held at cost at December 31, 2021 and no shares held at December 31, 2020)	(148)	—
Additional paid-in capital	1,288	1,268
Retained earnings (accumulated deficit)	475	(123)
Accumulated other comprehensive income (loss)	72	(8)
Total equity attributable to common stock	1,688	1,138
Equity attributable to noncontrolling interests	—	44
Total stockholders' equity	1,688	1,182
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,846	$ 3,074

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the year ended December 31, 2021, the period from November 1, 2020 through December 31, 2020, the period from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019
(in millions, except share and per share data)

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
REVENUES				
Oil, natural gas and NGL sales	$ 2,048	$ 237	$ 1,092	$ 2,270
Net (loss) gain from commodity derivatives	(676)	(141)	91	(59)
Sales of purchased natural gas	312	38	124	286
Electricity sales	172	15	86	112
Other revenue	33	3	14	25
Total operating revenues	1,889	152	1,407	2,634
OPERATING EXPENSES				
Operating costs	705	114	511	895
General and administrative expenses	200	40	212	290
Depreciation, depletion and amortization	213	34	328	471
Asset impairments	28	—	1,736	—
Taxes other than on income	145	10	134	157
Exploration expense	7	1	10	29
Purchased natural gas expense	196	24	78	201
Electricity generation expenses	96	10	53	68
Transportation costs	51	8	35	40
Accretion expense	50	8	33	36
Other operating expenses, net	29	9	56	18
Total operating expenses	1,720	258	3,186	2,205
Gain on asset divestitures	124	—	—	—
OPERATING INCOME (LOSS)	293	(106)	(1,779)	429
NON-OPERATING (EXPENSES) INCOME				
Reorganization items, net	(6)	(3)	4,060	—
Interest and debt expense, net	(54)	(11)	(206)	(383)
Net (loss) gain on early extinguishment of debt	(2)	—	5	126
Other non-operating expenses, net	(2)	(5)	(84)	(72)
INCOME (LOSS) BEFORE INCOME TAXES	229	(125)	1,996	100
Income tax benefit (provision)	396	—	—	(1)
NET INCOME (LOSS)	625	(125)	1,996	99
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS				
Mezzanine equity	—	—	(94)	(117)
Stockholders' equity	(13)	2	(13)	(10)
Net (income) loss attributable to noncontrolling interests	(13)	2	(107)	(127)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 612	$ (123)	$ 1,889	$ (28)
Net income (loss) attributable to common stock per share				
Basic	$ 7.46	$ (1.48)	$ 40.59	$ (0.57)
Diluted	$ 7.37	$ (1.48)	$ 40.42	$ (0.57)
Weighted-average common shares outstanding				
Basic	82.0	83.3	49.4	49.0
Diluted	83.0	83.3	49.6	49.0

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 year ended December 31, 2021, the period from November 1, 2020 through December 31, 2020, the period from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019
(in millions)

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Net income (loss)	$ 625	$ (125)	$ 1,996	$ 99
Net (income) loss attributable to noncontrolling interests	(13)	2	(107)	(127)
Other comprehensive income (loss):				
Actuarial gains (losses) associated with pension and postretirement plans[(a)]	16	(8)	(2)	(24)
Prior service credit[(a)]	65	—	2	7
Amortization of prior service cost credit included in net periodic benefit cost	(1)	—	—	—
Comprehensive income (loss) attributable to common stock	$ 692	$ (131)	$ 1,889	$ (45)

(a) No associated tax has been recorded for the components of other comprehensive (loss) income for 2021, 2020 or 2019. See *Note 12 Pension and Postretirement Benefit Plans* for additional information on the components of other comprehensive income related to our defined benefit plans.

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 year ended December 31, 2021, the period from November 1, 2020 through December 31, 2020, the period from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019
(in millions)

	Predecessor							
	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 (Deficit) Equity
Balance, December 31, 2018	$ —	$ —	$ 4,987	$ (5,342)	$ (6)	$ (361)	$ 114	$ (247)
Net (loss) income	—	—	—	(28)	—	(28)	10	(18)
Contribution from noncontrolling interest holder, net	—	—	—	—	—	—	49	49
Distributions to noncontrolling interest holders	—	—	—	—	—	—	(80)	(80)
Other comprehensive loss	—	—	—	—	(17)	(17)	—	(17)
Warrant issued	—	—	3			3		3
Share-based compensation, net	—	—	14	—	—	14	—	14
Balance, December 31, 2019	$ —	$ —	$ 5,004	$ (5,370)	$ (23)	$ (389)	$ 93	$ (296)
Net income	—	—	—	1,889	—	1,889	13	1,902
Distributions to noncontrolling interest holders	—	—	—	—	—	—	(37)	(37)
Shared-based compensation, net	—	—	10	—	—	10	—	10
Modification of noncontrolling interest	—	—	138	—	—	138	—	138
Gain on acquisition of noncontrolling interest	—	—	128	—	—	128	—	128
Issuance of Successor common stock for acquisition of a noncontrolling interest in connection with the Plan	—	—	261	—	—	261	—	261
Issuance of Successor common stock to creditors in connection with the Plan	—	—	408	—	—	408	—	408
Issuance of Subscription Rights to creditors in connection with the Plan	—	—	71	—	—	71	—	71
Issuance of Successor common stock for junior debtor-in-possession exit fee	—	—	12	—	—	12	—	12
Issuance of Successor common stock to Subscription Rights holders and backstop parties in connection with the Plan, net	1	—	445	—	—	446	—	446
Warrants issued in connection with the Plan	—	—	15	—	—	15	—	15
Fair value adjustment related to noncontrolling interest	—	—	—	—	—	—	7	7
Elimination of Predecessor equity	—	—	(5,224)	3,481	23	(1,720)	—	(1,720)
Balance, October 31, 2020	$ 1	$ —	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345

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

	Successor							
	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, October 31, 2020	$ 1	$ —	$ 1,268	$ —	$ —	$ 1,269	$ 76	$ 1,345
Net loss	—	—	—	(123)	—	(123)	(2)	(125)
Distributions to noncontrolling interest holder	—	—	—	—	—	—	(30)	(30)
Other comprehensive loss	—	—	—	—	(8)	(8)	—	(8)
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[(a)]	—	—	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

Note: Excludes amounts related to redeemable noncontrolling interests recorded in mezzanine equity.

(a) The remaining balance in equity attributable to noncontrolling interest was reallocated to additional paid-in capital of the parent upon redemption of ECR's preferred member interest in the BSP JV. No gain or loss was recognized on the equity transaction. See *Note 14 Chapter 11 Proceedings* for more information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the year ended December 31, 2021, the period from November 1, 2020 through December 31, 2020, the period from January 1, 2020 through October 31, 2020 and the year ended December 31, 2019
(in millions)

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
CASH FLOW FROM OPERATING ACTIVITIES				
Net income (loss)	$ 625	$ (125)	$ 1,996	$ 99
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	213	34	328	471
Deferred income tax benefit	(396)	—	—	—
Asset impairment	28	—	1,736	—
Net loss (gain) from commodity derivatives	676	141	(91)	59
Net settlement (payments) proceeds from commodity derivatives	(319)	(1)	108	111
Net loss (gain) on early extinguishment of debt	2	—	(5)	(126)
Amortization of deferred gain	—	—	(39)	(70)
Gain on asset divestitures	(124)	—	—	—
Other non-cash charges to income, net	62	27	60	131
Reorganization items, net (non-cash)	—	—	(4,128)	—
Reorganization items, net (debtor-in-possession financing costs)	—	—	25	—
Dry hole expenses	—	—	—	7
Changes in operating assets and liabilities, net:				
(Increase) decrease in trade receivables	(68)	(28)	128	22
Decrease (increase) in inventories	—	1	(1)	—
(Increase) decrease in other current assets	(47)	6	2	(1)
Increase (decrease) in accounts payable and accrued liabilities	8	(67)	(1)	(27)
Net cash provided (used) by operating activities	660	(12)	118	676
CASH FLOW FROM INVESTING ACTIVITIES				
Capital investments	(194)	(7)	(40)	(455)
Changes in accrued capital investments	20	(1)	(24)	(85)
Proceeds from asset divestitures	67	—	41	164
Acquisitions	(52)	—	—	(6)
Other	(2)	1	(7)	(12)
Net cash used in investing activities	(161)	(7)	(30)	(394)
CASH FLOW FROM FINANCING ACTIVITIES				
Proceeds from 2014 Revolving Credit Facility	—	—	797	2,330
Repayments of 2014 Revolving Credit Facility	—	—	(1,315)	(2,353)
Proceeds from debtor-in-possession facilities	—	—	802	—
Repayments of debtor-in-possession facilities	—	—	(802)	—
Proceeds from Revolving Credit Facility	16	82	225	—
Repayments of Revolving Credit Facility	(115)	(208)	—	—
Proceeds from Second Lien Term Loan	—	—	200	—
Debtor-in-possession financing costs	—	—	(25)	—
Proceeds from Senior Notes	600	—	—	—

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

Debt repurchases	—	—	(3)	(156)
Debt issuance costs	(13)	—	(20)	(2)
Repayment of Second Lien Term Loan	(200)	—	—	—
Repayment of EHP Notes	(300)	—	—	—
Repayment of 2020 Senior Notes	—	—	(100)	—
Contributions from noncontrolling interest holders	—	—	—	49
Distributions to noncontrolling interest holders	(50)	(30)	(104)	(151)
Repurchases of common stock	(148)	—	—	—
Common stock dividends	(14)	—	—	—
Acquisition of noncontrolling interest in connection with the Plan	—	—	(2)	—
Issuance of common stock	2	—	446	4
Shares cancelled for taxes and other	—	—	(1)	(3)
Net cash (used) provided by financing activities	(222)	(156)	98	(282)
Increase (decrease) in cash	277	(175)	186	—
Cash—beginning of period	28	203	17	17
Cash—end of period	$ 305	$ 28	$ 203	$ 17

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

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

Nature of Business

We are an independent oil and natural gas exploration and production company operating properties exclusively within 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 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. We proportionately consolidate our share of revenue and costs related to our development joint ventures with Alpine Energy Capital, LLC (Alpine) and Royale Energy, Inc. (Royale). In October 2021, the development agreement with Alpine was terminated. The termination does not affect the 90% working interest earned by Alpine in wells previously drilled. In December 2021, the development joint venture with Royale was mutually terminated by both parties and our operating results include activity through the termination date. Our consolidated results reflect only our working interest share in the productive wells in our development joint venture with Alpine.

We qualified for and adopted fresh start accounting upon emergence from Chapter 11 in October 2020 at which point we became a new entity for financial reporting purposes. We adopted an accounting convenience date of October 31, 2020 for the application of fresh start accounting.

As a result of the application of fresh start accounting and the effects of the implementation of our Plan of Reorganization, the financial statements after October 31, 2020 may not be comparable to the financial statements prior to that date. Accordingly, “black-line” financial statements are presented to distinguish between the Predecessor and Successor companies. References to "Predecessor” refer to the Company for periods ended on or prior to October 31, 2020 and references to “Successor” refer to the Company for periods subsequent to October 31, 2020. See *Note 14 Chapter 11 Proceedings* and *Note 15 Fresh Start Accounting* for additional information on our bankruptcy proceedings and the impact of fresh start accounting 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 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 and economic conditions. Additionally, the Coronavirus Disease 2019 (COVID-19) pandemic continues to create price volatility for the oil and gas industry. The ongoing impacts from COVID-19 on our financial position, results of operations and cash flows will depend on uncertain factors, including future developments that are beyond our control, vaccine availability and acceptance by individuals, resurgence of the pandemic or further mutations of the virus and pandemic restrictions being reinstated, among other things.

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, 2021, three California refineries each accounted for at least 10%, and collectively accounted for 51%, of our sales (before the effects of hedging). For the 2020 Successor period, three California refineries each accounted for at least 10%, and collectively accounted for 50%, of our sales (before the effects of hedging). For the 2020 Predecessor period and for the year ended December 31, 2019, two California refineries, each accounted for at least 10%, and collectively accounted for 46%, of our sales (before the effects of hedging).

Recently Adopted Accounting and Disclosure Changes

We adopted new accounting guidance on current expected credit losses on January 1, 2020, using a modified retrospective approach to the first period in which the guidance was effective. The new rules changed the measurement of credit losses for financial assets and certain other instruments, including trade and other receivables with a right to receive cash, and require the use of a new forward-looking expected loss model that results in the earlier recognition of an allowance for losses. The adoption of these new rules did not have a significant impact on our consolidated financial statements.

Significant Accounting Policies

Restructuring under Chapter 11 of the Bankruptcy Code and Workforce Reductions

On July 15, 2020, we filed voluntary petitions for relief under Chapter 11 of Title 11 of the Bankruptcy Code (Chapter 11 Cases) in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (Bankruptcy Court). On October 13, 2020, the Bankruptcy Court confirmed our joint plan of reorganization (the Plan) and we subsequently emerged from Chapter 11 proceedings on October 27, 2020 (Effective Date). See *Note 14 Chapter 11 Proceedings* for more information on our voluntary reorganization. We qualified for fresh start accounting and allocated the reorganization value to our individual assets and liabilities based on their estimated relative fair value. Our reorganization value was less than the fair value of identifiable assets of the emerging entity and we allocated the difference to nonfinancial assets on a relative fair value basis. Our valuation approach for determining the estimated fair value of our significant assets acquired and liabilities assumed is discussed in *Note 15 Fresh Start Accounting*.

In 2021, we reduced the size of our management team and realigned several functions, which resulted in headcount and cost reductions. We recorded a restructuring charge of $15 million during the year ended December 31, 2021. In 2020, we reduced our workforce in response to economic conditions, resulting in a restructuring charge of $10 million in the Predecessor period ended October 31, 2020 and $5 million in the Successor period ended December 31, 2020. These charges are included in other operating expenses, net on our consolidated statement of operations.

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, reserves 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, 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 25 years for a commercial office building we own in Bakersfield, California and 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. Commodity derivatives are the most significant items on our consolidated balance sheets affected by recurring fair value measurements.

Our property, plant and equipment (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.

Commodity sales contracts — Disaggregated revenue for sales of oil, natural gas and natural gas liquids (NGLs) to customers includes the following:

	Successor		Predecessor	
(in millions)	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Oil	$ 1,555	$ 176	$ 874	$ 1,884
NGLs	250	29	106	179
Natural gas	243	32	112	207
Oil, natural gas and NGL sales	$ 2,048	$ 237	$ 1,092	$ 2,270

See *Note 13 Revenue Recognition* for more information on our revenue from contracts with customers.

Allowance for Credit Losses

Our receivables from customers relate to sales of our commodity products, trading activities and joint interest billings. Credit exposure for each customer is monitored for outstanding balances and current activity. We actively manage our credit risk by selecting counterparties that we believe to be financially sound and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified. We believe exposure to counterparty credit-related losses at December 31, 2021 was not material and losses associated with counterparty credit risk have been insignificant for all periods presented.

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:

	Successor	Predecessor
(in millions)	2021	2020
Materials and supplies	$ 54	$ 58
Finished goods	6	3
Total	$ 60	$ 61

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 shares issuable under our long-term incentive plan were authorized by the Bankruptcy Court and the terms of a new long-term incentive plan were approved by our new board of directors in January 2021. In accordance with our new 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 (loss) per share is calculated as net income (loss) divided by the weighted average number of our common shares outstanding during the period. Diluted earnings (loss) per share is calculated by dividing net income (loss) 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 record an adjustment to both the ARO and PP&E. Over time the liability is increased, and expense is recognized for accretion, and the capitalized cost is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

At certain of our facilities, we have identified ARO that are related mainly to plant and field decommissioning, including plugging and abandonment of wells. In certain cases, we do not know or cannot estimate when we would perform the ARO work and, therefore, we cannot reasonably estimate the fair value of these liabilities. 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.

	Successor		Predecessor
(in millions)	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Beginning balance	$ 597	$ 593	$ 517
Liabilities settled and divested	(157)	(5)	(16)
Accretion expense on discounted obligation	50	8	33
Revisions of estimated obligation	19	—	—
Impact of fresh start accounting	—	—	57
Other	1	1	2
Liabilities reclassified as held for sale	(21)	—	—
Ending balance	$ 489	$ 597	$ 593
Current portion	$ 51	$ 50	$ 50
Non-current portion	$ 438	$ 547	$ 543

During 2021, our total asset retirement obligation decreased by $108 million, including $21 million of liabilities reclassified as held for sale. Our liability decreased by $157 million including $42 million for settlement payments and $115 million of liabilities assumed as part of our Ventura divestiture. Revisions to our future cost estimates and abandonment dates for our oil and gas assets resulted in an increase of $19 million. See *Note 3 Divestitures and Acquisitions* for more information on our sold properties and our liabilities reclassified as held for sale.

In 2020, upon emergence from bankruptcy and the adoption of fresh start accounting, ARO liabilities were adjusted to their estimated fair value resulting in a $57 million increase to our obligations at that time. See *Note 15 Fresh Start Accounting* for more information on our fresh start accounting adjustments.

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 bases. 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 15% of our total production for the year ended December 31, 2021.

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. Guaranteed deposit accounts are valued at the book value provided by the issuer.

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, 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 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 considered whether there was an identifiable asset and then considered 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 considered the average cost of borrowing for publicly traded corporate bond yields, which were 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 recognized 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. Our finance leases are not significant. 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, 2021 include the remaining assets and the associated asset retirement obligations in the Ventura basin. See *Note 3 Divestitures and Acquisitions* for more information.

Other Current Assets

Other current assets consisted of the following:

	Successor	
(in millions)	December 31, 2021	December 31, 2020
Amounts due from joint interest partners	$ 47	$ 42
Fair value of derivative contracts	6	—
Prepaid expenses	16	20
Prepaid greenhouse gas allowances	31	—
Collateral on natural gas purchases	12	—
Other	9	1
Other current assets	$ 121	$ 63

Other Noncurrent Assets

Other noncurrent assets consisted of the following:

	Successor	
(in millions)	December 31, 2021	December 31, 2020
Operating lease right-of-use assets	$ 43	$ 38
Deferred financing costs - Revolving Credit Facility	11	17
Emission reduction credits	11	11
Prepaid power plant maintenance	21	14
Fair value of derivative contracts	1	—
Deposits and other	11	10
Other noncurrent assets	$ 98	$ 90

Accrued Liabilities

Accrued liabilities consisted of the following:

	Successor	
(in millions)	December 31, 2021	December 31, 2020
Accrued employee-related costs	$ 61	$ 72
Accrued taxes other than on income	30	36
Asset retirement obligations	51	50
Accrued interest	19	1
Lease liability	11	7
Deferred premiums on derivative contracts	57	18
Net settlement payments due on derivative contracts	25	3
Other	43	24
Accrued liabilities	$ 297	$ 211

As of December 31, 2020, accrued employee-related costs included approximately $5 million of payroll taxes deferred under COVID-19 relief, half of which was paid before December 31, 2021 with the remainder due on or before December 31, 2022.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	Successor	
(in millions)	December 31, 2021	December 31, 2020
Compensation-related liabilities	38	44
Postretirement and pension benefit plans	59	140
Lease liability	37	35
Deferred premiums on derivative contracts	5	31
Other	6	19
Other long-term liabilities	$ 145	$ 269

Other Operating Expenses, net

Other operating expenses, net consisted of the following:

	Successor		Predecessor	
	Year ended December 31,	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31,
(in millions)	2021			2019
Severance and termination costs	$ 15	$ 5	$ 10	$ —
Deficiency payment on a pipeline delivery contract	—	—	20	—
Idle well fees	6	—	4	3
Power plant interruption	—	—	7	1
Ad valorem fees	—	—	4	—
Other, net	8	4	11	14
Other operating expenses, net	$ 29	$ 9	$ 56	$ 18

Reorganization Items, net

Reorganization items, net consisted of the following (in millions):

(in millions)	Successor: Year ended December 31, 2021	Successor: November 1, 2020 - December 31, 2020	Predecessor: January 1, 2020 - October 31, 2020
Gain on settlement of liabilities subject to compromise	$ —	$ —	$ 4,022
Unamortized deferred gain and issuance costs, net	—	—	125
Junior debtor-in-possession exit fee	—	—	(12)
Acceleration of unrecognized compensation expense on cancelled stock-based compensation awards	—	—	(5)
Write-off of prepaid directors and officers' insurance premiums	—	—	(2)
Total non-cash reorganization items	$ —	$ —	$ 4,128
Legal, professional and other, net	(6)	(3)	(43)
Debtor-in-possession financing costs	—	—	(25)
Total reorganization items, net	$ (6)	$ (3)	$ 4,060

Supplemental Cash Flow Information

Supplemental disclosures to our consolidated statements of cash flows, excluding leases, are presented below (in millions):

	Successor: Year ended December 31, 2021	Successor: November 1, 2020 - December 31, 2020	Predecessor: January 1, 2020 - October 31, 2020	Predecessor: Year ended December 31, 2019
Supplemental Cash Flow Information				
Cash paid for interest, net of amounts capitalized	$ (28)	$ (8)	$ (79)	$ (425)
Supplemental Disclosure of Noncash Investing and Financing Activities				
Successor common stock, Subscription Rights and Warrants issued pursuant to the Plan	$ —	$ —	$ (494)	$ —
Successor common stock issued for the junior debtor-in-possession exit fee pursuant to the Plan	$ —	$ —	$ (12)	$ —
Successor common stock and EHP Notes issued for acquisition of noncontrolling interest pursuant to the Plan	$ —	$ —	$ (561)	$ —
Successor common stock issued for a backstop commitment premium pursuant to the Plan	$ —	$ —	$ (52)	$ —
Warrant issued to a joint venture partner	$ —	$ —	$ —	$ (3)
Derivative related to additional earn-out consideration for the Ventura divestiture	$ 3	$ —	$ —	$ —

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

We capitalize the costs incurred to acquire or develop our oil and natural gas assets, including ARO and capitalized 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:

	Successor	
(in millions)	December 31, 2021	December 31, 2020
Proved oil and natural gas properties	$ 2,604	$ 2,416
Unproved oil and natural gas properties	1	1
Facilities and other	240	272
Total property, plant and equipment	2,845	2,689
Accumulated depreciation, depletion and amortization	(246)	(34)
Total property, plant and equipment, net[(a)]	$ 2,599	$ 2,655

(a) Upon our emergence from bankruptcy, we adopted fresh start accounting on October 31, 2020. At that time, we remeasured our assets at their relative fair value. See *Note 15 Fresh Start Accounting* for more information.

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

	Successor		Predecessor	
(in millions)	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Beginning balance	$ 3	$ 3	$ 7	$ 5
Additions to capitalized exploratory well costs	—	—	—	12
Reclassification to property, plant and equipment	—	—	—	(3)
Charged to expense	(2)	—	(2)	(7)
Impact of fresh start accounting	—	—	(2)	—
Ending balance	$ 1	$ 3	$ 3	$ 7

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, 2021 are for permitted wells that we intend to drill.

Asset Impairments

Asset impairments were $28 million for the year ended December 31, 2021, including $25 million related to the write-down of a commercial office building located in Bakersfield, California 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 resulted in an impairment as of our September 30, 2021 assessment date. In January 2022, we entered into an agreement to sell our commercial office building for $15 million. See *Note 16 Subsequent Events* for details of this potential divestiture. We determined that this asset did not meet the requirements to be classified as held for sale at December 31, 2021.

The following table presents a summary of our asset impairments during the Predecessor period of 2020 (in millions):

	Predecessor
	January 1, 2020 - October 31, 2020
Proved oil and natural gas properties	$ 1,487
Unproved properties	228
Other	21
Total	$ 1,736

The impairment charge of $1,736 million during the period ended October 31, 2020 was due to the sharp drop in commodity prices as of our March 31, 2020 assessment date.

The fair values of our proved oil and natural gas properties were determined using discounted cash flow models incorporating a number of fair value inputs which are categorized as Level 3 on the fair value hierarchy. These inputs were based on management's expectations for the future considering the then-current environment and included index prices based on forward curves, pricing adjustments for differentials, estimates of future oil and natural gas production, estimated future operating costs and capital development plans based on the embedded price assumptions. We used a market-based weighted average cost of capital to discount the future net cash flows. The impairment charge on our proved oil and gas properties primarily related to a steamflood property located in the San Joaquin basin.

As of our March 31, 2020 assessment date, we determined our ability to develop our unproved properties, which primarily consisted of leases held by production in the San Joaquin basin, was constrained for the foreseeable future and we did not intend to develop them.

We did not record an impairment charge during the Successor period of 2020 or the year ended December 31, 2019.

NOTE 3 DIVESTITURES AND ACQUISITIONS

Divestitures

Ventura Basin Transactions

During the second quarter of 2021, we entered into transactions to sell our Ventura basin assets. The transactions contemplate multiple closings that are subject to customary closing conditions. In total, we will receive cash consideration of up to $102 million, before purchase price adjustments, plus additional earn-out consideration that is linked to future commodity prices. The consideration, exclusive of the earn-out, includes $82 million of total cash consideration (subject to purchase price adjustments) and up to $20 million of potential additional consideration if the buyer does not perform certain abandonment obligations with respect to the divested properties. The additional consideration is secured by production payments of $20 million over a five-year period. To the extent the buyer satisfies all of the required abandonment obligations within a five-year period following the initial close date, none of the $20 million of potential additional consideration will be paid to us.

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. We expect to divest of the remaining assets in the Ventura basin during the first half of 2022. These remaining assets, consisting of property, plant and equipment and the associated asset retirement obligations, are classified as held for sale on our consolidated balance sheet as of December 31, 2021.

Lost Hills Transactions

In May 2019, we sold 50% of our working interest and transferred operatorship in certain horizons within our Lost Hills field, located in the San Joaquin basin, for proceeds of $164 million (after transaction costs and purchase price adjustments) plus a carried 200-well development program. The partial sale of proved property was accounted for as a normal retirement with no gain or loss recognized. The partial sale of unproved property was recorded as a recovery of cost.

On February 1, 2022, we sold our remaining 50% non-operated working interest in these horizons for proceeds of $55 million (before transaction costs and purchase price adjustments). See *Note 16 Subsequent Events* for more information on our Lost Hills divestiture.

Other Divestitures

In 2021, we also sold unimproved land and other non-core assets for $13 million in proceeds recognizing a $4 million gain.

In January 2020, we sold royalty interests and divested non-core assets resulting in $41 million of proceeds which was treated as a normal retirement and no gain or loss was recognized.

See *Note 16 Subsequent Events* for details on an agreement entered into in January 2022 related to our commercial office building located in Bakersfield, California.

Acquisitions

MIRA JV Acquisition

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 the San Joaquin basin in exchange for a 90% working interest in the related properties. In August 2021, we purchased MIRA’s entire working interest share in the conveyed assets for net cash payment of $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 2019, we had several acquisitions of non-core properties totaling approximately $6 million.

NOTE 4 DEBT

As of December 31, 2021 and 2020, our long-term debt consisted of the following (in millions):

	Successor		Interest Rate	Maturity
	2021	2020		
Revolving Credit Facility[a]	$ —	$ 99	LIBOR plus 3%-4% ABR plus 2%-3%	April 29, 2024
Senior Notes	600	—	7.125%	February 1, 2026
Second Lien Term Loan	—	200	LIBOR plus 9%-10.5% ABR plus 8%-9.5%	October 27, 2025
EHP Notes	—	300	6%	October 27, 2027
Principal amount of debt	$ 600	$ 599		
Unamortized debt issuance costs	(11)	(2)		
Long-term debt, net	$ 589	$ 597		

(a) In February 2022, we amended our Revolving Credit Facility to replace London Interbank Offered Rates (LIBOR). See *Note 16 Subsequent Events*, for further information on this amendment.

Fair Value

The estimated fair value of our debt at December 31, 2021 and 2020, including the fair value of the variable-rate portion, was approximately $623 million and $599 million, respectively, compared to a face value of approximately $600 million and $599 million, respectively. We estimate the fair value of fixed-rate debt based on prices known from market transactions as of December 31, 2021 (Level1). We estimate the fair value of fixed-rate debt based on unobservable inputs as of December 31, 2020 (Level 3). We estimate the fair value of our variable rate debt approximates its carrying value.

Revolving Credit Facility

On October 27, 2020, we entered into a Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of $492 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 $200 million for the issuance of letters of credit. As of December 31, 2021, we had approximately $367 million available for borrowing under the Revolving Credit Facility after taking into account $125 million of outstanding letters of credit. See *Note 16 Subsequent Events* for information on additional commitments.

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

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

Interest Rate – We could elect to borrow at either an adjusted LIBOR rate or an ABR rate, subject to a 1% floor and 2% floor, respectively, 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 adjusted LIBOR rate plus 1%. The applicable margin is adjusted based on the borrowing base utilization percentage and will vary from (i) in the case of LIBOR loans, 3% to 4% and (ii) in the case of ABR loans, 2% to 3%. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly. In February 2022, we amended our Revolving Credit Facility to replace LIBOR with the secured overnight financing rate (SOFR) as administered by the Federal Reserve Bank of New York. See *Note 16 Subsequent Events*, for further information on this amendment.

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 secured 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) EBITDAX is calculated as defined in the credit agreement.
(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 credit agreement.

Our Revolving Credit Facility also requires us to maintain hedges on a minimum amount of crude oil production, determined semi-annually, of no less than (i) 75% of our reasonably anticipated oil production from our proved reserves during the period November 1, 2020 through October 31, 2022, and (ii) 50% of our reasonably anticipated oil production from our proved reserves during the period November 1, 2022 through October 31, 2023. The Revolving Credit Facility specifies the forms of hedges and prices (which can be prevailing prices) that must be used for a portion of those hedges.

Further, our Revolving Credit Facility requires us to maintain acceptable commodity hedges for no less than 50% of the reasonably anticipated oil production from our proved reserves for at least 24 months following the date of delivery of each reserve report if our leverage ratio is greater than 2.00:1.00. If our leverage ratio is less than 2.00:1.00, then the minimum amount of hedges that we are required to maintain is reduced from 50% to 33%. Currently, we may not hedge more than 85% of reasonably anticipated total forecasted production of crude oil, natural gas and NGLs from our oil and gas properties for a 48-month period, except that we may purchase puts and floors up to 100% of such production. The percentage of our crude oil production hedged is calculated exclusive of offsetting positions on our derivative contracts.

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 credit agreement, that entitles our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

<u>Senior Notes</u>

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 – Prior to February 1, 2023, we may elect to redeem up to 35% of the aggregate principal amount of our Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 107% of the aggregate amount of the Senior Notes redeemed, plus accrued and unpaid interest. In addition, prior to February 1, 2023, we may redeem the Senior Notes at a "make whole" premium plus accrued and unpaid interest. On or after February 1, 2023, we may redeem the Senior Notes at any time prior to the maturity date at a redemption price equal to (i) 104% of the principal amount if redeemed in the twelve months beginning February 1, 2023, (ii) 102% of the principal amount if redeemed in the twelve months beginning February 1, 2024 and (iii) 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.

<u>*Second Lien Term Loan*</u>

On October 27, 2020, we entered into a $200 million credit agreement with Alter Domus Products Corp., as administrative agent, and certain other lenders (Second Lien Term Loan). The proceeds were used to refinance our Junior DIP Facility and to pay certain costs, fees and expenses related to the other transactions consummated on the Effective Date.

Security – The lenders had a second-priority lien (junior to the Revolving Credit Facility) on a substantial majority of our assets, except assets securing the EHP Notes as discussed below.

Interest Rate – We could elect to pay interest at either an adjusted LIBOR rate or ABR rate, subject to a 1% floor and 2% floor, respectively, plus an applicable margin. The ABR rate was equal to the highest of (i) the prime rate, (ii) the federal funds rate effective rate plus 0.50%, and (iii) the one-month adjusted LIBOR rate plus 1%. Prior to the second anniversary of the closing date of the Second Lien Term Loan, the applicable margin in the case of an ABR rate election was 8% per annum if paid in cash and 9.50% per annum if paid-in-kind, and the applicable margin in the case of an adjusted LIBOR rate election was 9% if paid in cash and 10.50% if paid-in-kind. After the second anniversary of the closing date, the applicable margin was 8% with respect to any ABR loan and 9% with respect to an adjusted LIBOR loan. Interest on ABR loans was paid quarterly in arrears and interest based on the adjusted LIBOR rate was due at the end of each LIBOR period, which could be one, two, three or six months but not less than quarterly. We also paid customary fees and expenses.

Maturity Date – Our Second Lien Term Loan would mature five years after the closing date, subject to extension.

Redemption – We could elect to redeem all or part of our Second Lien Term Loan, at any time prior to the maturity date, at redemption price equal to (i) 100% of the principal amount if redeemed prior to 90 days after closing, (ii) 105% of the principal amount if redeemed after 90 days and before the first anniversary date, (iii) 103% of the principal amount if redeemed on or after the first anniversary date and before the second anniversary date, (iv) 102% of the principal amount if redeemed on or after the second anniversary date and before the third anniversary date, (v) 101% of the principal amount if redeemed on or after the third anniversary date and before the fourth anniversary date, and (vi) at 100% of the principal amount if redeemed in the fifth year.

Financial Covenants – Our Second Lien Term Loan included certain financial covenants that were to be tested quarterly, including a consolidated total net leverage ratio and current ratio.

Liquidity – We would become subject to a monthly minimum liquidity requirement of $170 million if, as of the Spring 2021 Scheduled Redetermination (as defined in the Revolving Credit Facility), (a) our liquidity was less than $247 million and (b) we were not able to obtain at least $51 million in additional commitments under our Revolving Credit Facility or through capital markets or other junior financing transactions, for so long as the conditions in (a) and (b) remained unmet.

Other Covenants – Our Second Lien Term Loan included covenants that, among other things, restricted 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 were also restricted in the amount of cash dividends we could pay on our common stock unless we met certain covenants included in the credit agreement.

Our Second Lien Term Loan also required us to maintain hedges on a minimum amount of crude oil production on terms that were substantially consistent with the requirements of our Revolving Credit facility.

Events of Default and Change of Control – Our Second Lien Term Loan provided for certain events of default, including upon a change of control, as defined in the credit agreement, that would entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We were subject to a cross-default provision that causes a default under this facility if certain defaults occurred under the Revolving Credit Facility or the EHP Notes.

The Second Lien Term Loan was terminated and repaid with proceeds from our Senior Notes offering in January 2021 as described above.

EHP Notes

On the Effective Date, our wholly-owned subsidiary, EHP Midco Holding Company, LLC (Elk Hills Issuer) entered into a Note Purchase Agreement (Note Purchase Agreement) with certain subsidiaries of Ares and Wilmington Trust, N.A. as collateral agent. The $300 million Notes were issued as partial consideration for the Class B Preferred Units, Class A Common Units and Class C Common Units in the Ares JV previously held by ECR (EHP Notes).

The EHP Notes were senior notes due in 2027, and were secured by a first-priority security interest in all of the assets of Elk Hills Power, any third-party offtake contracts for power generated by Elk Hills Power, all of the equity interests of Elk Hills Power held by Elk Hills Issuer and all of the equity interests of Elk Hills Issuer held by its direct parent, EHP Topco Holding Company, LLC, our wholly-owned subsidiary. We and Elk Hills Power guaranteed, on a joint and several basis, all of the obligations of Elk Hills Issuer under the EHP Notes. The EHP Notes bore an interest rate of 6.0% per annum through the fourth anniversary of issuance, increasing to 7.0% per annum after the fourth anniversary of issuance and to 8.0% per annum after the fifth anniversary of issuance. We were permitted to redeem the EHP Notes at any time prior to their maturity date without payment of premium or penalty.

The EHP Notes were terminated and repaid with proceeds from our Senior Notes offering in January 2021 as described above.

Other

At December 31, 2021, all obligations under our Revolving Credit Facility and Senior Notes are guaranteed by certain of our material wholly owned subsidiaries.

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, 2021, we were in compliance with all debt covenants under our credit agreements.

Principal maturities of debt outstanding at December 31, 2021 (Successor) are as follows:

	As of December 31, 2021
	(in millions)
2022	$ —
2023	—
2024	—
2025	—
2026	600
Thereafter	—
Total	$ 600

NOTE 5 LEASES

Balance sheet information related to our operating and finance leases as of December 31, 2021 and December 31, 2020 were as follows:

	Classification	Successor 2021	Successor 2020
Assets		(in millions)	(in millions)
Operating	*Other noncurrent assets*	$ 43	$ 38
Finance	*PP&E*	—	1
Total right-of-use assets		$ 43	$ 39
Liabilities			
Current			
Operating	*Accrued liabilities*	$ 11	$ 6
Finance	*Accrued liabilities*	—	1
Long-term			
Operating	*Other long-term liabilities*	37	35
Total lease liabilities		$ 48	$ 42

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 buildings and increased by mobilization and demobilization fees for our drilling rigs. Certain of our lease agreements include options to renew, which we exercise at our sole discretion, and 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 certain of our commercial office buildings included 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, were as follows:

	Successor		Predecessor
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
	(in millions)		(in millions)
Operating lease costs	$ 14	$ 2	$ 23
Short-term lease costs[a]	48	7	25
Variable lease costs	4	—	4
Total operating lease costs	66	9	52
Finance lease costs	—	—	1
Sublease income	(2)	—	(1)
Total lease costs	$ 64	$ 9	$ 52

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

We have two contracts treated as finance leases, which were not material to our consolidated results of operations.

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. Sublease income was not material to our consolidated financial statements for all periods presented.

Other supplemental information related to our operating and finance leases as of December 31, 2021 and December 31, 2020 is provided below:

	Successor		Predecessor
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
	(in millions)		(in millions)
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows	$ 8	$ 2	$ 9
Investing cash flows	$ 4	$ —	$ 14
Financing cash flows	$ 1	$ —	$ 1
ROU assets obtained in exchange for new operating lease liabilities	$ 17	$ —	$ —
Impairment charges related to ROU assets	$ —	$ —	$ 2

	Successor	
	2021	2020
Operating Leases		
Weighted-average remaining lease term (in years)	8.25	6.81
Weighted-average discount rate	5.4 %	4.5 %
Finance Leases		
Weighted-average remaining lease term (in years)	0.33	1.33
Weighted-average discount rate	4.0 %	4.0 %

The difference in the weighted-average discount rate between operating leases and finance leases primarily relates to lease term.

Maturities of our operating liabilities at December 31, 2021 are as follows:

	Successor
	Operating Leases
	(in millions)
2022	$ 12
2023	8
2024	8
2025	6
2026	5
Thereafter	23
Less: Interest	(14)
Present value of lease liabilities	$ 48

NOTE 6 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2021 and 2020 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 is challenging 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 have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, land easements and field equipment. We also have a capital commitment of $12 million in 2022 for evaluation and development activities at one of our oil and natural gas properties. During 2021, we entered into an agreement which will relieve us from our remaining obligation upon acceptance of certain land use requirements which may occur on or before May 2022.

At December 31, 2021, total purchase obligations on a discounted basis were as follows:

	December 31, 2021
	(in millions)
2022	$ 54
2023	32
2024	10
2025	5
2026	5
Thereafter	30
Total	136
Less: Interest	(18)
Present value of purchase obligations	$ 118

NOTE 7 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 did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2021, 2020 and 2019. 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. We have also entered into incremental 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.*

Commodity-Price Risk

As part of our hedging program, we held the following Brent-based crude oil contracts as of December 31, 2021:

	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Sold Calls:					
Barrels per day	35,347	35,343	34,380	25,167	14,790
Weighted-average price per barrel	$ 60.37	$ 60.63	$ 60.76	$ 57.82	$ 58.01
Swaps					
Barrels per day	12,369	10,669	10,476	17,263	12,937
Weighted-average price per barrel	$ 54.38	$ 54.12	$ 53.97	$ 58.79	$ 59.08
Net Purchased Puts[(a)]					
Barrels per day	35,347	35,343	34,380	25,167	14,790
Weighted-average price per barrel	$ 53.32	$ 54.69	$ 55.95	$ 57.22	$ 40.00
Sold Puts					
Barrels per day	6,869	—	4,000	1,348	—
Weighted-average price per barrel	$ 32.00	$ —	$ 32.00	$ 32.00	$ —

(a) Purchased puts and sold puts with the same strike price have been presented on a net basis.

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.
- Sold puts – we make 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.

We use combinations of these positions to meet the requirements of our Revolving Credit Facility and to increase the efficacy of our hedging program.

Derivative instruments not designated as hedging instruments are required to be recorded on the balance sheet at fair value. Noncash derivative gains and losses, along with settlement payments, are reported in net (loss) gain from commodity derivatives on our consolidated statements of operations as shown in the table below:

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
(in millions)				
Non-cash commodity derivative loss, excluding noncontrolling interest	$ (357)	$ (138)	$ (19)	$ (166)
Non-cash commodity derivative (loss) gain, attributable to noncontrolling interest	—	(2)	2	(4)
Total non-cash changes	(357)	(140)	(17)	(170)
Net (payments) proceeds on commodity derivatives	(319)	(1)	108	111
Net (loss) gain from commodity derivatives	$ (676)	$ (141)	$ 91	$ (59)

Interest-Rate Risk

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to a notional amount of $1.3 billion of variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021. The contracts expired on May 4, 2021. We did not report any gains or losses on these contracts for the years ended December 31, 2021 or 2020. For the year ended December 31, 2019, we reported a loss on these contracts, included in other non-operating expenses on our consolidated statement of operations, of $4 million. No settlement payments were received in 2021, 2020, or 2019. As of December 31, 2021, we do not have any derivative contracts in place with respect to interest-rate exposure.

Fair Value of Derivatives

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.

Commodity Contracts

The following tables present the fair values (at gross and net) of our outstanding derivatives:

December 31, 2021 (Successor)

Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
Assets:		(in millions)	
Other current assets	$ 33	$ (27)	$ 6
Other noncurrent assets	12	(11)	1
Liabilities:			
Current - Fair value of derivative contracts	(297)	27	(270)
Noncurrent - Fair value of derivative contracts	(143)	11	(132)
	$ (395)	$ —	$ (395)

December 31, 2020 (Successor)

Classification	Gross Amounts at Fair Value	Netting	Net Fair Value
Assets:		(in millions)	
Other current assets	$ 21	$ (21)	$ —
Other noncurrent assets	63	(63)	—
Liabilities:			
Current - Fair value of derivative contracts	(71)	21	(50)
Noncurrent - Fair value of derivative contracts	(69)	63	(6)
	$ (56)	$ —	$ (56)

Interest-Rate Contracts

The fair value of our interest-rate derivatives contracts was not significant for all periods presented.

Counterparty Credit Risk

As of December 31, 2021, 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 as of December 31, 2021 was not significant. Losses associated with credit risk have been insignificant for all years presented. At December 31, 2021, and 2020, we had insignificant collateral posted.

NOTE 8 INCOME TAXES

Net income (loss) before income taxes, for all periods presented, was generated from domestic operations. For the year ended December 31, 2021, we released all of our valuation allowance of $549 million, which consisted of $258 million in the U.S. federal jurisdiction and $291 million in the state jurisdiction. A portion of the change in our valuation allowance was released against current year income and the remaining $161 million in the U.S. federal jurisdiction and $235 million in the state jurisdiction was recognized as a tax benefit reflecting the projected utilization of our deferred tax assets. We did not record an income tax provision (benefit) in the period ended December 31, 2020 or the period ended October 31, 2020. We recorded an insignificant income tax provision for the year ended December 31, 2019.

Total income tax (benefit) provision differs from the amounts computed by applying the U.S. federal income tax rate to pre-tax income (loss) as follows:

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
U.S. federal statutory tax rate	21 %	21 %	21 %	21 %
State income taxes, net	(81)	—	—	1
Exclusion of income attributable to noncontrolling interests	(1)	—	(1)	(27)
Debt restructuring	—	—	—	—
Changes in tax attributes	(8)	—	—	(7)
Executive compensation	2	—	—	2
Change in the U.S. federal valuation allowance	(106)	(20)	(21)	10
Other	—	(1)	1	1
Effective tax rate	(173) %	— %	— %	1 %

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2021 and 2020 were as follows:

	Successor			
	2021		2020	
(in millions)	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
Property, plant and equipment	$ 122	$ (151)	$ 209	$ (113)
Postretirement and pension benefit plans	18	—	43	—
Asset retirement obligations	152	—	178	—
Net operating loss and tax credit carryforwards	88	—	12	—
Business interest expense carryforward	177	—	180	—
Federal benefit of state income taxes	—	(49)	—	—
Other	59	(20)	60	(20)
Subtotal	616	(220)	682	(133)
Valuation allowance	—	—	(549)	—
Total deferred taxes	$ 616	$ (220)	$ 133	$ (133)

Management assesses the realizability of deferred tax assets each period by considering whether it is more-likely-than-not that all or a portion of our deferred tax assets will be realized. At each reporting date new evidence is considered, both positive and negative, including whether sufficient future taxable income may be generated to permit realization of existing deferred tax assets. For the assessment period ended December 31, 2021, management concluded that it was more-likely-than-not that all of our existing deferred tax assets would be realized. This determination was based, in part, on our three-year cumulative income position, the profitability of our business in recent periods and our projections of future taxable income at current commodity prices and our current cost structure. We also considered our ability to generate future taxable income in a lower commodity price environment as a potential source of negative evidence. Based on our assessment, we determined there is sufficient positive evidence to conclude that it is more-likely-than-not that our deferred tax assets of $396 million at December 31, 2021 are realizable and we released our remaining valuation allowance in the fourth quarter of 2021.

Realization of our deferred tax assets is subjective and remains dependent on our ability to generate sufficient taxable income in future periods. 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, 2021, we had U.S. federal net operating loss carryforwards of $84 million, which begin to expire in 2037, and $20 million of tax credits, which begin to expire in 2041. Our carryforward for business interest expense of $844 million does not expire.

As of December 31, 2021, we had California net operating loss carryforwards of approximately $2,431 million, which begin to expire in 2026, and $20 million of tax credit carryforwards, which begin to expire in 2041.

Our ability to utilize 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 did not recognize a tax benefit for $17 million U.S. federal net operating loss carryforwards and $1,905 million California net operating loss carryforwards which we expect will expire unused. Additionally, we did not recognize a tax benefit for $14 million of California tax credit carryforwards which we expect will expire unused.

Unrecognized Tax Benefits

We did not record a liability for unrecognized tax benefits in any Successor period. The following is a reconciliation of unrecognized tax benefits in our Predecessor periods:

	Predecessor	
(in millions)	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Unrecognized tax benefits – beginning balance	$ 101	$ 25
Gross (decreases) increases – tax positions in prior year	(101)	44
Gross increases – tax positions in current year	—	32
Unrecognized tax benefits – ending balance	$ —	$ 101

In 2020, we released our liabilities related to uncertain tax positions which primarily related to the calculation of the limitation on business interest expense. In 2020, the Internal Revenue Service (IRS) issued final regulations which clarified the calculation of the limitation on the deduction of business interest expense. Based on our evaluation of these final regulations, we determined that our income tax returns were filed at least on a more-likely-than-not basis and accordingly we reversed our liability for uncertain tax positions.

Other

We remain subject to audit by the Internal Revenue Service for calendar years 2018 through 2020 as well as 2017 through 2020 by the state of California.

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 shares issuable under the new long-term incentive plan had been previously authorized by the Bankruptcy Court in connection with our emergence from Chapter 11 and the terms of the new long-term incentive plan were approved by our Board of Directors. As a result, the Long Term Incentive Plan became effective on January 18, 2021. 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 replaces the earlier Amended and Restated California Resources Corporation Long Term Incentive Plan which was cancelled upon our emergence from bankruptcy, along with all outstanding stock-based compensation awards granted thereunder.

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.

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
(in millions)				
General and administrative expenses	$ 17	$ —	$ 2	$ 25
Operating costs	2	—	1	7
Total stock-based compensation expense	$ 19	$ —	$ 3	$ 32

We did not make any payments for the cash-settled portion of our awards for the year ended December 31, 2021 or in the Successor period of 2020. We made payments of $8 million for the cash-settled portion of our awards during the Predecessor period of 2020 and $25 million during the year ended December 31, 2019. We did not recognize any income tax provision or benefit related to our stock-based compensation expense in 2021, 2020 or 2019.

Successor Stock Based Compensation Plan

Management Incentive Plan

Restricted Stock Units

Executives and non-employee directors were granted RSUs during 2021 which are in the form of, or equivalent in value to, actual shares of our common stock. The awards generally vest ratably over three years, with one third of the granted units vesting on each of the first three anniversaries of the applicable date of grant. RSUs are settled in shares of our common stock at the end of the third year of the three-year vesting period.

The following table sets forth RSU activity for the year ended December 31, 2021:

	Number of Units (in thousands)	Weighted-Average Grant-Date Fair Value
Unvested at December 31, 2020 (Successor)	—	$ —
Granted	1,216	$ 25.23
Vested	(18)	$ 24.50
Cancelled or Forfeited	(68)	$ 24.50
Unvested at December 31, 2021 (Successor)	1,130	$ 25.28

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, 2021, the unrecognized compensation expense for our unvested RSUs was approximately $20 million and is expected to be recognized over a weighted-average remaining service period of approximately two years.

Performance Stock Units

Executives were granted PSUs during 2021. PSUs 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. Earned PSUs generally vest on the third anniversary of the grant date and are settled in shares of our common stock at that time.

The following table sets forth PSU activity for the year ended December 31, 2021:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2020 (Successor)	—	$ —
Granted	997	$ 20.09
Cancelled or Forfeited	(53)	$ 19.31
Unvested at December 31, 2021 (Successor)	944	$ 20.14

The range of assumptions used in the Monte Carlo simulation model for the PSUs granted during 2021 were as follows:

	Successor 2021
Expected volatility[(a)]	60.00% - 65.00%
Risk-free interest rate[(b)]	0.16% - 0.60%
Dividend yield[(c)]	— %
Forecast period (in years)	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, expected volatility included the historic volatility of our stock, excluding our first two trading months.
(b) Based on the U.S. Treasury yield for a two- or three-year term at the grant date.
(c) The Monte Carlo model used for valuation included a dividend adjusted stock price and assumed reinvestment of dividends during the performance period.

Compensation expense is recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any.

As of December 31, 2021, 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.

Long-Term Cash Incentive Awards

On June 30, 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 Monte Carlo simulation model for the performance cash awards as of December 31, 2021 were as follows:

	Successor
	2021
Expected volatility[(a)]	60 %
Risk-free interest rate[(b)]	0.85 %
Dividend yield[(c)]	— %
Forecast period (in years)	2.5

(a) Expected volatility was calculated using the historic volatility of our stock, excluding our first two trading months, and the historic volatility of a peer group.
(b) Based on the U.S. Treasury yield for the 2.5 year remaining term.
(c) The Monte Carlo model used for valuation included a dividend adjusted stock price and assumed reinvestment of dividends during the performance period.

As of December 31, 2021, the unrecognized compensation expense for all of our unvested cash-settled awards was $11 million and is expected to be recognized over a weighted-average remaining service period of approximately 2.5 years. The value of awards forfeited during the year ended December 31, 2021 was approximately $1 million.

Predecessor Stock-Based Compensation Plan

As a result of our bankruptcy, the outstanding stock-based awards granted under our Amended and Restated California Resources Corporation Long-Term Incentive Plan (Amended LTIP) were cancelled on our Effective Date.

In 2019, our stockholders approved the Amended LTIP, which provided for the issuance of stock, incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, stock bonuses, performance-based awards and other awards to executives, employees and non-employee directors. Shares of our common stock were permitted to be withheld by us in satisfaction of tax withholding obligations arising upon the exercise of stock options or the vesting of restricted stock units. Further, shares of our common stock were permitted to be withheld by us in payment of the exercise price of employee stock options, which also counted against the authorized shares specified above.

The maximum number of authorized shares of our common stock that were available for issuance pursuant to the Amended LTIP was 7,275,000 shares. As of December 31, 2019, 4,714,316 shares were issued or reserved under the Amended LTIP and 2,560,684 shares were available for future issuance of awards. In the second quarter of 2020, our then Board of Directors approved the following changes to awards previously granted during 2020: (i) the previously established target amounts under the 2020 variable compensation programs remained unchanged, but any unvested amounts under such programs were revised to only be eligible for cash settlement, and (ii) as a condition to receiving any award under our 2020 variable compensation programs, participants waived participation in our 2020 annual incentive program and forfeited all stock-based compensation awards previously granted in 2020. At the time of the amendments, there were no changes to any stock-based compensation awards granted prior to February 2020; however, as a result of our bankruptcy, the outstanding stock-based awards under our Amended LTIP were cancelled on our Effective Date.

The cancellation of the stock-based compensation awards granted under the Amended LTIP prior to 2020 resulted in the recognition of all previously unrecognized compensation expense for equity-based awards under the Amended LTIP and the elimination of the liability related to cash-based awards under the Amended LTIP.

Restricted Stock Units

As part of the Amended LTIP, executives and other employees were granted restricted stock units (RSUs). RSUs were service based and, depending on the terms of the awards, were settled in cash or stock at the time of vesting. The awards either (i) vested ratably over three years, with one third of the granted units becoming vested on the day before each of the first three anniversaries of the applicable date of grant, or (ii) cliff vested upon the third anniversary of the applicable date of grant. Our RSUs had nonforfeitable dividend rights, and any dividends or dividend equivalents declared during the vesting period were paid as declared.

For cash- and stock-settled RSUs, compensation value was initially measured on the date of grant using the quoted market price of our common stock. Compensation expense for cash-settled RSUs was adjusted on a monthly basis for the cumulative change in the value of the underlying stock. For the Predecessor period of 2020 and the year ended December 31, 2019, the weighted-average fair value of each stock-settled RSU granted was $6.20 and $21.71, respectively. Compensation expense for the stock-settled RSUs were recognized on a straight-line basis over the requisite service periods, adjusted for actual forfeitures. All outstanding RSUs were cancelled for no consideration as a result of our emergence from bankruptcy.

Performance Stock Units

Our performance stock units (PSUs) were restricted stock unit awards with performance targets with payouts ranging from 0% to 200% of the target award. Up to the target amount of the PSUs were eligible to be settled in cash or stock, and any amount of the PSUs earned in excess of the target amounts of such PSUs were to be settled in cash. These awards accrued dividend equivalents as dividends are declared during the vesting period, which were paid upon certification for the number of earned PSUs. Compensation expense was adjusted quarterly, on a cumulative basis, for any changes in the number of share equivalents expected to be paid based on the relevant performance criteria. For the Predecessor period of 2020 and the year ended December 31, 2019, the weighted-average fair value of each stock-settled PSU granted was $6.20 and $21.71, respectively. All outstanding PSUs were cancelled for no consideration as a result of our emergence from bankruptcy.

Stock Options

We granted stock options to certain executives under our Amended LTIP. These options permitted the purchase of Predecessor common stock at exercise prices no less than the fair market value of the stock on the date the options were granted, with the majority of options being granted at 10% above fair market value. The options had terms of seven years and vested ratably over three years, with one third of the granted options becoming exercisable on the day before each of the first three anniversaries of the applicable date of grant, subject to certain restrictions including continued employment. For the Predecessor period of 2020 and the year ended December 31, 2019, the weighted-average fair value of each option granted was $6.82 and $23.88, respectively. All outstanding stock options were cancelled for no consideration as a result of our emergence from bankruptcy.

NOTE 10 EQUITY

On the Effective Date, all of our Predecessor common and preferred stock, including contracts on our equity were cancelled pursuant to the Plan and 83,319,660 shares of new common stock were issued. See *Note 14 Chapter 11 Proceedings* for further information.

The following is a summary of changes in our shares outstanding during the year ended December 31, 2021 (Successor):

	Common Stock
	(in thousands)
Balance, December 31, 2020	83,319,660
Shares issued for warrant exercises	51,377
Shares issued under stock-based compensation arrangements	18,173
Shares repurchased	(4,089,988)
Balance, December 31, 2021	79,299,222

Share Repurchase Program

During 2021, our Board of Directors authorized a Share Repurchase Program for up to $250 million of our common stock through June 30, 2022. In February 2022, our Share Repurchase Program was increased by $100 million to $350 million in aggregate and we extended the term of the program until December 31, 2022. See *Note 16 Subsequent Events* for more information on this increase. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time.

As of December 31, 2021, we repurchased 4,089,988 shares of our common stock, at an average price of $36.08 per share, through either open market purchases or our Rule 10b5-1 plan for $148 million. Shares repurchased were held as treasury stock as of December 31, 2021.

Dividends

On November 11, 2021, our Board of Directors declared a quarterly cash dividend of $0.17 per share of common stock. The dividend was payable to shareholders of record at the close of business on December 1, 2021 and was paid on December 16, 2021. The dividend paid in the fourth quarter of 2021 was made pursuant to a cash dividend policy approved by the Board of Directors, which anticipates a total annual dividend of $0.68, payable in quarterly increments of $0.17 per share of common stock.

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 and position. See *Note 16 Subsequent Events* for more information on future cash dividends.

Noncontrolling Interests

<u>*BSP JV*</u>

Our development joint venture with Benefit Street Partners (BSP JV) contemplated that BSP would contribute 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.

Ares JV

See *Note 14 Chapter 11 Proceedings* for information on our Ares JV and Settlement Agreement.

Warrants

On the Effective Date, we issued warrants exercisable for an aggregate 4,384,182 shares of Successor common stock. The 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.

During 2021, we had issued 51,377 shares of common stock and received approximately $2 million in cash related to warrant exercises. As of December 31, 2021, we had outstanding warrants exercisable into 4,296,005 share of Successor common stock.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consists of unrealized gains (losses) associated with our pension and postretirement benefit plans. During the year ended December 31, 2021 we recognized a benefit of $65 million related to a change in our postretirement benefit plan design. See *Note 12 Pension and Postretirement Benefit Plans* for additional information on this plan amendment.

The elimination of Predecessor equity balances as part of fresh start accounting resulted in a reclassification of $23 million of accumulated other comprehensive loss to additional paid-in capital upon emergence from bankruptcy. See *Note 15 Fresh Start Accounting* for additional information.

Employee Stock Purchase Plan

On May 26, 2020, our California Resources Corporation 2014 Employee Stock Purchase Plan was terminated by our then Board of Directors. No additional shares were issued under the plan after March 31, 2020.

NOTE 11 EARNINGS PER SHARE

Basic and diluted earnings per share (EPS) were calculated using the treasury stock method for the Successor periods and the two-class method, which is required when there are participating securities, for the Predecessor periods. Certain of our restricted and performance stock unit awards outstanding prior to our emergence from bankruptcy were considered participating securities because they had non-forfeitable dividend rights at the same rate as our pre-emergence common stock. Our restricted and performance stock unit awards granted subsequent to our emergence from bankruptcy, as described in *Note 9 Stock-Based Compensation*, are not considered participating securities since the dividend rights on unvested shares are forfeitable.

Under the two-class method, undistributed earnings allocated to participating securities are 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 participating securities do not share in losses.

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, 2021.

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

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
(in millions, except per share amounts)				
Numerator for Basic and Diluted EPS				
Net income (loss)	$ 625	$ (125)	$ 1,996	$ 99
Less: Net income attributable to noncontrolling interests	(13)	2	(107)	(127)
Net income (loss) attributable to common stock	612	(123)	1,889	(28)
Less: Net income allocated to participating securities	—	—	(22)	—
Modification of noncontrolling interest[(a)]	—	—	138	—
Net (loss) income available to common stockholders	$ 612	$ (123)	$ 2,005	$ (28)
Denominator for Basic EPS				
Weighted-average common shares	82.0	83.3	49.4	49.0
Potential dilutive common shares:				
Restricted Stock Units	0.5	—	0.2	—
Performance Stock Units	0.5	—	—	—
Denominator for Diluted Earnings per Share				
Weighted-average shares - diluted	83.0	83.3	49.6	49.0
EPS				
Basic	$ 7.46	$ (1.48)	$ 40.59	$ (0.57)
Diluted	$ 7.37	$ (1.48)	$ 40.42	$ (0.57)

(a) Modification of noncontrolling interest relates to the deemed redemption of ECR's noncontrolling interest in the Ares JV in the third quarter of 2020. For more information on the Ares JV and the Settlement Agreement, see *Note 14 Chapter 11 Proceedings*.

The following table presents potentially dilutive weighted-average common shares which were excluded from the denominator for diluted earnings per share:

	Successor		Predecessor	
	Year ended December 31,	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31,
(in millions)	2021			2019
Shares issuable upon exercise of warrants which were issued at emergence from bankruptcy	4.4	4.4	—	—
Shares issuable upon exercise of warrants in connection with our Alpine JV	—	—	1.3	0.6
Shares issuable upon settlement of RSUs	—	—	0.2	0.6
Shares issuable upon settlement of PSUs	—	—	0.8	0.5
Shares issuable upon exercise of stock options	—	—	1.7	1.4
Total antidilutive shares	4.4	4.4	4.0	3.1

NOTE 12 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. As of December 31, 2021 and 2020, we recognized $30 million and $35 million in other long-term liabilities for these supplemental plans, respectively.

We expensed $19 million in 2021, $4 million in the Successor period of 2020, $28 million in the Predecessor period of 2020 and $36 million in 2019 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 2021, 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 to the plan, 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 will be recognized in our statement of operations over the average remaining years of future service for active employees as a component of other non-operating expenses, net.

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, as of December 31, 2021 and 2020 (in millions):

	Successor			
	2021		**2020**	
	Pension	**Postretirement**	**Pension**	**Postretirement**
Amounts recognized on the balance sheet				
Accrued liabilities	$ —	$ (4)	$ —	$ (4)
Other long-term liabilities	(15)	(44)	(15)	(125)
	$ (15)	$ (48)	$ (15)	$ (129)
Amounts recognized in accumulated other comprehensive income (loss)	$ (2)	$ 74	$ (1)	$ (7)

The following table shows the funding status of our pension and post-retirement benefit plans along with a reconciliation of our benefit obligations and fair value of plan asset as of December 31, 2021 and 2020 (in millions):

	Successor		Predecessor
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Pension			
Changes in the benefit obligation			
Benefit obligation—beginning of year	$ 47	$ 46	$ 45
Service cost—benefits earned during the period	1	—	1
Interest cost on projected benefit obligation	1	—	1
Actuarial loss	2	3	1
Benefits paid	(7)	(2)	(2)
Benefit obligation—end of year	$ 44	$ 47	$ 46
Changes in plan assets			
Fair value of plan assets—beginning of year	$ 32	$ 26	$ 27
Actual return on plan assets	2	2	1
Employer contributions	2	6	—
Benefits paid	(7)	(2)	(2)
Fair value of plan assets—end of year	$ 29	$ 32	$ 26
Net benefit liability (unfunded status)	$ (15)	$ (15)	$ (20)
Postretirement			
Changes in the benefit obligation (in millions)			
Benefit obligation—beginning of year	$ 129	$ 122	$ 116
Service cost—benefits earned during the period	4	1	4
Interest cost on projected benefit obligation	3	—	3
Actuarial (gain) loss	(17)	7	2
Benefits paid	(5)	(1)	(3)
Plan amendment	(65)	—	—
Benefit obligation—end of year	$ 49	$ 129	$ 122
Changes in plan assets			
Fair value of plan assets—beginning of year	$ —	$ —	$ —
Employer contributions	6	1	3
Benefits paid	(5)	(1)	(3)
Fair value of plan assets—end of year	$ 1	$ —	$ —
Net benefit liability (unfunded status)	$ (48)	$ (129)	$ (122)

Our accumulated benefit obligation for our defined benefit pension plans exceeded the fair value of our plan assets as shown in the table below for the years ended December 31:

	Successor	
(in millions)	2021	2020
Projected benefit obligation	$ 44	$
Accumulated benefit obligation	$ 39	$
Fair value of plan assets	$ 29	$

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 expenses on our consolidated statements of operations. The following table set forth the components of our net periodic pension and postretirement benefit costs (in millions):

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Pension				
Net periodic benefit costs				
Service cost—benefits earned during the period	$ 1	$ —	$ 1	$ 1
Interest cost on projected benefit obligation	1	—	1	2
Expected return on plan assets	(1)	—	(1)	(2)
Amortization of net actuarial loss	—	—	1	1
Settlement costs	—	—	1	9
Net periodic benefit costs	$ 1	$ —	$ 3	$ 11
Postretirement				
Net periodic benefit costs				
Service cost—benefits earned during the period	$ 4	$ 1	$ 4	$ 4
Interest cost on projected benefit obligation	3	—	3	4
Cost of special termination benefits	—	—	—	6
Amortization of prior service cost credit	(1)	—	—	—
Settlement costs	—	—	1	—
Net periodic benefit costs	$ 6	$ 1	$ 8	$ 14

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 before tax (in millions):

	Successor		Predecessor	
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020	Year ended December 31, 2019
Pension				
Amounts recognized in other comprehensive income (loss) (in millions)				
Net actuarial loss	$ (1)	$ (1)	$ (1)	$ (6)
Settlement costs	—	—	1	9
Amortization of net actuarial gain/loss	—	—	1	1
Total recognized in other comprehensive (loss) income	$ (1)	$ (1)	$ 1	$ 4
Postretirement				
Net actuarial gain (loss)	$ 17	$ (7)	$ (2)	$ (19)
Net prior service credit	65	—	—	—
Settlement costs	—	—	1	(2)
Amortization of prior service cost credit	(1)	—	—	—
Total recognized in other comprehensive income (loss)	$ 81	$ (7)	$ (1)	$ (21)

Settlement costs related to our pension and postretirement plans were associated with early retirements.

The following tables sets forth the valuation assumptions, on a weighted-average basis, used to determine our benefit obligations and net periodic benefit cost:

	Successor		Predecessor
	Year ended December 31, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Pension			
Benefit Obligation Assumptions			
Discount rate	2.79 %	2.42 %	2.70 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %
Net Periodic Benefit Cost Assumptions			
Discount rate	2.42 %	2.70 %	3.16 %
Assumed long-term rate of return on assets	6.25 %	5.42 %	5.42 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %

	Successor			Predecessor
	October 1, 2021 - December 31, 2021	January 1, 2021 - September 30, 2021	November 1, 2020 - December 31, 2020	January 1, 2020 - October 31, 2020
Postretirement[(a)]				
Benefit Obligation Assumptions				
Discount rate	2.75 %	2.69 %	2.92 %	3.11 %
Net Periodic Benefit Cost Assumptions				
Discount rate	2.69 %	2.92 %	3.11 %	3.48 %

(a) Our plan design change on September 30, 2021 resulted in a remeasurement of our postretirement benefit obligations.

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the Aon AA Above Median yield curve in both 2021 and 2020. 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 long-term rate of 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 2021, 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. Changes in mortality assumptions were reflected in the valuations of our pension and postretirement benefit obligations as part of fresh start accounting upon emergence from bankruptcy. These assumptions did not significantly change our pension benefit obligations or postretirement benefit obligations in 2021 as compared to the prior year.

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 2.57% and 2.06% as of December 31, 2021 and 2020, 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, 2021, health care cost trend rates would decrease from 6.25% in 2021 until they reach 4.50% in 2029 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 2021 and 2020, the target allocation of plan assets was 65% equity securities and 35% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies. Our postretirement benefit plan assets of $1 million are primarily invested in mutual funds.

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

	Fair Value Measurements at December 31, 2021 (Successor)			
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Cash equivalents	$ 5	$ —	$ —	$ 5
Commingled funds				
Fixed income	—	2	—	2
U.S. equity	—	3	—	3
International equity	—	2	—	2
Mutual funds				
Bond funds	5	—	—	5
Value funds	2	—	—	2
Growth funds	5	—	—	5
Guaranteed deposit account	—	—	5	5
Total pension plan assets	$ 17	$ 7	$ 5	$ 29

	Fair Value Measurements at December 31, 2020 (Successor)			
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Cash equivalents	$ 6	$ —	$ —	$ 6
Commingled funds				
Fixed income	—	2	—	2
U.S. equity	—	3	—	3
International equity	—	2	—	2
Mutual funds				
Bond funds	5	—	—	5
Value funds	2	—	—	2
Growth funds	6	—	—	6
Guaranteed deposit account	—	—	6	6
Total pension plan assets	$ 19	$ 7	$ 6	$ 32

Expected Contributions and Benefit Payments

In 2022, we expect to contribute $3 million to our pension and $5 million to our postretirement benefit plans. Estimated future undiscounted benefit payments by the plans, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits	Postretirement Benefits
For the years ended December 31,	(in millions)	
2022	$ 9	$ 5
2023	$ 3	$ 5
2024	$ 3	$ 4
2025	$ 3	$ 4
2026	$ 3	$ 4
2027 to 2031 Payouts	$ 10	$ 14

NOTE 13 REVENUE

Commodity Sales Contracts

We recognize revenue from the sale of our production when delivery has occurred and control passes to the customer. Our contracts with customers are short term, typically less than a year. We consider our performance obligations to be satisfied upon transfer of control of the commodity. In certain instances, transportation and processing fees are incurred by us prior to control being transferred to customers. We record these transportation costs as a component of operating expenses on our consolidated statements of operations.

Our commodity sales contracts are 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. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for disaggregated revenue by commodity type.

Electricity

The electrical output of our Elk Hills power plant that is not used in our operations is sold to the wholesale power market and a utility under a power purchase and sales agreement (PPA) through December 2023, which includes a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. 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 average index or California Independent System Operator (CAISO) market pricing with payment due the month following delivery. Payments under our PPA are settled monthly. We 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.

Sales 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 take advantage of market dislocations. We report sales of purchased natural gas in total operating revenues and associated purchases of natural gas related to our trading 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 14 CHAPTER 11 PROCEEDINGS

The commencement of the Chapter 11 Cases, as described in *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other*, constituted an event of default that accelerated our obligations under the following agreements: (i) Credit Agreement, dated as of September 24, 2014, among JPMorgan Chase Bank, N.A., as administrative agent, and the lenders that are party thereto (2014 Revolving Credit Facility), (ii) Credit Agreement, dated as of August 12, 2016, among The Bank of New York Mellon Trust Company, N.A., as collateral and administrative agent, and the lenders that are party thereto (2016 Credit Agreement), (iii) Credit Agreement, dated as of November 17, 2017, among The Bank of America Mellon Trust Company, N.A., as administrative agent, and the lenders that are party thereto (2017 Credit Agreement), and (iv) the indentures governing our 8% Senior Secured Second Lien Notes due 2022 (Second Lien Notes), 5.5% Senior Notes due 2021 (2021 Notes) and 6% Senior Notes due 2024 (2024 Notes). This resulted in the automatic and immediate acceleration of all of our outstanding pre-petition long-term debt. Any efforts to enforce payment obligations related to the acceleration of our long-term debt were automatically stayed by the commencement of our Chapter 11 Cases, and the creditors' rights of enforcement were subject to the applicable provisions of the Bankruptcy Code.

Upon the Effective Date, the balances of the 2016 Credit Agreement, 2017 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes were cancelled pursuant to the terms of the Plan, resulting in a gain of approximately $4 billion included in "Reorganization items, net" on our consolidated statement of operations for the period ended October 31, 2020. Our 2014 Revolving Credit Facility was repaid in full with proceeds from our debtor-in-possession facilities described below and terminated.

Debtor-in-Possession Credit Agreements

On July 23, 2020, we entered into a Senior Secured Superpriority DIP Credit Agreement with JP Morgan, as administrative agent, and certain other lenders (Senior DIP Credit Agreement), which provided for the senior DIP facility in an aggregate principal amount of up to $483 million (Senior DIP Facility). The Senior DIP Facility included a $250 million revolving facility which was primarily used by us to (i) fund working capital needs, capital expenditures and additional letters of credit during the pendency of the Chapter 11 Cases and (ii) pay certain costs, fees and expenses related to the Chapter 11 Cases and the Senior DIP Facility. Following a hearing, the Bankruptcy Court entered a final order on August 14, 2020, which approved the Senior DIP Facility on a final basis. The Senior DIP Facility also included (i) a $150 million letter of credit facility which was used to redeem letters of credit outstanding under the 2014 Revolving Credit Facility as issued under the Senior DIP Facility, and (ii) $83 million of term loan borrowings which were used to repay a portion of the 2014 Revolving Credit Facility. The Senior DIP Facility allowed for the issuance of an additional $35 million of letters of credit.

On July 23, 2020, we entered into a Junior Secured Superpriority DIP Credit Agreement with Alter Domus, as administrative agent, and certain lenders (Junior DIP Credit Agreement), which provided for a junior DIP facility in an aggregate principal amount of $650 million (Junior DIP Facility and together with the Senior DIP Facility, the DIP Facilities). The proceeds of the Junior DIP Facility were used to (i) refinance in full all remaining obligations under the 2014 Revolving Credit Facility and (ii) pay certain costs, fees and expenses related to the Chapter 11 Cases and the Junior DIP Facility.

The Senior DIP Credit Agreement and Junior DIP Credit Agreement both contained representations, warranties, covenants and events of default that are customary for DIP facilities of their type, including certain milestones applicable to the Chapter 11 Cases, compliance with an agreed budget, hedging on not less than 25% of our share of expected crude oil production for a specified period, and other customary limitations on additional indebtedness, liens, asset dispositions, investments, restricted payments and other negative covenants, in each case subject to exceptions.

Borrowings under the Senior DIP Facility bore interest at the London interbank offered rate (LIBOR) plus 4.5% for LIBOR loans and the alternative base rate (ABR) plus 3.5% for alternative base rate loans. We also agreed to pay an upfront fee equal to 1.0% on the commitment amount of the Senior DIP Facility and quarterly commitment fees of 0.5% on the undrawn portion of the Senior DIP Facility.

Borrowings under the Junior DIP Facility bore interest at a rate of LIBOR plus 9.0% for LIBOR loans and ABR plus 8.0% for alternate base rate loans. We also agreed to pay an upfront fee equal to 1.0% of the commitment amount funded on the closing date and a fronting fee to a fronting lender.

Certain of our subsidiaries, including each of the debtors in the Chapter 11 Cases, guaranteed all obligations under the Senior DIP Credit Agreement and Junior DIP Credit Agreement. We also granted liens on substantially all of our assets, whether now owned or hereafter acquired to secure the obligations under the Senior DIP Credit Agreement and Junior DIP Credit Agreement.

The Senior DIP Facility was repaid in full and terminated on the Effective Date using proceeds borrowed under our new Revolving Credit Facility discussed in *Note 4 Debt*. The Junior DIP Facility was also repaid in full and terminated on the Effective Date using (i) $200 million from the Second Lien Term Loan discussed in *Note 4 Debt* and (ii) $450 million from the Subscription Rights Offering discussed below.

Ares JV Settlement Agreement and Noncontrolling Interest

In February 2018, our wholly-owned subsidiary California Resources Elk Hills, LLC (CREH) entered into a midstream JV with ECR, a portfolio company of Ares, with respect to the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 MMcf/day cryogenic gas processing plant. These assets were held by the joint venture entity, Elk Hills Power, LLC (Ares JV or Elk Hills Power), and each of CREH and ECR held an equity interest in this entity. Our consolidated statements of operations for the Predecessor reflect the operations of the Ares JV, with ECR's share of net income (loss) reported in net income attributable to noncontrolling interests. Distributions to ECR reduced the carrying amount of noncontrolling interests on our consolidated balance sheets and are reported as a financing cash outflow for the Predecessor on our consolidated statements of cashflows. ECR's redeemable noncontrolling interests were reported in mezzanine equity due to an embedded optional redemption feature.

Prior to our Effective Date, we held 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR held 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. The Ares JV was required to distribute each month its excess cash flow over its working capital requirements first to the Class B holders and then to the Class C common interests, on a pro-rata basis.

We entered into a Settlement Agreement with ECR and Ares which, among other things, granted us the right (Conversion Right) to acquire all (but not less than all) of the equity interests of Elk Hills Power owned by ECR in exchange for the EHP Notes, 17.3 million shares of common stock and approximately $2 million in cash. The Conversion Right was exercised on the Effective Date. See *Note 4 Debt* for more information on the EHP Notes.

Although certain provisions in the Settlement Agreement were not effective until certain conditions were met, such as the Bankruptcy Court entering a final order, we determined that the amended terms were substantively different such that the existing Class A common, Class B preferred and Class C common member interests held by ECR were treated as redeemed in exchange for new member interests issued at fair value in the third quarter of 2020. The estimated fair value of the new member interests was lower than the carrying value of the existing member interests by $138 million. In accordance with GAAP, the modification of noncontrolling interest was recorded to additional paid-in capital and was included in our earnings per share calculations. See *Note 11 Earnings per Share* for adjustments to net income (loss) attributable to common stock of the Predecessor which includes a modification of noncontrolling interest.

We exercised the Conversion Right on the Effective Date and issued the EHP Notes in the aggregate principal amount of $300 million, new common stock comprising approximately 20.8% (subject to dilution) of our outstanding common stock at that time and approximately $2 million in cash (Conversion). Upon the Conversion, Elk Hills Power became our indirect wholly-owned subsidiary, and Ares and its affiliates ceased to have any direct or indirect interest in Elk Hills Power. In connection with the Conversion, Elk Hills Power's limited liability company agreement was amended and restated.

The following table presents the changes in noncontrolling interests for our consolidated joint ventures during the Predecessor periods ended December 31, 2019 and October 31, 2020, including both our BSP JV and Ares JV.

	Equity Attributable to Noncontrolling Interests			Mezzanine Equity - Redeemable Noncontrolling Interest	
	Ares JV	BSP JV	Total	Ares JV	Total
			(in millions)		
Balance, December 31, 2018	$ 15	$ 99	$ 114	$ 756	$ 756
Net (loss) income attributable to noncontrolling interests	(7)	17	10	117	117
Contributions from noncontrolling interest holders, net	—	49	49	—	—
Distributions to noncontrolling interest holders	(8)	(72)	(80)	(71)	(71)
Balance, December 31, 2019	$ —	$ 93	$ 93	$ 802	$ 802
Net income (loss) attributable to noncontrolling interests	3	10	13	94	94
Distributions to noncontrolling interest holders	(3)	(34)	(37)	(67)	(67)
Modification of noncontrolling interest	—	—	—	(138)	(138)
Acquisition of noncontrolling interest	—	—	—	(691)	(691)
Fair value adjustment of noncontrolling interest in fresh start accounting	—	7	7	—	—
Balance, October 31, 2020	$ —	$ 76	$ 76	$ —	$ —

In connection with the Conversion, on the Effective Date, we entered into a Sponsor Support Agreement dated the Effective Date (Support Agreement) pursuant to which, among other things, the parties agreed that Elk Hills Power will be our primary provider of electricity to, and will be the primary processor of our natural gas produced from, the Elk Hills field, which is consistent with our current practice.

On the Effective Date, in connection with the Conversion, we terminated: (a) the Commercial Agreement, dated as of February 7, 2018, by and between Elk Hills Power and CREH and (b) the Master Services Agreement, dated as of February 7, 2018, by and between Elk Hills Power and CREH.

Rights Offering and Backstop

Pursuant to the Plan, we issued subscription rights to holders of our 2017 Credit Agreement, 2016 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes (Rights Offering). These subscription rights entitled holders to purchase up to $450 million of newly issued shares of common stock at $13 per share upon our emergence from bankruptcy. Certain holders of our pre-emergence indebtedness agreed to backstop the Rights Offering and purchase additional shares in the event the Rights Offering was not fully subscribed in exchange for a premium. The Rights Offering closed on the Effective Date and we issued 38.1 million shares of common stock pursuant to the Rights Offering at that time, including 3.5 million common shares issued to the backstop parties as a premium.

Emergence

The following transactions occurred on October 27, 2020, the effective date of the Plan, where we issued an aggregate of 83.3 million shares of new common stock, reserved 4.4 million shares for future issuance upon exercise of the warrants described in *Note 10 Equity* and reserved 9.3 million shares for future issuance under our management incentive plan described in *Note 9 Stock-Based Compensation*:

- We acquired all of the member interests in the Ares JV held by ECR in exchange for the EHP Notes, 17.3 million shares of new common stock and approximately $2 million in cash;
- Holders of secured claims under the 2017 Credit Agreement received 22.7 million shares of new common stock in exchange for those claims, and holders of deficiency claims under the 2017 Credit Agreement and all outstanding obligations under the 2016 Credit Agreement, Second Lien Notes, 2021 Notes and 2024 Notes received 4.4 million shares of new common stock in exchange for those claims;
- In connection with the Subscription Rights and Backstop Commitment Agreement, 34.6 million shares of new common stock were issued in exchange for $446 million (net of a $4 million allocation adjustment credit paid to certain backstop parties), the gross proceeds of which were used to pay down our Junior DIP Facility;
- We issued 3.5 million shares as consideration for the backstop commitment premium; and
- We issued an aggregate of 821,000 shares to the lenders under our Junior DIP Facility as an exit fee.

All existing equity interests of the Predecessor, including contracts on equity, were cancelled and their holders received no recovery.

As a condition to our emergence, we repaid the outstanding balance of our debtor-in-possession financing with proceeds from our equity offering, Second Lien Term Loan and our new Revolving Credit Facility. For more information on our post-emergence indebtedness, see *Note 4 Debt*.

On October 27, 2020, all but one of our existing directors resigned and seven new non-employee directors were appointed to our Board of Directors (Board) in connection with our emergence from bankruptcy. In addition, our former Chief Executive Officer and director Todd A. Stevens departed on December 31, 2020. Our new Board currently consists of nine directors.

NOTE 15 FRESH START ACCOUNTING

Fresh Start Accounting

We adopted fresh start accounting upon emergence from bankruptcy because (1) the holders of existing voting shares prior to emergence received less than 50% of our new voting shares following our emergence from bankruptcy and (2) the reorganization value of our assets immediately prior to the confirmation of the Plan was less than the post-petition liabilities and allowed claims, which were included in liabilities subject to compromise as of our emergence date.

For financial reporting purposes, fresh start accounting was applied as of October 31, 2020, an accounting convenience date, to coincide with the timing our normal month-end close process. We evaluated and concluded that events between October 28, 2020 and October 31, 2020 were not significant and the use of an accounting convenience date was appropriate.

Under fresh start accounting, the reorganization value of the emerging entity was assigned to individual assets and liabilities based on their estimated relative fair values. Reorganization value represents the fair value of our total assets prior to the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value was derived from our enterprise value, which was the estimated fair value of our long-term debt, asset retirement obligations and shareholder’s equity at emergence. In support of the Plan, our enterprise value was estimated and approved by the Bankruptcy Court to be in the range of $2.2 billion to $2.8 billion.

This valuation analysis was prepared using reserve information, development schedules, other financial information and financial projections, and applying standard valuation techniques, including net asset value analysis, precedent transactions analyses and comparable public company analyses. We engaged third-party valuation advisors to assist in determining the value of our Elk Hills power plant, cryogenic gas processing plant, certain real estate and warrants. Using these valuations along with our own internal estimates and assumptions for the value of our proved oil and natural gas reserves, we estimated our enterprise value to be $2.5 billion for financial reporting purposes.

The following is a summary of our valuation approaches and assumptions for significant non-current assets and liabilities, which excludes our working capital where our carrying value approximated fair value.

Property, Plant and Equipment

Our principal assets are our oil and natural gas properties. In valuing our proved oil and natural gas properties we used an income approach. Our estimated future revenue, operating costs and development plans were developed internally by our reserve engineers. We applied a discount rate using a market-participant weighted average cost of capital which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. We used a risk-adjusted discount rate for our proved undeveloped locations only. We estimated futures prices to calculate future revenue, as reported on the ICE Brent for oil and NGLs and NYMEX Henry Hub for natural gas as of October 31, 2020, adjusted for pricing differentials and without giving effect to derivative transactions. Operating costs and realized prices for periods after the forward price curve becomes illiquid were adjusted for inflation. No value was ascribed to unproved locations.

The fair value of our Elk Hills power plant, cryogenic gas processing facility (CGP-1) and commercial building in Bakersfield were estimated using a cost approach. The cost approach estimates fair value by considering the amount required to construct or purchase a new asset of equal utility at current prices, with adjustments for asset function, age, physical deterioration and obsolescence. We also considered the history of major capital expenditures.

We internally valued our surface acreage based on recent market data.

Right of Use Assets and Lease Liabilities

The fair value of ROU assets and associated lease liabilities were measured at the present value of the remaining fixed minimum lease payments as if the leases were new leases at emergence. We used our incremental borrowing rate as the discount rate in determining the present value of the remaining lease payments. Based upon the corresponding lease term, our incremental borrowing rates ranged from 4% to 5%.

Pension and Postretirement Benefit Plans

The valuations of our pension liabilities and postretirement benefit obligations were performed by a third-party actuary. Valuation assumptions, including discount rates, expected future returns on plan assets, rates of future salary increases, rates of future increases in medical costs, turnover and mortality rates were developed in consultation with the third-party actuary based on current market conditions, current mortality rates and our expectation for future salary increases.

Long-term Debt Obligations

The fair value of our post-emergence long-term debt approximated carrying value based on the terms of the debt instruments and stated interest rates.

Asset Retirement Obligations

The fair value of our asset retirement obligations was estimated using a discounted cash flow approach for existing idle and currently producing wells and facilities. We estimated an average plugging and abandonment cost by field based on historical averages. We also factored in our testing plans related to idle well management and estimated failure rates to determine the timing of the cash flows. We utilized a credit adjusted risk free rate as our discount rate which was based on our credit rating and expected cost of borrowing at our emergence date. Our asset retirement obligations were reduced to our working interest share and factored in cost recovery related to our PSCs.

Warrants

The fair value of the warrants was estimated using a Black-Scholes model, a commonly used option pricing model. The Black-Scholes was used to estimate the fair value of our warrants with a stock price equal to book equity value per share, strike price, time to expiration, risk-free rate, equity volatility, which was based on a peer group of energy companies and dividend yield, which we estimated to be zero.

Reorganization Value

The following table summarizes our enterprise value upon emergence (in millions):

Fair value of total equity upon emergence	$	1,345
Fair value of long-term debt		725
Fair value of asset retirement obligations		593
Less: Unrestricted cash[(a)]		(163)
Total Enterprise Value	**$**	**2,500**

(a) Includes $118 million of cash used to temporarily collateralize letters of credit at our emergence date.

The following table reconciles our enterprise value to our reorganization value, or total asset value, upon emergence (in millions):

Enterprise value	$	2,500
Add: Unrestricted cash[(a)]		163
Add: Current liabilities[(b)]		396
Add: Other long-term liabilities[(b)]		231
Less: Other		(2)
Reorganization value	**$**	**3,288**

(a) Includes $118 million of cash used to temporarily collateralize letters of credit.
(b) Excludes asset retirement obligations of $50 million in current liabilities and $543 million in other long-term liabilities.

Consolidated Balance Sheet

The following consolidated balance sheet, with accompanying explanatory notes, illustrates the effects of the transactions contemplated by the Plan (Reorganization Adjustments) and fair value adjustments resulting from the adoption of fresh start accounting (Fresh Start Adjustments) as of October 31, 2020 (in millions):

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
CURRENT ASSETS						
Cash	$ 106	$ 97	(1)	$ —		$ 203
Trade receivables	149	—		—		149
Inventories	61	—		—		61
Other current assets, net	104	(2)	(2)	—		102
Total current assets	420	95		—		515
PROPERTY, PLANT AND EQUIPMENT	22,918	—		(20,236)	(12)	2,682
Accumulated depreciation, depletion and amortization	(18,588)	—		18,588	(12)	—
Total property, plant and equipment, net	4,330	—		(1,648)		2,682
OTHER ASSETS	77	18	(3)	(4)	(13)	91
TOTAL ASSETS	$ 4,827	$ 113		$ (1,652)		$ 3,288

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
CURRENT LIABILITIES						
Debtor-in-possession financing	733	(733)	(4)	—		—
Accounts payable	215	—		—		215
Accrued liabilities	233	(16)	(5)	14	(14)	231
Total current liabilities	1,181	(749)		14		446
LONG-TERM DEBT, NET	—	723	(6)	—		723
OTHER LONG-TERM LIABILITIES	725	—		49	(15)	774
LIABILITIES SUBJECT TO COMPROMISE	4,516	(4,516)	(7)	—		—
MEZZANINE EQUITY						
Redeemable noncontrolling interests	691	(691)	(8)	—		—
EQUITY						
Predecessor preferred stock	—	—		—		—
Predecessor common stock	—	—		—		—
Predecessor additional paid-in capital	5,149	(5,149)	(9)	—		—
Successor preferred stock	—			—		—
Successor common stock	—	1	(10)	—		1
Successor additional paid-in capital	—	1,253	(10)	—		1,253
Successor warrants	—	15	(10)	—		15
Accumulated deficit	(7,481)	9,226	(11)	(1,745)	(16)	—
Accumulated other comprehensive loss	(23)	—		23	(17)	—
Total equity attributable to common stock	(2,355)	5,346		(1,722)		1,269
Equity attributable to noncontrolling interests	69	—		7	(18)	76
Total equity	(2,286)	5,346		(1,715)		1,345
TOTAL LIABILITIES AND EQUITY	$ 4,827	$ 113		$ (1,652)		$ 3,288

Reorganization Adjustments

(1) Net change in cash upon our emergence included the following transactions (in millions):

Proceeds from Revolving Credit Facility	$ 225
Proceeds from Subscription Rights and Backstop Commitment, net	446
Proceeds from Second Lien Term Loan	200
Repayment of debtor-in-possession facilities	(733)
Payment of legal, professional and other fees	(15)
Debt issuance costs for the Revolving Credit Facility	(18)
Debt issuance costs for the Second Lien Term Loan	(2)
Acquisition of noncontrolling interest as part of the Settlement Agreement	(2)
Distribution to noncontrolling interest holder	(3)
Payment of accrued interest and bank fees	(1)
Net change	**$ 97**

Our cash balance of $203 million at October 31, 2020 included $158 million of restricted cash, of which $118 million was used to temporarily collateralize letters of credit, $22 million was held for distributions to a JV partner and $18 million was reserved for legal and professional fees related to our Chapter 11 Cases.

(2) Represents the write-off of unamortized insurance premiums for our directors and officers policy, which was cancelled as a result of changing the composition of our Board of Directors.

(3) Represents the capitalization of debt issuance costs for our Revolving Credit Facility.

(4) Represents the payoff of $733 million of debtor-in-possession financing including $83 million of borrowings that were outstanding under our Senior DIP Facility and $650 million of borrowings that were outstanding under our Junior DIP Facility. Refer to *Note 14 Chapter 11 Proceedings* for more information on our debtor-in-possession credit agreements.

(5) Reflects the payment of $15 million for legal, professional and other fees related to our bankruptcy proceedings upon emergence and $1 million for accrued interest and bank fees.

(6) Our exit financing at emergence included the following:

	October 31, 2020	
	($ in millions)	
Revolving Credit Facility	$	225
Second Lien Term Loan		200
EHP Notes		300
Long-term debt (principal amount)	**$**	**725**
Debt issuance costs		(2)
Total long-term debt, net	**$**	**723**

For additional information on our Successor debt, refer to *Note 4 Debt*.

(7) Our liabilities subject to compromise at emergence included the following (in millions):

Long-term debt (principal amount):		
2017 Credit Agreement	$	1,300
2016 Credit Agreement		1,000
Second Lien Notes		1,808
2021 Notes		100
2024 Notes		144
Accrued interest		164
Total liabilities subject to compromise	**$**	**4,516**

(8) Represents the acquisition of the noncontrolling interest in our Ares JV. In accordance with the Settlement Agreement, we exercised a conversion right upon our emergence from bankruptcy, allowing us to acquire all (but not less than all) of the equity interests in the Ares JV held by ECR in exchange for the EHP Notes, 17.3 million shares of common stock and approximately $2 million in cash.

(9) Represents the elimination of Predecessor additional paid-in capital.

(10) Represents the fair value of 83.3 million shares of Successor common stock and Warrants issued in accordance with the Plan as follows (in millions):

Par value	$	1
Additional paid-in capital		1,253
Warrants		15
Total	**$**	**1,269**

(11) Represents the decrease in accumulated deficit resulting from reorganization adjustments and the reclassification from Predecessor additional paid-in capital.

Fresh Start Adjustments

(12) Represents fair value adjustments to property, plant and equipment (PP&E), including the elimination of Predecessor accumulated depreciation, depletion and amortization.

The fair value of our PP&E at emergence consisted of the following:

Proved oil and natural gas properties	$	2,409
Facilities and other		273
Total PP&E	**$**	**2,682**

(13) Represents an adjustment to our right of use assets as if our lease agreements were new leases on our emergence date. See *Note 5 Leases* for more information on our leases.

(14) Represents a $20 million fair value adjustment to the current portion of asset retirement obligations partially offset by a $5 million decrease in our liability for self-insured medical. Also included are fair value adjustments for our postretirement benefits and a remeasurement of the current portion of our lease liability.

(15) Represents a $36 million fair value adjustment related to the long-term portion of asset retirement obligations and $8 million related to environmental and other abandonment obligations. The adjustment also includes $5 million related to remeasuring our long-term lease liability as if our contracts were new leases.

(16) Represents the elimination of Predecessor accumulated deficit.

(17) Represents the elimination of Predecessor accumulated other comprehensive loss.

(18) Represents a fair value adjustment of the noncontrolling interest in the BSP JV based on discounted expected future cash flows.

NOTE 16   SUBSEQUENT EVENTS

Divestitures

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, for proceeds of $55 million (before transaction costs and purchase price adjustments). 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. We also retained 100% of the deep rights and related seismic data.

In January 2022, we entered into an agreement to sell our commercial office building located in Bakersfield, California for $15 million, subject to customary adjustments to be calculated at closing. The sale is expected to close in the second quarter of 2022, contingent upon due diligence and a fit for purpose analysis to be performed by buyer. We expect to lease back a portion of the building on a short-term basis during a transition period. See *Note 2 Property, Plant and Equipment* for details of a $25 million impairment charge we recognized in the third quarter of 2021 on this property.

Dividends

On February 23, 2022, our Board of Directors declared a cash dividend of $0.17 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 7, 2022 and is expected to be paid on March 16, 2022. This quarterly dividend is made pursuant to a cash dividend policy approved by the Board of Directors in November 2021.

Share Repurchase Program

On February 22, 2022, our Board of Directors authorized an increase to our Share Repurchase Program by $100 million to $350 million in aggregate and we extended the term of the program until December 31, 2022.

Debt

In February 2022, we amended our Revolving Credit Facility to change the benchmark rate from LIBOR to SOFR. As a result of this amendment, we can elect to borrow at either an adjusted SOFR rate or an ABR rate, subject to a 1% floor and 2% floor, respectively, 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, 3% to 4% and (ii) in the case of ABR loans, 2% to 3%. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. 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.

In February 2022, we obtained additional commitments under our Revolving Credit Facility from new lenders increasing our aggregate commitment to $552 million from $492 million. After taking into account these additional commitments, our available borrowing capacity under our Revolving Credit Facility was increased by $60 million to $427 million from $367 million, after $125 million of outstanding letters of credit.

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)] (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total[(b)] (MMBoe)
Balance at December 31, 2018	530	60	734	712
Revisions of previous estimates[(c)]	(34)	(4)	(52)	(47)
Improved recovery	3	—	—	3
Extensions and discoveries	24	2	41	33
Divestitures	(11)	—	6	(10)
Production	(29)	(6)	(75)	(47)
Balance at December 31, 2019	483	52	654	644
Revisions of previous estimates[(c)]	(164)	(7)	(86)	(185)
Improved recovery	—	—	—	—
Extensions and discoveries	20	1	24	25
Divestitures	(1)	—	(3)	(2)
Production	(25)	(5)	(62)	(40)
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
PROVED DEVELOPED RESERVES				
December 31, 2018	389	47	565	530
December 31, 2019	357	45	543	493
December 31, 2020	266	39	460	382
December 31, 2021[(d)]	282	38	510	405
PROVED UNDEVELOPED RESERVES				
December 31, 2018	141	13	169	182
December 31, 2019	126	7	111	151
December 31, 2020	47	2	67	60
December 31, 2021	61	3	66	75

(a) Includes proved reserves related to economic arrangements similar to PSCs of 111 MMBbl, 85 MMBbl, 125 MMBbl and 131 MMBbl at December 31, 2021, 2020, 2019 and 2018, 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 22% of proved developed oil reserves, 8% of proved developed NGLs reserves, 16% of proved developed natural gas reserves and, overall, 19% of total proved developed reserves at December 31, 2021 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.

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 *Part II, Item 8 – Financial Statements and Supplementary Data, Note 3 Divestitures and Acquisitions* for more information on these transactions.

2020

Revisions of previous estimates – We had negative price-related revisions of 72 MMBoe primarily resulting from a lower commodity price environment in 2020 compared to 2019. The net price revision reflects the shortened economic lives of our fields, as estimated using 2020 SEC pricing, which for oil was significantly lower than current prices, partially offset by our lower operating costs.

We had 61 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 73 MMBoe and positive performance-related revisions of 12 MMBoe. Our negative performance-related revisions are primarily related to wells that underperformed their forecasts. A significant factor for this underperformance was a reduction in our capital program in 2020 due to the extremely low commodity price environment and constraints during our bankruptcy process. This led to higher overall decline rates due to injection curtailments, capacity limitations and reduced well maintenance. Our positive performance-related revisions of 12 MMBoe primarily related to better-than-expected well performance.

We removed 52 MMBoe of proved undeveloped reserves, all of which were no longer included in our development plans because they did not meet internal investment thresholds at lower SEC prices. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

Extensions and discoveries – We added 25 MMBoe from extensions and discoveries, approximately half of which resulted from the booking of proved undeveloped reserves in connection with fresh start accounting. Successful drilling and workovers in the San Joaquin and Los Angeles basins also contributed to the increase.

2019

Revisions of previous estimates – We had negative price-related revisions of 20 MMBoe primarily resulting from a lower commodity-price environment in 2019 compared to 2018.

We had 16 MMBoe of net positive performance-related revisions. We added 23 MMBoe primarily related to better-than-expected performance in the San Joaquin and Los Angeles basins and 18 MMBoe that had been previously removed due to budgeting and development timing. These volumes were brought back into our reserves based on re-evaluation of the applicable areas and management's plans. These positive revisions were partially offset by 25 MMBoe in negative performance-related revisions primarily related to delayed responses in certain waterflood and steamflood projects.

We removed 43 MMBoe of proved undeveloped reserves, of which 19 MMBoe related to expired projects not developed within the five-year window as the result of lower-than-anticipated product prices. The remaining 24 MMBoe had not yet expired but were no longer prioritized in our development plans in the current commodity price environment. The majority of these proved undeveloped reserves that were downgraded at management's discretion are located in the San Joaquin basin, meet economic investment criteria at current prices and are anticipated to be developed in the future.

Extensions and discoveries – We added 33 MMBoe from extensions and discoveries, primarily resulting from successful drilling in the San Joaquin and Los Angeles basins.

Improved recovery – We also added 3 MMBoe from improved recovery through IOR and EOR methods, which were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

Divestitures – We had a reduction of 10 MMBoe in connection with the Lost Hills divestiture and the Alpine JV entered into during the year. See *Part II, Item 7 Management's Discussion and Analysis, Acquisitions and Divestitures* for more on the Lost Hills divestiture and *Part II, Item 7 Management's Discussion and Analysis, Joint Ventures* for more on the Alpine JV.

CAPITALIZED COSTS

Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	Successor	
	December 31, 2021	**December 31, 2020**
	(in millions)	(in millions)
Proved properties	$ 2,626	$ 2,416
Unproved properties	1	1
Total capitalized costs	2,627	2,417
Accumulated depreciation, depletion and amortization	(219)	(31)
Net capitalized costs	$ 2,408	$ 2,386

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:

	Successor		Predecessor	
	Year ended December 31, 2021	**November 1, 2020 - December 31, 2020**	**January 1, 2020 - October 31, 2020**	**Year ended December 31, 2019**
Property acquisition costs	(in millions)		(in millions)	
Proved properties[(a)]	$ 53	$ —	$ —	$ 1
Unproved properties	—	—	—	4
Exploration costs	7	1	10	30
Development costs[(b)]	210	7	35	505
Costs incurred	$ 270	$ 8	$ 45	$ 540

(a) Acquisition costs relates to our acquisition of MIRA's working interests in certain wells in 2021.
(b) Development costs include a $19 million increase in ARO in 2021. There were no costs incurred for development costs related to ARO in 2020. Development costs include a $80 million increase in ARO in 2019.

RESULTS OF OPERATIONS

Our oil and natural gas producing activities, which exclude items such as asset dispositions, corporate overhead and interest, were as follows:

	Successor				Predecessor			
	Year ended December 31, 2021		November 1, 2020 - December 31, 2020		January 1, 2020 - October 31, 2020		Year ended December 31, 2019	
	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)
Revenues[a]	$ 1,729	$ 47.55	$ 235	$ 37.49	$ 1,196	$ 34.98	$ 2,377	$ 50.88
Operating costs[b]	705	19.39	114	18.19	511	14.95	895	19.16
General and administrative expenses	34	0.94	7	1.12	38	1.11	56	1.20
Other operating expenses[c]	25	0.68	6	0.94	20	0.58	35	0.75
Depreciation, depletion and amortization	190	5.23	31	4.95	299	8.75	439	9.40
Taxes other than on income	103	2.83	4	0.64	106	3.10	121	2.59
Asset impairment	—	—	—	—	1,733	50.69	—	—
Accretion expense	50	1.38	8	1.28	33	0.97	36	0.77
Exploration expenses	7	0.19	1	0.16	10	0.29	29	0.62
Pretax income	615	16.91	64	10.21	(1,554)	(45.46)	766	16.39
Income tax expense[d]	(144)	(3.96)	(18)	(2.87)	435	12.72	(205)	(4.39)
Results of operations	$ 471	$ 12.95	$ 46	$ 7.34	$ (1,119)	$ (32.74)	$ 561	$ 12.00

(a) Revenues include oil, natural gas and NGL sales, cash settlements on our commodity derivatives and other revenue related to our oil and 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. Operating costs on a per Boe basis, excluding the effects of PSCs, were $17.56 in 2021, $14.14 for the Successor period of 2020, $16.86 for the Predecessor period of 2020 and $17.70 for 2019.

(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 2021 includes the benefit of enhanced oil recovery 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, 2021, 2020 and 2019, 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, 2021, 2020 and 2019. 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

	Successor		Predecessor
(in millions)	December 31, 2021	December 31, 2020	December 31, 2019
Future cash inflows	$ 28,031	$ 15,532	$ 34,134
Future costs			
Operating costs[a]	(13,508)	(9,389)	(16,724)
Development costs[b]	(2,607)	(2,392)	(3,938)
Future income tax expense	(3,124)	(701)	(3,180)
Future net cash flows	8,792	3,050	10,292
Ten percent discount factor	(4,243)	(1,118)	(5,061)
Standardized measure of discounted future net cash flows	$ 4,549	$ 1,932	$ 5,231

(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

	Successor		Predecessor
(in millions)	2021	2020	2019
Beginning of year	$ 1,932	$ 5,231	$ 7,275
Sales of oil and natural gas, net of production and other operating costs	(543)	(1,257)	(1,198)
Changes in price, net of production and other operating costs	3,414	(3,940)	(1,998)
Previously estimated development costs incurred	185	519	556
Change in estimated future development costs	(401)	1,032	(283)
Extensions, discoveries and improved recovery, net of costs	115	122	433
Revisions of previous quantity estimates[a]	1,114	(1,407)	(638)
Accretion of discount	226	650	890
Net change in income taxes	(1,131)	1,124	518
Purchases and sales of reserves in place	(15)	(25)	(151)
Change in timing of estimated future production and other	(347)	(117)	(173)
Net change	2,617	(3,299)	(2,044)
End of year	$ 4,549	$ 1,932	$ 5,231

(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
2021 (Successor)					
Deferred tax valuation allowance	$ 549	$ (526)	$ (23)	$ —	$ —
Other asset valuation allowance	$ —	$ —	$ —	$ —	$ —
November 1, 2020 - December 31, 2020 (Successor)					
Deferred tax valuation allowance	$ 511	$ 35	$ 3	$ —	$ 549
Other asset valuation allowance	$ —	$ —	$ —	$ —	$ —
January 1, 2020 - October 31, 2020 (Predecessor)					
Deferred tax valuation allowance	$ 646	$ (571)	$ 436	$ —	$ 511
Other asset valuation allowance	$ 22	$ (22)	$ —	$ —	$ —
2019 (Predecessor)					
Deferred tax valuation allowance	$ 625	$ 16	$ 5	$ —	$ 646
Other asset valuation allowance	$ 31	$ (9)	$ —	$ —	$ 22

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, 2021 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, 2021, 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, 2021, 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, 2021 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

None.

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 2022 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2021 (2022 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 25, 2022
Mark A. (Mac) McFarland	President, Chief Executive Officer and Director since 2021; Chairman of the Board and Interim Chief Executive Officer 2020 to 2021; GenOn Energy Executive Chairman since December 2018; GenOn Energy President and Chief Executive Officer 2017 to 2018; Luminant Holdings Chief Executive Officer and Executive Vice President, Corporate Development 2013 to 2016; Luminant Holdings Chief Commercial Officer 2008 to 2013.	52
Francisco J. Leon	Executive Vice President and Chief Financial Officer since 2020; 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.	45
Shawn M. Kerns	Executive Vice President and Chief Operating Officer since 2021; Executive Vice President - Operations and Engineering 2018 to 2021; Executive Vice President - Corporate Development 2014 to 2018; Vintage Production California President and General Manager 2012 to 2014; Occidental of Elk Hills General Manager 2010 to 2012; Occidental of Elk Hills Asset Development Manager 2008 to 2010.	51
Michael L. Preston	Executive Vice President, Chief Administrative Officer and General Counsel since 2019; Executive Vice President, General Counsel and Corporate Secretary 2014 to 2019; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	57
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.	57
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.	51

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2022 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 2022 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 2022 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 2022 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).
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	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.

Exhibit Number	Exhibit Description
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	Credit Agreement, dated as of October 27, 2020, 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 Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.8	Credit Agreement, dated as of October 27, 2020, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Alter Domus Products Corp., as Administrative Agent and Collateral Agent (filed as Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.9	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).
10.10	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).
10.11	First Amendment to the Credit Agreement, dated as of May 7, 2021, 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 Current Report on Form 8-K filed May 10, 2021 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	California Resources Corporation Executive Severance Plan, dated as of March 20, 2020 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed March 24, 2020 and incorporated herein by reference).
10.13	Separation Agreement and General Release, dated August 18, 2020, by and between Marshall D. Smith and California Resources Corporation (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 18, 2020 and incorporated herein by reference).
10.14	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).
10.15	Interim Chief Executive Officer Agreement, dated December 21, 2020, by and between Mark A. McFarland and California Resources Corporation (filed as Exhibit 10.42 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.16	Separation Agreement and General Release, dated December 31, 2020, by and between Todd A. Stevens and California Resources Corporation (filed as Exhibit 10.43 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.17	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).
10.18	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).

Exhibit Number	Exhibit Description
10.19	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).
10.20	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).
10.21	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).
10.22	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).
10.23	Employment Agreement by and between Shawn M. Kerns and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed June 11, 2021 and incorporated herein by reference).
10.24	Employment Agreement by and between Francisco J. Leon and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed June 11, 2021 and incorporated herein by reference).
10.25	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).
10.26	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).
10.27	Employment Agreement by and between Chris Gould and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.28	Second Amendment to the Credit Agreement, dated as of February 11, 2022, 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 Current Report on Form 8-K filed February 16, 2022 and incorporated herein by reference.)
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers, Ryder Scott Company, L.P.
23.3*	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.
99.1*	Ryder Scott Company, L.P. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2021.
99.2*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2021.
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.

Exhibit Number	Exhibit Description
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.

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 25, 2022

By: /s/ Mark A. (Mac) McFarland
Mark A. (Mac) McFarland
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/ Mark A. (Mac) McFarland Mark A. (Mac) McFarland	President, Chief Executive Officer and Director	February 25, 2022
/s/ Francisco J. Leon Francisco J. Leon	Executive Vice President and Chief Financial Officer	February 25, 2022
/s/ Noelle M. Repetti Noelle M. Repetti	Senior Vice President and Controller and Principal Accounting Officer	February 25, 2022
/s/ Tiffany (TJ) Thom Cepak Tiffany (TJ) Thom Cepak	Chair of the Board	February 25, 2022
/s/ Andrew B. Bremner Andrew B. Bremner	Director	February 25, 2022
/s/ Douglas E. Brooks Douglas E. Brooks	Director	February 25, 2022
/s/ James N. Chapman James N. Chapman	Director	February 25, 2022
/s/ Nicole Neeman Brady Nicole Neeman Brady	Director	February 25, 2022
/s/ Julio M. Quintana Julio M. Quintana	Director	February 25, 2022
/s/ William B. Roby William B. Roby	Director	February 25, 2022
/s/ A. Alejandra Veltmann A. Alejandra Veltmann	Director	February 25, 2022

LIST OF OPERATING SUBSIDIARIES

The following is a list of our subsidiaries at December 31, 2021 other than certain subsidiaries that did not in the aggregate constitute a significant subsidiary.

Name	Jurisdiction of Formation
California Heavy Oil, Inc.	Delaware
California Resources Coles Levee, LLC	Delaware
California Resources Coles Levee, L.P.	Delaware
California Resources Elk Hills, LLC	Delaware
California Resources Long Beach, Inc.	Delaware
California Resources Petroleum Corporation	Delaware
California Resources Production Corporation	Delaware
California Resources Real Estate Ventures, LLC	Delaware
California Resources Royalty Holdings, LLC	Delaware
California Resources Tidelands, Inc.	Delaware
California Resources Wilmington, LLC	Delaware
CRC Marketing, Inc.	Delaware
CRC Services, LLC	Delaware
EHP Midco Holding Company, LLC	Delaware
EHP Topco Holding Company, LLC	Delaware
Elk Hills Power, LLC	Delaware
Socal Holding, LLC	Delaware
Southern San Joaquin Production, Inc.	Delaware
Thums Long Beach Company	Delaware
Tidelands Oil Production Company	Texas

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (Nos. 333-252736 and 333-254181) on Forms S-8 and S-3 of our report dated February 25, 2022, with respect to the consolidated financial statements and financial statement schedule II of California Resources Corporation and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Los Angeles, California
February 25, 2022

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

To the Board of Directors
California Resources Corporation:

We consent to the (i) inclusion in the California Resources Corporation ("CRC") Form 10-K for the year ended December 31, 2021, and the incorporation by reference in CRC's registration statements on Form S-3 (No. 333-254181) and Form S-8 (No. 333-252736) (collectively, the "Registration Statements"), of references to our name and to our letter dated February 16, 2022, relating to our audit of certain oil and gas proved reserves of CRC as of December 31, 2021 (our "Letter"), (ii) filing of our Letter with the Securities and Exchange Commission as Exhibit 99.1 to the Form 10-K and (iii) incorporation by reference of our Letter in the Registration Statement.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 16, 2022

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-254181) and Form S-8 (No. 333-252736) of California Resources Corporation (the "Company") of the reference to Netherland, Sewell & Associates, Inc. and the inclusion of our report dated February 18, 2022 in the Company's Annual Report on Form 10-K for the year ended December 31, 2021, filed with the Securities and Exchange Commission.

/s/ Netherland, Sewell & Associates, Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 22, 2022

EXHIBIT 31.1

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. (Mac) McFarland, certify that:

1. I have reviewed this annual report on Form 10-K of California Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Mark A. (Mac) McFarland

Mark A. (Mac) McFarland
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Francisco J. Leon, certify that:

1. I have reviewed this annual report on Form 10-K of California Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Francisco J. Leon
Francisco J. Leon
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO PURSUANT TO
18 U.S.C. § 1350,
AS ADOPTED PURSUANT TO
§ 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of California Resources Corporation (the "Company") for the fiscal period ended December 31, 2021, as filed with the Securities and Exchange Commission on February 25, 2022 (the "Report"), Mark A. (Mac) McFarland, as Chief Executive Officer of the Company, and Francisco J. Leon, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his or her knowledge, respectively:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Mark A. (Mac) McFarland

Name:	Mark A. (Mac) McFarland
Title:	President and Chief Executive Officer
Date:	February 25, 2022

/s/ Francisco J. Leon

Name:	Francisco J. Leon
Title:	Executive Vice President and Chief Financial Officer
Date:	February 25, 2022

A signed original of this written statement required by Section 906 has been provided to California Resources Corporation and will be retained by California Resources Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

Exhibit 99.1

CALIFORNIA RESOURCES CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2021

/s/ Larry P. Connor Larry P. Connor, P.E. TBPELS License No. 58639 Executive Vice President	/s/ Eric A. Sepolio Eric A. Sepolio, P.E. TBPELS License No. 128738 Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

February 16, 2022

California Resources Corporation
27200 Tourney Road, Suite 200
Santa Clarita, CA 91355

Ladies and Gentlemen:

At the request of California Resources Corporation (CRC), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2021 prepared by CRC's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on February 16, 2022 and presented herein, was prepared for public disclosure by CRC in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent CRC's estimated net reserves attributable to the leasehold and royalty interests in certain properties owned by CRC and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2021. The properties reviewed by Ryder Scott incorporate CRC reserves determinations and are located in the state of California.

The properties reviewed by Ryder Scott account for a portion of CRC's total net proved reserves as of December 31, 2021. Based on the estimates of total net proved reserves prepared by CRC, the reserves audit conducted by Ryder Scott addresses 40 percent of the total proved developed net liquid hydrocarbon reserves and 77 percent of the total proved developed net gas reserves or 48 percent of the total proved developed net reserves on a barrel of oil equivalent (BOE) basis. The report addresses 37 percent of the total proved undeveloped net liquid hydrocarbon reserves and 95 percent of the total proved undeveloped net gas reserves, or 46 percent of the total proved undeveloped net reserves on a BOE basis of CRC. On a total net proved developed plus undeveloped reserves, Ryder Scott addressed 39 percent of CRC's net liquid hydrocarbon reserves, 79 percent of CRC's gas reserves which represent 47 percent of CRC's proved reserves on a BOE basis.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by CRC, it is our opinion that the overall procedures and methodologies utilized by CRC in preparing their estimates of the proved reserves as of December 31, 2021 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by CRC are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. CRC has informed us that in the preparation of their reserves and income projections, as of December 31, 2021, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period and subject to adjustments for differentials, by geographic area where the hydrocarbons are sold; unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by CRC attributable to CRC's interest in properties that we reviewed and for those that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
California Resources Corporation
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott				
Net Reserves				
Oil/Condensate – MMBarrels	74	16	21	111
Plant Products – MMBarrels	34	3	3	40
Gas – Bcf	356	36	63	455
MMBOE	167	25	35	227
Not Audited by Ryder Scott				
Net Reserves				
Oil/Condensate – MMBarrels	148	44	40	232
Plant Products – MMBarrels	1	0	0	1
Gas – Bcf	72	46	3	121
MMBOE	160	52	41	253
Total Net Reserves				
Oil/Condensate – MMBarrels	222	60	61	343
Plant Products – MMBarrels	35	3	3	41
Gas – Bcf	428	82	66	576
MMBOE	328	77	75	480

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as millions of barrels (MMBarrels). The gas volumes are generally reported on an "as sold basis" expressed in billions of cubic feet (Bcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. These gas volumes do include volumes of gas consumed in operations; though these volumes are not material. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent barrels using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MMBOE means million barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of behind pipe zones and volumes associated with certain recently completed projects not yet reflected in the producing category.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At CRC's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward…" The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by CRC, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through December 2021, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by CRC or obtained from public data sources and were considered sufficient for the purpose thereof.

The proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by CRC for our review or which we have obtained from public data sources that were available through December 2021. The data utilized from the analogs in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

For the reserves audited by Ryder Scott, approximately 38 percent of the reserves forecast are expected to be recovered from unconventional wells.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by CRC relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by CRC for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2021 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by CRC for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by CRC to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used by CRC were reviewed by us for their reasonableness using information furnished by CRC for this purpose.

The table below summarizes CRC’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as CRC’s “average realized prices.” The average realized prices shown in the table below were determined from CRC’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and CRC’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the following table is presented in accordance with SEC disclosure requirements for the geographic area reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	Brent Spot	$69.47/Bbl	$68.73/Bbl
United States	NGLs	Brent Spot	$69.47/Bbl	$52.81/Bbl
	Gas	Henry Hub	$3.60/MMBTU	$3.99/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in CRC's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein include volumes of gas consumed in operations as reserves; those volumes are not material.

Operating costs furnished by CRC are based on the operating expense reports of CRC and include only those costs directly applicable to the leases, contract areas, or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases, contract areas and wells under terms of operating agreements**.** The operating costs furnished by CRC were reviewed by us for their reasonableness using information furnished by CRC for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases, contract areas or wells.

Development costs furnished by CRC are based on authorizations for expenditure (AFE) for the proposed work or actual costs for similar projects. The development costs furnished by CRC were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by CRC. The estimated net cost of abandonment after salvage was included by CRC for properties where abandonment costs net of salvage were material. CRC's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with CRC's plans to develop these reserves as of December 31, 2021. The implementation of CRC's development plans as presented to us is subject to the approval process adopted by CRC's management. As the result of our inquiries during the course of our review, CRC has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by CRC's management at the appropriate local, regional and corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to CRC. CRC has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, CRC has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by CRC were held constant throughout the life of the properties.

CRC's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by CRC to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by CRC. Wells or locations that are not currently producing may start producing earlier or later than anticipated in CRC's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and recompleting wells and constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and operating conditions, producing market demand and allowables or other constraints set by regulatory bodies.

CRC's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which CRC owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by CRC for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of CRC are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

CRC has informed us that they have furnished or otherwise made available to us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of CRC's forecast of future proved production, we have relied upon data furnished by CRC with respect to property interests owned or otherwise held, production and well tests from examined wells, normal direct costs of operating the wells or leases, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by CRC. We consider the factual data furnished to us by CRC to be appropriate and sufficient for the purpose of our review of CRC's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by CRC and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by CRC, it is our opinion that the overall procedures and methodologies utilized by CRC in preparing their estimates of the proved reserves as of December 31, 2021 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by CRC are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the

SPE auditing standards. Ryder Scott found the processes and controls used by CRC in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with CRC's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between CRC's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to CRC when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by CRC.

Other Properties

Other properties, as used herein, are those properties of CRC which we did not review. The proved net reserves attributable to the other properties account for 61 percent of the total proved net liquid hydrocarbon reserves and 21 percent of the total proved net gas reserves or 53 percent of the total proved net reserves on an equivalent barrel, BOE, basis based on estimates prepared by CRC as of December 31, 2021.

The same technical personnel of CRC were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to CRC. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by CRC.

CRC makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, CRC has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of CRC, of the references to our name, as well as to the references to our third party report for CRC, which appears in the December 31, 2021 annual report on Form 10-K of CRC. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by CRC.

We have provided CRC with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by CRC and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Larry P. Connor

Larry P. Connor, P.E.
TBPELS License No. 58639
Executive Vice President **[SEAL]**

/s/ Eric A. Sepolio

Eric A. Sepolio, P.E.
TBPELS License No. 128738
Vice President **[SEAL]**

LPC-EAS (HGA)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Larry Connor was the primary technical person responsible for preparing the estimate of the reserves and future production included in this report.

Mr. Connor, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1981, is the Executive Vice President and is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Connor served in a number of engineering positions with Amoco Production Company. For more information regarding Mr. Connor's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Connor earned a Bachelor of Science degree in Industrial Engineering from Texas A&M University in 1977 and is a licensed Professional Engineer in the State of Texas, and the Provinces of Alberta, British Columbia and Saskatchewan, Canada. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. Mr. Connor has served as the Chairman of the Houston Chapter of the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Connor fulfills. Mr. Connor attended an additional 27 hours of formalized in-house training during 2021 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. In addition to internal training, Mr. Connor has participated in a total of 12 hours of industry training to professionals outside of Ryder Scott. Mr. Connor has served as course instructor for the formalized in-house training of PSA programming using PHDWin™ software to analyze prospect evaluations.

Based on his educational background, professional training and more than 44 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Connor has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.2

February 18, 2022

California Resources Corporation
27200 Tourney Road, Suite 200
Santa Clarita, California 91355

Ladies and Gentlemen:

In accordance with your request, we have audited the estimates prepared by California Resources Corporation (CRC), as of December 31, 2021, of the proved reserves to the CRC interest in certain oil and gas properties located in California. The scope of our work did not include auditing the future net revenue associated with these reserves. It is our understanding that the proved reserves estimates shown herein constitute approximately 35 percent of all proved reserves owned by CRC. Economic analysis was performed by CRC only to confirm economic producibility and determine economic limits for the properties. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, and economic producibility using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for CRC's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth CRC's estimates of the net reserves, as of December 31, 2021, for the audited properties:

	Net Reserves	
	Oil	Gas
Category	(MBBL)	(MMCF)
Proved Developed Producing	114,339.6	5,578.8
Proved Developed Non-Producing	21,048.7	1,369.1
Proved Undeveloped	30,939.7	1,186.6
Total Proved	166,328.0	8,134.5

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a field-by-field basis, some of the estimates of CRC are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of CRC's reserves are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by CRC in preparing the December 31, 2021, estimates of reserves, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by CRC.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. CRC's estimates do not include probable or possible reserves that may exist for these properties.

Oil and gas prices were used only to confirm economic producibility and determine economic limits for the properties. Prices used by CRC are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2021. For oil volumes, the average Brent spot price of $69.47 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.60 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $67.36 per barrel of oil and $4.04 per MCF of gas.

Costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used by CRC are based on historical operating expense records. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of CRC are included to the extent that they are covered under joint operating agreements for the operated properties. Capital costs used by CRC are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Abandonment costs used are CRC's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of CRC and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by CRC, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by CRC with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of CRC's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by CRC, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. C. Ashley Smith, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ C. Ashley Smith	/s/ Shane M. Howell
By:	By:
C. Ashley Smith, P.E. 100560	Shane M. Howell, P.G. 11276
Vice President	Vice President
Date Signed: February 18, 2022	Date Signed: February 18, 2022

CAS:MSS