

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

or

☐ **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: 001-32886



CONTINENTAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Oklahoma
(State or other jurisdiction of incorporation or organization)

73-0767549
(I.R.S. Employer Identification No.)

20 N. Broadway, Oklahoma City, Oklahoma 73102
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (405) 234-9000

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

<u>Title of each class</u>	<u>Trading symbol(s)</u>	<u>Name of each exchange on which registered</u>
Common Stock, \$0.01 par value	CLR	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that 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, 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	<input checked="" type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

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 ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2021 was approximately \$2.5 billion, based upon the closing price of \$38.03 per share as reported by the New York Stock Exchange on such date.

364,298,349 shares of our \$0.01 par value common stock were outstanding on January 31, 2022.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Shareholders to be held in May 2022, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

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Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:

“*basin*” A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“*Bbl*” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

“*Bcf*” One billion cubic feet of natural gas.

“*Boe*” Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

“*Btu*” British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

“*completion*” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

“*conventional play*” An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

“*DD&A*” Depreciation, depletion, amortization and accretion.

“*de-risked*” Refers to acreage and locations in which the Company believes the geological risks and uncertainties related to recovery of crude oil and natural gas have been reduced as a result of drilling operations to date. However, only a portion of such acreage and locations have been assigned proved undeveloped reserves and ultimate recovery of hydrocarbons from such acreage and locations remains subject to all risks of recovery applicable to other acreage.

“*developed acreage*” The number of acres allocated or assignable to productive wells or wells capable of production.

“*development well*” A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“*dry hole*” Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

“*enhanced recovery*” The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.

“*exploratory well*” A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

“*field*” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“*formation*” A layer of rock which has distinct characteristics that differs from nearby rock.

“*fracture stimulation*” A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production. Also may be referred to as hydraulic fracturing.

“*gross acres*” or “*gross wells*” Refers to the total acres or wells in which a working interest is owned.

“*held by production*” or “*HBP*” Refers to an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

“*horizontal drilling*” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

“*MBbl*” One thousand barrels of crude oil, condensate or natural gas liquids.

“*MBoe*” One thousand Boe.

“*Mcf*” One thousand cubic feet of natural gas.

“*MMBo*” One million barrels of crude oil.

“*MMBoe*” One million Boe.

“*MMBtu*” One million British thermal units.

“*MMcf*” One million cubic feet of natural gas.

“*net acres*” or “*net wells*” Refers to the sum of the fractional working interests owned in gross acres or gross wells.

“*Net crude oil and natural gas sales*” Represents total crude oil and natural gas sales less total transportation expenses. Net crude oil and natural gas sales presented herein is a non-GAAP measure. See *Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for a discussion and calculation of this measure.

“*Net sales price*” Represents the average net wellhead sales price received by the Company for its crude oil or natural gas sales after deducting transportation expenses. Net sales price is calculated by taking revenues less transportation expenses divided by sales volumes for a period, whether for crude oil or natural gas, as applicable. Net sales prices presented herein are non-GAAP measures. See *Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for a discussion and calculation of this measure.

“*NYMEX*” The New York Mercantile Exchange.

“*pad drilling*” or “*pad development*” Describes a well site layout which allows for drilling multiple wells from a single pad resulting in less environmental impact and lower per-well drilling and completion costs.

“*play*” A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

“*productive well*” A well found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“*prospect*” A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

“*proved reserves*” The quantities of crude oil and natural 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 renewal is reasonably certain.

“*proved developed reserves*” Reserves expected to be recovered through existing wells with existing equipment and operating methods.

“*proved undeveloped reserves*” or “*PUD*” Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion.

“*PV-10*” When used with respect to crude oil and natural gas reserves, PV-10 represents the estimated future gross revenues to be generated from the production of proved reserves using a 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December, net of estimated production and future development and abandonment costs based on costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission (“SEC”). PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles (“GAAP”) and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company’s crude oil and natural gas properties. The Company and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

“*reservoir*” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“*residue gas*” Refers to gas that has been processed to remove natural gas liquids.

“*resource play*” Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.

“*royalty interest*” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

“*SCOOP*” Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.

“*STACK*” Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations.

“*spacing*” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

“*Standardized Measure*” Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax net cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis in the crude oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

“*unconventional play*” An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These areas tend to have low permeability and may be closely associated with source rock, as is the case with oil and gas shale, tight oil and gas sands and coalbed methane, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production.

“*undeveloped acreage*” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

“*unit*” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“*well bore*” The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well. Also called a well or borehole.

“*working interest*” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Cautionary Statement for the Purpose of the “Safe Harbor” Provisions of the Private Securities Litigation Reform Act of 1995

This report and information incorporated by reference in this report include “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 statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company’s business and statements or information concerning the Company’s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, included in this report are forward-looking statements. The words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget,” “target,” “plan,” “continue,” “potential,” “guidance,” “strategy” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include, but are not limited to, statements about:

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- future crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- shutting in of production and the resumption of production activities;
- competition;
- marketing of crude oil and natural gas;
- transportation of crude oil, natural gas liquids, and natural gas to markets;
- property exploitation, property acquisitions and dispositions, or joint development opportunities;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position, dividend payments, bond repurchases, share repurchases, or income tax payments;
- the impact of the COVID-19 (novel coronavirus) pandemic on economic conditions, the demand for crude oil, the Company’s operations and the operations of its customers, suppliers, and service providers;
- credit markets;
- our liquidity and access to capital;
- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;
- our future operating and financial results;
- our future commodity or other hedging arrangements; and
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us.

Forward-looking statements are based on the Company’s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company’s control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate or will not change over time. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under *Part I, Item 1A. Risk Factors* and elsewhere in this report, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Many of the foregoing risks and uncertainties have been, and may further be, exacerbated by the COVID-19 pandemic and any potential worsening of the global economic environment. New factors emerge from time to time, and it is not possible for us to predict all such factors. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, the Company’s actual results and plans could differ materially from those

expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Part I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report. Unless the context otherwise requires, references in this report to “Continental Resources,” “Continental,” “we,” “us,” “our,” “ours” or “the Company” refer to Continental Resources, Inc. and its subsidiaries.

Item 1. Business

General

We are an independent crude oil and natural gas company formed in 1967 engaged in the exploration, development, management, and production of crude oil and natural gas and associated products in the North, South and East regions of the United States. Additionally, we pursue the acquisition and management of perpetually owned minerals located in our key operating areas.

During 2021 we executed strategic acquisitions to expand our operations into the Permian Basin of Texas and the Powder River Basin of Wyoming. See the subsequent section titled *Acquisition Activities* as well as *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions* for additional information on these acquisitions.

Our North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, Powder River Basin, and the Red River units. Our South region includes all properties south of Nebraska and west of the Mississippi River and includes the SCOOP and STACK areas of Oklahoma and the Permian Basin of Texas. Our East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

Our operations in the North region comprised 55% of our crude oil and natural gas production and 63% of our crude oil and natural gas revenues for the year ended December 31, 2021. Approximately 46% of our proved reserves as of December 31, 2021 are located in the North region. Our operations in the South region comprised 45% of our crude oil and natural gas production, 37% of our crude oil and natural gas revenues, and 54% of our proved reserves as of and for the year ended December 31, 2021.

We focus our activities in large crude oil and natural gas plays that provide us the opportunity to acquire undeveloped acreage positions and apply our geologic and operational expertise to drill and develop properties at attractive rates of return. We have been successful in targeting large repeatable resource plays where three dimensional seismic, horizontal drilling, geosteering technologies, advanced completion technologies (e.g., fracture stimulation), pad/row development, and enhanced recovery technologies allow us to develop and produce crude oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drill bit. We also grew in 2021 through the strategic acquisitions described below under *Part I, Item 1. Business—Acquisition Activities*. From January 1, 2019 through December 31, 2021, proved reserves added through extensions, discoveries and other additions totaled 828 MMBoe and proved reserves added through property acquisitions totaled 252 MMBoe.

As of December 31, 2021, our proved reserves were 1,645 MMBoe, with proved developed reserves representing 908 MMBoe, or 55%, of our total proved reserves. The standardized measure of our discounted future net cash flows totaled \$16.64 billion at December 31, 2021. For 2021, we generated crude oil and natural gas revenues of \$5.79 billion and operating cash flows of \$3.97 billion. Crude oil accounted for 49% of our total production and 68% of our crude oil and natural gas revenues for 2021. Our total production averaged 329,647 Boe per day for 2021, an increase of 10% compared to 2020.

The table below summarizes our total proved reserves, PV-10 (non-GAAP) and net producing wells as of December 31, 2021 and our average daily production for the quarter ended December 31, 2021 for our principal operating areas. The PV-10 values shown below are not intended to represent the fair market value of our crude oil and natural gas properties. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. See *Part I, Item 1A. Risk Factors* and “Critical Accounting Policies and Estimates” in *Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations* of this report for further discussion of uncertainties inherent in the reserve estimates.

	December 31, 2021				Average daily production for fourth quarter 2021 (Boe per day)	Percent of total
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells		
North Region:						
Bakken	708,369	43.2 %	\$ 9,659	1,997	175,585	51.6 %
Powder River Basin	31,901	1.9 %	\$ 464	148	7,189	2.1 %
Red River Units	23,354	1.4 %	\$ 396	251	6,212	1.8 %
South Region:						
Oklahoma	678,535	41.2 %	\$ 7,027	825	146,131	43.0 %
Permian Basin (2)	203,103	12.3 %	\$ 2,946	319	4,997	1.5 %
Other	48	— %	\$ 1	4	54	— %
Total	1,645,310	100.0 %	\$ 20,493	3,544	340,168	100.0 %

- (1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately \$3.86 billion. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for further discussion.
- (2) The presentation of average daily 2021 fourth quarter production represents production during the period from the closing of our acquisition of Permian properties on December 21, 2021 through December 31, 2021 averaged over 92 days in the fourth quarter. At the time of closing, our Permian properties produced on average approximately 42,000 Boe per day based on two-stream reporting.

Our Business Strategies

Our business strategies continue to be focused on generating significant shareholder value by finding and developing crude oil and natural gas reserves at low costs and attractive rates of return. For 2022, our primary business strategies will include:

- Continuing to exercise capital and operational discipline to maximize cash flow generation and competitive returns on capital employed;
- Reducing outstanding debt and maintaining a strong balance sheet to enhance financial flexibility;
- Maintaining strong shareholder alignment by maximizing capital and corporate returns to shareholders;
- Developing our recently acquired properties in the Permian Basin and Powder River Basin by applying our geologic and operational expertise;
- Maintaining low-cost, capital efficient operations; and
- Driving continued improvement in our health, safety, and environmental performance and governance programs.

Our Business Strengths

We have a number of strengths to allow us to successfully execute our business strategies, including the following:

Large acreage inventory with access to both crude oil and natural gas resources. We held approximately 538,400 net undeveloped acres and 1.40 million net developed acres under lease as of December 31, 2021 concentrated in core areas of premier U.S. resource plays that provide optionality and access to crude oil, natural gas, and natural gas liquids.

Expertise with pad and row development, horizontal drilling, and optimized completion methods. We have substantial experience with horizontal drilling and optimized completion methods and continue to be among industry leaders in the use of new drilling and completion technologies. We continue to improve drilling and completion efficiencies through the use of multi-well pad and row development strategies. Further, we are among industry leaders in drilling long lateral lengths. We have also been among industry leaders in testing and utilizing optimized completion technologies involving various combinations of fluid types, proppant types and volumes, and stimulation stage spacing to determine optimal methods for improving recoveries and rates of return. We continually refine our drilling and completion techniques in an effort to deliver improved results across our properties.

Control operations over a substantial portion of our assets and investments. As of December 31, 2021, we operated properties comprising 89% of our total proved reserves. By controlling a significant portion of our operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and completion methods used. Additionally, we capitalize on our geologic knowledge and land expertise to strategically acquire minerals in areas of future growth, thereby allowing us to enhance cash flows and project economics through the alignment of mineral ownership with our drilling schedule. Further, we continue to grow our significant portfolio of water gathering, recycling, and disposal infrastructure assets which allow for uninterrupted flow back and recycling capabilities, supports timely completion activities, and generates additional service revenues and cash flows. Our strategies for growing our mineral ownership portfolio and water infrastructure assets serve as additional avenues to generate shareholder value.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry and with operating in challenging commodity price environments. Our Chairman of the Board, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our 9 executive officers have an average of 40 years of oil and gas industry experience.

Financial Position and Liquidity. We have a credit facility with lender commitments totaling \$2.0 billion that matures in October 2026. We had approximately \$1.76 billion of borrowing availability on our credit facility at January 31, 2022 after considering outstanding borrowings and letters of credit. Our credit facility is unsecured and does not have a borrowing base requirement that is subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants.

Acquisition Activities

We regularly seek to acquire oil and gas properties that complement our operations, provide exploration and development opportunities, and provide enhanced cash flows and corporate returns. On December 21, 2021, we acquired oil and gas properties and related assets in the Permian Basin of Texas from certain subsidiaries of Pioneer Natural Resources Company for \$3.06 billion of cash, representing a \$3.25 billion purchase price less customary closing adjustments. The properties included approximately 92,000 net leasehold acres, approximately 50,000 net royalty acres in the same area normalized to a 1/8th royalty, production totaling approximately 42,000 Boe per day (~78% oil) based on two-stream reporting at the time of closing, and extensive water infrastructure. We funded the purchase price and related transaction costs through a combination of cash on hand, utilization of credit facility borrowing capacity, and the issuance of senior notes.

Additionally, in March 2021 and November 2021 we executed strategic acquisitions to expand our operations into the Powder River Basin of Wyoming for aggregate cash consideration of \$453 million and, on January 24, 2022, we executed a definitive agreement to acquire additional oil and gas properties in the Powder River Basin for \$450 million of cash, the closing of which is expected to occur in late March 2022 and remains subject to the completion of customary due diligence procedures and closing conditions. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions* and *Note 20. Subsequent Events* for additional information on the above acquisitions.

As a result of our acquisitions in the Permian Basin and Powder River Basin we now have substantial strategic positions in four leading basins in the United States, providing our Company and shareholders with enhanced geologic and geographic diversity and commodity optionality. We believe these transactions will be accretive on financial metrics and will complement our existing deep portfolio of assets in the Bakken and Oklahoma. We expect enhanced cash flows from the acquisitions will provide continued support for additional returns to shareholders via debt reduction, dividend increases, share repurchases, and increased returns on capital employed.

Information on the proved reserves and leasehold acreage associated with our new positions in the Permian Basin and Powder River Basin as of December 31, 2021 is presented in the tables that follow.

Crude Oil and Natural Gas Operations

Proved Reserves

Proved reserves are those quantities of crude oil and natural 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 renewal is reasonably certain. In connection with the estimation of proved reserves, the term “reasonable certainty” implies a high degree of confidence the quantities of crude oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reserve engineers and Ryder Scott Company, L.P (“Ryder Scott”), our independent reserve engineers, employed technologies demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps including isopach and structure maps, analogy and statistical analysis, and available downhole, production, seismic, and well test data.

The table below sets forth estimated proved crude oil and natural gas reserves information by reserve category as of December 31, 2021. Proved reserves attributable to noncontrolling interests are not material relative to our consolidated reserves and are not separately presented herein. The standardized measure of our discounted future net cash flows totaled approximately \$16.64 billion at December 31, 2021. Our reserve estimates as of December 31, 2021 are based primarily on a reserve report prepared by Ryder Scott. In preparing its report, Ryder Scott evaluated properties representing approximately 98% of our PV-10 and 98% of our total proved reserves as of December 31, 2021. Our internal technical staff evaluated the remaining properties. A copy of Ryder Scott’s summary report is included as an exhibit to this Annual Report on Form 10-K.

Our estimated proved reserves and related future net revenues, Standardized Measure and PV-10 at December 31, 2021 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2021 through December 2021, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were \$66.56 per Bbl for crude oil and \$3.60 per MMBtu for natural gas (\$62.19 per Bbl for crude oil and \$3.46 per Mcf for natural gas adjusted for location and quality differentials). These average prices are significantly higher than 2020 levels, which resulted in significant upward price-related revisions to proved reserves in 2021, as further discussed below.

The following table summarizes our estimated proved reserves by commodity and reserve classification as of December 31, 2021.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	415,861	2,853,980	891,524	\$ 13,256.4
Proved developed non-producing	8,292	47,167	16,154	230.5
Proved undeveloped	369,377	2,209,532	737,632	7,006.0
Total proved reserves	793,530	5,110,679	1,645,310	\$ 20,492.9
Standardized Measure (1)				\$ 16,636.4

- (1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately \$3.86 billion. See *Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for further discussion.

The following table provides additional information regarding our estimated proved crude oil and natural gas reserves by region as of December 31, 2021.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North Region:						
Bakken	222,986	856,607	365,754	241,364	607,509	342,615
Powder River Basin	12,080	22,661	15,857	12,585	20,758	16,044
Red River Units	23,354	—	23,354	—	—	—
South Region:						
Oklahoma	81,586	1,826,973	386,081	50,614	1,451,038	292,454
Permian Basin	84,122	194,769	116,584	64,814	130,227	86,519
Other	25	137	48	—	—	—
Total	424,153	2,901,147	907,678	369,377	2,209,532	737,632

The following table provides information regarding changes in total estimated proved reserves for the periods presented.

MBoe	Year Ended December 31,		
	2021	2020	2019
Proved reserves at beginning of year	1,103,762	1,619,265	1,522,365
Revisions of previous estimates	53,569	(504,874)	(148,848)
Extensions, discoveries and other additions	371,105	91,387	365,034
Production	(120,321)	(109,833)	(124,244)
Sales of minerals in place	(148)	—	(1,840)
Purchases of minerals in place	237,343	7,817	6,798
Proved reserves at end of year	1,645,310	1,103,762	1,619,265

Revisions of previous estimates. Revisions for 2021 are comprised of (i) upward price revisions of 92 MMBo and 458 Bcf (totaling 168 MMBoe) due to the significant increase in average crude oil and natural gas prices in 2021 compared to 2020 resulting from the lifting of COVID-19 restrictions, the resumption of normal economic activity, and the resulting improvement in supply and demand fundamentals, (ii) the removal of 31 MMBo and 155 Bcf (totaling 57 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to continual refinement of our drilling and development programs and reallocation of capital to areas providing the best opportunities to improve efficiencies, recoveries, and rates of return, (iii) downward revisions of 12 MMBo and 263 Bcf (totaling 56 MMBoe) from the removal of PUD reserves due to changes in anticipated well densities, economics, performance, and other factors, and (iv) downward revisions for oil reserves of 35 MMBo and upward revisions for natural gas reserves of 195 Bcf (netting to 2 MMBoe of downward revisions) due to changes in ownership interests, operating costs, anticipated production, and other factors.

Extensions, discoveries and other additions. Extensions, discoveries and other additions for each of the three years reflected in the table above were due to successful drilling and completion activities and continual refinement of our drilling programs. Proved reserve additions in the Bakken totaled 202 MMBoe, 41 MMBoe, and 160 MMBoe for 2021, 2020, and 2019, respectively, while reserve additions in Oklahoma totaled 169 MMBoe, 50 MMBoe, and 205 MMBoe for 2021, 2020, and 2019, respectively. See the subsequent section titled *Summary of Crude Oil and Natural Gas Properties and Projects* for a discussion of our 2021 drilling activities.

Sales of minerals in place. We had no individually significant dispositions of proved reserves in the past three years.

Purchases of minerals in place. Purchases in 2021 were primarily attributable to our acquisitions of properties in the Permian Basin and Powder River Basin described above. Proved reserves acquired in the Permian Basin totaled 149 MMBo and 326 Bcf (totaling 203 MMBoe) and proved reserves acquired in the Powder River Basin totaled 26 MMBo and 46 Bcf (totaling 34 MMBoe). We had no individually significant acquisitions of proved reserves in 2020 and 2019.

Proved Undeveloped Reserves

All of our PUD reserves at December 31, 2021 are located in our most active development areas. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2021. Our PUD reserves at December 31, 2021 include 68 MMBoe of reserves associated with wells where drilling has occurred but the wells have not been completed or are completed but not producing ("DUC wells"). Our DUC wells are classified as PUD reserves when relatively major expenditures are required to complete and produce from the wells.

	Crude Oil (MMbbls)	Natural Gas (MMcf)	Total (MMBoe)
Proved undeveloped reserves at December 31, 2020	215,069	1,567,713	476,355
Revisions of previous estimates	(45,340)	(329,237)	(100,214)
Extensions, discoveries and other additions	157,384	1,183,484	354,631
Sales of minerals in place	—	—	—
Purchases of minerals in place	77,399	150,985	102,563
Conversion to proved developed reserves	(35,135)	(363,413)	(95,703)
Proved undeveloped reserves at December 31, 2021	369,377	2,209,532	737,632

Revisions of previous estimates. As previously discussed, in 2021 we removed 31 MMBo and 155 Bcf (totaling 57 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to continual refinement of our drilling and development programs and reallocation of capital to areas providing the best opportunities to improve efficiencies, recoveries, and rates of return. Of these removals, 25 MMBo and 53 Bcf (totaling 34 MMBoe) was related to Bakken properties and 6 MMBo and 102 Bcf (totaling 23 MMBoe) was related to Oklahoma properties. Additionally, changes in anticipated well densities, economics, performance, and other factors resulted in downward PUD reserve revisions of 12 MMBo and 263 Bcf (totaling 56 MMBoe) in 2021. The significant increases in average crude oil and natural gas prices in 2021 resulted in upward price revisions of 15 MMBo and 73 Bcf (totaling 27 MMBoe). Finally, changes in ownership interests, operating costs, anticipated production, and other factors resulted in downward revisions for oil PUD reserves of 17 MMBo and net upward revisions for natural gas PUD reserves of 16 Bcf (totaling a net downward revision of 15 MMBoe) in 2021.

Extensions, discoveries and other additions. Extensions, discoveries and other additions were due to successful drilling activities and continual refinement of our drilling and development programs. PUD reserve additions in the Bakken totaled 133 MMBo and 359 Bcf (totaling 193 MMBoe) in 2021, while PUD reserve additions in Oklahoma totaled 24 MMBo and 824 Bcf (totaling 161 MMBoe).

Sales of minerals in place. We had no individually significant dispositions of PUD reserves in 2021.

Purchases of minerals in place. Purchases in 2021 were primarily attributable to our acquisitions of properties in the Permian Basin and Powder River Basin described above. PUD reserves acquired in the Permian Basin totaled 65 MMBo and 130 Bcf (totaling 87 MMBoe) and PUD reserves acquired in the Powder River Basin totaled 12 MMBo and 21 Bcf (totaling 16 MMBoe).

Conversion to proved developed reserves. In 2021, we developed approximately 24% of our PUD locations and 20% of our PUD reserves booked as of December 31, 2020 through the drilling and completion of 269 gross (137 net) development wells at an aggregate capital cost of approximately \$508 million incurred in 2021.

Development plans. We have acquired substantial leasehold positions in our key operating areas. Our drilling programs to date in our historical operating areas have focused on proving our undeveloped leasehold acreage through strategic drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations (i.e., categorized as held by production) and resulting in a reduced amount of leasehold acreage in the primary term of the lease. While we may opportunistically drill strategic exploratory wells, a substantial portion of our future capital expenditures will be focused on developing our PUD locations, including our drilled but not completed locations. Our inventory of DUC wells classified as PUDs total 259 gross (83 net) operated and non-operated locations at December 31, 2021 and represent 9% of our PUD reserves at that date. The costs to drill our uncompleted wells were incurred prior to December 31, 2021 and only the remaining completion costs are included in future development plans.

Estimated future development costs relating to the development of PUD reserves at December 31, 2021 are projected to be approximately \$1.2 billion in 2022, \$1.9 billion in 2023, \$1.7 billion in 2024, \$1.7 billion in 2025, and \$1.2 billion in 2026. These capital expenditure projections have been established based on an expectation of drilling and completion costs, available cash flows, borrowing capacity, and the commodity price environment in effect at the time of preparing our reserve estimates and may be adjusted as market conditions evolve. Development of our existing PUD reserves at December 31, 2021 is expected

to occur within five years of the date of initial booking of the PUDs. PUD reserves not expected to be drilled within five years of initial booking because of changes in business strategy or for other reasons have been removed from our reserves at December 31, 2021. We had no PUD reserves at December 31, 2021 that remain undrilled beyond five years from the date of initial booking.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Ryder Scott, our independent reserves evaluation consulting firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 98% of our PV-10 and 98% of our total proved reserves as of December 31, 2021 included in this Form 10-K. The Ryder Scott technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Refer to Exhibit 99 included with this Form 10-K for further discussion of the qualifications of Ryder Scott personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team is in contact regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserves estimates. Proved reserves information is reviewed by our Audit Committee with representatives of Ryder Scott and by our internal technical staff before the information is filed with the SEC on Form 10-K. Additionally, certain members of our senior management review and approve the Ryder Scott reserves report and on a semi-annual basis review any internal proved reserves estimates.

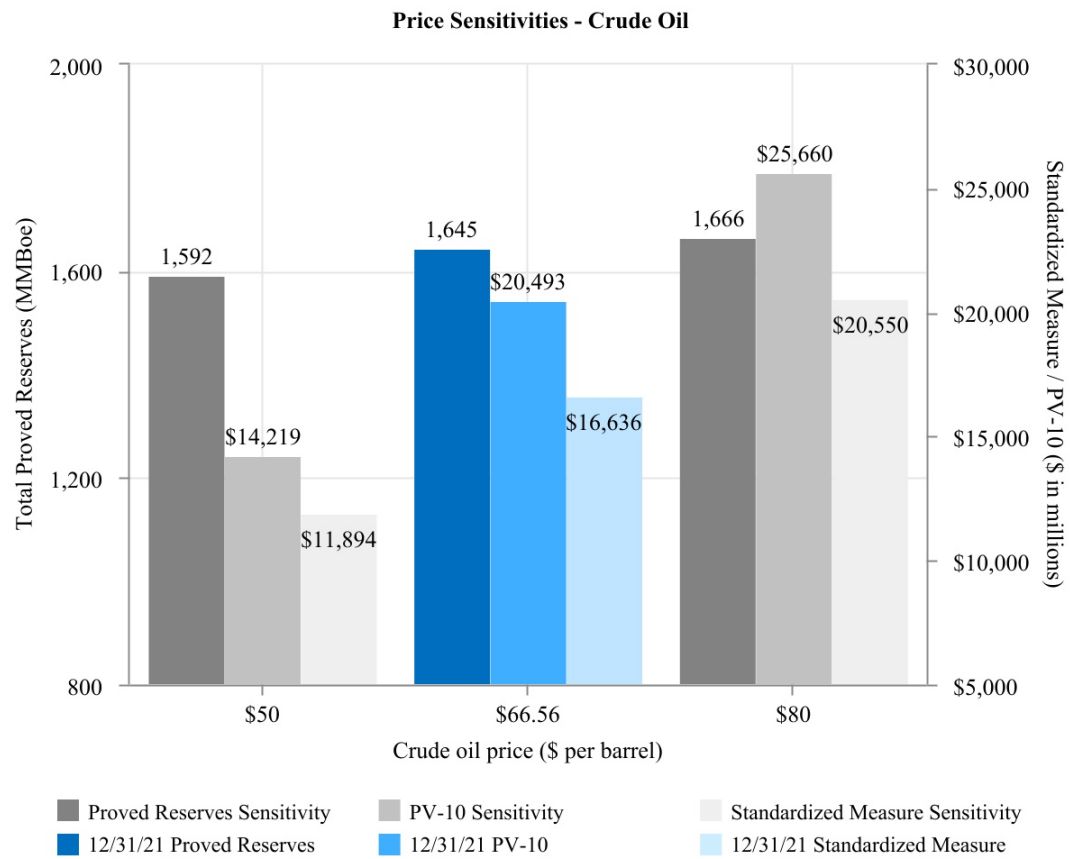
Our Vice President—Corporate Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, an MBA in Finance and 37 years of industry experience with positions of increasing responsibility in operations, acquisitions, engineering and evaluations. He has worked in the area of reserves and reservoir engineering most of his career and is a member of the Society of Petroleum Engineers. The Vice President—Corporate Reserves reports directly to our Vice Chairman of Strategic Growth Initiatives. The reserves estimates are reviewed and approved by certain members of the Company's executive management.

Proved Reserves, Standardized Measure, and PV-10 Sensitivities

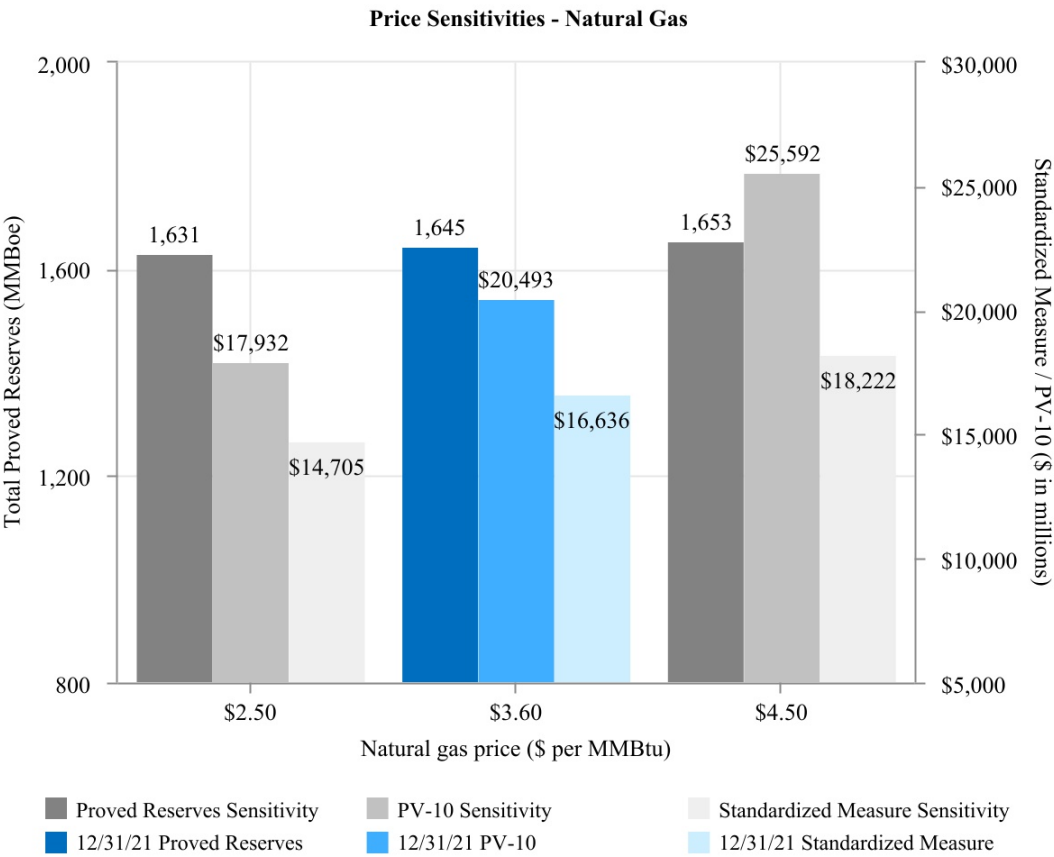
Our year-end 2021 proved reserves, Standardized Measure, and PV-10 estimates were prepared using 2021 average first-day-of-the-month prices of \$66.56 per Bbl for crude oil and \$3.60 per MMBtu for natural gas (\$62.19 per Bbl for crude oil and \$3.46 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may be materially higher or lower than those used in our year-end estimates.

Provided below are sensitivities illustrating the potential impact on our estimated proved reserves, Standardized Measure, and PV-10 at December 31, 2021 under different commodity price scenarios for crude oil and natural gas. In these sensitivities, all factors other than the commodity price assumption have been held constant for each well. These sensitivities do not take into account a potential increase in our drilling activities and associated booking of additional proved reserves that may occur at higher commodity prices and there is no assurance the outcomes reflected below will be realized.

The crude oil price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain crude oil price scenarios, with natural gas prices being held constant at the 2021 average first-day-of-the-month price of \$3.60 per MMBtu.



The natural gas price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain natural gas price scenarios, with crude oil prices being held constant at the 2021 average first-day-of-the-month price of \$66.56 per Bbl.



Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2021:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken	1,125,023	702,709	116,922	69,175	1,241,945	771,884
Powder River Basin	111,197	76,750	189,180	140,835	300,377	217,585
Red River Units	154,643	139,363	19,891	10,186	174,534	149,549
Other	80,287	54,113	29,040	25,654	109,327	79,767
South Region:						
Oklahoma	581,811	341,056	219,872	107,231	801,683	448,287
Permian Basin	80,605	80,605	76,015	65,756	156,620	146,361
Other	20,916	9,364	90,425	72,763	111,341	82,127
East Region	734	661	52,929	46,815	53,663	47,476
Total	2,155,216	1,404,621	794,274	538,415	2,949,490	1,943,036

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2021 scheduled to expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates or the leases are renewed.

	2022		2023		2024	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken	47,272	29,243	9,779	7,639	10,467	6,986
Powder River Basin	10,893	10,142	3,044	1,703	2,268	1,695
Other	—	—	17,847	17,847	—	—
South Region:						
Oklahoma	54,083	29,789	35,837	16,704	26,109	13,426
Permian Basin	—	—	—	—	26,347	16,285
Other	14,660	11,031	13,436	13,086	37,399	9,985
East Region	4,856	3,732	5,968	5,272	3,052	2,717
Total	131,764	83,937	85,911	62,251	105,642	51,094

Drilling Activity

During the three years ended December 31, 2021, we participated in the drilling and completion of exploratory and development wells as set forth in the table below.

	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	11	8.0	1	—	2	1.6
Natural gas	2	1.9	1	—	4	1.8
Dry holes	—	—	1	0.9	—	—
Total exploratory wells	13	9.9	3	0.9	6	3.4
Development wells:						
Crude oil	376	144.6	300	115.5	615	222.9
Natural gas	38	20.3	31	15.9	68	9.7
Dry holes	—	—	—	—	—	—
Total development wells	414	164.9	331	131.4	683	232.6
Total wells	427	174.8	334	132.3	689	236.0

As of December 31, 2021, there were 393 gross (153 net) operated and non-operated wells that have been spud and are in the process of drilling, completing or waiting on completion.

Summary of Crude Oil and Natural Gas Properties and Projects

In the following discussion, we review our budgeted number of wells and capital expenditures for 2022 in our key operating areas. Our 2022 capital budget, based on our current expectations of commodity prices and costs, is expected to be funded from operating cash flows. Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our spending should commodity prices materially decrease from current levels.

The following table provides information regarding well counts and budgeted capital expenditures for 2022.

	2022 Plan		
	Gross wells (1)	Net wells (1)	Capital expenditures (in millions) (2)
Bakken	264	116	\$ 800
Powder River Basin	34	20	200
Oklahoma	117	41	400
Permian Basin	49	46	400
Total exploration and development	464	223	\$ 1,800
Land			127
Mineral acquisitions attributable to Continental (3)			23
Capital facilities, workovers, water infrastructure, and other			344
Seismic			6
2022 capital budget attributable to Continental			\$ 2,300
Mineral acquisitions attributable to Franco-Nevada (3)			91
Total 2022 capital budget (4)			\$ 2,391

(1) Represents operated and non-operated wells expected to have first production in 2022.

(2) Represents total capital expenditures for operated and non-operated wells expected to have first production in 2022 and wells spud that will be in the process of drilling, completing or waiting on completion as of year-end 2022.

- (3) Represents planned spending for mineral acquisitions by The Mineral Resources Company II, LLC ("TMRC II") under our relationship with Franco-Nevada Corporation described in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 17. Noncontrolling Interests*. Continental holds a controlling financial interest in TMRC II and therefore consolidates the financial results and capital expenditures of the entity. With a carry structure in place, Continental will fund 20% of 2022 planned spending, or \$23 million, and Franco-Nevada will fund the remaining 80%, or \$91 million.
- (4) Amount excludes the \$450 million purchase price for our pending acquisition of properties in the Powder River Basin as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 20. Subsequent Events*.

North Region

Our properties in the North region represented 46% of our total proved reserves as of December 31, 2021 and 55% of our average daily Boe production for the fourth quarter of 2021. Our principal producing properties in the North region are located in the Bakken field of North Dakota and Montana and our recently acquired properties in the Powder River Basin of Wyoming.

Bakken Field

The Bakken field of North Dakota and Montana is one of the largest crude oil resource plays in the United States. We are a leading producer, leasehold owner and operator in the Bakken. As of December 31, 2021, we controlled one of the largest leasehold positions in the Bakken with approximately 1.2 million gross (771,900 net) acres under lease.

Our total Bakken production averaged 175,585 Boe per day for the fourth quarter of 2021, down 4% from the 2020 fourth quarter. For the year ended December 31, 2021, our average daily Bakken production increased 7% compared to 2020, reflecting the impact of voluntary production curtailments in 2020 and additional drilling and completion activities in 2021. In 2021, we participated in the drilling and completion of 252 gross (102 net) wells in the Bakken compared to 188 gross (77 net) wells in 2020. Our 2021 activities in the Bakken focused on ongoing multi-zone unit development in core areas of the play.

Our Bakken properties represented 43% of our total proved reserves at December 31, 2021 and 52% of our average daily Boe production for the 2021 fourth quarter. Our total proved Bakken field reserves as of December 31, 2021 were 708 MMBoe, an increase of 39% compared to December 31, 2020 primarily due to reserves added from our drilling program and upward reserve revisions prompted by improved commodity prices. Our inventory of proved undeveloped drilling locations in the Bakken totaled 1,254 gross (701 net) wells as of December 31, 2021.

For 2022, our budget for exploration and development capital expenditures in the Bakken is \$800 million. In 2022, we plan to average approximately six operated rigs and two well completion crews in the Bakken and expect to have first production on 264 gross (116 net) operated and non-operated wells during the year. Our 2022 drilling and completion activities in the Bakken will continue to focus on multi-zone unit development in areas that provide opportunities to improve capital efficiency, reduce finding and development costs, improve recoveries and rates of return, and maximize cash flows.

Powder River Basin

Our production in the Powder River Basin averaged 7,189 Boe per day for the fourth quarter of 2021. During 2021, we participated in the drilling and completion of 10 gross (8 net) wells in the play. Our Powder River properties represented 2% of our total proved reserves at December 31, 2021 and 2% of our average daily Boe production for the 2021 fourth quarter. Our proved reserves in the play totaled 32 MMBoe as of December 31, 2021 and our inventory of proved undeveloped drilling locations totaled 55 gross (34 net) wells.

For 2022, our budget for exploration and development capital expenditures in the Powder River Basin is \$200 million. In 2022, we plan to average approximately two operated rigs and one well completion crew in the play and expect to have first production on 34 gross (20 net) operated and non-operated wells during the year.

South Region

Our properties in the South region represented 54% of our total proved reserves as of December 31, 2021 and 45% of our average daily Boe production for the fourth quarter of 2021. Our principal producing properties in the South region are located in the SCOOP and STACK areas of Oklahoma and our recently acquired properties in the Permian Basin of Texas.

Oklahoma

We are a leading producer, leasehold owner and operator in Oklahoma. As of December 31, 2021, we controlled one of the largest leasehold positions in Oklahoma with approximately 801,700 gross (448,300 net) acres under lease.

Our properties in Oklahoma represented 41% of our total proved reserves as of December 31, 2021 and 43% of our average daily Boe production for the fourth quarter of 2021. Production in Oklahoma averaged 146,131 Boe per day during the fourth quarter of 2021, down 2% compared to the 2020 fourth quarter. For the year ended December 31, 2021, average daily production in Oklahoma increased 9% compared to 2020, reflecting the impact of voluntary production curtailments in 2020 and additional drilling and completion activities in 2021. We participated in the drilling and completion of 161 gross (63 net) wells in Oklahoma during 2021 compared to 145 gross (54 net) wells in 2020. Our proved reserves in Oklahoma as of December 31, 2021 totaled 679 MMBoe, an increase of 18% compared to December 31, 2020 primarily due to reserves added from our drilling program and upward reserve revisions prompted by improved commodity prices. Our inventory of proved undeveloped drilling locations in Oklahoma totaled 313 gross (170 net) wells as of December 31, 2021.

For 2022, our aggregate budget for exploration and development capital expenditures in Oklahoma is \$400 million. In 2022, we plan to average approximately seven operated rigs and two well completion crews in Oklahoma and expect to have first production on 117 gross (41 net) operated and non-operated wells during the year. Our 2022 activities will focus on continued development in areas that provide opportunities to improve capital efficiency, reduce finding and development costs, improve recoveries and rates of return, and maximize cash flows.

Permian Basin

Proved reserves associated with our Permian Basin properties acquired in late 2021 totaled 203 MMBoe, representing 12% of our total proved reserves as of December 31, 2021. Production from our Permian properties averaged approximately 42,000 Boe per day based on two-stream reporting during our short duration of ownership from December 21, 2021 to December 31, 2021.

For 2022, our budget for exploration and development capital expenditures in the Permian Basin is \$400 million. In 2022, we plan to average approximately four operated rigs and one well completion crew in the play and expect to have first production on 49 gross (46 net) operated and non-operated wells during the year.

Production and Price History

The following table sets forth information concerning our production results, average sales prices and production costs for the years ended December 31, 2021, 2020 and 2019 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2021.

	Year ended December 31,		
	2021	2020	2019
Net production volumes:			
Crude oil (MBbls)			
North Dakota Bakken	40,121	40,052	52,420
SCOOP	11,318	12,585	11,679
Total Company	58,636	58,745	72,267
Natural gas (MMcf)			
North Dakota Bakken	120,517	97,532	98,186
SCOOP	179,553	136,410	111,436
Total Company	370,110	306,528	311,865
Crude oil equivalents (MBoe)			
North Dakota Bakken	60,207	56,308	68,784
SCOOP	41,244	35,320	30,252
Total Company	120,321	109,833	124,244
Average net sales prices (1):			
Crude oil (\$/Bbl)			
North Dakota Bakken	\$ 63.24	\$ 33.53	\$ 50.96
SCOOP	66.46	37.88	54.92
Total Company	64.06	34.71	51.82
Natural gas (\$/Mcf)			
North Dakota Bakken	\$ 4.52	\$ 0.23	\$ 1.28
SCOOP	5.33	1.64	2.36
Total Company	4.88	1.04	1.77
Crude oil equivalents (\$/Boe)			
North Dakota Bakken	\$ 51.21	\$ 24.24	\$ 40.66
SCOOP	41.44	19.90	29.80
Total Company	46.24	21.47	34.56
Average costs per Boe:			
Production expenses (\$/Boe)			
North Dakota Bakken	\$ 4.27	\$ 4.35	\$ 4.28
SCOOP	1.24	1.06	1.21
Total Company	3.38	3.27	3.58
Production taxes (\$/Boe)	\$ 3.36	\$ 1.75	\$ 2.88
General and administrative expenses (\$/Boe)	\$ 1.94	\$ 1.79	\$ 1.57
DD&A expense (\$/Boe)	\$ 15.76	\$ 17.12	\$ 16.25

- (1) See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of net sales prices, which are non-GAAP measures.

The following table sets forth information regarding our average daily production by region for the fourth quarter of 2021:

	Fourth Quarter 2021 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken	116,548	354,222	175,585
Powder River Basin	5,704	8,912	7,189
Red River Units	6,212	—	6,212
South Region:			
Oklahoma	34,314	670,904	146,131
Permian Basin (1)	3,885	6,671	4,997
Other	31	133	54
Total	166,694	1,040,842	340,168

(1) The presentation of average daily 2021 fourth quarter production represents production during the period from the closing of our acquisition of Permian properties on December 21, 2021 through December 31, 2021 averaged over 92 days in the fourth quarter. At the time of closing, our Permian properties produced on average approximately 42,000 Boe per day (78% oil) based on two-stream reporting.

Productive Wells

Gross wells represent the number of wells in which we own a working interest and net wells represent the total of our fractional working interests owned in gross wells. The following table presents the total gross and net productive wells by region and by crude oil or natural gas completion as of December 31, 2021. One or more completions in the same well bore are counted as one well.

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken	5,610	1,997	—	—	5,610	1,997
Powder River Basin	235	143	7	5	242	148
Red River Units	267	251	—	—	267	251
South Region:						
Oklahoma	1,214	521	943	304	2,157	825
Permian Basin	409	318	2	1	411	319
Other	2	2	23	2	25	4
Total	7,737	3,232	975	312	8,712	3,544

Title to Properties

As is customary in the crude oil and natural gas industry, upon initiation of acquiring oil and gas leases covering fee mineral interests on undeveloped lands which do not have associated proved reserves, contract landmen conduct a title examination of courthouse records and production databases to determine fee mineral ownership and availability. Title, lease forms and terms are reviewed and approved by Company landmen prior to consummation.

For acquisitions from third parties, whether lands are producing crude oil and natural gas or non-producing, Company and contract landmen perform title examinations at applicable courthouses, obtain physical well site inspections, and examine the seller's internal records (land, legal, operational, production, environmental, well, marketing and accounting) upon execution of a mutually acceptable purchase and sale agreement. Company landmen may also procure an acquisition title opinion from outside legal counsel on higher value properties.

Prior to the commencement of drilling operations, Company landmen procure an original title opinion, or supplement an existing title opinion, from outside legal counsel and perform curative work to satisfy requirements pertaining to material title issues, if any. Company landmen will not approve commencement of drilling operations until material title defects pertaining to the Company's interest are cured.

The Company has cured material title opinion issues as to Company interests on substantially all of its producing properties and believes it holds at least defensible title to its producing properties in accordance with standards generally accepted in the crude oil and natural gas industry. The Company's crude oil and natural gas properties are subject to customary royalty and leasehold burdens which do not materially interfere with the Company's interest in the properties or affect the Company's carrying value of such properties.

Marketing

We sell most of our operated crude oil production to crude oil refining companies or midstream marketing companies at major market centers. In the Bakken, Powder River, Permian, SCOOP, and STACK areas we have significant volumes of production directly connected to pipeline gathering systems, with the remaining production primarily transported by truck to a point on a pipeline system for further delivery. We do not transport any of our oil production prior to sale by rail, but several purchasers of our Bakken production are connected to rail delivery systems and may choose those methods to transport the oil they have purchased from us. We sell some operated crude oil production at the lease. Our share of crude oil production from non-operated properties is marketed at the discretion of the operators.

We sell most of our operated natural gas production to midstream customers at our lease locations based on market prices in the field where the sales occur, with the remaining production sold at centrally gathered locations or natural gas processing plants. These contracts include multi-year term agreements, many with acreage dedications. Under certain arrangements, we have the right to take a volume of processed residue gas and/or natural gas liquids ("NGLs") in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement for the sale of our operated natural gas production. When we do take volumes in kind, we pay third parties to transport the residue gas volumes taken in kind to downstream delivery points, where we then sell to customers at prices applicable to those downstream markets. Sales at the downstream markets are mostly under daily and monthly packaged volumes deals, shorter term seasonal packages, and long term multi-year contracts. We continue to develop relationships and have the potential to enter into additional contracts with end-use customers, including utilities, industrial users, and liquefied natural gas exporters, for sale of products we elect to take in-kind in lieu of monetary settlement for our leasehold sales. Our share of natural gas production from non-operated properties is generally marketed at the discretion of the operators.

Environmental Stewardship

Throughout our operations, we seek to limit associated waste through emissions management and mitigation programs, increased recycling and re-use of produced water, and the use of footprint-reducing measures. Our environmental stewardship strategies, policies, and efforts are monitored by our Board of Directors' Nominating, Environmental, Social and Governance Committee ("Committee"), which is the primary Committee responsible for overseeing and managing our ESG initiatives in respect of our business goals. Our focus on continuous improvement in ESG performance has resulted in sustained, year-over-year decreases since 2016 in both greenhouse gas and methane intensities. From 2019 through 2020, the most recent reporting year, we achieved a 28% decrease in greenhouse gas intensity and a 34% decrease in methane intensity.

Competition

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas, and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for crude oil and

natural gas properties, minerals, and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions economically in a highly competitive environment. In addition, as a result of depressed commodity prices in recent years, the number of providers of materials and services has decreased in the regions where we operate. Further, recent supply chain disruptions stemming from the COVID-19 pandemic have led to shortages of certain materials and equipment and increased costs. As a result, the likelihood of experiencing competition and shortages of materials and services may be further increased in connection with any period of sustained commodity price recovery. Finally, the emerging impact of climate change activism, fuel conservation measures, governmental requirements for renewable energy resources, increasing demand for alternative forms of energy, and technological advances in energy generation devices may result in reduced demand for the crude oil and natural gas we produce.

Regulation of the Crude Oil and Natural Gas Industry

All of our operations are conducted onshore in the United States. The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations, policies, and interpretations affecting our industry have been and are pervasive with the frequent imposition of new or increased requirements. These laws, regulations and other requirements often carry substantial penalties for failure to comply and may have a significant effect on our operations and may increase the cost of doing business and reduce our profitability. In addition, because public policy changes affecting the crude oil and natural gas industry are commonplace and because laws, rules and regulations may be enacted, amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws, rules and regulations. We do not expect future legislative or regulatory initiatives will affect us materially different than they will affect our similarly situated competitors.

The following is a discussion of certain significant laws, rules and regulations, as amended from time to time, that may affect us in the areas in which we operate.

Regulation of sales and transportation of crude oil and natural gas liquids

Our physical sales of crude oil and any derivative instruments relating to crude oil are subject to anti-market manipulation laws and related regulations enforced by the Federal Trade Commission ("FTC") and the Commodity Futures Trading Commission ("CFTC"). These laws, among other things, prohibit fraudulent or deceptive conduct in connection with wholesale purchases or sales of crude oil and price manipulation in the commodity and futures markets. If we violate the anti-market manipulation laws and regulations, we can be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

We transport most of our operated crude oil production to market centers using a combination of trucks and pipeline transportation facilities owned and operated by third parties. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration establishes safety regulations relating to transportation of crude oil by pipeline. Further, our sales of crude oil are affected by the availability, terms and costs of transportation. The transportation of crude oil and natural gas liquids ("NGLs") is subject to rate and access regulation. The Federal Energy Regulatory Commission ("FERC") regulates interstate crude oil and NGL pipeline transportation rates under the Interstate Commerce Act and the Energy Policy Act of 1992, and intrastate crude oil and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. As the interstate and intrastate transportation rates we pay are generally applicable to all comparable shippers, the regulation of such transportation rates will not affect us in a way that materially differs from the effect on our similarly situated competitors.

Further, interstate pipelines and intrastate common carrier pipelines must provide service on an equitable basis and offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When such pipelines operate at full capacity we are subject to proration provisions, which are described in the pipelines' published tariffs. We generally will have access to crude oil pipeline transportation services to the same extent as our similarly situated competitors.

From time to time we may sell our operated crude oil production at market centers in the United States to third parties who then subsequently export and sell the crude oil in international markets. The International Maritime Organization ("IMO"), an agency of the United Nations, has issued regulations requiring the maritime shipping industry to gradually reduce its carbon emissions over time by mandating a 1% improvement in the efficiency of fleets each year between 2015 and 2025. In conjunction with this initiative, the IMO issued regulations requiring ship owners to lower the concentration of the sulfur content used in their fuels from 3.5% to 0.5% beginning on January 1, 2020. To achieve and maintain compliance with the new regulations, it is expected ship owners will either have to switch to more expensive higher quality marine fuel, install and utilize

emissions-cleaning systems, or switch to alternative fuels such as liquefied natural gas. Failure to comply with the regulations may result in fines or shipping vessels being detained, thereby resulting in exportation capacity constraints that inhibit a third party's ability to transport and sell domestic crude oil production overseas, which may have a material impact on the markets and prices for various grades of domestic and international crude oil. The ultimate long-term impact of the IMO regulations is uncertain.

We do not own or operate pipeline or rail transportation facilities, rail cars, or infrastructure used to facilitate the exportation of crude oil. However, regulations that impact the domestic transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at market centers throughout the United States. We do not expect such regulations will affect us in a materially different way than similarly situated competitors.

Regulation of sales and transportation of natural gas

We are also required to observe the aforementioned anti-market manipulation laws and related regulations enforced by the FERC and CFTC in connection with physical sales of natural gas and any derivative instruments relating to natural gas. Additionally, the FERC regulates interstate natural gas transportation rates and service conditions under the Natural Gas Act and the Natural Gas Policy Act of 1978, which affects the marketing of natural gas we produce, as well as revenues we receive for sales of our natural gas. The FERC has endeavored to increase competition and make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis and has issued a series of orders to implement its open access policies. We cannot provide any assurance the pro-competitive regulatory approach established by the FERC will continue. However, we do not believe any action taken by the FERC will affect us in a materially different way than similarly situated natural gas producers.

The gathering of natural gas, which occurs upstream of jurisdictional transmission services, is generally regulated by the states. Although its policies on gathering systems have varied in the past, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the potential to increase costs for our purchasers and reduce the revenues we receive for our natural gas stream. State regulation of natural gas gathering facilities generally includes various safety, environmental, and in some circumstances, equitable take requirements. We do not believe such regulations will affect us in a materially different way than our similarly situated competitors.

Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas we produce, as well as the revenues we receive for sales of our natural gas. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers on a comparable basis, the regulation of intrastate natural gas transportation in states in which we operate will not affect us in a way that materially differs from our similarly situated competitors.

The U.S. Department of Energy ("U.S. DOE") regulates the terms and conditions for the exportation and importation of natural gas (including liquefied natural gas or "LNG"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a Free Trade Agreement ("FTA") with the United States providing for national treatment of trade in natural gas; however, the U.S. DOE's regulation of imports and exports from and to countries without an FTA is more comprehensive. The FERC also regulates the construction and operation of import and export facilities, including LNG terminals. Regulation of imports and exports and related facilities may materially affect natural gas markets and sales prices and could inhibit the development of LNG infrastructure.

Regulation of production

The production of crude oil and natural gas is regulated by a wide range of federal, state, and local laws, rules, and regulations, which require, among other matters, permits for drilling operations, drilling bonds, and reports concerning operations. Each of the states where we own and operate properties have laws and regulations governing conservation, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing, the plugging and abandonment of wells, the regulation of greenhouse gas emissions, and limitations or prohibitions on the venting or flaring of natural gas. These laws and regulations directly and indirectly limit the amount of crude oil and natural gas we can produce from our wells and the number of wells and locations we can drill, although we can and do apply for exceptions to such laws and regulations or to have reductions in well spacing. Moreover, each state generally imposes a production, severance or excise tax on the production and sale of crude oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with the above laws, rules, and regulations can result in substantial penalties. Our similarly situated competitors are generally subject to the same laws, rules, and regulations as we are.

Environmental regulation

General. We are subject to stringent, complex, and overlapping federal, state, and local laws, rules and regulations governing environmental compliance, including the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits to conduct exploration, drilling and production operations;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas including areas containing endangered species of plants and animals;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

These laws, rules and regulations may restrict the level of substances generated by our operations that may be emitted into the air, discharged to surface water, and disposed or otherwise released to surface and below-ground soils and groundwater, and may also restrict the rate of crude oil and natural gas production to a rate that is economically infeasible for continued production. The regulatory burden on the crude oil and natural gas industry increases the cost of doing business and affects profitability. Additionally, in the name of combatting climate change, President Biden has issued, and may continue to issue, executive orders that result in more stringent and costly requirements for the domestic crude oil and natural gas industry, or which restrict, delay or ban oil and gas permitting or leasing on federal lands. Any regulatory or executive changes that impose further requirements on domestic producers for emissions control, waste handling, disposal, cleanup and remediation could have a significant impact on our operating costs and production of oil and gas. Failure to comply with these and other laws, rules and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations or the incurrence of capital expenditures, the occurrence of restrictions, delays or cancellations in the permitting, development or expansion of projects, the issuance of orders enjoining performance of some or all of our operations, and potential litigation in a particular area. Additionally, certain of these environmental laws may result in imposition of joint and several or strict liability, which could cause us to become liable for the conduct of others or for consequences of our own actions. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners or other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Certain environmental laws also provide for certain citizen suits, which allow persons or organizations to act in place of the government and sue operators for alleged violations of environmental laws. We have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental laws and regulations. The following is a description of some of the environmental laws, rules and regulations, as amended from time to time, that apply to our operations.

Air emissions. Federal, state, and local laws, rules, and regulations have been and, in the future, will likely be enacted to address concerns about emissions of regulated air pollutants. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit standards or utilize specific equipment or technologies to control emissions of certain pollutants. For example, in October 2021, the U.S. Environmental Protection Agency (“EPA”) announced its intention to initiate a rule-making to reassess and lower, by the end of 2023, the current National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone, which was last set by the EPA under the Obama Administration in 2015. State implementation of a revised NAAQS for ground-level ozone could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, or result in increased expenditures for pollution control equipment, the costs of which could be significant.

Regulation of greenhouse gas emissions. The threat of climate change continues to attract considerable attention in the United States and in foreign countries and, as a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of greenhouse gases as well as to reduce, restrict, or eliminate such future emissions. As a result, our operations as well as the operations of the oil and gas industry in general are subject to a series of regulatory, political, litigation and financial risks associated with the production of fossil fuels and emission of greenhouse gases.

Federal regulatory initiatives have focused on establishing construction and operating permit reviews for greenhouse gas emissions from certain large stationary sources, requiring the monitoring and annual reporting of greenhouse gas emissions from certain petroleum and natural gas system sources, and reducing methane emissions from oil and gas production and natural gas processing and transmission operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements. In recent years, there has been considerable uncertainty surrounding regulation of methane emissions. During 2020, the Trump Administration revised performance standards for methane established in 2016 to lessen the impact of those standards and remove the transmission and storage segments from the source category for certain regulations. However, shortly after taking office in 2021, President Biden issued an executive order calling on the EPA to revisit federal regulations regarding methane and establish new or more stringent standards for existing or new sources in the oil and gas sector, including the transmission and storage segments. The U.S. Congress also passed, and President Biden signed into law, a revocation of the 2020 rulemaking, effectively reinstating the 2016 standards. In response to President Biden's executive order, in November 2021 the EPA issued a proposed rule that, if finalized, would establish Quad Ob new source and Quad Oc first-time existing source standards of performance for methane and volatile organic compound (VOC) emissions in the crude oil and natural gas source category. This proposed rule would apply to upstream and midstream facilities at oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. Owners or operators of affected emission units or processes would have to comply with specific standards of performance that may include leak detection using optical gas imaging and subsequent repair requirements, reduction of emissions by 95% through capture and control systems, zero-emission requirements, operation and maintenance requirements, and so-called green well completion requirements. The EPA plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 that will contain additional requirements that were not included in the November 2021 proposed rule. The EPA anticipates issuing a final rule before end-of-year 2022. Additionally, the House of Representatives version of the Build Back Better Act included a fee on methane emissions, targeting industries that produce, transport, and store natural gas throughout the United States at \$900 per ton in 2023, \$1,200 per ton in 2024, and \$1,500 per ton in 2025 and beyond. Congress could seek to include this or a similar fee in future legislation.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement among participating nations to limit their greenhouse gas emissions through individually-determined reduction goals every five years after 2020. President Biden announced in April 2021 a new, more rigorous nationally determined emissions reduction level of 50%-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. Moreover, in November 2021 at the 26th Conference of the Parties ("COP26"), multiple announcements (not having the effect of law) were made, including a call for parties to eliminate certain measures perceived to subsidize fossil fuel production and consumption, and to pursue further action on non-CO2 GHGs. Relatedly, the United States and European Union jointly announced at COP26 the launch of a Global Methane Pledge, an initiative which over 100 countries joined, committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time.

Governmental, scientific and public concern over the threat of climate change arising from greenhouse gas emissions has given rise to increasing federal political risk for the domestic crude oil and natural gas industry. In the United States, President Biden has issued several executive orders calling for more expansive action to address climate change and suspend new oil and gas operations on federal lands and waters. The suspension of the federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021, effectively halting implementation of the leasing suspension. The federal government is appealing the district court decision. Litigation risks are also increasing, as a number of states, municipalities and other parties have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts.

Moreover, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in energy companies but concerned about the potential effects of climate change may elect to shift some or all of their investments into non-energy related sectors. Institutional investors who provide financing to energy companies have also focused on sustainability lending practices that favor alternative power sources perceived to be more clean (despite their negative impacts on the environment), such as wind and solar. Some of these investors may elect not to provide traditional funding for energy companies. Many of the largest U.S. banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those

emissions. 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. These and other developments in the financial sector could lead to some lenders restricting or eliminating access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding to the fossil fuel sector. In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, 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 challenges most relevant to central banks and supervisory authorities. While we cannot predict what policies may result from this, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for acquisition, exploration, development, production, transportation, and processing activities, which could impact our business and operations. To the extent the rules impose additional reporting obligations, we could face increased costs. Furthermore, the SEC has announced it will propose rules that, among other matters, will establish a framework for the reporting of climate risks. However, no such rules have been proposed to date and we cannot predict what any such rules may require. To the extent rules impose additional reporting obligations, we could face increased costs. Separately, the SEC has also announced it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC was to allege that an issuer’s existing climate disclosures were misleading or deficient.

Environmental protection and natural gas flaring. One of our environmental initiatives is the reduction of air emissions produced from our operations, including the flaring of natural gas from our operated well sites in the Bakken field of North Dakota. North Dakota law permits flaring of natural gas from a well that has not been connected to a gas gathering line for a period of one year from the date of a well’s first production. After one year, a producer is required to cap the well, connect it to a gas gathering line, find acceptable alternative uses for a percentage of the flared gas, or apply to the North Dakota Industrial Commission (“NDIC”) for a written exemption for any future flaring; otherwise, the producer is required to pay royalties and production taxes based on the volume and value of the gas flared from the unconnected well.

In addition, NDIC rules for new drilling permit applications also require the submission of gas capture plans setting forth plans taken by operators to capture and not flare produced gas, regardless of whether it has been or will be connected within the first year of production. The NDIC currently requires us to capture 91% of the natural gas produced from a field. We capture in excess of the NDIC requirement. If an operator is unable to attain the applicable gas capture percentage goal at maximum efficient rate, wells will be restricted in production to 200 barrels of crude oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise crude oil production from such wells is not permitted to exceed 100 barrels of crude oil per day. However, the NDIC will consider temporary exemptions from the foregoing restrictions or for other types of extenuating circumstances after notice and hearing if the effect is a significant net increase in gas capture within one year of the date such relief is granted. Monetary penalty provisions also apply under this regulation if an operator fails to timely file for a hearing with the NDIC upon being unable to meet such percentage goals or if the operator fails to timely implement production restrictions once below the applicable percentage goals. Ongoing compliance with the NDIC’s flaring requirements or the imposition of any additional limitations on flaring could result in increased costs and have an adverse effect on our operations.

We seek to reduce or eliminate natural gas flaring, but our efforts may not always be successful or cost-effective. Our levels of flaring are impacted by external factors such as investment from third parties in the development and continued operation of gas gathering and processing facilities and the granting of reasonable right-of-way access by land owners. Increased emissions from our facilities due to flaring could subject our facilities to more stringent air emission permitting requirements, resulting in increased compliance costs and potential construction delays.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppant and additives under pressure into rock formations to stimulate crude oil and natural gas production. In recent years there has been public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies or to induce seismic events. As a result, several federal and state agencies have studied the environmental risks with respect to hydraulic fracturing, and proposals have been made to enact separate federal, state and local legislation that would potentially increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (“SDWA”) over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance related to such activities. Also, the EPA has issued a final regulation under the Clean Water Act prohibiting discharges to publicly owned treatment works of wastewater from onshore unconventional oil and gas extraction facilities. We do not

discharge wastewater to publicly owned treatment works, so the impact of this regulation on us is not currently, and is not expected to be, material.

In late 2016 the EPA published a final study of the potential impacts of hydraulic fracturing activities on water resources in which the EPA indicated it found evidence that such activities can impact drinking water resources under some circumstances. In its final report, the EPA indicated it was not able to calculate or estimate the national frequency of impacts on drinking water resources from hydraulic fracturing activities or fully characterize the severity of impacts. Nonetheless, the results of the EPA's study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

In 2016, the BLM under the Obama Administration published final rules related to the regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity, and handling of flowback water. However, the BLM under the Trump Administration published a final rule rescinding the 2016 final rule in November 2018. Litigation challenging the BLM's 2016 final rule as well as its 2018 final rule rescinding the 2016 rule has been pursued by various states and industry and environmental groups. While a California federal court vacated the 2018 final rule in July 2020, a Wyoming federal court subsequently vacated the 2016 final rule in October 2020 and, accordingly, the 2016 final rule is no longer in effect. However, appeals to those decisions are ongoing. Notwithstanding these recent legal developments, further administrative and regulatory restrictions may be adopted by the Biden Administration that could restrict hydraulic fracturing activities on federal lands and waters.

In addition, regulators in states in which we operate have adopted additional requirements related to seismicity and its potential association with hydraulic fracturing. For example, the Oklahoma Corporation Commission (the "OCC") has promulgated guidance for operators of crude oil and natural gas wells in certain seismically-active areas of the SCOOP and STACK plays in Oklahoma. The OCC's guidance provides for seismic monitoring and for implementation of mitigation procedures, which may include curtailment or even suspension of operations in the event of concurrent seismic events within a particular radius of operations of a magnitude exceeding 2.5 on the Richter scale. If seismic events exceeding the OCC guidance thresholds were to occur near our active stimulation operations on a frequent basis, they could have an adverse effect on our operations.

Waste water disposal. Underground injection wells are a predominant method for disposing of waste water from oil and gas activities. In response to seismic events near underground injection wells used for the disposal of oil and gas-related waste waters, federal and some state agencies have investigated whether such wells have caused increased seismic activity. To address concerns regarding seismicity, some states, including states in which we operate, have pursued remedies that included delaying permit approvals, mandating a reduction in injection volumes, or shutting down or imposing moratoria on the use of injection wells. Moreover, regulators in states in which we operate have implemented additional requirements related to seismicity. For example, the OCC has adopted rules for operators of saltwater disposal wells in certain seismically-active areas in the Arbuckle formation of Oklahoma. These rules require, among other things, that disposal well operators conduct mechanical integrity testing or make certain demonstrations of such wells' respective depths that, depending on the depth, could require plugging the well and/or the reduction of volumes disposed in such wells. Oklahoma utilizes a "traffic light" system wherein the OCC reviews new or existing disposal wells for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. At the federal level, the EPA's current regulatory requirements for such wells do not require the consideration of seismic impacts when issuing permits. We cannot predict the EPA's future actions in this regard.

The introduction of new environmental laws and regulations related to the disposal of wastes associated with the exploration, development or production of hydrocarbons could limit or prohibit our ability to utilize underground injection wells. A lack of waste water disposal sites could cause us to delay, curtail or discontinue our exploration and development plans. Additionally, increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. These costs are commonly incurred by oil and gas producers and we do not expect the costs associated with the disposal of produced water will have a material adverse effect on our operations to any greater degree than other similarly situated competitors. In recent years, we have increased our operation and use of water recycling and distribution facilities that economically reuse stimulation water for both operational efficiencies and environmental benefits.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures are included within our overall capital and operating budgets and are not separately itemized. Historically, our environmental compliance costs have not had a material adverse impact on our financial condition and results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material impact on our business, financial condition, results of operations or cash flows.

Employee Health and Safety. We are also subject to the requirements of the federal Occupational Safety and Health Act and comparable state laws that regulate the protection of the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration hazard communication standard, the EPA community right-to-know regulation under Title III of the federal superfund Amendment and Reauthorization Act and similar state laws and regulations require information be maintained about hazardous materials used or produced in operations and this information be provided to employees, state and local governmental authorities and citizens.

Human Capital

Employees and Labor Relations

As of December 31, 2021, we employed 1,254 people, all of which were employed in the United States, with 721 employees being located at our corporate headquarters in Oklahoma City, Oklahoma and 533 employees located in our field offices located in Oklahoma, North Dakota, South Dakota, Montana, Wyoming, and Texas. None of our employees are subject to collective bargaining agreements. We believe our overall relations with our workforce are good.

Compensation

Because we operate in a highly competitive environment, we have designed our compensation program to attract, retain and motivate experienced, talented individuals. Our program is also designed to align employee's interests with those of our shareholders and to reward them for achieving the business and strategic objectives determined to be important to help the Company create and maintain advantage in a competitive environment. We align our employee's interests with those of our shareholders by making annual restricted stock awards to virtually all of our employees. We reward our employees for their performance in helping the Company achieve its annual business and strategic objectives through our bonus program, which is also available to virtually all of our employees. In order to ensure our compensation package remains competitive and fulfills our goal of recruiting and retaining talented employees, we consider competitive market compensation paid by other companies comparable to the Company in size, geographic location, and operations.

Safety

Safety is our highest priority and one of our core values. We promote safety with a robust health and safety program that includes employee orientation and training, contractor management, risk assessments, hazard identification and mitigation, audits, incident reporting and investigation, and corrective/preventative action development.

Through our "Brother's Keeper" program, we encourage each of our employees to be a proactive participant in ensuring the safety of all of the Company's personnel. We developed this program to leverage and continuously improve our ability to identify and prevent reoccurrence of unsafe behaviors and conditions. This program recognizes and rewards Company employees and contractors who observe and report outstanding safety and environmental behavior such as utilizing stop work authority, looking out for a co-worker, reporting incidents and near misses, or following proper safety procedures. This program positively impacts safety culture and performance and has contributed to a substantial increase in our reporting rates and to decreases in recordable incident and lost time incident rates. Our Total Recordable Incident Rate (TRIR), a commonly used safety metric that measures the number of recordable incidents per 100 full-time employees and contractors during a one year period, has decreased sequentially in each of the past four years and measured 0.33 for 2021, a 61% decrease compared to 2017.

Training and Development

We are committed to the training and development of our employees. We believe that supporting our employees in achieving their career and development goals is a key element of our approach to attracting and retaining top talent. We have invested in a variety of resources to support employees in achieving their career and development goals, including developing learning paths for individual contributors and leaders, operating the Continental Leadership Learning Center which offers numerous instructor-led programs designed to foster employee development and maintaining a learning management system which provides access to numerous technical and soft skills online courses. We also invest time and resources in supporting the creation of individual development plans for our employees.

Health and Wellness

We offer various benefit programs designed to promote the health and well-being of our employees and their families. These benefits include medical, dental, and vision insurance plans; disability and life insurance plans; paid time off for holidays, vacation, sick leave, and other personal leave; and healthcare flexible spending accounts, among other things. In addition to these programs, we have a number of other programs designed to further promote the health and wellness of our employees. For

instance, employees at our corporate headquarters have access to our fitness center. Additionally, we have an employee assistance program that offers counseling and referral services for a broad range of personal and family situations. We also offer a wellness plan that includes annual biometric screenings, flu shots, smoking cessation programs, and healthy snack options in our break rooms to encourage total body wellness.

From the earliest days of the COVID-19 pandemic we have taken, and continue to take, proactive measures to protect the health and safety of our employees, both at work and at home. These measures have included offering free in-office testing, providing flexible work schedules for impacted employees, holding in-office vaccination clinics so that interested employees and household members could conveniently receive vaccinations as soon as possible, maintaining physical distancing policies, limiting the number of employees attending meetings, reducing the number of people at our sites, requiring the use of masks in certain circumstances, frequently and extensively disinfecting common areas, and implementing self-isolation and quarantine requirements, among other things. We are committed to maintaining best practices with our COVID-19 response protocols and will continue to work under the guidance of public health officials to ensure a safe workplace as long as COVID-19 remains a threat to our employees and communities.

Diversity and Inclusion

We are committed to providing a diverse and inclusive workplace and career development opportunities to attract and retain talented employees. We prohibit discrimination and harassment of any type and afford equal employment opportunities to employees and applicants without regard to race, color, religion, sex, national origin, age, disability, genetic information, veteran status, or any other basis protected by local, state, or federal law. We also maintain a robust compliance program rooted in our Code of Business Conduct and Ethics, which provides policies and guidance on non-discrimination, anti-harassment, and equal employment opportunities.

We believe embracing diversity and inclusion is more than a matter of compliance. We recognize and appreciate the importance of creating an environment in which all employees feel valued, included, and empowered to do their best work and bring great ideas to the table. We believe a diverse and inclusive workforce provides the best opportunity to obtain unique perspectives, experiences, ideas, and solutions to help sustain our business success; a diverse and inclusive culture is the high-performance fuel that enhances our ability to innovate, execute and grow. To that end, we have begun implementing a long-term initiative for enhancing awareness of, and continuously improving our approach to, building and sustaining a diverse and inclusive culture. We have chartered a Diversity and Inclusion Committee comprised of employees across all company functions. We have engaged external training resources for our entire workforce, including interview training for hiring managers focused on ensuring a fair and systematic approach for recruiting and selecting individuals from diverse backgrounds for competitive job openings. We are intentional about proactively conducting outreach and recruitment at job fairs and other events hosted by diverse organizations. We are working with our newly formed Diversity and Inclusion Committee to provide new opportunities for our leadership and all employees to hold targeted discussions on issues related to diversity and inclusion, such as unconscious bias, disability inclusion, and equality through inclusive interaction. We are committed to continuous improvement in this critical area, evaluating more ways to sustain and strengthen our diverse and inclusive workforce.

Company Contact Information

Our corporate internet website is www.clr.com. Through the investor relations section of our website, we make available free of charge our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the SEC. For a current version of various corporate governance documents, including our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for various committees of our Board of Directors, please see our website. We intend to disclose amendments to, or waivers from, our Code of Business Conduct and Ethics by posting to our website. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

We intend to use our website as a means of disclosing material information and for complying with our disclosure obligations under SEC Regulation FD. Such disclosures will be included on our website in the “Investors” section. Accordingly, investors should monitor that portion of our website in addition to following our press releases, SEC filings and public conference calls and webcasts.

We electronically file periodic reports and proxy statements with the SEC. The SEC maintains an internet website that contains reports, proxy and information statements, and other information registrants file with the SEC. The address of the SEC’s website is www.sec.gov.

Our principal executive offices are located at 20 N. Broadway, Oklahoma City, Oklahoma 73102, and our telephone number at that address is (405) 234-9000.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all other information contained in this report in connection with an investment in our securities. If any of the following risks develop into actual events, our business, financial condition, results of operations, or cash flows could be materially adversely affected, the trading price of our securities could decline and you may lose all or part of your investment.

Business and Operating Risks

Substantial declines in commodity prices or extended periods of low commodity prices adversely affect our business, financial condition, results of operations and cash flows and our ability to meet our capital expenditure needs and financial commitments.

The prices we receive for sales of our crude oil and natural gas production impact our revenue, profitability, cash flows, access to capital, capital budget, rate of growth, and carrying value of our properties. Crude oil and natural gas are commodities and prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for crude oil and natural gas have been volatile and unpredictable and commodity prices will likely remain volatile in the future. Our future crude oil production and a portion of our future natural gas production is unhedged as of the time of this filing and is exposed to continued volatility in market prices, whether favorable or unfavorable.

The prices we receive for sales of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide, domestic, and regional economic conditions impacting the supply of, and demand for, crude oil, natural gas, and natural gas liquids;
- the actions of the Organization of Petroleum Exporting Countries and other petroleum producing nations;
- the nature, extent, and impact of domestic and foreign governmental laws, regulations, and taxation, including environmental laws and regulations governing the imposition of trade restrictions and tariffs;
- executive, regulatory or legislative actions by Congress, the Biden Administration, or states in which we operate;
- geopolitical events and conditions, including domestic political uncertainty or foreign regime changes that impact government energy policies;
- the level of global, national, and regional crude oil and natural gas exploration and production activities;
- the level of global, national, and regional crude oil and natural gas inventories, which may be impacted by economic sanctions applied to certain producing nations;
- the level and effect of speculative trading in commodity futures markets;
- the relative strength of the United States dollar compared to foreign currencies;
- the price and quantity of imports of foreign crude oil;
- the price and quantity of exports of crude oil or liquefied natural gas from the United States;
- military and political conditions in, or affecting other, crude oil-producing and natural gas-producing nations;
- localized supply and demand fundamentals;
- the cost and availability, proximity and capacity of transportation, processing, storage and refining facilities for various quantities and grades of crude oil, natural gas, and natural gas liquids;
- adverse climatic conditions, natural disasters, and national and global health epidemics and concerns, including the COVID-19 pandemic;
- technological advances affecting energy production and consumption;
- the effect of worldwide energy conservation and greenhouse gas emission limitations or other environmental protection efforts;
- the impact arising from increasing attention to environmental, social, and governance (“ESG”) matters; and
- the price and availability of alternative fuels or other energy sources.

Sustained material declines in commodity prices reduce cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; may limit our ability to borrow money or raise additional capital; and may reduce our proved reserves and the amount of crude oil and natural gas we can economically produce.

In addition to reducing our revenue, cash flows and earnings, depressed prices for crude oil and/or natural gas may adversely affect us in a variety of other ways. If commodity prices decrease substantially, some of our exploration and development projects could become uneconomic, and we may also have to make significant downward adjustments to our estimated proved reserves and our estimates of the present value of those reserves. If these price effects occur, or if our estimates of production or economic factors change, accounting rules may require us to write down the carrying value of our crude oil and/or natural gas properties.

Lower commodity prices may also lead to reductions in our drilling and completion programs, which may result in insufficient production to satisfy our transportation and processing commitments. If production is not sufficient to meet our commitments we would incur deficiency fees that would need to be paid absent any cash inflows generated from the sale of production.

Lower commodity prices may also reduce our access to capital and lead to a downgrade or other negative rating action with respect to our credit rating. A downgrade of our credit rating could negatively impact our cost of capital, increase borrowing costs under our revolving credit facility, and limit our ability to access capital markets and execute aspects of our business plans. As a result, substantial declines in commodity prices or extended periods of low commodity prices may materially and adversely affect our future business, financial condition, results of operations, cash flows, liquidity and ability to meet our capital expenditure needs and commitments.

The ability or willingness of Saudi Arabia and other members of OPEC, and other oil exporting nations, including Russia, to set and maintain production levels has a significant impact on crude oil prices.

The Organization of Petroleum Exporting Countries ("OPEC") is an intergovernmental organization that seeks to manage the price and supply of crude oil on the global energy market. Actions taken by OPEC members, including those taken alongside other oil exporting nations such as Russia, may have a significant impact on global oil supply and pricing. There can be no assurance that OPEC members and other oil exporting nations will comply with agreed-upon production targets, agree to further production targets in the future, or utilize other actions to support and stabilize oil prices, nor can there be any assurance they will not increase production or deploy other actions aimed at reducing oil prices. Uncertainty regarding future actions to be taken by OPEC members or other oil exporting countries could lead to increased volatility in the price of oil, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our business operations, financial position, results of operations, and cash flows have been and may continue to be materially and adversely affected by the COVID-19 pandemic.

The ongoing COVID-19 pandemic has negatively impacted, and may continue to negatively impact, the global economy which has led to, among other things, reduced global demand for crude oil, disruption of global supply chains, and significant volatility and disruption of financial and commodity markets. The adverse effects of COVID-19 have included and may in the future include the following:

- Reduced crude oil prices;
- Limitations on storage and transportation capacity and an inability to market our production;
- Curtailment or shutting in of production;
- Delay or cessation of drilling and completion projects;
- Insufficient production to satisfy transportation and processing commitments;
- Impairment of assets;
- Downgrades or other negative credit rating actions resulting in increased borrowing costs;
- An inability to develop acreage before lease expiration;
- A reduction in the volume and value of proved reserves from price declines, changes in drilling programs, and the effects of shutting in production;
- Increased difficulty in our ability to repay or refinance indebtedness, increase our credit facility commitments, borrow money, or raise capital;
- Disruptions in energy industry supply chains and increased rates of inflation;

- Credit losses due to insolvency of customers, joint interest owners, and counterparties;
- Cyber incidents or information security breaches resulting in information theft, data corruption, operational disruption, and/or financial loss as a consequence of employees accessing information from remote work locations; and
- Shortages of drilling rigs, well completion crews, field services, personnel, and equipment in future periods of commodity price recovery.

The future impact of the pandemic on global and local economies and our business will continue to depend on future developments such as the emergence of future variant strains of COVID-19, the availability and distribution of effective medical treatments and vaccines, vaccination rates, as well as government-imposed restrictions or mandates, all of which are uncertain and cannot be predicted.

Drilling for and producing crude oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Our future financial condition and results of operations depend on the success of our exploration, development and production activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells may be uncertain before drilling commences.

In this report, we describe some of our current prospects and plans to develop our key operating areas. Our management has specifically identified prospects and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations is subject to a number of risks and uncertainties as described herein. If future drilling results do not establish sufficient reserves to achieve an economic return, we may curtail our drilling and completion activities. Prospects we decide to drill that do not produce crude oil or natural gas in expected quantities may adversely affect our results of operations, financial condition, and rates of return on capital employed. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether crude oil or natural gas will be present in expected or economically producible quantities. We cannot assure you the wells we drill will be as productive as anticipated or whether the analogies we draw from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects. Because of these uncertainties, we do not know if our potential drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations in sufficient quantities to achieve an economic return.

Risks we face while drilling include, but are not limited to, failing to place our well bore in the desired target producing zone; not staying in the desired drilling zone while drilling horizontally through the formation; failing to run our casing the entire length of the well bore; and not being able to run tools and other equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages; failing to run tools the entire length of the well bore during completion operations; not successfully cleaning out the well bore after completion of the final fracture stimulation stage; increased seismicity in areas near our completion activities; unintended interference of completion activities performed by us or by third parties with nearby operated or non-operated wells being drilled, completed, or producing; and failure of our optimized completion techniques to yield expected levels of production.

Further, many factors may occur that cause us to curtail, delay or cancel scheduled drilling and completion projects, including but not limited to:

- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment or qualified personnel;
- shortages of or delays in obtaining components used in fracture stimulation processes such as water and proppants;
- delays associated with suspending our operations to accommodate nearby drilling or completion operations being conducted by other operators;
- mechanical difficulties, fires, explosions, equipment failures or accidents, including ruptures of pipelines or storage facilities, or train derailments;
- restrictions on the use of underground injection wells for disposing of waste water from oil and gas activities;

- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- decreases in, or extended periods of low, crude oil and natural gas prices;
- title problems;
- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- adverse climatic conditions and natural disasters;
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by us or by third party service providers;
- limitations in infrastructure, including transportation, processing, refining and exportation capacity, or markets for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements including permitting.

Any of the above risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations;
- repair and remediation costs; and
- litigation.

We are not insured against all risks associated with our business. We may elect to not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented or for other reasons. In addition, pollution and environmental risks are generally not fully insurable.

Losses and liabilities arising from any of the above events could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations and cash flows.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated crude oil and natural gas reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The Company's current estimates of reserves could change, potentially in material amounts, in the future due to changes in commodity prices, business strategies, and other factors. Additionally, unless we replace our crude oil and natural gas reserves, our total reserves and production will decline, which could adversely affect our cash flows and results of operations.

The process of estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions, production rates, drilling and operating expenses, and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves* for information about our estimated crude oil and natural gas reserves, standardized measure of discounted future net cash flows, and PV-10 as of December 31, 2021.

In order to prepare reserve estimates, we must project production rates and the amount and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data in preparing reserve estimates. The extent, quality and reliability of this data can vary which in turn can affect our ability to model the porosity, permeability and pressure relationships in unconventional resources. The process also requires economic assumptions, based on historical data projected into the future, about crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds.

Actual future production, crude oil and natural gas sales prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves will vary and could vary significantly from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves, which in turn could have an adverse effect on the value of our assets. In addition, we may remove or adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development activities, changes in business strategies, prevailing crude oil and natural gas prices and other factors, some of which are beyond our control.

You should not assume the present value of future net revenues from our proved reserves is the current market value of our estimated crude oil and natural gas reserves. We base the estimated discounted future net revenues from proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future prices may be materially higher or lower than the average prices used in the calculations. In addition, the use of a 10% discount factor, which is required by the SEC to be used to calculate discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil and natural gas industry. For the year ended December 31, 2021, average prices used to calculate our estimated proved reserves were \$66.56 per Bbl for crude oil and \$3.60 per MMBtu for natural gas (\$62.19 per Bbl for crude oil and \$3.46 per Mcf for natural gas adjusted for location and quality differentials). NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2022 and February 1, 2022 averaged \$81.71 per barrel and \$4.65 per MMBtu, respectively. See *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserves, Standardized Measure, and PV-10 Sensitivities* for proved reserve sensitivities under certain increasing and decreasing commodity price scenarios.

In addition, the development of our proved undeveloped reserves may take longer than anticipated and may not be ultimately developed or produced. At December 31, 2021, approximately 45% of our total estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions may not prove to be accurate. Our reserve report at December 31, 2021 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately \$7.7 billion. We cannot be certain the estimated costs of the development of these reserves are accurate, development will occur as scheduled, or the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves as a result of our inability to fund necessary capital expenditures or otherwise, we will be required to remove the associated volumes from our reported proved reserves. Proved undeveloped reserves generally must be drilled within five years from the date of initial booking under SEC reserve rules. Changes in the timing of development plans that impact our ability to develop such reserves in the required time frame have resulted, and will likely in the future result, in fluctuations in reserves between periods as reserves booked in one period may need to be removed in a subsequent period. In 2021, 57 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates associated with locations no longer scheduled to be drilled within five years from the date of initial booking due to the continual refinement of our drilling and development programs and reallocation of capital to areas providing the best opportunities to improve efficiencies, recoveries, and rates of return.

Additionally, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. If we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 37% of our total net undeveloped acreage at December 31, 2021. At that date, we had leases representing 83,937 net acres expiring in 2022, 62,251 net acres expiring in 2023, and 51,094 net acres expiring in 2024.

Furthermore, unless we conduct successful exploration, development and exploitation activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flows and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations could be materially adversely affected.

Our business depends on crude oil and natural gas transportation, processing, refining, and export facilities, most of which are owned by third parties.

The value we receive for our crude oil and natural gas production depends in part on the availability, proximity and capacity of gathering, pipeline and rail systems and processing, refining, and export facilities owned by third parties. The inadequacy or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells, the delay or

discontinuance of development plans for properties, or higher operational costs associated with air quality compliance controls. Although we have some contractual control over the transportation of our products, changes in these business relationships or failure to obtain such services on acceptable terms could adversely affect our operations. If our production becomes shut-in for any of these or other reasons, we will be unable to realize revenue from those wells until other arrangements are made for the sale or delivery of our products and acreage lease terminations could result if production is shut-in for a prolonged period.

The disruption of transportation, processing, refining, or export facilities due to contractual disputes or litigation, labor disputes, maintenance, civil disturbances, international trade disputes, public protests, terrorist attacks, cyber attacks, adverse climatic events, natural disasters, seismic events, health epidemics and concerns, changes in tax and energy policies, federal, state and international regulatory developments, changes in supply and demand, equipment failures or accidents, including pipeline and gathering system ruptures or train derailments, and general economic conditions could negatively impact our ability to achieve the most favorable prices for our crude oil and natural gas production. We have no control over when or if access to such facilities would be restored or the impact on prices in the areas we operate. A significant shut-in of production in connection with any of the aforementioned items could materially affect our cash flows, and if a substantial portion of the impacted production fulfills transportation or processing commitments or is hedged at lower than market prices, those commitments or financial hedges would have to be paid from borrowings in the absence of sufficient operating cash flows.

Our operated crude oil and natural gas production is ultimately transported to downstream market centers in the United States primarily using transportation facilities and equipment owned and operated by third parties. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for a discussion of regulations impacting the transportation of crude oil and natural gas. From time to time we may sell our operated crude oil production at market centers in the United States to third parties who then subsequently export and sell the crude oil in international markets. We do not currently own or operate infrastructure used to facilitate the transportation and exportation of crude oil; however, third party compliance with regulations that impact the transportation or exportation of our production may increase our costs of doing business and inhibit a third party's ability to transport and sell our production, whether domestically or internationally, the consequences of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In response to a July 2020 U.S. District Court decision vacating the U.S. Army Corps of Engineers ("Corps") grant of an easement to the Dakota Access Pipeline ("DAPL") and issuance of an order requiring the Corps to conduct an Environmental Impact Statement ("EIS") for the pipeline, the Corps is currently conducting the court-ordered environmental review to determine whether DAPL poses a threat to the drinking water supply of the Standing Rock Sioux Reservation. DAPL currently remains in operation and, while the owners of DAPL appealed the District Court decision to the U.S. Supreme Court in September 2021, the Corps continues to conduct the review, which is estimated to be completed no later than November 2022. Once the review is completed, the Corps will determine whether DAPL is safe to operate or must be shut down. There has not been any decision on whether the U.S. Supreme Court will hear the appeal and we are unable to determine the outcome or the impact on DAPL in the future.

We utilize DAPL to transport a portion of our North region crude oil production to ultimate markets on the U.S. gulf coast. Our transportation commitment on the pipeline increased from 3,550 barrels per day to 30,000 barrels per day effective August 1, 2021 in conjunction with the completion of a DAPL expansion project. This commitment will continue through February 2026 at which time the commitment decreases to 26,450 barrels per day through July 2028.

If transportation capacity on DAPL becomes restricted or unavailable, we have the ability to utilize other third party pipelines or rail facilities to transport our Bakken crude oil production to market, although such alternatives may be more costly. A restriction of DAPL's takeaway capacity may have an impact on prices for Bakken-produced barrels and result in wider differentials relative to WTI benchmark prices in the future, the amount of which is uncertain.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on acceptable terms, which could lead to a decline in our crude oil and natural gas reserves, production and revenues.

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. We have budgeted \$2.30 billion for capital expenditures attributable to us in 2022, excluding acquisitions, of which approximately \$1.80 billion is allocated to exploration and development activities. We may adjust our 2022 capital spending plans upward or downward depending on market conditions. Our 2022 capital budget, based on our current expectations of commodity prices and costs, is expected to be funded from operating cash flows. However, the sufficiency of our cash flows from operations is subject to a number of variables, including but not limited to:

- the prices at which crude oil and natural gas are sold;

- the volume of our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell from existing wells; and
- our ability to acquire, locate and produce new reserves;

If oil and gas industry conditions weaken as a result of low commodity prices or other factors, we may not be able to generate sufficient cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or planned levels. A decline in cash flows from operations may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities.

We have a revolving credit facility with lender commitments totaling \$2.0 billion that matures in October 2026. In the future, we may not be able to access adequate funding under our revolving credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments under the credit facility. Our lenders could decline to increase their commitments based on our financial condition, the financial condition of our industry or the economy as a whole or for other reasons beyond our control. Due to these and other factors, we cannot be certain that funding, if needed, will be available to the extent required or on terms we find acceptable. If operating cash flows are insufficient and we are unable to access funding or execute capital transactions when needed on acceptable terms, we may not be able to fully implement our business plans, fund our capital program and commitments, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due. Should any of the above risks occur, they could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The unavailability or high cost of drilling rigs, well completion crews, water, equipment, supplies, personnel and field services could adversely affect our ability to execute our exploration and development plans within budget and on a timely basis.

In the regions in which we operate, there have been shortages of drilling rigs, well completion crews, equipment, personnel, field services, and supplies, including key components used in fracture stimulation processes such as water and proppants, as well as high costs associated with these critical components of our operations. With current technology, water is an essential component of drilling and hydraulic fracturing processes. The availability of water sources and disposal facilities is becoming increasingly competitive, constrained, subject to social and regulatory scrutiny, and impacted by third-party supply chains over which we may have limited control. Limitations or restrictions on our ability to secure, transport, and use sufficient amounts of water, including limitations resulting from natural causes such as drought, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling or completion sites, resulting in increased costs.

The demand for qualified and experienced field service providers and associated equipment, supplies, and materials can fluctuate significantly, often in correlation with commodity prices or supply chain disruptions, causing periodic shortages and/or higher costs. For instance, recent supply chain disruptions stemming from the COVID-19 pandemic have led to shortages of certain materials and equipment and increased costs. While we have not yet experienced material shortages in supply as a result of these disruptions, if they become prolonged or expand in scope the resulting shortages or higher costs could delay the execution of our drilling and development plans or cause us to incur expenditures not provided for in our capital budget or to not achieve the rates of return we are targeting for our development program, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in new or emerging areas are more uncertain than drilling results in developed and producing areas. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage in the emerging areas may decline if drilling results are unsuccessful.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an ownership interest are operated by other companies and involve third-party working interest owners. As of December 31, 2021, non-operated properties represented 14% of our estimated proved developed reserves, 7% of our estimated proved undeveloped reserves, and 11% of our estimated total proved reserves. We have limited ability to influence or control the operations or future development of non-operated properties, including the

marketing of oil and gas production, compliance with environmental, occupational safety and health and other regulations, or the amount of expenditures required to fund the development and operation of such properties. Moreover, we are dependent on other working interest owners on these projects to fund their contractual share of capital and operating expenditures. These limitations and our dependence on the operators and other working interest owners for these projects could cause us to incur unexpected future costs and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may be subject to risks in connection with acquisitions, divestitures, and joint development arrangements.

As part of our business strategy, we have made and expect to continue making acquisitions of oil and gas properties, divest assets, and enter into joint development arrangements. The successful acquisition of oil and gas properties requires an assessment of several factors, including but not limited to:

- reservoir modeling and evaluation of recoverable reserves;
- future crude oil and natural gas prices and location and quality differentials;
- the quality of the title to acquired properties;
- the ability to access future drilling locations;
- availability and cost of gathering, processing, and transportation facilities;
- availability and cost of drilling and completion equipment and of skilled personnel;
- future development and operating costs and potential environmental and other liabilities; and
- regulatory, permitting and similar matters.

The accuracy of these acquisition assessments is inherently uncertain. In connection with these assessments, we perform a review, which we believe to be generally consistent with industry practices, of the subject properties. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities prior to acquisition. Inspections may not always be performed on every property, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller of the subject properties may be unwilling or unable to provide effective contractual protection against all or part of the problems. We sometimes are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Significant acquisitions and other strategic transactions may involve other risks that may impact our business, including:

- diversion of our management’s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired assets and operations with our preexisting assets and operations while carrying on our ongoing business; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

As a result of our 2021 property acquisitions in the Permian Basin and Powder River Basin, the size and geographic footprint of our business has increased, and into new jurisdictions. Our future success will depend, in part, on our ability to manage our expanded business, which may pose challenges including those related to the management and monitoring of new operations and basins and associated increased costs and complexity. We believe these acquisitions will complement our business strategies by delivering enhanced free cash flows, corporate returns, and shareholder value, among other things. However, the anticipated benefits of the transactions may be less significant than expected or may take longer to achieve than anticipated. If we are not able to achieve these objectives and realize the anticipated benefits within anticipated timing or at all, our business, financial condition and operating results may be adversely affected.

In addition, from time to time we may sell or otherwise dispose of certain assets as a result of an evaluation of our asset portfolio or to provide cash flow for use in reducing debt and enhancing liquidity. Such divestitures have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets, and potential post-closing adjustments and claims for indemnification. Additionally, volatility and unpredictability in commodity prices may result in fewer potential bidders, unsuccessful sales efforts, and a higher risk that buyers may seek to terminate a transaction prior to

closing. The occurrence of any of the matters described above could have an adverse impact on our business, financial condition, results of operations and cash flows.

Volatility in the financial markets or in global economic conditions, including consequences resulting from domestic political uncertainty, geopolitical events, international trade disputes and tariffs, and health epidemics could adversely impact our business.

United States and global economies may experience periods of volatility and uncertainty from time to time, resulting in unstable consumer confidence, diminished consumer demand and spending, diminished liquidity and credit availability, and inability to access capital markets. In recent years, certain global economies have experienced periods of political uncertainty, slowing economic growth, rising interest rates, changing economic sanctions, health-related concerns, and currency volatility. These global macroeconomic conditions may have a negative impact on commodity prices and the availability and cost of materials used in our industry, which in turn could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In recent years, the United States government has initiated new tariffs on certain imported goods and has imposed increases to certain existing tariffs on imported goods. In response, certain foreign governments, most notably China, imposed retaliatory tariffs on certain goods their countries import from the United States. These and other events, including the United Kingdom's withdrawal from the European Union and the COVID-19 pandemic, have contributed to increased uncertainty for domestic and global economies. Additionally, growing trends toward populism and political polarization globally and in the U.S. have resulted in uncertainty regarding potential changes in regulations, fiscal policy, social programs, domestic and foreign relations, and government energy policies, which could pose a potential threat to domestic and global economic growth.

Trade restrictions or other governmental actions related to tariffs or trade policies have impacted, and have the potential to further impact, our business and industry by increasing the cost of materials used in various aspects of upstream, midstream, and downstream oil and gas activities. Furthermore, tariffs and any quantitative import restrictions, particularly those impacting the cost and availability of steel and aluminum, may cause disruption in the energy industry's supply chain, resulting in the delay or cessation of drilling and completion efforts or the postponement or cancellation of new pipeline transportation projects the U.S. industry is relying on to transport its onshore production to market, as well as endangering U.S. liquefied natural gas export projects resulting in negative impacts on natural gas production. Additionally, trade and/or tariff disputes have impacted, and have the potential to further impact, domestic and global economies overall, which could result in reduced demand for crude oil and natural gas. Any of the above consequences could have a material adverse effect on our business, financial condition, results of operations and cash flows.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

Our business and industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We rely heavily on digital technologies, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data; analyze seismic, drilling, completion and production information; manage production equipment; conduct reservoir modeling and reserves estimation; communicate with employees and business associates; perform compliance reporting and many other activities. The availability and integrity of these systems are essential for us to conduct our operations. Our business associates, including employees, vendors, service providers, financial institutions, and transporters, processors, and purchasers of our production are also heavily dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates have been and continue to be the target of cyber attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release or theft of confidential or protected information, corruption of data or other disruptions of our business operations. For example, there have been well-publicized cases in recent years involving cyber attacks on software vendors utilized by the Company. In response to those incidents, we deployed our cybersecurity incidence response protocols and promptly took steps to contain and remediate potential vulnerabilities. We believe there have been no compromises to our operations as a result of the attacks; however, other similar attacks in the future could have a significant negative impact on our systems and operations.

A cyber attack involving our information systems and related infrastructure, and/or that of our business associates and customers, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to unauthorized access to, or theft of, sensitive or proprietary information and data corruption or operational disruption that adversely affects our ability to carry on our business. Any such event could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability, which could have a material adverse effect on our business, financial condition, results of operations or cash flows. In addition, certain cyber incidents such as reconnaissance of our

systems and those of our business associates, may remain undetected for an extended period, which could result in significant consequences. We do not maintain specialized insurance for possible liability resulting from cyber attacks due to lack of coverage for what we consider sensitive and proprietary data.

While the Company has well-established cyber security systems and controls, disclosure controls and procedures and incident response protocols, these systems, controls, procedures and protocols may not identify all risks and threats we face, or may fail to protect data or mitigate the adverse effects of data loss.

To our knowledge we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of a breach of our systems or those of our business associates. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the growth of cyber attacks has resulted in evolving legal and compliance matters which may impose significant costs that are likely to increase over time.

Competition in the crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude oil and natural gas and secure trained personnel.

Our ability to acquire additional prospects and find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, securing long-term transportation and processing capacity, marketing crude oil and natural gas, and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for productive crude oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our inability to effectively compete in this environment could have a material adverse effect on our financial condition, results of operations and cash flows.

Severe climatic events and natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe climatic events and natural disasters such as hurricanes, tornadoes, seismic events, floods, blizzards, extreme cold, drought, and ice storms affecting the areas in which we operate, including our corporate headquarters, could cause disruptions and in some cases suspension of our or our third party service providers' operations, which could have a material adverse effect on our business. Climate changes could result in increased frequency and severity of these climatic events, as well as chronic shifts in temperature and precipitation patterns. The consequences of such events may include the evacuation of personnel; damage to and disruption of production equipment, drilling rigs, or gathering, transportation, processing, storage, refining, and export facilities; delivery stoppages by third party vendors upon whom we rely upon for goods and services; the shut-in of production resulting from an inability to transport crude oil or natural gas products to market centers and other factors; an inability to access well sites; destruction of information and communication systems; and the disruption of administrative and management processes, any of which could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations or cash flows. Our planning for normal climatic variation, insurance programs and emergency recovery plans may inadequately mitigate the effects of such climatic conditions, and not all such effects can be predicted, eliminated or insured against. Longer term changes in temperature and precipitation patterns may result in changes to the amount, timing, or location of demand for energy or our production. While our consideration of changing climatic conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities abroad and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that infrastructure we rely on could be a direct target or an indirect casualty of an act of terrorism. Any of these events could materially and adversely affect our business and results of operations.

Financial Risks

Our derivative activities could result in financial losses or reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in commodity prices, from time to time we may enter into derivative instruments for a potentially significant portion of our production. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 6. Derivative Instruments* for a summary of our commodity derivative positions as of December 31, 2021. Additionally, see *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Derivative Instruments* for a summary of additional derivative instruments entered into subsequent to December 31, 2021. We do not designate our derivative instruments as hedges for accounting purposes and we record all derivatives on our balance sheet at fair value. Changes in the fair value of derivatives are recognized in earnings. Accordingly, our earnings may fluctuate materially as a result of changes in commodity prices and resulting changes in the fair value of any outstanding derivatives.

Derivative instruments expose us to the risk of financial loss in certain circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, derivative arrangements limit the benefit we would otherwise receive from increases in commodity prices. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to hedge future production if the pricing environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to settle derivative positions prior to the expiration of their contractual maturities.

Our revolving credit facility and indentures for our senior notes contain certain covenants and restrictions that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our goals.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our revolving credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. At December 31, 2021, we had \$500 million of outstanding borrowings on our credit facility and our consolidated net debt to total capitalization ratio, as defined, was 0.43.

The indentures governing our senior notes contain covenants that, among other things, limit our ability to create liens securing certain indebtedness, enter into certain sale and leaseback transactions, and consolidate, merge or transfer certain assets.

The covenants in our revolving credit facility and senior note indentures may restrict our ability to expand or pursue our business strategies. Our ability to comply with the provisions of our revolving credit facility or senior note indentures may be impacted by changes in economic or business conditions, results of operations, or events beyond our control. The breach of any covenant could result in a default under our revolving credit facility or senior note indentures, in which case, depending on the actions taken by the lenders or trustees thereunder or their successors or assignees, could result in all amounts outstanding thereunder, together with accrued interest, to be due and payable. If our indebtedness is accelerated, our assets may not be sufficient to repay in full such indebtedness, which would have a material adverse effect our business, financial condition, results of operations, and cash flows.

The inability of joint interest owners, significant customers, and service providers to meet their obligations to us may adversely affect our financial results.

Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies (\$1.1 billion in receivables at December 31, 2021) and our joint interest and other receivables (\$279 million at December 31, 2021). These counterparties may experience insolvency or liquidity issues and may not be able to meet their obligations and liabilities owed to us, particularly during a period of depressed commodity prices. Defaults by these counterparties could adversely impact our financial condition and results of operations.

Additionally, we rely on field service companies and midstream companies for services associated with the drilling and completion of wells and for certain midstream services. A worsening of the commodity price environment may result in a material adverse impact on the liquidity and financial position of the parties with whom we do business, resulting in delays in payment of, or non-payment of, amounts owed to us, delays in operations, loss of access to equipment and facilities and similar impacts. These events could have an adverse impact on our business, financial condition, results of operations and cash flows.

Legal and Regulatory Risks

Laws, regulations, guidance, executive actions or other regulatory initiatives regarding environmental protection and occupational safety and health could increase our costs of doing business and result in operating restrictions, delays, or cancellations in the drilling and completion of crude oil and natural gas wells, which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our crude oil and natural gas exploration and production operations are subject to stringent federal, state and local legal requirements governing environmental protection and occupational safety and health. These requirements may take the form of laws, regulations, executive actions and various other legal initiatives. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for a discussion of those environmental and occupational safety and health legal requirements that govern us, including with respect to air emissions, including natural gas flaring limitations and ozone standards; climate change, including restriction of methane or other greenhouse gas emissions and suspensions of, or more stringent limitations upon, new leasing and permitting on federal lands and waters; hydraulic fracturing; waste water disposal regulatory developments; occupational safety standards, and other risks or regulations relating to environmental protection. One or more of these legal requirements could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We are subject to certain complex federal, state and local laws and regulations in areas other than environmental protection and occupational safety and health that could result in increased costs, operating restrictions or delays, limitations or prohibitions on our ability to develop and produce reserves, or expose us to significant liabilities.

Our crude oil and natural gas exploration and production operations are subject to complex and stringent federal, state and local laws and regulations in areas other than environmental protection and occupational safety and health, including with respect to production, sales and transport of crude oil, NGLs and natural gas, and employees and labor relations. Following is a discussion of certain significant laws, rules and regulations that affect us in these areas in which we operate. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for further discussion of the regulations that affect us.

Taxation of oil and gas activities—President Biden's administration is pursuing legislative changes to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and gas exploration and production companies, including: (i) the elimination of deductions for intangible drilling and exploration and development costs; (ii) a repeal of the percentage depletion allowance for crude oil and natural gas properties; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is uncertain whether these or other changes being pursued will be enacted or, if enacted, how soon any such changes would become effective. The passage of such legislation or any other similar change in U.S. federal income tax law could adversely affect our business, financial condition, results of operations and cash flows.

Dodd-Frank Act derivative regulations—In 2010, the U.S. Congress adopted the Dodd-Frank Act, which, among other provisions, established federal oversight and regulation of the over-the-counter derivatives market. If we do not qualify for an end user exemption from the Dodd-Frank Act requirements, the regulations could increase the cost of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, lead to fewer potential counterparties, and increase our exposure to less creditworthy counterparties, any of which could limit our desire and ability to implement commodity price risk management strategies. Certain other regulations, including regulations related to capital requirements, which are yet to be implemented, may have an effect that results in the reduction of the number of products and counterparties in the over-the-counter derivatives market available to us and could result in significant additional costs being passed through to us. If our use of derivatives becomes limited as a result of the regulations, our results of operations may become more volatile and our cash flows may be less predictable. Aspects of the Dodd-Frank rulemaking have been finalized in certain areas, but other areas have not been finalized or implemented and the ultimate effect of these regulations on our business remains uncertain.

Failure to comply with the above and other laws and regulations may trigger a variety of administrative, civil and criminal enforcement investigations or actions, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, the issuance of orders or judgments limiting or enjoining future operations, criminal sanctions, or litigation. Moreover, changes to existing laws or regulations or changes in interpretations of laws and regulations may unfavorably impact us or the infrastructure used for transporting our products. Similarly, changes in regulatory policies and

priorities, including those in response to the January 2021 change in U.S. presidential administrations and shift in control of Congress, could result in the imposition of new laws or regulations that adversely impact us or our industry. Any such changes could increase our operating costs, delay our operations or otherwise alter the way we conduct our business, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Our operations and the operations of our customers are subject to a number of risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce the demand for the crude oil and natural gas we produce.

Risks arising out of the threat of climate change, fuel conservation measures, governmental requirements for renewable energy resources, increasing consumer demand for alternative forms of energy, and technological advances in fuel economy and energy generation devices may create new competitive conditions that result in reduced demand for the crude oil and natural gas we produce. The potential impact of changing demand for crude oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows. Additionally, variability in power generation output from alternative energy facilities that are dependent on weather conditions, such as wind and solar, may result in intermittent changes in demand for the commodities we produce which could lead to increased volatility in commodity prices. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for further discussion relating to risks arising out of the threat of climate change and emission of greenhouse gases, climate change activism, energy conservation measures, initiatives that stimulate demand for alternative forms of energy, and physical effects of climate change. One or more of these developments could have an adverse effect on our assets and operations.

We are involved in legal proceedings that could result in substantial liabilities.

Like other similarly-situated oil and gas companies, we are, from time to time, involved in various legal proceedings in the ordinary course of business including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities, and other matters. The outcome of such legal matters often cannot be predicted with certainty. We vigorously defend ourselves in all such matters. However, if our efforts to defend ourselves are not successful, it is possible the outcome of one or more such proceedings could result in substantial liability, penalties, sanctions, judgments, consent decrees, or orders requiring a change in our business practices, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Judgments and estimates to determine accruals related to legal and other proceedings could change from period to period, and such changes could be material.

Increasing scrutiny on environmental, social, and corporate governance matters may impact our business.

Companies across all industries are facing increasing scrutiny from stakeholders related to their ESG practices. ESG standards are evolving and if we are perceived to have not responded appropriately to certain standards, regardless of whether there is a legal requirement to do so, we may suffer from reputational damage and our business, financial condition, and/or stock price could be materially and adversely affected. Increasing attention to climate change, increasing societal expectations on companies to address climate change, and potential consumer use of alternative forms of energy may result in increased costs, reduced demand for hydrocarbon products, reduced profits, increased investigations and litigation, and negative impacts on our stock price, our ability to recruit necessary talent, and our access to capital markets.

In addition, 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. Currently, there are no universal standards for such scores or ratings and, in fact, different standards focus, to varying degrees, on different attributes of environmental, social, and corporate governance matters. This disparity between the “standards” may result in investors focusing on inadequate or improper metrics which may lead to a misperception of a company and its ESG practices. Conversely, pressures to create more uniformity among these “standards” may result in a skewed and potentially misplaced focus on certain factors over other, equally valuable factors. For example, of the 17 United Nations Sustainability Goals, the vast majority fall within the societal component, but many sustainability “standards” provide little weight to these goals, instead emphasizing the environmental component. Nonetheless, the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. ESG ratings are used by some investors to inform their investment and voting decisions. Additionally, certain investors use these scores to benchmark companies against their peers, and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company’s sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of our stock from consideration by certain investment funds, engagement by investors seeking to improve such scores, and a negative perception of our operations by certain investors.

Risks Related to our Corporate Structure

Our Chairman of the Board and members of his family beneficially own approximately 82% of our outstanding common stock, giving them influence and control in corporate transactions and other matters, including a sale of our Company.

As of December 31, 2021, Harold G. Hamm, our Chairman of the Board, and members of his family, beneficially owned approximately 82% of our outstanding common shares. As a result, Mr. Hamm and his family have control over our Company and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. Therefore, Mr. Hamm and his family could cause, delay or prevent a change of control of our Company. The interests of Mr. Hamm and his family may not coincide with the interests of other holders of our common stock.

We have historically entered into, and may enter into, transactions from time to time with companies or persons affiliated with Mr. Hamm and his family, if, after an independent review by our Audit Committee or by the independent members of our Board of Directors, it is determined such transactions are in the Company's best interests and are on terms no less favorable to us than could be achieved with an unaffiliated third party. These transactions may result in conflicts of interest between Mr. Hamm's affiliated parties and us.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2021.

Item 2. Properties

The information required by Item 2 is contained in *Part I, Item 1. Business—Crude Oil and Natural Gas Operations* and *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Delivery Commitments* and is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, we do not expect them to have a material effect on our financial condition, results of operations or cash flows.

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

Our common stock is listed on the New York Stock Exchange and trades under the symbol "CLR." As of February 2, 2022, the number of record holders of our common stock was 1,269. On February 2, 2022, after inquiry, management believes that the number of beneficial owners of our common stock is 79,854. On February 2, 2022, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was \$55.08 per share.

In May 2019, our Board of Directors approved the initiation of a dividend payment program. On February 9, 2022, the Company declared a quarterly cash dividend of \$0.23 per share on its outstanding common stock, which will be paid on March 4, 2022 to shareholders of record as of February 22, 2022. The Company intends to continue paying a quarterly dividend; however, any payment of future dividends will be at the discretion of our Board of Directors and will depend on, among other things, our future earnings, financial condition, cash flows, capital requirements, levels of indebtedness, prevailing business conditions and other considerations our Board of Directors may deem relevant.

The following table provides information about purchases of our common stock during the quarter ended December 31, 2021:

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (1)	Maximum dollar value of shares that may yet be purchased under the plans or programs (in millions) (1)
October 1, 2021 to October 31, 2021				
Repurchases for tax withholdings (2)	11,288	\$ 52.13	—	\$ —
November 1, 2021 to November 30, 2021				
Repurchases for tax withholdings (2)	41,154	\$ 49.36	—	\$ —
Share repurchase program (1)	1,102,682	\$ 46.30	1,102,682	\$ 566.5
Purchases by principal shareholder (3)	108,500	\$ 47.69	—	\$ —
December 1, 2021 to December 31, 2021				
Share repurchase program (1)	179,820	\$ 42.33	179,820	\$ 558.9
Purchases by principal shareholder (3)	367,020	\$ 43.82	—	\$ —
Total for the quarter	1,810,464	\$ 45.59	1,282,502	

- (1) In May 2019 our Board of Directors approved the initiation of a share repurchase program to acquire up to \$1 billion of our common stock beginning in June 2019 at times and levels deemed appropriate by management. The program was announced on June 3, 2019 and does not have a set expiration date. As of December 31, 2021, the total dollar value of shares that may yet be purchased under the original program totaled \$558.9 million. On February 8, 2022, our Board of Directors approved an increase in the size of the share repurchase program to \$1.5 billion, inclusive of cumulative amounts repurchased to date. As of the date of this filing, we have repurchased a cumulative \$441.1 million of our common stock. Accordingly, the total dollar value of shares that may yet be purchased now totals approximately \$1.06 billion under the modified program. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.
- (2) Amounts represent shares surrendered by employees to cover tax liabilities in connection with the vesting of restricted stock granted under the Company's 2013 Long-Term Incentive Plan. We paid the associated taxes to the applicable taxing authorities. The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.
- (3) Represents shares of our common stock purchased in open market transactions by Harold G. Hamm, our Chairman of the Board and principal shareholder.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2021 relating to equity compensation plans:

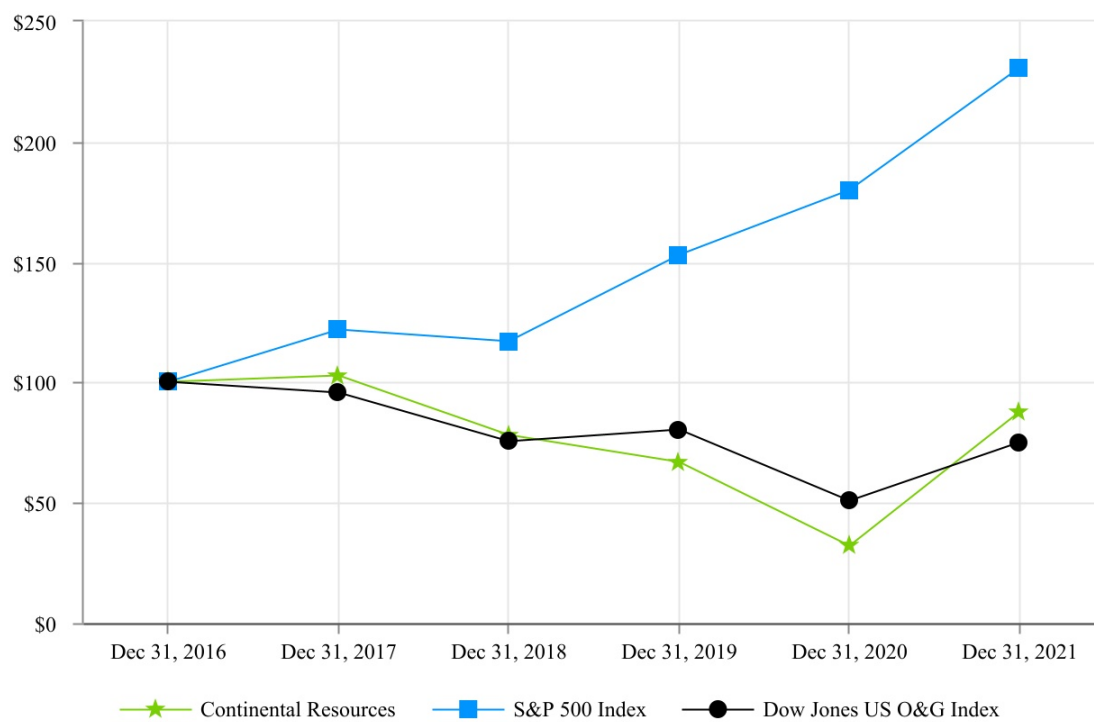
	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	8,492,645
Equity Compensation Plans Not Approved by Shareholders	—	—	—

(1) Represents the remaining shares available for issuance under the 2013 Plan.

Performance Graph

The following graph compares our common stock performance with the performance of the Standard & Poor's 500 Stock Index ("S&P 500 Index") and the Dow Jones US Oil and Gas Index ("Dow Jones US O&G Index") for the period of December 31, 2016 through December 31, 2021. The graph assumes the value of the investment in our common stock and in each index was \$100 on December 31, 2016 and that any dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.



ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes included elsewhere in this report. Results attributable to noncontrolling interests are not material relative to consolidated results and are not separately presented or discussed below.

The following discussion and analysis includes forward-looking statements and should be read in conjunction with *Part I, Item 1A. Risk Factors* in this report, along with *Cautionary Statement for the Purpose of the “Safe Harbor” Provisions of the Private Securities Litigation Reform Act of 1995* at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development, management, and production of crude oil and natural gas and associated products. Additionally, we pursue the acquisition and management of perpetually owned minerals located in our key operating areas. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas and expect this to continue in the future. We are the largest leaseholder and the largest producer in the Bakken field of North Dakota and Montana. We also have significant positions in the SCOOP and STACK plays in Oklahoma and recently acquired positions in the Permian Basin of Texas and Powder River Basin of Wyoming. Our common stock trades on the New York Stock Exchange under the symbol “CLR” and our corporate internet website is www.clr.com.

2021 Highlights

Financial and operating highlights for 2021 are summarized below. Our 2021 results underscore our continued focus on maximizing cash flow generation, maintaining low-cost capital efficient operations in an environmentally responsible manner, achieving consistent asset performance, and delivering capital and corporate returns to shareholders.

- Generated \$1.25 billion in operating cash flows in the fourth quarter, bringing year-to-date operating cash flows to a Company record \$3.97 billion;
- Completed strategic acquisitions to expand our operations into the Permian Basin for cash consideration of \$3.06 billion and the Powder River Basin for cash consideration totaling \$453 million;
- Sequentially increased our quarterly fixed dividend throughout year, paying \$166 million of dividends in 2021 with an additional \$82 million of declared dividends to be paid in the first quarter of 2022;
- Repurchased 3.2 million shares of common stock in 2021 under our share repurchase program at an aggregate cost of \$124 million; and
- Continued to maintain low cost operations with production expenses averaging \$3.38 per Boe for 2021.

With our acquisitions in the Permian Basin and Powder River Basin in 2021 we now have substantial strategic positions in four leading basins in the United States, providing our Company and shareholders with enhanced geologic and geographic diversity and commodity optionality. We believe these transactions will be accretive on financial metrics and will complement our existing deep portfolio of assets in the Bakken and Oklahoma. We expect enhanced cash flows from the acquisitions will provide continued support for additional returns to shareholders via debt reduction, dividend increases, share repurchases, and increased returns on capital employed. See *Part I, Item 1. Business—Acquisition Activities* and *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions* for additional information on the acquisitions.

Financial and Operating Metrics

Our operating results for 2020 were severely impacted by the economic effects from the COVID-19 pandemic on crude oil demand and prices. In response to the significant reduction in crude oil prices during 2020, we curtailed approximately 55% of our operated crude oil production and associated natural gas in the 2020 second quarter and significantly reduced our capital spending. In July 2020 we began to gradually restore our curtailed production and subsequently brought our remaining curtailed production back online in September 2020. These actions resulted in material reductions in our production, revenues, and cash flows for 2020.

Crude oil and natural gas prices have increased significantly in 2021 compared to 2020 levels in response to the lifting of COVID-19 restrictions, the resumption of normal economic activity, and the resulting improvement in supply and demand fundamentals. The increase in commodity prices and resumption of our operations resulted in significantly improved operating results in 2021 compared to 2020 as further described below.

The following table contains financial and operating highlights for the periods presented. Average net sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

The previously described Permian Basin acquisition closed on December 21, 2021 and thus had a limited impact on fourth quarter and full year 2021 operating results given our short duration of ownership. The acquired Permian assets contributed 460 MBoe of production (42,000 Boe per day on average of which 78% was oil), \$29.4 million of revenues, and \$14.1 million (\$0.04 per basic and diluted share) of net income to our consolidated results during the period of ownership from December 21, 2021 to December 31, 2021.

	Year ended December 31,		
	2021	2020	2019
Average daily production:			
Crude oil (Bbl per day)	160,647	160,505	197,991
Natural gas (Mcf per day)	1,014,000	837,509	854,424
Crude oil equivalents (Boe per day)	329,647	300,090	340,395
Average net sales prices: (1)			
Crude oil (\$/Bbl)	\$ 64.06	\$ 34.71	\$ 51.82
Natural gas (\$/Mcf)	\$ 4.88	\$ 1.04	\$ 1.77
Crude oil equivalents (\$/Boe)	\$ 46.24	\$ 21.47	\$ 34.56
Crude oil net sales price discount to NYMEX (\$/Bbl)	\$ (4.00)	\$ (5.80)	\$ (5.15)
Natural gas net sales price premium (discount) to NYMEX (\$/Mcf)	\$ 1.00	\$ (1.10)	\$ (0.86)
Production expenses (\$/Boe)	\$ 3.38	\$ 3.27	\$ 3.58
Production taxes (% of net crude oil and natural gas sales)	7.3 %	8.2 %	8.3 %
DD&A (\$/Boe)	\$ 15.76	\$ 17.12	\$ 16.25
Total general and administrative expenses (\$/Boe)	\$ 1.94	\$ 1.79	\$ 1.57

(1) See the subsequent section titled *Non-GAAP Financial Measures* for a discussion and calculation of net sales prices, which are non-GAAP measures.

Results of Operations

The following table presents selected financial and operating information for the periods presented.

<i>In thousands, except sales price data</i>	Year Ended December 31,		
	2021	2020	2019
Crude oil and natural gas sales	\$ 5,793,741	\$ 2,555,434	\$ 4,514,389
Gain (loss) on derivative instruments, net	(128,864)	(14,658)	49,083
Crude oil and natural gas service operations	54,441	45,694	68,475
Total revenues	5,719,318	2,586,470	4,631,947
Operating costs and expenses	(3,257,638)	(3,140,362)	(3,374,535)
Other expenses, net	(275,542)	(220,859)	(270,250)
Income (loss) before income taxes	2,186,138	(774,751)	987,162
(Provision) benefit for income taxes	(519,730)	169,190	(212,689)
Net income (loss)	1,666,408	(605,561)	774,473
Net income (loss) attributable to noncontrolling interests	5,440	(8,692)	(1,168)
Net income (loss) attributable to Continental Resources	\$ 1,660,968	\$ (596,869)	\$ 775,641
Diluted net income (loss) per share attributable to Continental Resources	\$ 4.56	\$ (1.65)	\$ 2.08
Production volumes:			
Crude oil (MBbl)	58,636	58,745	72,267
Natural gas (MMcf)	370,110	306,528	311,865
Crude oil equivalents (MBoe)	120,321	109,833	124,244
Sales volumes:			
Crude oil (MBbl)	58,757	58,793	72,136
Natural gas (MMcf)	370,110	306,528	311,865
Crude oil equivalents (MBoe)	120,442	109,881	124,113

Year ended December 31, 2021 compared to the year ended December 31, 2020

Below is a discussion of changes in our results of operations for 2021 compared to 2020. A discussion of changes in our results of operations for 2020 compared to 2019 has been omitted from this Form 10-K, but may be found in *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Form 10-K for the year ended December 31, 2020 as filed with the SEC on February 16, 2021.

Production

The following table summarizes the changes in our average daily Boe production by major operating area for the periods presented.

<i>Boe production per day</i>	Fourth Quarter			Year Ended December 31,		
	2021	2020	% Change	2021	2020	% Change
Bakken	175,585	183,141	(4 %)	169,636	158,604	7 %
Oklahoma	146,131	149,341	(2 %)	147,249	134,506	9 %
Powder River Basin	7,189	—	— %	5,161	—	— %
Permian Basin (1)	4,997	—	— %	1,260	—	— %
All other	6,266	6,825	(8 %)	6,341	6,980	(9 %)
Total	340,168	339,307	— %	329,647	300,090	10 %

- (1) The presentation of average daily production represents production during the period from the closing of our acquisition of Permian properties on December 21, 2021 through December 31, 2021 averaged over the respective fourth quarter and full year periods. At the time of closing, our Permian properties produced on average approximately 42,000 Boe per day based on two-stream reporting.

The following tables reflect our production by product and region for the periods presented.

	Year Ended December 31,				Volume increase (decrease)	Volume percent increase (decrease)
	2021		2020			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	58,636	49 %	58,745	53 %	(109)	— %
Natural gas (MMcf)	370,110	51 %	306,528	47 %	63,582	21 %
Total (MBoe)	120,321	100 %	109,833	100 %	10,488	10 %

	Year Ended December 31,				Volume increase	Volume percent increase
	2021		2020			
	MBoe	Percent	MBoe	Percent		
North Region	66,105	55 %	60,591	55 %	5,514	9 %
South Region	54,216	45 %	49,242	45 %	4,974	10 %
Total	120,321	100 %	109,833	100 %	10,488	10 %

Over the past year we increased our allocation of capital to gas-weighted projects to capitalize on improvements in market prices for natural gas and natural gas liquids. These actions contributed to an increase in our natural gas production as a percentage of total production and led to a 21% increase in natural gas production in 2021 compared to 2020. Natural gas production in Oklahoma increased 37,345 MMcf, or 18%, and natural gas production in the Bakken increased 23,122 MMcf, or 23%, over the prior year. Additionally, properties acquired in the Powder River Basin in March and November 2021 added 2,517 MMcf to our natural gas production, while properties acquired in the Permian Basin added 614 MMcf during the short duration of our ownership of the properties in late 2021.

Our crude oil production was flat in 2021 compared to 2020 resulting from our change in allocation of capital from oil-weighted projects to gas-weighted projects over the past year and the timing of well completions. Crude oil production in the Bakken was flat between years, while oil production in Oklahoma decreased 1,708 MBbls, or 12%, compared to 2020. This decrease was offset by new production added from our 2021 acquisitions. Properties acquired in the Powder River Basin in March and November 2021 added 1,464 MBbls to our crude oil production, while properties acquired in the Permian Basin added 357 MBbls during the short duration of our ownership of the properties in late 2021.

Revenues

Our revenues consist of sales of crude oil and natural gas, gains and losses resulting from changes in the fair value of our derivative instruments, and revenues associated with crude oil and natural gas service operations.

Net crude oil and natural gas sales and related net sales prices presented below are non-GAAP measures. See the subsequent section titled *Non-GAAP Financial Measures* for discussion and calculation of these measures.

Net crude oil and natural gas sales. Net crude oil and natural gas sales for 2021 totaled \$5.57 billion, a 136% increase compared to net sales of \$2.36 billion for 2020 due to significant increases in net sales prices and natural gas sales volumes as discussed below.

Total sales volumes for 2021 increased 10,561 MBoe, or 10%, compared to 2020, reflecting reduced sales in the prior period from the previously described production curtailments in the second and third quarters of 2020 and our subsequent resumption of usual operations. For 2021, our crude oil sales volumes were flat compared to 2020, while our natural gas sales volumes increased 21% driven by our increased allocation of capital toward gas-weighted projects over the past year.

Our crude oil net sales prices averaged \$64.06 per barrel for 2021, an increase of 85% compared to \$34.71 per barrel for 2020 due to a significant increase in market prices driven by improved supply and demand fundamentals along with improved price differentials. The differential between NYMEX West Texas Intermediate calendar month crude oil prices and our realized crude oil net sales prices averaged \$4.00 per barrel in 2021 compared to \$5.80 per barrel in 2020. Crude oil prices for 2020 were severely impacted by adverse changes in supply and demand fundamentals from the economic effects of the COVID-19 pandemic, which negatively impacted location differentials and price realizations in the 2020 period with no similar impacts in 2021.

Our natural gas net sales prices averaged \$4.88 per Mcf for 2021 compared to \$1.04 per Mcf for 2020 due to a significant increase in market prices and improved price differentials. The difference between our net sales prices and NYMEX Henry Hub calendar month natural gas prices was a premium of \$1.00 per Mcf for 2021 compared to a discount of \$1.10 per Mcf for 2020.

In February 2021, severe winter weather and freezing temperatures in the southern United States led to a period of increased spot prices for residue natural gas that resulted in a significant improvement in our price realizations in the 2021 first quarter compared to the prior year. Additionally, prices for natural gas liquids have increased significantly in 2021 compared to 2020 levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream. For the fourth quarter of 2021, the difference between our net sales prices and NYMEX Henry Hub prices was a premium of \$0.49 per Mcf.

Derivatives. The significant improvement in commodity prices in 2021 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of \$128.9 million for the year, representing \$149.7 million of cash losses partially offset by \$20.8 million of unsettled non-cash gains. For 2020, we recognized negative revenue adjustments of \$14.7 million resulting from changes in market prices that had an unfavorable impact on the fair value of our derivatives.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities, which are impacted by our production volumes and the timing and extent of our drilling and completion projects. Revenues associated with such activities increased \$8.7 million, or 19%, from \$45.7 million for 2020 to \$54.4 million for 2021 due to increased water handling activities resulting from increases in completion activities and production volumes compared to 2020.

Operating Costs and Expenses

Production expenses. Production expenses increased \$47.6 million, or 13%, to \$406.9 million for 2021 compared to \$359.3 million for 2020 primarily due to the previously described 10% increase in total sales volumes. Production expenses on a per-Boe basis averaged \$3.38 per Boe for 2021, consistent with \$3.27 per Boe for 2020.

Production taxes. Production taxes increased \$211.6 million, or 110%, to \$404.4 million for 2021 compared to \$192.7 million for 2020 due to the previously described increase in crude oil and natural gas sales partially offset by a decrease in our average production tax rate. Our production taxes as a percentage of net crude oil and natural gas sales decreased to 7.3% for 2021 compared to 8.2% for 2020 primarily resulting from an increase in the proportion of our revenues being generated in Oklahoma in the current period, which has lower production tax rates compared to North Dakota.

Depreciation, depletion, amortization and accretion (“DD&A”). Total DD&A amounted to \$1.90 billion for 2021, consistent with \$1.88 billion for 2020, reflecting a 10% increase in total sales volumes the impact of which was nearly offset by a decrease in our DD&A rate per Boe as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

\$/Boe	Year ended December 31,			
	2021		2020	
Crude oil and natural gas properties	\$	15.45	\$	16.84
Other equipment		0.22		0.19
Asset retirement obligation accretion		0.09		0.09
Depreciation, depletion, amortization and accretion	\$	15.76	\$	17.12

Estimated proved reserves are a key component in our computation of DD&A expense. Proved reserves are determined using the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months as required by SEC rules. Holding all other factors constant, if proved reserves are revised downward due to commodity price declines or other reasons, the rate at which we record DD&A expense increases. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense decreases.

Our proved reserves were revised upward in 2021 prompted by significant increases in first-day-of-the-month commodity prices and other factors, which resulted in a decrease in our DD&A rate for crude oil and natural gas properties in the current period. As a result of these upward revisions, our DD&A rate decreased to \$14.34 per Boe for the 2021 fourth quarter compared to \$19.01 per Boe for the 2020 fourth quarter, the impact of which helped offset higher DD&A recognized in 2021 from increased sales volumes.

NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2022 and February 1, 2022 averaged \$81.71 per barrel and \$4.65 per MMBtu, respectively, which are notably higher than average prices in 2021. If commodity prices remain at current levels for an extended period, additional upward price-related revisions of proved reserves may occur in the future, which may be significant and could result in a further decrease in our DD&A rate relative to the 2021 fourth quarter. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property impairments. Property impairments decreased \$239.6 million to \$38.4 million for 2021 compared to \$277.9 million for 2020, primarily reflecting lower proved property impairments in the current period. No proved property impairments were recognized in 2021 as estimated future net cash flows were determined to be in excess of cost basis due to improved commodity prices, while proved property impairments totaled \$207.1 million in 2020. Additionally, impairments of unproved properties decreased \$32.5 million in 2021 compared to 2020 reflecting a decrease in the amortization of undeveloped leasehold costs from changes in management's estimates of properties not expected to be developed before lease expiration in response to significantly improved commodity prices compared to the prior year. Our unamortized balance of unproved properties increased significantly in late 2021 in connection with our 2021 fourth quarter property acquisitions and now totals \$1.36 billion at December 31, 2021. Accordingly, our amortized impairments of unproved property costs are expected to increase in 2022 relative to 2021 levels, the amount of which is uncertain.

General and administrative ("G&A") expenses. G&A expenses increased \$37.0 million, or 19%, to \$233.6 million for 2021 compared to \$196.6 million for 2020.

Total G&A expenses include non-cash charges for equity compensation of \$63.2 million and \$64.6 million for 2021 and 2020, respectively. G&A expenses other than equity compensation totaled \$170.4 million for 2021, an increase of \$38.4 million, or 29%, compared to \$132.0 million for 2020 due to an increase in employee benefits partially offset by higher overhead recoveries from joint interest owners driven by increased drilling, completion, and production activities compared to 2020.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

\$/Boe	Year ended December 31,			
	2021		2020	
General and administrative expenses	\$	1.42	\$	1.20
Non-cash equity compensation		0.52		0.59
Total general and administrative expenses	\$	1.94	\$	1.79

Acquisition costs. We incurred \$13.9 million of expenses in connection with our December 2021 acquisition of properties in the Permian Basin, which are reflected in the caption "Acquisition costs" in the consolidated statements of comprehensive income (loss) for 2021.

Interest expense. Interest expense decreased \$6.6 million, or 3%, to \$251.6 million for 2021 compared to \$258.2 million for 2020 due to a decrease in our annual weighted average outstanding debt from \$5.8 billion in 2020 to \$5.6 billion in 2021. Our outstanding debt totaled \$6.8 billion at December 31, 2021, reflecting an increase of \$2.1 billion in the 2021 fourth quarter due to credit facility and senior note borrowings incurred to fund a portion of our December 2021 acquisition of properties in the Permian Basin.

Gain (loss) on extinguishment of debt. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Long-Term Debt* for discussion of gains and losses recognized on debt extinguishments in 2021 and 2020.

Other non-operating expense. As discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Commitments and Contingencies—Pledge commitment*, we recognized a \$25.0 million charge to earnings upon execution of an irrevocable ten-year pledge commitment in December 2021, which is reflected in the caption "Other income (expense)—Other" in the consolidated statements of comprehensive income (loss) for 2021.

Income Taxes. For 2021 and 2020 we provided for income taxes at a combined federal and state tax rate of 24.5% of pre-tax income/loss. We recorded an income tax provision of \$519.7 million and an income tax benefit of \$169.2 million for 2021 and 2020, respectively, which resulted in effective tax rates of 23.8% and 21.8%, respectively, after taking into account the application of statutory tax rates, permanent taxable differences, tax effects from equity compensation, changes in valuation allowances, and other items. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Income Taxes* for a summary of the sources and tax effects of items comprising our income tax provision and resulting effective tax rates for 2021 and 2020.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt securities. Additionally, asset dispositions and joint development arrangements have provided a source of cash flow for use in reducing debt and enhancing liquidity. We are committed to operating in a responsible manner to preserve financial flexibility, liquidity, and the strength of our balance sheet.

At January 31, 2022, we had approximately \$1.76 billion of borrowing availability under our credit facility after considering outstanding borrowings and letters of credit, which represents a \$260 million increase in availability compared to year-end 2021. Our credit facility, which is unsecured and has no borrowing base subject to redetermination, does not mature until October 2026.

Based on our planned capital spending, including our pending property acquisition described below, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility and senior note indentures. Further, based on current market indications, we expect to meet our contractual cash commitments to third parties subsequently described under the heading *Future Capital Requirements*, recognizing we may be required to meet such commitments even if our business plan assumptions were to change. We monitor our capital spending closely based on actual and projected cash flows and have the ability to reduce spending or dispose of assets if needed to preserve liquidity and financial flexibility to fund our operations.

Cash Flows

Cash flows from operating activities

Net cash provided by operating activities increased \$2.55 billion, or 179%, to \$3.97 billion for 2021 compared to \$1.42 billion for 2020 primarily due to a \$3.24 billion increase in crude oil and natural gas revenues due to the previously described increases in commodity prices and natural gas sales volumes in the current period. This increase was partially offset by a \$211.6 million increase in production taxes associated with higher crude oil and natural gas revenues and a \$121.5 million increase in realized cash losses on matured commodity derivatives in the current period. Additionally, we experienced an increase in certain cash operating expenses primarily due to an increase in total sales volumes, which included a \$47.6 million increase in production expenses and a \$28.3 million increase in transportation expenses.

Cash flows used in investing activities

Net cash used in investing activities totaled \$4.99 billion and \$1.51 billion for 2021 and 2020, respectively, the \$3.48 billion increase of which reflects our 2021 property acquisition activities discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions*.

Cash flows from financing activities

Net cash provided by financing activities for 2021 totaled \$989.1 million, primarily consisting of \$1.59 billion of net proceeds received from our November 2021 issuances of senior notes and \$340 million of net credit facility borrowings incurred to fund a portion of our December 2021 Permian Basin acquisition. These increases were partially offset by \$630.8 million of senior note redemptions during the year, \$123.9 million of cash used to repurchase shares of our common stock, and \$165.9 million of cash dividends paid on common stock.

Net cash provided by financing activities for 2020 totaled \$97.1 million, primarily resulting from \$1.48 billion of net proceeds received from our November 2020 issuance of senior notes due 2031, \$105.0 million of net credit facility borrowings, and net proceeds of \$26.0 million from term loans executed during 2020. These increases were partially offset by \$1.34 billion of senior note repurchases and redemptions during 2020 using available cash and proceeds from our issuance of 2031 Notes, \$25.2 million of premiums and costs paid upon the redemptions and repurchases, \$126.9 million of cash used to repurchase shares of our common stock, and \$18.5 million of cash dividends paid on common stock.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our cash balance, and availability under our credit facility should be sufficient to meet our normal operating needs, debt service obligations, budgeted capital expenditures, the pending property acquisition described below, cash payments for income taxes, and dividend payments for at least the next 12 months and to meet our contractual cash commitments to third parties described under the heading *Future Capital Requirements* beyond 12 months.

Based on current market indications, our budgeted capital spending plans for 2022 are expected to be funded from operating cash flows. Any deficiencies in operating cash flows relative to budgeted spending are expected to be funded by borrowings under our credit facility. If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our credit facility if needed to fund our operations and business plans.

We may choose to access banking or capital markets for additional financing or capital to fund our operations or take advantage of business opportunities that may arise. Further, we may sell assets or enter into strategic joint development opportunities in order to obtain funding if such transactions can be executed on satisfactory terms. However, no assurance can be given that such transactions will occur.

Credit facility

We have an unsecured credit facility, maturing in October 2026, with aggregate lender commitments totaling \$2.0 billion. The commitments are from a syndicate of 12 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of January 31, 2022, we had \$1.76 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit.

The commitments under our credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants. Downgrades of our credit rating will, however, trigger increases in our credit facility's interest rates and commitment fees paid on unused borrowing availability under certain circumstances.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Long-Term Debt* for a discussion of how this ratio is calculated pursuant to our credit agreement.

We were in compliance with our credit facility covenants at December 31, 2021 and expect to maintain compliance. At December 31, 2021, our consolidated net debt to total capitalization ratio was 0.43. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing if needed to support our business.

Future Capital Requirements

Our material future cash requirements are summarized below. Based on current market indications, we expect to meet our contractual cash commitments to third parties as of December 31, 2021, recognizing we may be required to meet such commitments even if our business plan assumptions were to change.

Senior notes

Our debt includes outstanding senior note obligations totaling \$6.36 billion at December 31, 2021, exclusive of interest payment obligations thereon. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. The earliest scheduled senior note maturity is our \$649.6 million of 2023 Notes due in April 2023. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to *Note 8. Long-Term Debt* in *Part II, Item 8. Notes to Consolidated Financial Statements*.

We were in compliance with our senior note covenants at December 31, 2021 and expect to maintain compliance. We do not believe the senior note covenants will materially limit our ability to undertake additional debt financing. Downgrades or other negative rating actions with respect to the credit ratings assigned to our senior unsecured debt do not trigger additional senior note covenants.

Credit facility borrowings

As of January 31, 2022, we had \$240 million of outstanding borrowings on our credit facility, which represents a decrease of \$260 million compared to \$500 million outstanding at year-end 2021. Our credit facility matures in October 2026.

Transportation, gathering, and processing commitments

We have entered into transportation, gathering, and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities that require us to pay per-unit charges regardless of the amount of capacity used. Future commitments remaining as of December 31, 2021 under the arrangements amount to approximately \$1.31 billion. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Commitments and Contingencies* for additional information.

Capital Expenditures

2021 Capital Spending

For the year ended December 31, 2021, we invested \$1.54 billion in our capital program excluding \$3.58 billion of unbudgeted acquisitions, excluding \$21.3 million of mineral acquisitions attributable to Franco-Nevada, and including \$114.1 million of capital costs associated with increased accruals for capital expenditures as compared to December 31, 2020. Our 2021 capital

expenditures were allocated as follows by quarter. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions* for discussion of our notable property acquisitions executed in 2021.

<i>In millions</i>	1Q 2021	2Q 2021	3Q 2021	4Q 2021	Total 2021
Exploration and development drilling	\$ 255.6	\$ 216.2	\$ 312.3	\$ 382.6	\$ 1,166.7
Land costs	7.5	14.5	18.5	111.1	151.6
Mineral acquisitions attributable to Continental	0.2	1.3	1.5	2.9	5.9
Capital facilities, workovers, water infrastructure, and other corporate assets	27.4	57.3	51.0	68.4	204.1
Seismic	2.7	0.2	0.4	9.2	12.5
Capital expenditures attributable to Continental, excluding unbudgeted acquisitions	\$ 293.4	\$ 289.5	\$ 383.7	\$ 574.2	\$ 1,540.8
Acquisitions of producing properties (1)	183.3	(5.4)	0.3	2,390.3	2,568.5
Acquisitions of non-producing properties (1)	24.3	18.7	3.0	967.5	1,013.5
Total unbudgeted acquisitions	207.6	13.3	3.3	3,357.8	3,582.0
Total capital expenditures attributable to Continental	501.0	302.8	387.0	3,932.0	5,122.8
Mineral acquisitions attributable to Franco-Nevada	0.9	2.8	6.0	11.6	21.3
Total capital expenditures	501.9	305.6	393.0	3,943.6	5,144.1

(1) Fourth quarter amounts primarily represent our December 2021 Permian Basin acquisition. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 2. Property Acquisitions and Dispositions* for additional information.

2022 Capital Budget

In 2022, we will remain committed to operating in a disciplined, capital-efficient manner to maximize cash flow generation and capital and corporate returns to shareholders. Our 2022 capital budget is expected to be allocated as reflected in the table below. Acquisition expenditures are not budgeted, with the exception of planned levels of spending for mineral acquisitions made in conjunction with our relationship with Franco-Nevada.

<i>In millions</i>	2022 Budget
Exploration and development	\$ 1,800
Land costs	127
Mineral acquisitions attributable to Continental (1)	23
Capital facilities, workovers, water infrastructure, and other corporate assets	344
Seismic	6
2022 capital budget attributable to Continental	\$ 2,300
Mineral acquisitions attributable to Franco-Nevada (1)	91
Total 2022 capital budget (2)	\$ 2,391

(1) Represents planned spending for mineral acquisitions by TMRC II under our relationship with Franco-Nevada Corporation. Continental holds a controlling financial interest in TMRC II and therefore consolidates the financial results and capital expenditures of the entity. With a carry structure in place, Continental will fund 20% of 2022 planned spending, or \$23 million, and Franco-Nevada will fund the remaining 80%, or \$91 million.

(2) Excludes the \$450 million purchase price for our pending acquisition of properties in the Powder River Basin discussed below under the caption *Pending Property Acquisition*.

Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling and completion results, operational process improvements, the availability of drilling and completion rigs and other services and equipment, cost inflation, the availability of transportation, gathering and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our spending should commodity prices materially decrease from current levels.

Pending Property Acquisition

As discussed in *Note 20. Subsequent Events in Part II, Item 8. Notes to Consolidated Financial Statements*, on January 24, 2022, we executed a definitive agreement to acquire oil and gas properties in the Powder River Basin for \$450 million of cash, subject to customary closing price adjustments. The properties include approximately 172,000 net leasehold acres and producing properties with production totaling approximately 16,000 barrels of oil equivalent per day based on two-stream reporting. Closing of the acquisition is expected to occur in late March 2022 and remains subject to the completion of customary due diligence procedures and closing conditions.

We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at attractive terms.

Cash Payments for Income Taxes

As of February 10, 2022, the publicly available forward commodity strip prices for the remainder of 2022 averaged \$83.38 per barrel for crude oil and \$4.09 per Mcf for natural gas. If commodity prices remain at these levels for the year, we could potentially utilize the full amount of our federal net operating loss carryforwards and certain state net operating loss carryforwards and generate significant taxable income in 2022, which could result in us making cash payments for income taxes in the upcoming year. Because of the significant uncertainty inherent in numerous factors utilized in projecting taxable income, including future commodity prices, production levels, development activities, capital spending, profitability, and general economic conditions, we cannot predict the amount of future income tax payments with certainty, but such payments could be significant.

Dividend Declaration

On February 9, 2022, the Company declared a quarterly cash dividend of \$0.23 per share on its outstanding common stock, which will be paid on March 4, 2022 to shareholders of record as of February 22, 2022.

Delivery Commitments

We have various natural gas volume delivery commitments that are related to our North and South areas. We expect to primarily fulfill our contractual obligations with production from our proved reserves. However, we may purchase third-party volumes to satisfy our commitments. The volumes disclosed herein represent gross production associated with properties operated by us and do not reflect our net proportionate share of such amounts. Additionally, in the South region certain of our firm sales contracts for oil include delivery commitments that specify the delivery of a fixed and determinable quantity. We expect to primarily fulfill our contractual obligations with production from our proved reserves. As of December 31, 2021, we were committed to deliver the following fixed quantities of natural gas production.

Year Ending December 31,	Natural Gas Bcf	Crude Oil MMBo
2022	146	13
2023	84	13
2024	73	3
2025	18	—
2026	15	—

Derivative Instruments

See *Note 6. Derivative Instruments in Part II, Item 8. Notes to Consolidated Financial Statements* for discussion of our hedging activities, including a summary of derivative contracts in place as of December 31, 2021. Between January 1, 2022 and February 10, 2022 we entered into additional derivative instruments as summarized in the tables below.

Natural gas derivatives

Period and Type of Contract	Average Volumes Hedged	Weighted Average Hedge Price (\$/MMBtu)		
		Swaps	Floor	Ceiling
April 2022 - September 2022				
Swaps - Henry Hub	200,000 MMBtus/day	\$ 4.03		
April 2022 - September 2022				
Collars - Henry Hub	110,000 MMBtus/day		\$ 4.50	\$ 6.00
July 2022 - December 2022				
Swaps - WAHA	45,000 MMBtus/day	\$ 3.41		
October 2022 - March 2023				
Collars - Henry Hub	210,000 MMBtus/day		\$ 4.12	\$ 5.52
January 2023 - December 2023				
Swaps - WAHA	40,000 MMBtus/day	\$ 2.69		
April 2023 - September 2023				
Swaps - Henry Hub	100,000 MMBtus/day	\$ 3.25		
October 2023 - March 2024				
Collars - Henry Hub	100,000 MMBtus/day		\$ 3.14	\$ 4.00
April 2024 - December 2024				
Swaps - Henry Hub	100,000 MMBtus/day	\$ 3.11		

Crude oil derivatives

Period and Type of Contract	Average Volumes Hedged	Weighted Average Hedge Price (\$/Bbl)	
March 2022 - December 2022			
NYMEX Roll Swaps	24,000 Bbls/day	\$ 1.10	

Share repurchase program

In May 2019 our Board of Directors approved the initiation of a share repurchase program to acquire up to \$1 billion of our common stock beginning in June 2019. On February 8, 2022, our Board of Directors approved an increase in the size of the share repurchase program to \$1.5 billion, inclusive of cumulative amounts repurchased to date. As of the date of this filing, we have repurchased and retired a cumulative total of approximately 17.0 million shares under the program at an aggregate cost of \$441.1 million, leaving approximately \$1.06 billion of authorized repurchasing capacity under the modified program. The timing and amount of the Company's share repurchases are subject to market conditions and management discretion. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.

Senior note repurchases and redemptions

As discussed in *Note 8. Long-Term Debt* in *Part II, Item 8. Notes to Consolidated Financial Statements*, in recent years we have repurchased or redeemed a portion of our outstanding senior notes. From time to time, we may seek to execute additional repurchases or redemptions of our senior notes for cash in open market transactions, privately negotiated transactions, or otherwise. Such repurchases or redemptions will depend on prevailing market conditions, our liquidity and prospects for future access to capital, and other factors. The amounts involved in any such transactions, individually or in the aggregate, may be material.

Critical Accounting Policies and Estimates

Our consolidated financial statements and related footnotes contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, and the disclosure and estimation of contingent assets and liabilities. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies* and *Note 9. Revenues* for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used.

In management's opinion, the most significant reporting areas impacted by management's judgments and estimates are crude oil and natural gas reserve estimations, revenue recognition, the choice of accounting method for crude oil and natural gas activities and derivatives, impairment of assets, income taxes and contingent liabilities. These areas are discussed below. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters and are believed to be reasonable under the circumstances. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from the estimates as additional information becomes known.

Crude Oil and Natural Gas Reserves Estimation and Standardized Measure of Future Cash Flows

Our external independent reserve engineers, Ryder Scott, and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. Even though Ryder Scott and our internal technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Estimates of reserves and their values, future production rates, and future costs and expenses are inherently uncertain for various reasons, including many factors beyond the Company's control. Reserve estimates are updated by us at least semi-annually and take into account recent production levels and other technical information about each of our properties.

Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions or removals of estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, changes in business strategies, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered. For the years ended December 31, 2021, 2020, and 2019, net upward (downward) revisions of our proved reserves totaled approximately 54 MMBoe, (505) MMBoe, and (149) MMBoe, respectively. We cannot predict the amounts or timing of future reserve revisions or removals.

Estimates of proved reserves are key components of the Company's most significant financial estimates including the computation of depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense would increase, reducing net income. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense would decrease. Future revisions of reserves may be material and could significantly alter future depreciation, depletion, and amortization expense and may result in material impairments of assets.

At December 31, 2021, our proved reserves totaled 1,645 MMBoe as determined using 12-month average first-day-of-the-month prices of \$66.56 per barrel for crude oil and \$3.60 per MMBtu for natural gas. Actual future prices may be materially higher or lower than those used in our year-end estimates. NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2022 and February 1, 2022 averaged \$81.71 per barrel and \$4.65 per MMBtu, respectively.

Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were increased to \$80 per barrel our proved reserves at December 31, 2021 could increase by approximately 21 MMBoe, or 1%. If the increase in proved reserves under this oil price sensitivity existed throughout 2021, our DD&A expense for 2021 would have decreased by approximately 2%.

Holding all other factors constant, if natural gas prices used in our year-end reserve estimates were increased to \$4.50 per MMBtu our proved reserves at December 31, 2021 could increase by approximately 8 MMBoe, or less than 1%. If the increase in proved reserves under this gas price sensitivity existed throughout 2021, our DD&A expense for 2021 would have decreased by approximately 1%.

Our DD&A calculations for oil and gas properties are performed on a field basis and revisions to proved reserves will not necessarily be applied ratably across all fields and may not be applied to some fields at all. Further, reserve revisions in significant fields may individually affect our DD&A rate. As a result, the impact on DD&A expense from revisions in reserves cannot be predicted with certainty and may result in changes in expense that are greater or less than the underlying changes in reserves.

See *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserves, Standardized Measure, and PV-10 Sensitivities* for additional proved reserve sensitivities under certain increasing and decreasing commodity price scenarios for crude oil and natural gas.

Revenue Recognition

We derive substantially all of our revenues from the sale of crude oil and natural gas. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Revenues* for discussion of our accounting policies governing the recognition and presentation of revenues.

Operated crude oil and natural gas revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. For non-operated properties, the Company's proportionate share of production is generally marketed at the discretion of the operators. Non-operated revenues are recognized by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive.

At the end of each month, to record revenues we estimate the amount of production delivered and sold to customers and the prices at which they were sold. Variances between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received and are reflected in our financial statements as crude oil and natural gas sales. These variances have historically not been material.

For the sale of crude oil and natural gas, we evaluate whether we are the principal, and report revenues on a gross basis (revenues presented separately from associated expenses), or an agent, and report revenues on a net basis. In this assessment, we consider if we obtain control of the products before they are transferred to the customer as well as other indicators. Judgment may be required in determining the point in time when control of products transfers to customers.

Successful Efforts Method of Accounting

Our business is subject to accounting rules that are unique to the crude oil and natural gas industry. Two generally accepted methods of accounting for oil and gas activities are available—the successful efforts method and the full cost method. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. We use the successful efforts method of accounting for our oil and gas properties. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies* for further discussion of the accounting policies applicable to the successful efforts method of accounting.

Derivative Activities

From time to time we may utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production and for other purposes. We have elected not to designate any of our price risk management activities as cash flow hedges. As a result, we mark our derivative instruments to fair value and recognize the changes in fair value in current earnings.

In determining the amounts to be recorded for outstanding derivative contracts, we are required to estimate the fair value of the derivatives. We use an independent third party to provide our derivative valuations. The third party's valuation models for derivative contracts are industry-standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value calculations for collars requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

We validate our derivative valuations through management review and by comparison to our counterparties' valuations for reasonableness. Differences between our fair value calculations and counterparty valuations have historically not been material.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk-adjusted proved reserves. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable.

Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis. If the carrying amount of a field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value using a discounted cash flow model. For producing properties, the impairment evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for crude oil and natural gas, future costs to produce those products, estimates of future crude oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions or removals of crude oil and natural gas reserves. Estimates of anticipated sales prices and recoverable reserves are highly judgmental and are subject to material revision in future periods.

No impairments were recognized for our proved crude oil and natural gas properties for the year ended December 31, 2021 as estimated future net cash flows were determined to be in excess of cost basis. Commodity price assumptions used for the year-end December 31, 2021 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2026 and were then escalated at 3% per year thereafter. Holding all other factors constant, as forward commodity prices decrease, our probability for recognizing producing property impairments may increase, or the magnitude of impairments to be recognized may increase. Conversely, as forward commodity prices increase, our probability for recognizing producing property impairments may decrease, or the magnitude of impairments to be recognized may decrease or be eliminated. As of December 31, 2021, the publicly available forward commodity strip prices for the year 2026 used in our fourth quarter impairment calculations averaged \$58.42 per barrel for crude oil and \$3.03 per Mcf for natural gas. If forward commodity prices materially decrease from current levels for an extended period, impairments of producing properties may be recognized in the future. Because of the uncertainty inherent in the numerous factors utilized in determining the fair value of producing properties, we cannot predict the timing and amount of future impairment charges, if any.

Impairment losses for unproved properties are generally recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management. The estimated timing and rate of successful drilling is highly judgmental and is subject to material revision in future periods as better information becomes available.

Income Taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. We apply judgment to determine the weight of both positive and negative evidence in order to conclude whether a valuation allowance is necessary for our deferred tax assets. In determining whether a valuation allowance is required, we consider, among other factors, our financial position, results of operations, projected future taxable income, reversal of existing deferred tax liabilities against deferred tax assets, and tax planning strategies. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production, development activities, profitability of future business strategies and forecasted economics in the oil and gas industry. Additionally, changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and may affect the valuation of deferred tax balances in the future. Changes in judgment regarding future realization of deferred tax assets may result in a reversal of all or a portion of the valuation allowance.

We believe our net deferred tax assets will ultimately be realized. During 2020, a \$14.5 million valuation allowance was established for the deferred tax asset associated with a portion of our Oklahoma state net operating loss carryforwards. In 2021, we reassessed the realizability of the deferred tax asset related to Oklahoma state net operating loss carryforwards, and based on current year activity, determined it was more likely than not that such assets would be realized. Therefore, it was determined that the previously recorded valuation allowance in 2020 should be released in 2021. We will continue to evaluate both the

positive and negative evidence on a quarterly basis in determining the need for a valuation allowance with respect to our deferred tax assets.

Contingent Liabilities

A provision for legal, environmental and other contingencies is charged to expense when a loss is probable and the loss or range of loss can be reasonably estimated. Determining when liabilities and expenses should be recorded for these contingencies and the appropriate amounts of accruals is subject to an estimation process that requires subjective judgment of management. In certain cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies dealing with similar matters, and management's decision on how it intends to respond to a particular matter; for example, a decision to contest it vigorously or a decision to seek a negotiated settlement. Actual losses can differ from estimates for various reasons, including differing interpretations of laws and opinions and assessments on the amount of damages. We closely monitor known and potential legal, environmental and other contingencies and make our best estimate of when or if to record liabilities and losses for matters based on available information.

New Accounting Pronouncement

See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies—Adoption of new accounting pronouncement* for a discussion of the new income tax accounting standard adopted on January 1, 2021, which did not have a material impact on our financial position, results of operations, or cash flows.

Legislative and Regulatory Developments

The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. In January 2021, President Biden issued executive orders that, among other things, establish new greenhouse gas emission standards for the oil and gas sector. Additionally, the Biden Administration is pursuing legislative changes to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and gas exploration and production companies, as well as other tax policy changes including a proposed increase in the U.S. corporate income tax rate, among other things. These changes, if enacted, could have a material adverse effect on our results of operations and cash flows. President Biden may continue to issue additional executive orders in pursuit of his regulatory agenda and there is the potential for the revision of existing laws and regulations or the adoption of new legislation that could adversely affect the oil and gas industry. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for further discussion of significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.

Inflation

Certain drilling and completion costs and costs of oilfield services, equipment, and materials decreased in recent years as service providers reduced their costs in response to reduced demand arising from historically low crude oil prices. However, inflationary pressures returned in 2021 and are expected to continue in 2022 in conjunction with the significant improvement in commodity prices over the past year in response to the lifting of COVID-19 restrictions, the resumption of normal economic activity, and the resulting improvement in supply and demand fundamentals. Additionally, recent supply chain disruptions stemming from the COVID-19 pandemic have led to shortages of certain materials and equipment and resulting increases in material and labor costs. If these supply chain disruptions persist or worsen, and commodity prices continue to remain at attractive levels that stimulate increased industry activity, we may face shortages of service providers, equipment, and materials. Such shortages could result in increased competition which may lead to further increases in costs.

Non-GAAP Financial Measures

Net crude oil and natural gas sales and net sales prices

Revenues and transportation expenses associated with production from our operated properties are reported separately as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Revenues*. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received. As a result, the separate presentation of revenues and transportation expenses from our operated properties differs from the net presentation from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results and to achieve comparability between operated and non-operated revenues, we have presented crude oil and natural gas sales net of transportation expenses in *Management's Discussion and Analysis of Financial Condition and Results of Operations*, which we refer to as "net crude oil and natural gas sales," a non-GAAP measure. Average sales prices calculated using net crude oil and natural gas sales are referred to as "net sales prices," a non-GAAP measure, and are calculated by taking revenues less transportation expenses divided by sales volumes, whether for crude oil or natural gas, as applicable. Management believes presenting our revenues and sales prices net of transportation expenses is useful because it normalizes the presentation differences between operated and non-operated revenues and allows for a useful comparison of net realized prices to NYMEX benchmark prices on a Company-wide basis.

The following table presents a reconciliation of total Company crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for 2021, 2020, and 2019.

Total Company <i>In thousands</i>	Year Ended December 31, 2021			Year Ended December 31, 2020			Year Ended December 31, 2019		
	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	\$ 3,949,294	\$ 1,844,447	\$ 5,793,741	\$ 2,199,976	\$ 355,458	\$ 2,555,434	\$ 3,929,994	\$ 584,395	\$ 4,514,389
Less: Transportation expenses	(185,130)	(39,859)	(224,989)	(158,989)	(37,703)	(196,692)	(191,998)	(33,651)	(225,649)
Net crude oil and natural gas sales (non-GAAP)	\$ 3,764,164	\$ 1,804,588	\$ 5,568,752	\$ 2,040,987	\$ 317,755	\$ 2,358,742	\$ 3,737,996	\$ 550,744	\$ 4,288,740
Sales volumes (MBbl/MMcf/MBoe)	58,757	370,110	120,442	58,793	306,528	109,881	72,136	311,865	124,113
Net sales price (non-GAAP)	\$ 64.06	\$ 4.88	\$ 46.24	\$ 34.71	\$ 1.04	\$ 21.47	\$ 51.82	\$ 1.77	\$ 34.56

The following tables present reconciliations of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for North Dakota Bakken and SCOOP for 2021, 2020, and 2019 as presented in *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Production and Price History*.

North Dakota Bakken <i>In thousands</i>	Year Ended December 31, 2021			Year Ended December 31, 2020			Year Ended December 31, 2019		
	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	\$ 2,695,738	\$ 549,932	\$ 3,245,670	\$ 1,469,450	\$ 24,714	\$ 1,494,164	\$ 2,826,136	\$ 128,426	\$ 2,954,562
Less: Transportation expenses	(154,359)	(4,831)	(159,190)	(127,036)	(2,580)	(129,616)	(157,076)	(2,530)	(159,606)
Net crude oil and natural gas sales (non-GAAP)	\$ 2,541,379	\$ 545,101	\$ 3,086,480	\$ 1,342,414	\$ 22,134	\$ 1,364,548	\$ 2,669,060	\$ 125,896	\$ 2,794,956
Sales volumes (MBbl/MMcf/MBoe)	40,186	120,517	60,272	40,040	97,532	56,295	52,374	98,186	68,738
Net sales price (non-GAAP)	\$ 63.24	\$ 4.52	\$ 51.21	\$ 33.53	\$ 0.23	\$ 24.24	\$ 50.96	\$ 1.28	\$ 40.66

SCOOP <i>In thousands</i>	Year Ended December 31, 2021			Year Ended December 31, 2020			Year Ended December 31, 2019		
	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	\$ 756,596	\$ 980,323	\$ 1,736,919	\$ 486,076	\$ 246,125	\$ 732,201	\$ 640,097	\$ 277,230	\$ 917,327
Less: Transportation expenses	(2,854)	(23,808)	(26,662)	(5,275)	(21,909)	(27,184)	(3,539)	(14,795)	(18,334)
Net crude oil and natural gas sales (non-GAAP)	\$ 753,742	\$ 956,515	\$ 1,710,257	\$ 480,801	\$ 224,216	\$ 705,017	\$ 636,558	\$ 262,435	\$ 898,993
Sales volumes (MBbl/MMcf/MBoe)	11,341	179,553	41,267	12,694	136,410	35,429	11,592	111,436	30,164
Net sales price (non-GAAP)	\$ 66.46	\$ 5.33	\$ 41.44	\$ 37.88	\$ 1.64	\$ 19.90	\$ 54.92	\$ 2.36	\$ 29.80

PV-10

Our PV-10 value, a non-GAAP financial measure, is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2021, our PV-10 totaled approximately \$20.49 billion. The standardized measure of our discounted future net cash flows was approximately \$16.64 billion at December 31, 2021, representing a \$3.86 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at Standardized Measure. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General. We are exposed to a variety of market risks including commodity price risk, credit risk, and interest rate risk. We seek to address these risks through a program of risk management which may include the use of derivative instruments.

Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Prices for crude oil and natural gas have been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the quarter ended December 31, 2021, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately \$608 million for each \$10.00 per barrel change in crude oil prices at December 31, 2021 and \$380 million for each \$1.00 per Mcf change in natural gas prices at December 31, 2021.

To reduce price risk caused by market fluctuations in crude oil and natural gas prices, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds to be used for our capital program and for general corporate purposes. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to settle existing derivative positions prior to the expiration of their contractual maturities. While hedging, if utilized, may limit the downside risk of adverse price movements, it also may limit future revenues from upward price movements.

The fair value of our derivative instruments at December 31, 2021 was a net asset of \$34.3 million, which is comprised of a \$33.3 million net asset associated with our natural gas derivatives and a \$1.0 million net asset associated with our crude oil derivatives. The following table shows how a hypothetical +/- 10% change in the underlying forward prices used to calculate the fair value of our derivatives would impact the fair value estimates as of December 31, 2021.

In thousands	Change in Forward Price	Hypothetical Fair Value
		Asset (Liability)
Crude Oil	-10%	\$1,273
Crude Oil	+10%	\$641
Natural Gas	-10%	\$99,641
Natural Gas	+10%	(\$33,074)

Changes in the fair value of our derivatives from the above price sensitivities would produce a corresponding change in our total revenues.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies (\$1.1 billion in receivables at December 31, 2021) and our joint interest and other receivables (\$279 million at December 31, 2021).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's credit worthiness. We have not generally required our counterparties to provide collateral to secure crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was \$19 million at December 31, 2021, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on a co-owner's interest in the well, to net production proceeds against amounts owed in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to variable-rate borrowings we may have outstanding from time to time under our credit facility. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates.

We had \$240 million of variable rate borrowings outstanding on our credit facility at January 31, 2022. The impact of a 0.25% increase in interest rates on this amount of debt would result in increased interest expense and reduced income before income taxes of approximately \$0.6 million per year.

We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2021:

<i>In thousands</i>	2022	2023	2024	2025	2026	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	\$ —	\$ 649,625	\$ 911,000	\$ —	\$ 800,000	\$ 4,000,000	\$ 6,360,625
Weighted-average interest rate	—	4.5%	3.8%	—	2.3 %	4.7 %	4.2 %
Notes payable:							
Principal amount (1)	\$ 2,326	\$ 2,410	\$ 2,495	\$ 2,587	\$ 2,681	\$ 9,952	\$ 22,451
Interest rate	3.5 %	3.5 %	3.5 %	3.5 %	3.5 %	3.5 %	3.5 %
Variable rate debt:							
Credit facility:							
Principal amount	\$ —	\$ —	\$ —	\$ —	\$ 500,000	\$ —	\$ 500,000
Weighted-average interest rate	—	—	—	—	1.6 %	—	1.6 %

(1) Amounts represent scheduled maturities and do not reflect any discount or premium at which the notes were issued or any debt issuance costs.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the “Company”) as of December 31, 2021 and 2020, the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the “financial statements”). In our opinion, the 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 each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated February 14, 2022 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the 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 financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

- Estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion expense, proved and unproved crude oil and natural gas reserves used in the assessment and measurement of impairment of proved crude oil and natural gas properties, and recording of the fair value of crude oil and natural gas properties in the Permian Basin Acquisition and Powder River Basin Acquisitions (herein referred to as “the crude oil and natural gas reserves”)

As described in Note 1 to the consolidated financial statements, the Company accounts for its crude oil and natural gas properties using the successful efforts method of accounting, which requires management to make estimates of proved crude oil and natural gas reserve volumes and future cash flows to record depletion expense

and proved and unproved crude oil and natural gas reserves to assess its crude oil and natural gas properties for impairment. Additionally, as described in Note 2 to the consolidated financial statements, the Company acquired significant oil and natural gas properties through asset acquisitions and a business combination. Crude oil and natural gas reserves are a significant input to the determination of the acquisition date fair value of crude oil and natural gas properties acquired by the Company in asset acquisitions and business combinations. To estimate the crude oil and natural gas reserves and future cash flows, management makes significant estimates and assumptions including forecasting the production decline rate of producing crude oil and natural gas properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties and unproved properties. In addition, the estimation of the crude oil and natural gas reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with the crude oil and natural gas reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and impairment assessments / measurements. We identified the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion expense and proved and unproved crude oil and natural gas reserves for the assessment / measurement of impairment of crude oil and natural gas properties as a critical audit matter.

The principal considerations for our determination that the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion expense and proved and unproved crude oil and natural gas reserves for the assessment / measurement of impairment of crude oil and natural gas properties and the recording of oil and natural gas properties values in the Permian Basin Acquisition and Powder River Basin Acquisitions is a critical audit matter is that relatively minor changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future cash flows of the Company's crude oil and natural gas reserves could have a significant impact on the measurement of depletion expense or assessment / measurement of impairment expense and the acquisition date values of crude oil and natural gas properties.

Our audit procedures related to the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion expense and proved and unproved crude oil and natural gas reserves for the assessment and measurement of impairment and the amount of crude oil and natural gas properties recorded from acquisitions and business combinations included the following, among others.

- Tested the design and operating effectiveness of controls relating to management's estimation of proved crude oil and natural gas reserves for the purpose of estimating depletion expense and proved and unproved crude oil and natural gas reserves for assessing / measuring the Company's proved crude oil and gas properties for impairment and acquisitions and business combinations.
- Assessed the independence, objectivity, and professional qualifications of the Company's reservoir engineer specialists, made inquiries of these specialists (internal and external) regarding the process followed and judgments used to make significant estimates, including but not limited to crude oil and natural gas reserve volumes, decline rates, and economically recoverable crude oil and natural gas reserves and reviewed the reserve estimates prepared by the Company's specialists.
- To the extent key inputs and assumptions used to determine crude oil and natural gas reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, discount rates, and ownership interests, we tested management's process for determining the assumptions, including examining underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by:
 - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials
 - Evaluated the models used to estimate the operating costs at year-end and compared to historical operating costs

- Compared the estimates of future capital expenditures in the reserve reports to management's forecasts and amounts expended for recently drilled and completed wells
- Evaluated the working and net revenue interests used in the reserve report by inspecting land and division order records
- Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties
- Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year reserve report
- Evaluated the reasonableness of the Company's classification of reserves as proved or unproved
- Evaluated the reasonableness of risk-adjustment factors applied to unproved crude oil and natural gas reserves that were taken into consideration to determine estimated future net cash flows used to evaluate proved property impairment and for acquisitions and business combinations
- As it relates to the recording of the acquisition date values of crude oil and natural gas properties in acquisitions and a business combination, we utilized internal valuation specialists with specialized skills and knowledge to assist with evaluating certain assumptions, such as risk-adjustment factors and the valuation of unproved oil and gas properties on per net acre basis, as compared to industry surveys and publicly available market data

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2004.

Oklahoma City, Oklahoma
February 14, 2022

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

<i>In thousands, except par values and share data</i>	December 31,	
	2021	2020
Assets		
Current assets:		
Cash and cash equivalents	\$ 20,868	\$ 47,470
Receivables:		
Crude oil and natural gas sales	1,122,415	561,127
Joint interest and other	278,753	143,829
Allowance for credit losses	(2,814)	(2,462)
Receivables, net	1,398,354	702,494
Derivative assets	22,334	15,303
Inventories	105,568	72,157
Prepaid expenses and other	17,266	15,121
Total current assets	1,564,390	852,545
Net property and equipment, based on successful efforts method of accounting	16,975,465	13,737,292
Derivative assets, noncurrent	13,188	—
Operating lease right-of-use assets	16,370	8,557
Other noncurrent assets	21,698	34,704
Total assets	\$ 18,591,111	\$ 14,633,098
Liabilities and equity		
Current liabilities:		
Accounts payable trade	\$ 582,317	\$ 361,704
Revenues and royalties payable	627,171	327,029
Accrued liabilities and other	285,740	167,013
Derivative liabilities	899	227
Current portion of operating lease liabilities	1,674	2,588
Current portion of long-term debt	2,326	2,245
Total current liabilities	1,500,127	860,806
Long-term debt, net of current portion	6,826,566	5,530,173
Other noncurrent liabilities:		
Deferred income tax liabilities, net	2,139,884	1,620,154
Asset retirement obligations, net of current portion	215,701	177,194
Derivative liabilities, noncurrent	318	1,584
Operating lease liabilities, net of current portion	13,800	5,839
Other noncurrent liabilities	38,390	14,623
Total other noncurrent liabilities	2,408,093	1,819,394
Commitments and contingencies (Note 13)		
Equity:		
Preferred stock, \$0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding	—	—
Common stock, \$0.01 par value; 1,000,000,000 shares authorized;		
364,297,520 shares issued and outstanding at December 31, 2021;		
365,220,435 shares issued and outstanding at December 31, 2020;	3,643	3,652
Additional paid-in capital	1,131,602	1,205,148
Retained earnings	6,340,211	4,847,646
Total shareholders' equity attributable to Continental Resources	7,475,456	6,056,446
Noncontrolling interests	380,869	366,279
Total equity	7,856,325	6,422,725
Total liabilities and equity	\$ 18,591,111	\$ 14,633,098

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)

<i>In thousands, except per share data</i>	Year Ended December 31,		
	2021	2020	2019
Revenues:			
Crude oil and natural gas sales	\$ 5,793,741	\$ 2,555,434	\$ 4,514,389
Gain (loss) on derivative instruments, net	(128,864)	(14,658)	49,083
Crude oil and natural gas service operations	54,441	45,694	68,475
Total revenues	5,719,318	2,586,470	4,631,947
Operating costs and expenses:			
Production expenses	406,906	359,267	444,649
Production taxes	404,362	192,718	357,988
Transportation expenses	224,989	196,692	225,649
Exploration expenses	21,047	17,732	14,667
Crude oil and natural gas service operations	21,480	18,294	33,230
Depreciation, depletion, amortization and accretion	1,898,082	1,880,959	2,017,383
Property impairments	38,370	277,941	86,202
Acquisition costs	13,920	—	—
General and administrative expenses	233,628	196,572	195,302
Net (gain) loss on sale of assets and other	(5,146)	187	(535)
Total operating costs and expenses	3,257,638	3,140,362	3,374,535
Income (loss) from operations	2,461,680	(553,892)	1,257,412
Other income (expense):			
Interest expense	(251,598)	(258,240)	(269,379)
Gain (loss) on extinguishment of debt	(290)	35,719	(4,584)
Other	(23,654)	1,662	3,713
	(275,542)	(220,859)	(270,250)
Income (loss) before income taxes	2,186,138	(774,751)	987,162
(Provision) benefit for income taxes	(519,730)	169,190	(212,689)
Net income (loss)	1,666,408	(605,561)	774,473
Net income (loss) attributable to noncontrolling interests	5,440	(8,692)	(1,168)
Net income (loss) attributable to Continental Resources	\$ 1,660,968	\$ (596,869)	\$ 775,641
Net income (loss) per share attributable to Continental Resources:			
Basic	\$ 4.61	\$ (1.65)	\$ 2.09
Diluted	\$ 4.56	\$ (1.65)	\$ 2.08
Comprehensive income (loss):			
Net income (loss)	\$ 1,666,408	\$ (605,561)	\$ 774,473
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	—	—	140
Release of cumulative translation adjustments	—	—	(555)
Total other comprehensive income (loss), net of tax	—	—	(415)
Comprehensive income (loss)	1,666,408	(605,561)	774,058
Comprehensive income (loss) attributable to noncontrolling interests	5,440	(8,692)	(1,168)
Comprehensive income (loss) attributable to Continental Resources	\$ 1,660,968	\$ (596,869)	\$ 775,226

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Equity

	Shareholders' equity attributable to Continental Resources								
	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income	Treasury stock	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
<i>In thousands, except share data</i>									
Balance at December 31, 2018	376,021,575	\$ 3,760	\$ 1,434,823	\$ 415	\$ —	\$ 4,706,135	\$ 6,145,133	\$ 276,728	\$ 6,421,861
Net income (loss)	—	—	—	—	—	775,641	775,641	(1,168)	774,473
Cash dividends declared	—	—	—	—	—	(18,747)	(18,747)	—	(18,747)
Change in dividends payable	—	—	—	—	—	195	195	—	195
Common stock repurchased	—	—	—	—	(190,239)	—	(190,239)	—	(190,239)
Common stock retired	(5,646,553)	(56)	(190,183)	—	190,239	—	—	—	—
Other comprehensive loss, net of tax	—	—	—	(415)	—	—	(415)	—	(415)
Stock-based compensation	—	—	52,030	—	—	—	52,030	—	52,030
Restricted stock:									
Granted	1,526,825	15	—	—	—	—	15	—	15
Repurchased and canceled	(477,789)	(5)	(21,938)	—	—	—	(21,943)	—	(21,943)
Forfeited	(350,022)	(3)	—	—	—	—	(3)	—	(3)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	105,528	105,528
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(14,404)	(14,404)
Balance at December 31, 2019	371,074,036	\$ 3,711	\$ 1,274,732	\$ —	\$ —	\$ 5,463,224	\$ 6,741,667	\$ 366,684	\$ 7,108,351
Net loss	—	—	—	—	—	(596,869)	(596,869)	(8,692)	(605,561)
Cumulative effect adjustment from adoption of ASU 2016-13	—	—	—	—	—	(137)	(137)	—	(137)
Cash dividends declared	—	—	—	—	—	(18,580)	(18,580)	—	(18,580)
Change in dividends payable	—	—	—	—	—	8	8	—	8
Common stock repurchased	—	—	—	—	(126,906)	—	(126,906)	—	(126,906)
Common stock retired	(8,122,104)	(81)	(126,825)	—	126,906	—	—	—	—
Stock-based compensation	—	—	64,585	—	—	—	64,585	—	64,585
Restricted stock:									
Granted	2,738,625	27	—	—	—	—	27	—	27
Repurchased and canceled	(306,845)	(3)	(7,344)	—	—	—	(7,347)	—	(7,347)
Forfeited	(163,277)	(2)	—	—	—	—	(2)	—	(2)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	21,557	21,557
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(13,270)	(13,270)
Balance at December 31, 2020	365,220,435	\$ 3,652	\$ 1,205,148	\$ —	\$ —	\$ 4,847,646	\$ 6,056,446	\$ 366,279	\$ 6,422,725
Net income	—	—	—	—	—	1,660,968	1,660,968	5,440	1,666,408
Cash dividends declared	—	—	—	—	—	(168,536)	(168,536)	—	(168,536)
Change in dividends payable	—	—	—	—	—	133	133	—	133
Common stock repurchased	—	—	—	—	(123,924)	—	(123,924)	—	(123,924)
Common stock retired	(3,198,571)	(32)	(123,892)	—	123,924	—	—	—	—
Stock-based compensation	—	—	63,145	—	—	—	63,145	—	63,145

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Equity

Restricted stock:									
Granted	3,050,491	31	—	—	—	—	31	—	31
Repurchased and canceled	(478,697)	(5)	(12,799)	—	—	—	(12,804)	—	(12,804)
Forfeited	(296,138)	(3)	—	—	—	—	(3)	—	(3)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	33,086	33,086
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(23,936)	(23,936)
Balance at December 31, 2021	<u>364,297,520</u>	<u>\$ 3,643</u>	<u>\$ 1,131,602</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 6,340,211</u>	<u>\$ 7,475,456</u>	<u>\$ 380,869</u>	<u>\$ 7,856,325</u>

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

<i>In thousands</i>	Year Ended December 31,		
	2021	2020	2019
Cash flows from operating activities:			
Net income (loss)	\$ 1,666,408	\$ (605,561)	\$ 774,473
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	1,893,106	1,882,458	2,019,704
Property impairments	38,370	277,941	86,202
Non-cash (gain) loss on derivatives, net	(20,814)	(13,492)	15,612
Stock-based compensation	63,173	64,613	52,044
Provision (benefit) for deferred income taxes	519,730	(166,971)	212,689
Net (gain) loss on sale of assets and other	(5,146)	187	(535)
(Gain) loss on extinguishment of debt	290	(35,719)	4,584
Other, net	35,614	16,970	10,408
Changes in assets and liabilities:			
Accounts receivable	(694,981)	332,128	(33,619)
Inventories	(33,411)	12,859	(21,204)
Other current assets	(2,144)	1,471	(4,459)
Accounts payable trade	106,367	(133,977)	(36,359)
Revenues and royalties payable	298,552	(143,260)	69,195
Accrued liabilities and other	109,540	(66,071)	(36,467)
Other noncurrent assets and liabilities	(803)	(1,272)	3,420
Net cash provided by operating activities	3,973,851	1,422,304	3,115,688
Cash flows from investing activities:			
Exploration and development	(2,382,413)	(1,408,149)	(2,783,149)
Purchase of producing crude oil and natural gas properties	(2,548,575)	(81,994)	(51,558)
Purchase of other property and equipment	(66,598)	(23,994)	(25,983)
Proceeds from sale of assets	8,041	2,779	88,734
Net cash used in investing activities	(4,989,545)	(1,511,358)	(2,771,956)
Cash flows from financing activities:			
Credit facility borrowings	1,663,000	2,052,000	1,216,000
Repayment of credit facility	(1,323,000)	(1,947,000)	(1,161,000)
Proceeds from issuance of Senior Notes	1,587,776	1,485,000	—
Redemption and repurchase of Senior Notes	(630,782)	(1,343,250)	(500,000)
Premium and costs on redemption of Senior Notes	—	(25,173)	(4,167)
Proceeds from other debt	—	26,000	—
Repayment of other debt	(2,243)	(6,679)	(2,352)
Debt issuance costs	(12,082)	(4,368)	—
Contributions from noncontrolling interests	31,493	27,116	109,137
Distributions to noncontrolling interests	(22,447)	(13,809)	(14,164)
Repurchase of common stock	(123,924)	(126,906)	(190,239)
Repurchase of restricted stock for tax withholdings	(12,804)	(7,347)	(21,943)
Dividends paid on common stock	(165,895)	(18,460)	(18,380)
Net cash provided by (used in) financing activities	989,092	97,124	(587,108)
Effect of exchange rate changes on cash	—	—	27
Net change in cash and cash equivalents	(26,602)	8,070	(243,349)
Cash and cash equivalents at beginning of period	47,470	39,400	282,749
Cash and cash equivalents at end of period	\$ 20,868	\$ 47,470	\$ 39,400

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

Note 1. Organization and Summary of Significant Accounting Policies

Description of the Company

Continental Resources, Inc. (the “Company”) was formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company’s principal business is crude oil and natural gas exploration, development, management, and production with properties located in the North, South, and East regions of the United States. Additionally, the Company pursues the acquisition and management of perpetually owned minerals located in its key operating areas.

In 2021 the Company executed strategic acquisitions to expand its operations into the Permian Basin of Texas and the Powder River Basin of Wyoming. See *Note 2. Property Acquisitions and Dispositions* for additional information on the acquisitions. The Company’s North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, Powder River Basin, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River and includes the SCOOP and STACK areas of Oklahoma and the Permian Basin of Texas. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations. For financial reporting purposes, the Company has one reportable segment due to the similar nature of its business, which is the exploration, development, and production of crude oil and natural gas in the United States.

Basis of presentation of consolidated financial statements

The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries, and entities in which the Company has a controlling financial interest. Intercompany accounts and transactions have been eliminated upon consolidation. Noncontrolling interests reflected herein represent third party ownership in the net assets of consolidated subsidiaries. The portions of consolidated net income (loss) and equity attributable to the noncontrolling interests are presented separately in the Company’s financial statements.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (“U.S. GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates. The most significant estimates and assumptions impacting reported results are estimates of the Company’s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties.

Cash and cash equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. As of December 31, 2021, the Company had cash deposits in excess of federally insured amounts of approximately \$19.4 million. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk in this area.

Accounts receivable

Receivables arising from crude oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and are considered delinquent after 60 days. The Company writes off specific receivables when they become noncollectable and any payments subsequently received on those receivables are credited to the allowance for credit losses. Write-offs of noncollectable receivables have historically not been material. The Company’s allowance for credit losses totaled \$2.8 million and \$2.5 million as of December 31, 2021 and 2020, respectively. See *Note 10. Allowance for Credit Losses* for additional information.

Concentration of credit risk

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with significant purchasers. For the year ended December 31, 2021, sales to the Company’s largest purchaser accounted for approximately 10% of the Company’s total crude oil and natural gas sales. No other purchaser accounted for more than 10% of the Company’s total crude oil and natural gas sales for 2021. The Company generally does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

Continental Resources, Inc. and Subsidiaries
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Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines, pipeline imbalances, and tubular goods and equipment to be used in the Company's exploration and development activities. Crude oil inventories are valued at the lower of cost or net realizable value primarily using the first-in, first-out inventory method. Tubular goods and equipment are valued primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of December 31, 2021 and 2020 consisted of the following:

<i>In thousands</i>	December 31,	
	2021	2020
Tubular goods and equipment	\$ 12,506	\$ 13,671
Crude oil	93,062	58,486
Total	\$ 105,568	\$ 72,157

In the first quarter of 2020 the Company recognized a \$24.5 million impairment to reduce its crude oil inventory to estimated net realizable value at the time of impairment. The impairment is included in the caption "Property impairments" in the consolidated statements of comprehensive income (loss) for the year ended December 31, 2020.

Crude oil and natural gas properties

The Company uses the successful efforts method of accounting for crude oil and natural gas properties whereby costs incurred to acquire interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells, and expenditures for enhanced recovery operations are capitalized. Geological and geophysical costs, seismic costs incurred for exploratory projects, lease rentals and costs associated with unsuccessful exploratory wells or projects are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. To the extent a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between capitalized development costs and exploration expense. Maintenance and repairs are expensed as incurred.

Under the successful efforts method of accounting, the Company capitalizes exploratory drilling costs on the balance sheet pending determination of whether the well has found proved reserves in economically producible quantities. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, the associated capitalized costs become part of well equipment and facilities. However, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value.

Production expenses are those costs incurred by the Company to operate and maintain its crude oil and natural gas properties and associated equipment and facilities. Production expenses include but are not limited to labor costs to operate the Company's properties, repairs and maintenance, certain waste water disposal costs, utility costs, certain workover-related costs, and materials and supplies utilized in the Company's operations.

Service property and equipment

Service property and equipment consist primarily of automobiles and aircraft; machinery and equipment; gathering and recycling systems; storage tanks; office and computer equipment, software, furniture and fixtures; and buildings and improvements. Major renewals and replacements are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

Depreciation and amortization of service property and equipment are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. The estimated useful lives of service property and equipment are as follows:

Continental Resources, Inc. and Subsidiaries
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<i>Service property and equipment</i>	Useful Lives In Years
Automobiles and aircraft	5-10
Machinery and equipment	6-20
Gathering and recycling systems	15-30
Storage tanks	10-30
Office and computer equipment, software, furniture and fixtures	3-25
Buildings and improvements	4-40

Depreciation, depletion and amortization

Depreciation, depletion and amortization of capitalized drilling and development costs of producing crude oil and natural gas properties, including related support equipment and facilities, are computed using the unit-of-production method on a field basis based on total estimated proved developed reserves. Amortization of producing leaseholds is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable crude oil and natural gas reserves are established based on estimates made by the Company's internal geologists and engineers and external independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Sales of proved properties constituting a part of an amortization base are accounted for as normal retirements with no gain or loss recognized if doing so does not significantly affect the unit-of-production amortization rate. Unit-of-production rates are revised whenever there is an indication of a need, but at least in conjunction with semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Asset retirement obligations

The Company accounts for its asset retirement obligations by recording the fair value of a liability for an asset retirement obligation in the period in which a legal obligation is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the capitalized asset retirement costs are charged to expense through the depreciation, depletion and amortization of crude oil and natural gas properties and the liability is accreted to the expected future abandonment cost ratably over the related asset's life.

The Company's primary asset retirement obligations relate to future plugging and abandonment costs and related disposal of facilities on its crude oil and natural gas properties. The following table summarizes the changes in the Company's future abandonment liabilities from January 1, 2019 through December 31, 2021:

<i>In thousands</i>	2021	2020	2019
Asset retirement obligations at January 1	\$ 179,676	\$ 153,673	\$ 141,360
Accretion expense	11,125	9,393	8,443
Revisions (1)	(1,291)	10,743	(1,762)
Plus: Additions for new assets (2)	32,351	7,048	8,392
Less: Plugging costs and sold assets	(2,037)	(1,181)	(2,760)
Total asset retirement obligations at December 31	\$ 219,824	\$ 179,676	\$ 153,673
Less: Current portion of asset retirement obligations at December 31 (3)	4,123	2,482	1,899
Non-current portion of asset retirement obligations at December 31	\$ 215,701	\$ 177,194	\$ 151,774

- (1) Revisions primarily represent changes in the present value of liabilities resulting from changes in estimated costs and economic lives of producing properties.
- (2) Balance for 2021 includes \$21.4 million of asset retirement obligations recognized in conjunction with the 2021 property acquisitions discussed in *Note 2. Property Acquisitions and Dispositions*.
- (3) Balance is included in the caption "Accrued liabilities and other" in the consolidated balance sheets.

As of December 31, 2021 and 2020, net property and equipment on the consolidated balance sheets included \$72.8 million and \$56.1 million, respectively, of net asset retirement costs.

Asset impairment

Continental Resources, Inc. and Subsidiaries
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Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value.

Impairment losses for unproved properties are generally recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The Company's impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management.

Debt issuance costs

Costs incurred in connection with the execution of the Company's notes payable and revolving credit facility and any amendments thereto are capitalized and amortized over the terms of the arrangements on a straight-line basis, the use of which approximates the effective interest method. Costs incurred upon the issuances of the Company's various senior notes (collectively, the "Notes") were capitalized and are being amortized over the terms of the Notes using the effective interest method.

The Company had aggregate capitalized costs of \$60.6 million and \$45.8 million (net of accumulated amortization of \$36.9 million and \$30.5 million) relating to its long-term debt at December 31, 2021 and 2020, respectively. The increase in 2021 resulted from the capitalization of costs incurred in connection with the amendment of the Company's credit facility and the issuance of new senior notes as discussed in *Note 8. Long-Term Debt*.

Unamortized capitalized costs associated with the Company's Notes and note payable totaled \$50.9 million and \$42.5 million at December 31, 2021 and 2020, respectively, and are reflected as a reduction of "Long-term debt, net of current portion" on the consolidated balance sheets.

Unamortized capitalized costs associated with the Company's revolving credit facility totaled \$9.7 million and \$3.3 million at December 31, 2021 and 2020, respectively, and are reflected in "Other noncurrent assets" on the consolidated balance sheets.

For the years ended December 31, 2021, 2020 and 2019, the Company recognized amortization expense associated with capitalized debt issuance costs of \$7.2 million, \$7.8 million and \$8.3 million, respectively, which are reflected in "Interest expense" on the consolidated statements of comprehensive income (loss).

Derivative instruments

The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value with such amounts classified as current or long-term based on contractual settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the changes in fair value in the consolidated statements of comprehensive income (loss) under the caption "Gain (loss) on derivative instruments, net." See *Note 6. Derivative Instruments* for additional information.

Fair value of financial instruments

The Company's financial instruments consist primarily of cash, trade receivables, trade payables, derivative instruments and long-term debt. See *Note 7. Fair Value Measurements* for a discussion of the methods used to determine fair value for the Company's financial instruments and the quantification of fair value for its derivatives and long-term debt obligations at December 31, 2021 and 2020.

Income taxes

Income taxes are accounted for using the asset and liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at period-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. The Company's policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense.

The Company establishes a valuation allowance if it believes it is more likely than not that some or all of its deferred tax assets will not be realized. Significant judgment is applied in evaluating the need for and the magnitude of appropriate valuation allowances against deferred tax assets. See *Note 11. Income Taxes* for additional information.

Continental Resources, Inc. and Subsidiaries
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Earnings per share attributable to Continental Resources

Basic net income (loss) per share is computed by dividing net income (loss) attributable to the Company by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects the potential dilution of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share attributable to the Company for the years ended December 31, 2021, 2020 and 2019.

<i>In thousands, except per share data</i>	Year ended December 31,		
	2021	2020	2019
Net income (loss) attributable to Continental Resources (numerator)	\$ 1,660,968	\$ (596,869)	\$ 775,641
Weighted average shares (denominator):			
Weighted average shares - basic	360,434	361,538	370,699
Non-vested restricted stock (1)	4,019	—	1,839
Weighted average shares - diluted	364,453	361,538	372,538
Net income (loss) per share attributable to Continental Resources:			
Basic	\$ 4.61	\$ (1.65)	\$ 2.09
Diluted	\$ 4.56	\$ (1.65)	\$ 2.08

- (1) For the year ended December 31, 2020, the Company had a net loss and therefore the potential dilutive effect of approximately 934,000 weighted average non-vested restricted shares were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computation.

Foreign currency translation

In 2014, the Company initiated operations in Canada through a wholly-owned Canadian subsidiary. The Company's operations in Canada were immaterial and were sold in the fourth quarter of 2019. See *Note 11. Income Taxes* and *Note 2. Property Acquisitions and Dispositions* for further discussion. The Company designated the Canadian dollar as the functional currency for its Canadian operations. Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars were included in "Accumulated other comprehensive income" within equity on the consolidated balance sheets and "Other comprehensive income (loss), net of tax" in the consolidated statements of comprehensive income (loss).

Adoption of new accounting pronouncement

On January 1, 2021 the Company adopted ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*. This standard eliminated certain exceptions to the guidance in Topic 740 related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period, and the recognition of deferred tax liabilities for outside basis differences. The new guidance also clarified certain aspects of the existing guidance, among other things. The Company adopted the standard on a prospective basis, which did not have a material impact on its financial position, results of operations, or cash flows.

Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Note 2. Property Acquisitions and Dispositions

2021

Permian Basin Acquisition

On December 21, 2021, the Company acquired oil and gas assets and properties from certain subsidiaries of Pioneer Natural Resources Company pursuant to a purchase and sale agreement in which the Company purchased: (a) 100% of the issued and outstanding limited liability company interests of Jagged Peak Energy LLC, which in turn owns 100% of the issued and outstanding limited liability company interests of Parsley SoDe Water LLC; and (b) certain oil and gas assets and properties in the Permian Basin of Texas (collectively, the “Pioneer Acquisition”). The properties included approximately 92,000 net leasehold acres, approximately 50,000 net royalty acres in the same area normalized to a 1/8th royalty, production totaling approximately 42,000 net barrels of oil equivalent per day (78% oil) based on two-stream reporting at the time of closing, and extensive water infrastructure.

The purchase price paid to the sellers was approximately \$3.06 billion in cash, representing a \$3.25 billion purchase price less customary closing adjustments made pursuant to the agreement. The Company funded the purchase price through a combination of cash on hand, utilization of credit facility borrowing capacity, and the issuance of senior notes as further discussed in *Note 8. Long-Term Debt*.

The Pioneer Acquisition was accounted for using the acquisition method under ASC Topic 805, Business Combinations, which requires all assets acquired and liabilities assumed to be recorded at fair value at the acquisition date. Provisional fair value measurements have been made by the Company for acquired assets and liabilities, and adjustments to those measurements may be made in subsequent periods (up to one year from the acquisition date) as additional information necessary to complete the fair value analysis is obtained.

The following table summarizes the provisional fair values assigned to assets acquired and liabilities assumed as of the acquisition date (presented in millions). Certain studies necessary to complete the purchase price allocation are still under evaluation, including, but not limited to, the valuation of service properties and equipment, inventory, and lease liabilities. The Company will finalize the purchase price allocation during the twelve-month period following the acquisition date, during which time the value of the assets and liabilities presented below may be revised if necessary.

<i>In millions</i>	As of December 21, 2021
Receivables	\$ 3
Proved crude oil and natural gas properties	2,396
Unproved crude oil and natural gas properties	693
Service properties, equipment and other	6
Operating lease right-of-use assets	2
Total assets acquired	\$ 3,100
Revenues and royalties payable	\$ 14
Accrued liabilities and other	8
Operating lease liabilities	2
Asset retirement obligations	16
Total liabilities assumed	\$ 40
Net assets acquired	\$ 3,060

The fair values of proved and unproved properties acquired were measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant unobservable inputs included future commodity prices adjusted for differentials, projections of estimated quantities of recoverable reserves, forecasted production based on decline curve analysis, estimated timing and amount of future operating and development costs, and a weighted average cost of capital.

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For income tax purposes, the Pioneer Acquisition will be treated as an asset purchase such that the tax basis in the assets and liabilities will generally reflect the allocated fair value at closing. Therefore, the Company does not anticipate a material tax consequence for deferred income taxes related to the Pioneer Acquisition.

The Pioneer Acquisition contributed \$29.4 million of revenues and \$14.1 million (\$0.04 per basic and diluted share) of net income to the Company's consolidated results during the period of ownership from December 21, 2021 to December 31, 2021, excluding transaction expenses. The Company incurred \$13.9 million of expenses in connection with the transaction which are reflected in the caption "Acquisition costs" in the consolidated statements of comprehensive income (loss) for the year ended December 31, 2021.

The table below summarizes the Company's pro forma results as if the Pioneer Acquisition and associated increase in debt described in *Note 8. Long-Term Debt* had been completed on January 1, 2020 and were combined with the Company's historical results. The following pro forma information is unaudited, is provided for informational purposes only, and does not represent actual results that would have occurred if the Pioneer Acquisition was completed on January 1, 2020, nor are they indicative of future results.

<i>In millions</i>	Year Ended December 31,			
	2021		2020	
Pro forma combined total revenues	\$	6,657	\$	3,174
Pro forma combined net income (loss) attributable to Continental	\$	2,097	\$	(481)

Powder River Basin Acquisitions

In March 2021, the Company acquired undeveloped leasehold and producing properties in the Powder River Basin of Wyoming for \$206.6 million, consisting of a \$21.5 million escrow deposit paid in December 2020 upon execution of a definitive purchase agreement and a \$185.1 million payment made at closing in March 2021. The acquisition was accounted for as an asset acquisition under ASC Topic 805 and included approximately 130,000 net acres and producing properties with production totaling approximately 7,200 net barrels of oil equivalent per day at the time of closing. Of the purchase price, \$183 million was allocated to proved properties and \$24 million was allocated to unproved properties. The \$21.5 million escrow deposit paid in December 2020 is included in the caption "Other noncurrent assets" on the Company's balance sheet at December 31, 2020, which was subsequently reclassified to "Net property and equipment" on the closing date. The Company recognized approximately \$4.9 million of asset retirement obligations and \$8.2 million of right-of-use assets and corresponding lease liabilities associated with the acquired properties.

In November 2021, the Company acquired undeveloped leasehold and producing properties in the Powder River Basin for \$246.8 million. The acquisition was accounted for as an asset acquisition under ASC Topic 805 and included approximately 72,000 net acres and immaterial amounts of production. Of the purchase price, \$27 million was allocated to proved properties and \$220 million was allocated to unproved properties. The Company recognized approximately \$0.5 million of asset retirement obligations and an immaterial amount of right-of-use assets and corresponding lease liabilities associated with the acquired properties.

2020

In October 2020, the Company acquired undeveloped leasehold and producing properties in the SCOOP play for \$162.8 million. The acquisition included approximately 19,500 net acres and immaterial amounts of production.

2019

In November 2019, the Company sold its Canadian subsidiary and related operations for cash proceeds of \$1.7 million and recognized a \$1.0 million pre-tax gain on the sale. The Company designated the Canadian dollar as the functional currency for its Canadian operations and, with the sale of the Canadian subsidiary, \$0.5 million of cumulative translation adjustments included in "Accumulated other comprehensive income" on the consolidated balance sheets were released and included in the determination of the gain on sale. The disposed subsidiary and properties represented an immaterial portion of the Company's assets and operating results.

In July 2019, the Company sold certain water gathering, recycling, and disposal assets in the STACK play for proceeds of \$85.3 million, with no gain or loss recognized. The sale represented an immaterial portion of the Company's assets and operating results.

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Notes to Consolidated Financial Statements

Note 3. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income tax payments and refunds. Also disclosed is information about investing activities that affects recognized assets and liabilities but does not result in cash receipts or payments.

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Supplemental cash flow information:			
Cash paid for interest	\$ 214,727	\$ 256,633	\$ 267,421
Cash paid for income taxes	3	4	229
Cash received for income tax refunds (1)	58	9,600	107
Non-cash investing activities:			
Asset retirement obligation additions and revisions, net	31,060	17,791	6,630

(1) Amount received in 2020 primarily represents alternative minimum tax refunds.

As of December 31, 2021 and 2020, the Company had \$242.9 million and \$128.8 million, respectively, of accrued capital expenditures included in "Net property and equipment" with an offsetting amount in "Accounts payable trade" in the consolidated balance sheets.

As of December 31, 2021 and 2020, the Company had \$1.7 million and \$0.1 million, respectively, of accrued contributions from noncontrolling interests included in "Receivables-Joint interest and other" with an offsetting amount in "Equity-Noncontrolling interests" in the condensed consolidated balance sheets.

As of December 31, 2021 and 2020, the Company had \$2.5 million and \$1.0 million, respectively, of accrued distributions to noncontrolling interests included in "Revenues and royalties payable" with an offsetting amount in "Equity-Noncontrolling interests" in the condensed consolidated balance sheets.

As of December 31, 2021, the Company recognized approximately \$21.4 million of asset retirement obligations and \$10.0 million of right-of-use assets and corresponding lease liabilities associated with the 2021 property acquisitions discussed in *Note 2. Property Acquisitions and Dispositions*.

Note 4. Net Property and Equipment

Net property and equipment includes the following at December 31, 2021 and 2020. See *Note 2. Property Acquisitions and Dispositions* for discussion of certain acquisitions executed in 2021 that contributed to the increase in net property and equipment in 2021.

<i>In thousands</i>	December 31,	
	2021	2020
Proved crude oil and natural gas properties	\$ 31,613,656	\$ 27,726,954
Unproved crude oil and natural gas properties	1,358,673	368,256
Service properties, equipment and other	484,989	414,066
Total property and equipment	33,457,318	28,509,276
Accumulated depreciation, depletion and amortization	(16,481,853)	(14,771,984)
Net property and equipment	\$ 16,975,465	\$ 13,737,292

Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Note 5. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2021 and 2020:

<i>In thousands</i>	December 31,			
	2021		2020	
Prepaid advances from joint interest owners	\$	18,964	\$	25,209
Accrued compensation		82,844		47,985
Accrued production taxes, ad valorem taxes and other non-income taxes		90,597		40,818
Accrued interest		75,983		50,009
Current portion of asset retirement obligations		4,123		2,482
Other		13,229		510
Accrued liabilities and other	\$	285,740	\$	167,013

Note 6. Derivative Instruments

From time to time the Company enters into derivative contracts to economically hedge against the variability in cash flows associated with future sales of production. The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 7. Fair Value Measurements*.

At December 31, 2021 the Company had outstanding derivative contracts as set forth in the tables below.

<i>Natural gas derivatives</i> Period and Type of Contract	Average Volumes Hedged		Weighted Average Hedge Price (\$/MMBtu)				
			Basis Swaps	Swaps	Sold Put	Floor	Ceiling
January 2022 - December 2023							
Basis Swaps - NGPL TXOK	75,000	MMBtus/day	\$ (0.17)				
January 2022 - March 2022							
Collars - Henry Hub	90,000	MMBtus/day				\$ 3.00	\$ 6.33
Three-way collars - Henry Hub	280,000	MMBtus/day			\$ 2.33	\$ 3.02	\$ 4.46
Swaps - Henry Hub	45,000	MMBtus/day		\$ 3.86			
April 2022 - September 2022							
Swaps - Henry Hub	190,000	MMBtus/day		\$ 4.02			
October 2022 - December 2022							
Collars - Henry Hub	150,000	MMBtus/day				\$ 3.54	\$ 5.34
Three-way collars - Henry Hub	50,000	MMBtus/day			\$ 3.00	\$ 4.07	\$ 5.00
Swaps - Henry Hub	50,000	MMBtus/day		\$ 4.20			
January 2023 - December 2023							
Collars - Henry Hub	62,500	MMBtus/day				\$ 3.41	\$ 4.87
Three-way collars - Henry Hub	12,500	MMBtus/day			\$ 3.00	\$ 4.32	\$ 5.00
Swaps - Henry Hub	175,000	MMBtus/day		\$ 3.38			
January 2024 - December 2024							
Swaps - Henry Hub	125,000	MMBtus/day		\$ 3.12			
Collars - Henry Hub	25,000	MMBtus/day				\$ 3.10	\$ 4.18
January 2025 - December 2025							
Swaps - Henry Hub	10,000	MMBtus/day		\$ 3.08			

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Crude oil derivatives

Period and Type of Contract	Average Volumes Hedged		Weighted Average Hedge Price (\$/Bbl)	
January 2022 - March 2022				
NYMEX Roll Swaps	32,500	Bbls/day	\$	0.71
April 2022 - June 2022				
NYMEX Roll Swaps	15,000	Bbls/day	\$	0.85
July 2022 - December 2022				
NYMEX Roll Swaps	7,500	Bbls/day	\$	0.90

Derivative gains and losses

Cash receipts and payments in the following table reflect the gains or losses on derivative contracts which matured during the applicable period, calculated as the difference between the contract price and the market settlement price of matured contracts. The Company's derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate ("WTI") pricing and natural gas derivative settlements based primarily on NYMEX Henry Hub pricing. Non-cash gains and losses below represent the change in fair value of derivative instruments which continued to be held at period end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Cash received (paid) on derivatives:			
Crude oil fixed price swaps	\$ (44,463)	\$ (31,179)	\$ —
Crude oil collars	(9,365)	—	—
Crude oil NYMEX roll swaps	(163)	—	—
Natural gas fixed price swaps	(84,141)	1,071	58,836
Natural gas collars	(11,546)	1,958	5,859
Cash received (paid) on derivatives, net	(149,678)	(28,150)	64,695
Non-cash gain (loss) on derivatives:			
Crude oil collars	227	(227)	—
Crude oil NYMEX roll swaps	957	—	—
Natural gas fixed price swaps	25,565	2,043	(10,130)
Natural gas basis swaps	(177)	—	—
Natural gas collars	(7,690)	11,676	(5,482)
Natural gas three-way collars	1,932	—	—
Non-cash gain (loss) on derivatives, net	20,814	13,492	(15,612)
Gain (loss) on derivative instruments, net	\$ (128,864)	\$ (14,658)	\$ 49,083

Balance sheet offsetting of derivative assets and liabilities

The Company's derivative contracts are recorded at fair value in the consolidated balance sheets under the captions "Derivative assets," "Derivative assets, noncurrent," "Derivative liabilities," and "Derivative liabilities, noncurrent," as applicable. Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the consolidated balance sheets.

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The following table presents the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets at December 31, 2021, all at fair value.

<i>In thousands</i>	December 31,	
	2021	2020
Commodity derivative assets:		
Gross amounts of recognized assets	\$ 42,903	\$ 15,900
Gross amounts offset on balance sheet	(7,381)	(597)
Net amounts of assets on balance sheet	35,522	15,303
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(8,598)	(2,408)
Gross amounts offset on balance sheet	7,381	597
Net amounts of liabilities on balance sheet	\$ (1,217)	\$ (1,811)

The following table reconciles the net amounts disclosed above to the individual financial statement line items in the consolidated balance sheets.

<i>In thousands</i>	December 31,	
	2021	2020
Derivative assets	\$ 22,334	\$ 15,303
Derivative assets, noncurrent	13,188	—
Net amounts of assets on balance sheet	35,522	15,303
Derivative liabilities	(899)	(227)
Derivative liabilities, noncurrent	(318)	(1,584)
Net amounts of liabilities on balance sheet	(1,217)	(1,811)
Total derivative assets, net	\$ 34,305	\$ 13,492

Note 7. Fair Value Measurements

The Company follows a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3: Unobservable inputs not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available.

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Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company's derivative instruments are reported at fair value on a recurring basis. In determining the fair values of swap contracts, a discounted cash flow method is used due to the unavailability of relevant comparable market data for the Company's exact contracts. The discounted cash flow method estimates future cash flows based on quoted market prices for forward commodity prices and a risk-adjusted discount rate. The fair values of swap contracts are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collars requires the use of an industry-standard option pricing model that considers various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. These assumptions are observable in the marketplace or can be corroborated by active markets or broker quotes and are therefore designated as Level 2 within the valuation hierarchy. The Company's calculation of fair value for each of its derivative positions is compared to the counterparty valuation for reasonableness.

The following tables summarize the valuation of derivative instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2021 and 2020.

<i>In thousands</i>	Fair value measurements at December 31, 2021 using:				Total
	Level 1	Level 2	Level 3		
Derivative assets (liabilities):					
Fixed price swaps	\$ —	\$ 27,608	\$ —	\$	27,608
Basis swaps	—	(177)	—		(177)
Collars	—	3,986	—		3,986
Three-way collars	—	1,931	—		1,931
NYMEX roll swaps	—	957	—		957
Total	\$ —	\$ 34,305	\$ —	\$	34,305

<i>In thousands</i>	Fair value measurements at December 31, 2020 using:				Total
	Level 1	Level 2	Level 3		
Derivative assets (liabilities):					
Swaps	—	\$ 2,043	—		2,043
Collars	—	11,449	—		11,449
Total	\$ —	\$ 13,492	\$ —	\$	13,492

Assets Measured at Fair Value on a Nonrecurring Basis

Certain assets are reported at fair value on a nonrecurring basis in the consolidated financial statements. The following methods and assumptions were used to estimate the fair values for those assets.

Asset impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. Significant unobservable inputs (Level 3) utilized in the determination of discounted future net cash flows include future commodity prices adjusted for differentials, forecasted production based on decline curve analysis, estimated future operating and development costs, property ownership interests, and a 10% discount rate. At December 31, 2021, the Company's commodity price assumptions were based on forward NYMEX strip prices through year-end 2026 and were then escalated at 3% per year thereafter. Operating cost assumptions were based on current costs escalated at 3% per year beginning in 2023.

Unobservable inputs to the Company's fair value assessments are reviewed and revised as warranted based on a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Fair value measurements of proved properties are reviewed and approved by certain members of the Company's management.

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For the year ended December 31, 2021, estimated future net cash flows were determined to be in excess of cost basis, and therefore no impairment was recorded for the Company's proved crude oil and natural gas properties in 2021.

For the years ended December 31, 2020 and 2019, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Such impairments totaled \$207.1 million and \$3.7 million for 2020 and 2019, respectively, which for 2020 reflected fair value adjustments on legacy properties in the Red River Units totaling \$168.1 million and various non-core properties in the North and South regions totaling \$14.5 million. The impaired properties were written down to their estimated fair value at the time of impairment of \$145.7 million. Impairments for 2020 also include a \$24.5 million impairment recognized in the first quarter of 2020 to reduce the Company's crude oil inventory to estimated net realizable value at the time of impairment. Proved property impairments recognized in 2019 reflected write-offs of various non-core properties in the North and South regions.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2021, 2020, and 2019, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

The following table sets forth the non-cash impairments of both proved and unproved properties for the indicated periods. Proved and unproved property impairments are recorded under the caption "Property impairments" in the consolidated statements of comprehensive income (loss).

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Proved property and inventory impairments	\$ —	\$ 207,119	\$ 3,745
Unproved property impairments	38,370	70,822	82,457
Total	\$ 38,370	\$ 277,941	\$ 86,202

Financial Instruments Not Recorded at Fair Value

The following table sets forth the estimated fair values of financial instruments that are not recorded at fair value in the consolidated financial statements. See *Note 8. Long-Term Debt* for discussion of the changes in the Company's outstanding debt during the year ended December 31, 2021.

<i>In thousands</i>	December 31, 2021		December 31, 2020	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Credit facility	\$ 500,000	\$ 500,000	\$ 160,000	\$ 160,000
Notes payable	22,356	22,000	24,590	24,700
5% Senior Notes due 2022	—	—	630,470	632,900
4.5% Senior Notes due 2023	648,078	670,200	646,943	669,900
3.8% Senior Notes due 2024	908,061	950,000	906,922	939,500
2.268% Senior Notes due 2026	792,621	795,200	—	—
4.375% Senior Notes due 2028	991,880	1,082,100	990,746	1,024,400
5.75% Senior Notes due 2031	1,482,319	1,769,600	1,480,879	1,651,900
2.875% Senior Notes due 2032	791,521	780,500	—	—
4.9% Senior Notes due 2044	692,056	781,500	691,868	689,600
Total debt	\$ 6,828,892	\$ 7,351,100	\$ 5,532,418	\$ 5,792,900

The fair value of credit facility borrowings approximate carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and are classified as Level 2 in the fair value hierarchy.

The fair value of notes payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the notes payable and an assumed discount rate. The fair value of notes payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of notes payable is classified as Level 3 in the fair value hierarchy.

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The fair values of the Company's senior notes are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

Note 8. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling \$54.2 million and \$43.7 million at December 31, 2021 and 2020, respectively, consists of the following.

<i>In thousands</i>	December 31,	
	2021	2020
Credit facility	\$ 500,000	\$ 160,000
Notes payable	22,356	24,590
5% Senior Notes due 2022	—	630,470
4.5% Senior Notes due 2023	648,078	646,943
3.8% Senior Notes due 2024	908,061	906,922
2.268% Senior Notes due 2026	792,621	—
4.375% Senior Notes due 2028	991,880	990,746
5.75% Senior Notes due 2031	1,482,319	1,480,879
2.875% Senior Notes due 2032	791,521	—
4.9% Senior Notes due 2044	692,056	691,868
Total debt	6,828,892	5,532,418
Less: Current portion of long-term debt	2,326	2,245
Long-term debt, net of current portion	\$ 6,826,566	\$ 5,530,173

Credit Facility

On October 29, 2021, the Company replaced its credit facility which resulted in an increase in aggregate commitments from \$1.5 billion to \$1.7 billion and an extension of the maturity date from April 2023 to October 2026. On November 22, 2021, the Company incrementally increased the amount of aggregate credit facility commitments from \$1.7 billion to \$2.0 billion. The new credit facility provides for benchmark replacement mechanics to address the transition from LIBOR, while all other terms, conditions, and covenants remain substantially unchanged from the prior credit facility. The Company's credit facility is unsecured and has no borrowing base requirement subject to redetermination.

The Company had \$500 million of outstanding borrowings on its credit facility at December 31, 2021, which were incurred to fund a portion of the Company's December 2021 acquisition of properties in the Permian Basin of Texas as discussed in *Note 2. Property Acquisitions and Dispositions*. Credit facility borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The weighted-average interest rate on outstanding credit facility borrowings at December 31, 2021 was 1.6%.

The Company had approximately \$1.50 billion of borrowing availability on its credit facility at December 31, 2021 after considering outstanding borrowings and letters of credit. The Company incurs commitment fees based on currently assigned credit ratings of 0.20% per annum on the daily average amount of unused borrowing availability.

The credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the credit facility covenants at December 31, 2021.

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Senior Notes

In November 2021 the Company issued \$800 million of 2.268% Senior Notes due 2026 ("2026 Notes") and \$800 million of 2.875% Senior Notes due 2032 ("2032 Notes") and received combined total net proceeds from the offerings of \$1.59 billion after deducting the initial purchasers' fees and original issuance discount. The 2026 Notes were sold at par and the 2032 Notes were sold at 99.922% of par in private placement transactions exempt from the registration requirements of the Securities Act to eligible purchasers. The Company used the net proceeds from the offerings to finance a portion of its December 2021 acquisition of properties in the Permian Basin as discussed in *Note 2. Property Acquisitions and Dispositions*.

The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company's outstanding senior note obligations at December 31, 2021.

	2023 Notes	2024 Notes	2026 Notes	2028 Notes	2031 Notes	2032 Notes	2044 Notes
Face value (in thousands)	\$649,625	\$911,000	\$800,000	\$1,000,000	\$1,500,000	\$800,000	\$700,000
Maturity date	April 15, 2023	June 1, 2024	November 15, 2026	January 15, 2028	January 15, 2031	April 1, 2032	June 1, 2044
Interest payment dates	April 15, Oct 15	June 1, Dec 1	May 15, Nov 15	Jan 15, July 15	Jan 15, Jul 15	April 1, Oct 1	June 1, Dec 1
Make-whole redemption period (1)	Jan 15, 2023	Mar 1, 2024	Nov 15, 2023	Oct 15, 2027	Jul 15, 2030	January 1, 2032	Dec 1, 2043

- (1) At any time prior to the indicated dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the "make-whole" redemption amounts specified in the respective senior note indentures plus any accrued and unpaid interest to the date of redemption. On or after the indicated dates, the Company may redeem all or a portion of its senior notes at a redemption amount equal to 100% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption.

The Company's senior notes are not subject to any mandatory redemption or sinking fund requirements.

The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, or consolidate, merge or transfer certain assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at December 31, 2021.

The senior notes are obligations of Continental Resources, Inc. Additionally, as of December 31, 2021 three of the Company's wholly-owned consolidated subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, whose assets, equity, and results of operations are not material, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company plans to designate Jagged Peak Energy LLC and Parsley SoDe Water LLC, its recently acquired consolidated subsidiaries discussed in *Note 2. Property Acquisitions and Dispositions*, as restricted subsidiaries under the Company's senior note indentures. As a result, such entities will fully and unconditionally guarantee the senior notes on a joint and several basis along with the Company's other subsidiary guarantors. The Company's other subsidiaries existing at December 31, 2021, whose assets, equity, and results of operations attributable to the Company are not material, do not guarantee the senior notes.

Retirement of Senior Notes

2021

In January 2021, the Company redeemed \$400.0 million principal amount of its outstanding 2022 Notes and subsequently redeemed the remaining \$230.8 million principal amount of its 2022 Notes in April 2021. The Company recognized pre-tax losses on extinguishment of debt totaling \$0.3 million related to the redemptions, which included the pro-rata write-off of deferred financing costs and unamortized debt premium associated with the redeemed notes. The losses are reflected in the caption "Gain (loss) on extinguishment of debt" in the consolidated statements of comprehensive income (loss).

2020

In March and April 2020, the Company repurchased a portion of its 2023 Notes and 2024 Notes in open market transactions at a substantial discount to the face value of the notes, including \$50.4 million face value of its 2023 Notes at an aggregate cost of \$29.3 million and \$89.0 million face value of its 2024 Notes at an aggregate cost of \$46.9 million, in each case, including accrued and unpaid interest to the repurchase dates. The Company recognized pre-tax gains on extinguishment of debt totaling

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\$64.6 million related to the repurchases, which included the pro-rata write-off of deferred financing costs and unamortized debt discount associated with the notes.

In November 2020, the Company repurchased \$469.2 million of its 2022 Notes and \$800.0 million of its 2023 Notes using proceeds from its November 2020 issuance of \$1.5 billion of 5.75% Senior Notes due 2031. For the 2022 Notes, the purchase price was equal to 100.250% of the principal amount repurchased plus accrued and unpaid interest to the repurchase date. The aggregate of the principal amount, premium, and accrued interest paid upon repurchase of the 2022 Notes was \$475.0 million. For the 2023 Notes, the purchase price was equal to 103.000% of the principal amount repurchased plus accrued and unpaid interest to the repurchase date. The aggregate of the principal amount, premium, and accrued interest paid upon repurchase of the 2023 Notes was \$828.0 million. The Company recorded pre-tax losses on extinguishment of debt related to these repurchases totaling \$28.9 million, which included the premium and pro-rata write-off of deferred financing costs and unamortized debt premium associated with the notes.

2019

In September 2019, the Company redeemed \$500 million of its previously outstanding \$1.6 billion of 2022 Notes. The redemption price was equal to 100.833% of the principal amount called for redemption plus accrued and unpaid interest to the redemption date. The aggregate of the principal amount, redemption premium, and accrued interest paid upon redemption was \$516.5 million. The Company recorded a pre-tax loss on extinguishment of debt related to the redemption of \$4.6 million, which included the redemption premium and pro-rata write-off of deferred financing costs and unamortized debt premium associated with the notes.

Notes payable

In June 2020, the Company borrowed an aggregate of \$26.0 million under two 10-year amortizing term loans secured by the Company's corporate office building and its interest in parking facilities in Oklahoma City, Oklahoma. The loans mature in May 2030 and bear interest at a fixed rate of 3.50% per annum through June 9, 2025, at which time the interest rate will be reset and fixed through the maturity date. Principal and interest are payable monthly through the maturity date and, accordingly, \$2.3 million is reflected as a current liability under the caption "Current portion of long-term debt" in the consolidated balance sheets as of December 31, 2021 associated with the loans. A portion of the proceeds from the new loans was used to fully repay the Company's previous note payable that was set to mature in February 2022, which had a balance at pay-off of \$4.4 million.

Note 9. Revenues

Below is a discussion of the nature, timing, and presentation of revenues arising from the Company's major revenue-generating arrangements.

Operated crude oil revenues – The Company pays third parties to transport the majority of its operated crude oil production from lease locations to downstream market centers, at which time the Company's customers take title and custody of the product in exchange for prices based on the particular market where the product was delivered. Operated crude oil revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. Crude oil sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred. Operated crude oil revenues are presented separately from transportation expenses, as the Company controls the operated production prior to its transfer to customers. Transportation expenses associated with the Company's operated crude oil production totaled \$185.1 million, \$159.0 million, and \$192.0 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Operated natural gas revenues – The Company sells the majority of its operated natural gas production to midstream customers at its lease locations based on market prices in the field where the sales occur. Under these arrangements, the midstream customers obtain control of the unprocessed gas stream at the lease location and the Company's revenues from each sale are determined using contractually agreed pricing formulas which contain multiple components, including the volume and Btu content of the natural gas sold, the midstream customer's proceeds from the sale of residue gas and natural gas liquids ("NGLs") at secondary downstream markets, and contractual pricing adjustments reflecting the midstream customer's estimated recoupment of its investment over time. Such revenues are recognized net of pricing adjustments applied by the midstream customer during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Natural gas sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred.

Under certain arrangements, in periods of significantly depressed prices for natural gas and NGLs the contractual pricing adjustments applied by the midstream customer in a particular month may exceed the consideration to be received by the Company under the arrangement, resulting in a net payment owed by the Company to the midstream customer. In these

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situations, the net amounts paid or payable by the Company are reflected as a reduction of natural gas sales in the caption "Crude oil and natural gas sales" in the consolidated statements of comprehensive income (loss). Such payments, which are referred to herein as negative gas revenues, were immaterial for 2021 and 2019 and totaled \$25.6 million for operated properties for 2020.

Under certain arrangements, the Company has the right to take a volume of processed residue gas and/or NGLs in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement for the sale of the Company's operated natural gas production. When the Company elects to take volumes in kind, it pays third parties to transport the processed products it took in-kind to downstream delivery points, where it then sells to customers at prices applicable to those downstream markets. In such situations, operated revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Operated sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, the Company's revenues include the pricing adjustments applied by the midstream processing entity according to the applicable contractual pricing formula, but exclude the transportation expenses the Company incurs to transport the processed products to downstream customers. Transportation expenses associated with these arrangements totaled \$39.9 million, \$37.7 million, and \$33.7 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Non-operated crude oil and natural gas revenues – The Company's proportionate share of production from non-operated properties is generally marketed at the discretion of the operators. For non-operated properties, the Company receives a net payment from the operator representing its proportionate share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds to be received by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive. Proceeds are generally received by the Company within two to three months after the month in which production occurs.

In periods of significantly depressed prices for natural gas and NGLs the costs incurred by the outside operator in a particular month may exceed the consideration to be received by the Company, resulting in a net payment owed by the Company to the outside operator. In these situations, the net amounts paid or payable by the Company are reflected as a reduction of natural gas sales in the caption "Crude oil and natural gas sales" in the consolidated statements of comprehensive income (loss). Such negative gas revenues associated with non-operated properties were immaterial for 2021 and 2019 and totaled \$17.3 million for 2020.

Revenues from derivative instruments – See Note 6. *Derivative Instruments* for discussion of the Company's accounting for its derivative instruments.

Revenues from service operations – Revenues from the Company's crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of crude oil reclaimed from waste products. Revenues associated with such activities, which are derived using market-based rates or rates commensurate with industry guidelines, are recognized during the month in which services are performed, the Company has an unconditional right to receive payment, and collectability is probable. Payment is generally received by the Company within one month after the month in which services are provided.

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Disaggregation of crude oil and natural gas revenues

The following table presents the disaggregation of the Company's crude oil and natural gas revenues for the periods presented.

<i>In thousands</i>	Year ended December 31,								
	2021			2020			2019		
	North Region	South Region	Total	North Region	South Region	Total	North Region	South Region	Total
Crude oil revenues:									
Operated properties	\$ 2,392,465	\$ 838,129	\$ 3,230,594	\$ 1,264,149	\$ 537,961	\$ 1,802,110	\$ 2,365,574	\$ 786,652	\$ 3,152,226
Non-operated properties	656,727	61,973	718,700	362,952	34,914	397,866	727,068	50,700	777,768
Total crude oil revenues	3,049,192	900,102	3,949,294	1,627,101	572,875	2,199,976	3,092,642	837,352	3,929,994
Natural gas revenues:									
Operated properties (1)	460,376	1,186,937	1,647,313	28,086	301,486	329,572	109,668	411,464	521,132
Non-operated properties (2)	115,420	81,714	197,134	720	25,166	25,886	25,188	38,075	63,263
Total natural gas revenues	575,796	1,268,651	1,844,447	28,806	326,652	355,458	134,856	449,539	584,395
Crude oil and natural gas sales	\$ 3,624,988	\$ 2,168,753	\$ 5,793,741	\$ 1,655,907	\$ 899,527	\$ 2,555,434	\$ 3,227,498	\$ 1,286,891	\$ 4,514,389
Timing of revenue recognition									
Goods transferred at a point in time	\$ 3,624,988	\$ 2,168,753	\$ 5,793,741	\$ 1,655,907	\$ 899,527	\$ 2,555,434	\$ 3,227,498	\$ 1,286,891	\$ 4,514,389
Goods transferred over time	—	—	—	—	—	—	—	—	—
	\$ 3,624,988	\$ 2,168,753	\$ 5,793,741	\$ 1,655,907	\$ 899,527	\$ 2,555,434	\$ 3,227,498	\$ 1,286,891	\$ 4,514,389

- (1) Operated natural gas revenues for the North region include negative gas revenues totaling \$25.6 million for the year ended December 31, 2020.
(2) Non-operated natural gas revenues for the North region include negative gas revenues totaling \$17.3 million for the year ended December 31, 2020.

Performance obligations

The Company satisfies the performance obligations under its crude oil and natural gas sales contracts upon delivery of its production and related transfer of control to customers. Judgment may be required in determining the point in time when control transfers to customers. Upon delivery of production, the Company has a right to receive consideration from its customers in amounts determined by the sales contracts.

The Company's outstanding crude oil sales contracts at December 31, 2021 are primarily short-term in nature with contract terms of less than one year. For such contracts, the Company has utilized the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

The majority of the Company's operated natural gas production is sold at lease locations to midstream customers under multi-year term contracts. For such contracts having a term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14A which indicates an entity is not required to disclose the transaction price allocated to remaining performance obligations, if any, if variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's sales contracts, whether for crude oil or natural gas, each unit of production delivered to a customer represents a separate performance obligation; therefore, future volumes to be delivered are wholly unsatisfied at period-end and disclosure of the transaction price allocated to remaining performance obligations is not applicable.

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Contract balances

Under the Company's crude oil and natural gas sales contracts or activities that give rise to service revenues, the Company recognizes revenue after its performance obligations have been satisfied, at which point the Company has an unconditional right to receive payment. Accordingly, the Company's commodity sales contracts and service activities generally do not give rise to contract assets or contract liabilities under ASC Topic 606. Instead, the Company's unconditional rights to receive consideration are presented as a receivable within "Receivables—Crude oil and natural gas sales" or "Receivables—Joint interest and other," as applicable, in its consolidated balance sheets.

Revenues from previously satisfied performance obligations

To record revenues for commodity sales, at the end of each month the Company estimates the amount of production delivered and sold to customers and the prices to be received for such sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer and are reflected in the financial statements within the caption "Crude oil and natural gas sales". Revenues recognized during the years ended December 31, 2021, 2020, and 2019 related to performance obligations satisfied in prior reporting periods were not material.

Note 10. Allowance for Credit Losses

The Company's principal exposure to credit risk is through the sale of its crude oil and natural gas production and its receivables associated with billings to joint interest owners. Accordingly, the Company classifies its receivables into two portfolio segments as depicted on the consolidated balance sheets as "Receivables—Crude oil and natural gas sales" and "Receivables—Joint interest and other."

Historically, the Company's credit losses on receivables have been immaterial. The Company's aggregate allowance for credit losses totaled \$2.8 million and \$2.5 million at December 31, 2021 and 2020, respectively, which is reported as "Allowance for credit losses" in the consolidated balance sheets. Aggregate credit loss expenses totaled \$0.8 million, \$1.8 million, and \$1.6 million for the years ended December 31, 2021, 2020, and 2019, respectively, which are included in "General and administrative expenses" in the consolidated statements of comprehensive income (loss).

Receivables—Crude oil and natural gas sales

The Company's crude oil and natural gas production from operated properties is generally sold to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies. The Company monitors its credit loss exposure to these counterparties primarily by reviewing credit ratings, financial statements, and payment history. Credit terms are extended based on an evaluation of each counterparty's credit worthiness. The Company has not generally required its counterparties to provide collateral to secure its crude oil and natural gas sales receivables.

Receivables associated with crude oil and natural gas sales are short term in nature. Receivables from the sale of crude oil and natural gas from operated properties are generally collected within one month after the month in which a sale has occurred, while receivables associated with non-operated properties are generally collected within two to three months after the month in which production occurs.

The Company's allowance for credit losses on crude oil and natural gas sales was negligible at both December 31, 2021 and December 31, 2020. The allowance was determined by considering a number of factors, primarily including the Company's history of credit losses with adjustment as needed to reflect current conditions, the length of time accounts are past due, whether amounts relate to operated properties or non-operated properties, and the counterparty's ability to pay. There were no significant write-offs, recoveries, or changes in the provision for credit losses on this portfolio segment during the years ended December 31, 2021, 2020, and 2019.

Receivables—Joint interest and other

Joint interest and other receivables primarily arise from billing the individuals and entities who own a partial interest in the wells we operate. Joint interest receivables are due within 30 days and are considered delinquent after 60 days. In order to minimize our exposure to credit risk with these counterparties we generally request prepayment of drilling costs where it is allowed by contract or state law. Such prepayments are used to offset future capital costs when billed, thereby reducing the Company's credit risk. We may have the right to place a lien on a co-owner's interest in the well, to net production proceeds against amounts owed in order to secure payment or, if necessary, foreclose on the co-owner's interest.

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The Company's allowance for credit losses on joint interest receivables totaled \$2.8 million and \$2.5 million at December 31, 2021 and 2020, respectively. The allowance was determined by considering a number of factors, primarily including the Company's history of credit losses with adjustment as needed to reflect current conditions, the length of time accounts are past due, the ability to recoup amounts owed through netting of production proceeds, the balance of co-owner prepayments if any, and the co-owner's ability to pay. There were no significant write-offs, recoveries, or changes in the provision for credit losses on this portfolio segment during the years ended December 31, 2021, 2020, and 2019.

Note 11. Income Taxes

The items comprising the Company's provision (benefit) for income taxes are as follows for the periods presented:

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Current income tax provision (benefit):			
United States federal	\$ —	\$ (2,248)	\$ —
Various states	—	29	—
Total current income tax provision (benefit)	—	(2,219)	—
Deferred income tax provision (benefit):			
United States federal	467,051	(148,828)	191,328
Various states	52,679	(18,143)	21,361
Total deferred income tax provision (benefit)	519,730	(166,971)	212,689
Provision (benefit) for income taxes	\$ 519,730	\$ (169,190)	\$ 212,689
Effective tax rate	23.8 %	21.8 %	21.5 %

The Company's effective tax rate differs from the United States federal statutory tax rate due to the effect of state income taxes, equity compensation, changes in valuation allowances, and other tax items as reflected in the table below.

<i>In thousands, except tax rates</i>	Year ended December 31,		
	2021	2020	2019
Income (loss) before income taxes	\$ 2,186,138	\$ (774,751)	\$ 987,162
U.S. federal statutory tax rate	21.0 %	21.0 %	21.0 %
Expected income tax provision (benefit) based on U.S. federal statutory tax rate	459,089	(162,698)	207,304
Items impacting the effective tax rate:			
State and local income taxes, net of federal benefit	77,979	(24,808)	31,967
Tax (benefit) deficiency from stock-based compensation	5,869	4,927	(7,971)
Sale of Canadian subsidiary and assets	—	—	(16,860)
Other, net	(8,733)	(1,085)	(1,751)
Change in valuation allowance	(14,474)	14,474	—
Provision (benefit) for income taxes	\$ 519,730	\$ (169,190)	\$ 212,689
Effective tax rate	23.8 %	21.8 %	21.5 %

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In assessing the realizability of deferred tax assets the Company must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company applies judgment to determine the weight of both positive and negative evidence in order to conclude whether a valuation allowance is necessary for its deferred tax assets. In determining whether a valuation allowance is required, the Company considers, among other factors, the Company's financial position, results of operations, projected future taxable income, reversal of existing deferred tax liabilities against deferred tax assets, and tax planning strategies. During 2020, a \$14.5 million valuation allowance was established for the deferred tax asset associated with a portion of the Company's Oklahoma state net operating loss carryforwards. In 2021, the Company reassessed the realizability of the deferred tax asset related to Oklahoma state net operating loss carryforwards, and based on current year activity, determined it was more likely than not that such assets would be realized. Therefore, it was determined that the previously recorded valuation allowance in 2020 should be released in 2021.

The Company will continue to evaluate both the positive and negative evidence on a quarterly basis in determining the need for a valuation allowance with respect to its deferred tax assets. Changes in positive and negative evidence, including differences between estimated and actual results, could result in changes in the valuation of our deferred tax assets that could have a material impact on our consolidated financial statements. Changes in existing tax laws could also affect actual tax results and the realization of deferred tax assets over time.

In 2019, the Company sold its Canadian subsidiary and associated properties. Prior to the sale, the Company had recognized cumulative valuation allowances totaling \$19.6 million against deferred tax assets associated with operating loss carryforwards generated by the Canadian subsidiary for which the Company did not expect to realize a benefit. In conjunction with the sale, the deferred tax assets, deferred tax liabilities, and cumulative valuation allowance related to the Canadian subsidiary were removed, and an income tax benefit of \$16.9 million was recorded related to the resulting capital loss on the sale of the stock.

The components of the Company's deferred tax assets and deferred tax liabilities as of December 31, 2021 and 2020 are reflected in the table below.

<i>In thousands</i>	December 31,	
	2021	2020
Deferred tax assets		
United States net operating loss carryforwards	\$ 365,602	\$ 579,781
Equity compensation	12,751	12,900
Other	29,421	10,691
Total deferred tax assets	407,774	603,372
Valuation allowance	—	(14,474)
Total deferred tax assets, net of valuation allowance	407,774	588,898
Deferred tax liabilities		
Property and equipment	(2,536,938)	(2,204,378)
Other	(10,720)	(4,674)
Total deferred tax liabilities	(2,547,658)	(2,209,052)
Deferred income tax liabilities, net	\$ (2,139,884)	\$ (1,620,154)

As of December 31, 2021, the Company had federal and state net operating loss carryforwards of \$1.17 billion and \$3.63 billion, respectively. Approximately \$283 million of the Company's federal net operating loss carryforwards were generated in tax years prior to 2018 and expire in 2037, with the remaining \$887 million having an indefinite life. The Company's net operating loss carryforward in Oklahoma totaled \$3.07 billion at December 31, 2021, of which \$1.96 billion expires between 2030 and 2037, and the remaining \$1.11 billion has an indefinite life. The Company's net operating loss carryforward in North Dakota totaled \$457 million at December 31, 2021 and has an indefinite life. Any available statutory depletion carryforwards will be recognized when realized. The Company files income tax returns in U.S. federal and state jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years prior to 2018.

Note 12. Leases

The Company's lease liabilities recognized on the balance sheet as a lessee totaled \$15.5 million and \$8.4 million as of December 31, 2021 and 2020, respectively, at discounted present value, which is comprised of the asset classes reflected in the table below. All leases recognized on the Company's balance sheet are classified as operating leases. The amounts disclosed

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herein primarily represent costs associated with properties operated by the Company that are presented on a gross basis and do not represent the Company's net proportionate share of such amounts. A portion of these costs have been or will be billed to other working interest owners. Once paid, the Company's share of these costs are included in property and equipment, production expenses, or general and administrative expenses, as applicable.

The Company accounts for lease and non-lease components in its contracts as a single lease component for all asset classes. Additionally, the Company does not apply the recognition requirements of ASC Topic 842 to leases with durations of twelve months or less and uses hindsight in determining the lease term for all leases. The Company's leasing activities as a lessor are negligible.

<i>In thousands</i>	December 31,	
	2021	2020
Drilling rig commitments	\$ —	\$ 2,025
Surface use agreements	12,354	4,928
Field equipment	2,095	928
Other	1,025	546
Total	\$ 15,474	\$ 8,427

Minimum future commitments by year for the Company's operating leases as of December 31, 2021 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the balance sheet.

<i>In thousands</i>	Amount
2022	\$ 2,369
2023	2,263
2024	1,831
2025	1,295
2026	1,258
Thereafter	13,084
Total operating lease liabilities, at undiscounted value	\$ 22,100
Less: Imputed interest	(6,626)
Total operating lease liabilities, at discounted present value	\$ 15,474
Less: Current portion of operating lease liabilities	(1,674)
Operating lease liabilities, net of current portion	\$ 13,800

Additional information for the Company's operating leases is presented below. Lease costs primarily represent costs incurred for drilling rigs, most of which are short term contracts that are not recognized as right-of-use assets and lease liabilities on the balance sheet. Variable lease costs primarily represent differences between minimum payment obligations and actual operating day-rate charges incurred by the Company for its long term drilling rig contracts. Short-term lease costs primarily represent operating day-rate charges for drilling rig contracts with durations of one year or less and month-to-month field equipment rentals. A portion of such lease costs are borne by other interest owners.

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<i>In thousands, except weighted average data</i>	Year ended December 31,		
	2021	2020	2019
Lease costs:			
Operating lease costs	\$ 6,653	\$ 6,444	\$ 11,130
Variable lease costs	3,271	4,956	11,930
Short-term lease costs	77,551	107,984	176,586
Total lease costs	\$ 87,475	\$ 119,384	\$ 199,646
Other information:			
Right-of-use assets obtained in exchange for new operating lease liabilities (1)	\$ 10,481	\$ 7,377	\$ 1,208
Operating cash flows from operating leases included in lease liabilities	1,731	890	804
Weighted average remaining lease term as of December 31 (in years)	14.4	13.2	11.5
Weighted average discount rate as of December 31	5.0 %	4.8 %	4.9 %

(1) Balance for 2021 primarily represents \$10.0 million of right-of-use assets and corresponding lease liabilities recognized in connection with the Company's property acquisitions discussed in *Note 2. Property Acquisitions and Dispositions*.

Note 13. Commitments and Contingencies

Transportation, gathering, and processing commitments – The Company has entered into transportation, gathering, and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. The commitments, which have varying terms extending as far as 2031, require the Company to pay per-unit transportation, gathering, or processing charges regardless of the amount of capacity used. Future commitments remaining as of December 31, 2021 under the arrangements amount to approximately \$1.31 billion, of which \$275 million is expected to be incurred in 2022, \$270 million in 2023, \$251 million in 2024, \$164 million in 2025, \$139 million in 2026, and \$214 million thereafter. A portion of these future costs will be borne by other interest owners. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. These commitments do not qualify as leases under ASC Topic 842 and are not recognized on the Company's balance sheet.

Lease commitments – The Company has various lease commitments primarily associated with surface use agreements and field equipment. See *Note 12. Leases* for additional information.

Pledge commitment – The Company entered into a \$25.0 million ten-year irrevocable pledge agreement with Oklahoma State University in December 2021. The pledge agreement provides for ten equal payments of \$2.5 million to be paid annually on or before December 31 of each year until the pledge is paid in full on December 31, 2030. In connection with the pledge, the Company recognized a \$25.0 million charge to earnings which is reflected in the caption "Other income (expense)—Other" in the consolidated statements of comprehensive income (loss) for the year ended December 31, 2021.

Pending property acquisition – See *Note 20. Subsequent Events* for discussion of a definitive acquisition agreement executed by the Company subsequent to December 31, 2021.

Litigation – The Company is involved in various legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of December 31, 2021 and 2020, the Company had recognized a liability within "Other noncurrent liabilities" of \$7.9 million and \$7.7 million, respectively, for various matters, none of which are believed to be individually significant.

Environmental risk – Due to the nature of the crude oil and natural gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

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Note 14. Related Party Transactions

Certain officers of the Company own or control entities that own working and royalty interests in wells operated by the Company. The Company paid revenues to these affiliates, including royalties, of \$0.4 million, \$0.2 million, and \$0.4 million and received payments from these affiliates of \$0.1 million, \$0.3 million, and \$0.3 million during the years ended December 31, 2021, 2020, and 2019, respectively, relating to the operations of the respective properties. At December 31, 2021 and 2020, approximately \$39,000 and \$18,000, respectively, was due from these affiliates relating to these transactions, which is included in “Receivables—Joint interest and other” on the consolidated balance sheets. At December 31, 2021 and 2020, approximately \$37,000 and \$18,000, respectively, was due to these affiliates relating to these transactions, which is included in “Revenues and royalties payable” on the consolidated balance sheets.

The Company allows certain affiliates to use its corporate aircraft and crews and has used the aircraft of those same affiliates from time to time in order to facilitate efficient transportation of Company personnel. The rates charged between the parties vary by type of aircraft used. For usage during 2021, 2020, and 2019, the Company charged affiliates approximately \$11,300, \$8,100, and \$17,600, respectively, for use of its corporate aircraft crews, fuel, and reimbursement of expenses and received approximately \$5,000, \$9,500, and \$18,900 from affiliates in 2021, 2020, and 2019, respectively, in connection with such items. The Company was charged approximately \$117,000, \$120,000, and \$303,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2021, 2020, and 2019 and paid \$84,000, \$158,000, and \$426,000 to the affiliates in 2021, 2020, and 2019, respectively. At December 31, 2021, approximately \$6,300 was due from an affiliate relating to these transactions, which is included in “Receivables—Joint interest and other” on the consolidated balance sheets. At December 31, 2021, approximately \$33,000 was due to an affiliate relating to these transactions, which is included in “Accounts payable trade” on the consolidated balance sheets. No amounts were due to or from the affiliate at December 31, 2020.

Note 15. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2013 Long-Term Incentive Plan, as amended (“2013 Plan”). The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the consolidated statements of comprehensive income (loss), was \$63.2 million, \$64.6 million, and \$52.0 million for the years ended December 31, 2021, 2020, and 2019, respectively.

In March 2019, the Company amended and restated its 2013 Plan and specified 12,983,543 shares of common stock may be issued pursuant to the amended plan. Subject to limited exceptions, the 2013 Plan allows previously issued shares to be reissued if such shares are subsequently forfeited or withheld to satisfy tax withholdings. As of December 31, 2021, the Company had 8,492,645 shares of common stock available for long-term incentive awards to employees and directors under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company’s common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock and to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from 1 to 3 years.

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A summary of changes in non-vested restricted shares from December 31, 2018 to December 31, 2021 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2018	4,022,409	\$ 38.44
Granted	1,526,825	43.21
Vested	(1,737,304)	24.19
Forfeited	(350,022)	47.13
Non-vested restricted shares at December 31, 2019	3,461,908	\$ 46.82
Granted	2,738,625	26.93
Vested	(1,146,618)	45.78
Forfeited	(163,277)	36.69
Non-vested restricted shares at December 31, 2020	4,890,638	\$ 36.26
Granted	3,050,491	24.73
Vested	(1,750,483)	44.36
Forfeited	(296,138)	26.61
Non-vested restricted shares at December 31, 2021	5,894,508	\$ 28.38

The grant date fair value of restricted stock represents the closing market price of the Company's common stock on the date of grant. Compensation expense for a restricted stock grant is determined at the grant date fair value and is recognized over the vesting period as services are rendered by employees and directors. The Company estimates the number of forfeitures expected to occur in determining the amount of stock-based compensation expense to recognize. There are no post-vesting restrictions related to the Company's restricted stock. The fair value at the vesting date of restricted stock that vested during 2021, 2020, and 2019 was approximately \$46.7 million, \$27.5 million, and \$79.7 million, respectively. As of December 31, 2021, there was approximately \$70 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.4 years.

Note 16. Shareholders' Equity Attributable to Continental Resources

Share Repurchases

In May 2019 the Company's Board of Directors approved the initiation of a share repurchase program to acquire up to \$1 billion of the Company's common stock beginning in June 2019. See *Note 20. Subsequent Events* for discussion of an increase in the authorized amount of the Company's share repurchase program made subsequent to December 31, 2021. As of December 31, 2021, the Company has repurchased and retired a cumulative total of approximately 17.0 million shares under the program at an aggregate cost of \$441.1 million as reflected in the table below by year.

	Number of shares	Aggregate cost (in thousands)
2019 Share Repurchases	5,646,553	\$ 190,239
2020 Share Repurchases	8,122,104	126,906
2021 Share Repurchases	3,198,571	123,924
Total	16,967,228	\$ 441,069

The timing and amount of the Company's share repurchases are subject to market conditions and management discretion. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.

Dividend Payments

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The following table summarizes the dividends paid by the Company on its outstanding common stock for the years ended December 31, 2021, 2020, and 2019.

	Amount (in thousands)	Dividend per share
Year Ended December 31, 2019		
Fourth quarter	\$ 18,747	\$ 0.05
Total	\$ 18,747	
Year Ended December 31, 2020		
First quarter	\$ 18,580	\$ 0.05
Total	\$ 18,580	
Year Ended December 31, 2021		
Second quarter	\$ 40,429	\$ 0.11
Third quarter	55,132	\$ 0.15
Fourth quarter	72,975	\$ 0.20
Total	\$ 168,536	

Accumulated other comprehensive income

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in “Accumulated other comprehensive income” within shareholders’ equity attributable to Continental Resources on the consolidated balance sheets and “Other comprehensive income (loss), net of tax” in the consolidated statements of comprehensive income (loss). The following table summarizes the change in accumulated other comprehensive income for the year ended December 31, 2019.

<i>In thousands</i>	2019
Beginning accumulated other comprehensive income, net of tax	\$ 415
Foreign currency translation adjustments	140
Release of cumulative translation adjustments (1)	(555)
Income taxes (2)	—
Other comprehensive income (loss), net of tax	(415)
Ending accumulated other comprehensive income, net of tax	\$ —

- (1) In conjunction with the Company’s sale of its Canadian operations in 2019, the cumulative translation adjustments were released. See *Note 2. Property Acquisitions and Dispositions* for further information.
- (2) A valuation allowance had been recognized against all deferred tax assets associated with losses generated by the Company’s Canadian operations, thereby resulting in no income taxes on other comprehensive income.

Note 17. Noncontrolling Interests

Strategic mineral relationship

In October 2018, Continental entered into a strategic relationship with Franco-Nevada Corporation to acquire oil and gas mineral interests within an area of mutual interest through a minerals subsidiary named The Mineral Resources Company II, LLC (“TMRC II”). At closing in October 2018, Continental contributed most of its previously acquired mineral interests to TMRC II in exchange for a 50.1% ownership interest in the entity and Franco-Nevada paid \$214.8 million to Continental for a 49.9% ownership interest in TMRC II and for funding of its share of certain mineral acquisition costs. Under the arrangement, Continental is to fund 20% of future mineral acquisitions and will be entitled to receive between 25% and 50% of total revenues generated by TMRC II based upon performance relative to certain predetermined production targets.

Continental holds a controlling financial interest in TMRC II and manages its operations. Accordingly, Continental consolidates the financial results of the entity and presents the portion of TMRC II’s results attributable to Franco-Nevada as a noncontrolling interest in its consolidated financial statements. Periodically, Franco-Nevada makes capital contributions to, and receives revenue distributions from, TMRC II and the portion of Continental’s consolidated net assets attributable to Franco-Nevada totaled \$369.8 million and \$355.1 million at December 31, 2021 and 2020, respectively.

Joint ownership arrangement

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Continental maintains an arrangement with a third party to jointly own parking facilities adjacent to the companies' corporate office buildings. The activities of the parking facilities, which are immaterial to Continental, are managed through an entity named SFPG, LLC ("SFPG"). Continental holds a controlling financial interest in SFPG and manages its operations. Accordingly, Continental consolidates the financial results of the entity and includes the results attributable to the third party within noncontrolling interests in Continental's financial statements. The portion of Continental's consolidated net assets attributable to the third party's ownership interest in SFPG totaled \$11.1 million and \$11.2 million at December 31, 2021 and 2020, respectively.

Note 18. Crude Oil and Natural Gas Property Information

The tables reflected below represent consolidated figures for the Company and its subsidiaries. In 2014, the Company initiated operations in Canada which were sold in the fourth quarter of 2019. The Company's Canadian operations have not had a material impact on historical capital expenditures, production, and revenues. Accordingly, the results of operations, costs incurred, and capitalized costs associated with the Canadian operations have not been shown separately from the consolidated figures in the tables below. Additionally, results attributable to noncontrolling interests are not material relative to the Company's consolidated results and are not separately presented below.

The following table sets forth the Company's consolidated results of operations from crude oil and natural gas producing activities for the years ended December 31, 2021, 2020 and 2019.

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Crude oil and natural gas sales	\$ 5,793,741	\$ 2,555,434	\$ 4,514,389
Production expenses	(406,906)	(359,267)	(444,649)
Production taxes	(404,362)	(192,718)	(357,988)
Transportation expenses	(224,989)	(196,692)	(225,649)
Exploration expenses	(21,047)	(17,732)	(14,667)
Depreciation, depletion, amortization and accretion	(1,872,075)	(1,859,893)	(1,997,854)
Property impairments	(38,370)	(277,941)	(86,202)
Income tax (provision) benefit (1)	(690,902)	83,427	(323,025)
Results from crude oil and natural gas producing activities	\$ 2,135,090	\$ (265,382)	\$ 1,064,355

- (1) Income taxes reflect the application of a combined federal and state tax rate of 24.5% on pre-tax income/loss generated by our operations in the United States. Additionally, the 2019 period includes the \$16.9 million income tax benefit recognized upon the Company's sale of its Canadian operations during that year.

Costs incurred in crude oil and natural gas activities

Costs incurred, both capitalized and expensed, in connection with the Company's consolidated crude oil and natural gas acquisition, exploration and development activities for the years ended December 31, 2021, 2020 and 2019 are presented below. See *Note 2. Property Acquisitions and Dispositions* for discussion of notable property acquisitions executed in 2021 that gave rise to the significant increase in costs incurred and aggregate capitalized costs in the current year.

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Property acquisition costs:			
Proved	\$ 2,580,271	\$ 60,494	\$ 51,558
Unproved	1,197,507	201,919	312,680
Total property acquisition costs	3,777,778	262,413	364,238
Exploration Costs	171,549	48,282	50,143
Development Costs	1,174,828	1,053,532	2,388,582
Total	\$ 5,124,155	\$ 1,364,227	\$ 2,802,963

Costs incurred above include asset retirement costs and revisions thereto of \$31.1 million, \$18.1 million and \$6.7 million for the years ended December 31, 2021, 2020 and 2019, respectively.

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Aggregate capitalized costs

Aggregate capitalized costs relating to the Company's consolidated crude oil and natural gas producing activities and related accumulated depreciation, depletion and amortization as of December 31, 2021 and 2020 are as follows:

<i>In thousands</i>	December 31,	
	2021	2020
Proved crude oil and natural gas properties	\$ 31,613,656	\$ 27,726,954
Unproved crude oil and natural gas properties	1,358,673	368,256
Total	32,972,329	28,095,210
Less accumulated depreciation, depletion and amortization	(16,310,054)	(14,622,376)
Net capitalized costs	\$ 16,662,275	\$ 13,472,834

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling and completion operations are complete, management attempts to determine whether the well has discovered crude oil and natural gas reserves and, if so, whether those reserves can be classified as proved reserves. Often, the determination of whether proved reserves can be recorded under SEC guidelines cannot be made when drilling is completed. In those situations where management believes that economically producible hydrocarbons have not been discovered, the exploratory drilling costs are reflected on the consolidated statements of comprehensive income (loss) as dry hole costs, a component of "Exploration expenses." Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred under the caption "Net property and equipment" on the consolidated balance sheets pending the outcome of those activities.

On at least a quarterly basis, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities—in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period of determination.

The following table presents the amount of capitalized exploratory well costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended:

<i>In thousands</i>	Year ended December 31,		
	2021	2020	2019
Balance at January 1	\$ 32,737	\$ 6,257	\$ 3,959
Additions to capitalized exploratory well costs pending determination of proved reserves	122,068	32,880	28,280
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(117,131)	(72)	(23,200)
Capitalized exploratory well costs charged to expense	(1)	(6,328)	(2,782)
Balance at December 31	\$ 37,673	\$ 32,737	\$ 6,257
Number of gross wells	17	16	11

As of December 31, 2021, the Company had no significant exploratory well costs that were suspended one year beyond the completion of drilling.

Note 19. Supplemental Crude Oil and Natural Gas Information (Unaudited)

The table below shows estimates of proved reserves prepared by the Company's internal technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company, L.P. prepared reserve estimates for properties comprising approximately 98%, 95%, and 91% of the Company's total proved reserves as of December 31, 2021, 2020, and 2019, respectively. Remaining reserve estimates were prepared by the Company's internal technical staff. All proved reserves stated herein are located in the United States. No proved reserves have been included for the Company's Canadian operations for the periods presented. Proved reserves attributable to noncontrolling interests are not material relative to the Company's consolidated reserves and are not separately presented in the tables below.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate

Continental Resources, Inc. and Subsidiaries
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expire, unless evidence indicates renewal is reasonably certain. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company's might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions or removals of estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, changes in business strategies, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered.

Reserves at December 31, 2021, 2020, and 2019 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by SEC rules.

Natural gas imbalance receivables and payables for each of the three years ended December 31, 2021, 2020, and 2019 were not material and have not been included in the reserve estimates.

Proved crude oil and natural gas reserves

Changes in proved reserves were as follows for the periods presented:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved reserves as of December 31, 2018	757,096	4,591,614	1,522,365
Revisions of previous estimates	(88,307)	(363,239)	(148,848)
Extensions, discoveries and other additions	162,710	1,213,947	365,034
Production	(72,267)	(311,865)	(124,244)
Sales of minerals in place	(803)	(6,224)	(1,840)
Purchases of minerals in place	1,758	30,238	6,798
Proved reserves as of December 31, 2019	760,187	5,154,471	1,619,265
Revisions of previous estimates	(249,845)	(1,530,174)	(504,874)
Extensions, discoveries and other additions	42,106	295,686	91,387
Production	(58,745)	(306,528)	(109,833)
Sales of minerals in place	—	—	—
Purchases of minerals in place	3,272	27,269	7,817
Proved reserves as of December 31, 2020	496,975	3,640,724	1,103,762
Revisions of previous estimates	14,574	233,966	53,569
Extensions, discoveries and other additions	165,268	1,235,022	371,105
Production	(58,636)	(370,110)	(120,321)
Sales of minerals in place	(70)	(469)	(148)
Purchases of minerals in place	175,419	371,546	237,343
Proved reserves as of December 31, 2021	793,530	5,110,679	1,645,310

Revisions of previous estimates. Revisions for 2021 are comprised of (i) upward price revisions of 92 MMBo and 458 Bcf (totaling 168 MMBoe) due to the significant increase in average crude oil and natural gas prices in 2021 compared to 2020 resulting from the lifting of COVID-19 restrictions, the resumption of normal economic activity, and the resulting improvement in supply and demand fundamentals, (ii) the removal of 31 MMBo and 155 Bcf (totaling 57 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due continual refinement of our drilling and development programs and reallocation of capital to areas providing the best opportunities to improve efficiencies, recoveries, and rates of return, (iii) downward revisions of 12 MMBo and 263 Bcf (totaling 56 MMBoe) from the removal of PUD reserves due to changes in anticipated well densities, economics, performance, and other factors, and (iv) downward revisions for oil reserves of 35 MMBo and upward revisions for natural gas reserves of 195 Bcf (netting to 2 MMBoe of downward revisions) due to changes in ownership interests, operating costs, anticipated production, and other factors.

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Revisions for 2020 are comprised of (i) the removal of 50 MMBo and 345 Bcf (totaling 107 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to a reduction in the scope of future drilling programs based on adverse market conditions, reduced demand, and lower prices caused by the COVID-19 pandemic and our resulting allocation of capital to areas providing the best opportunities to improve efficiencies, recoveries, and rates of return, (ii) downward revisions of 29 MMBo and 172 Bcf (totaling 58 MMBoe) from the removal of PUD reserves due to changes in economics, performance, and other factors, (iii) downward price revisions of 214 MMBo and 1,043 Bcf (totaling 388 MMBoe) due to a significant decrease in average crude oil and natural gas prices in 2020 compared to 2019 resulting from the economic turmoil caused by the COVID-19 pandemic and other factors, and (iv) net upward revisions for oil reserves of 43 MMBo and 31 Bcf (totaling 48 MMBoe) due to changes in ownership interests, operating costs, anticipated production, and other factors.

Revisions for 2019 are comprised of (i) the removal of 17 MMBo and 108 Bcf (totaling 35 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to continual refinement of the Company's drilling programs and reallocation of capital to areas providing the greatest opportunities to improve efficiencies, recoveries, and rates of return, (ii) downward revisions of 38 MMBo and 278 Bcf (totaling 85 MMBoe) from the removal of PUD reserves due to changes in economics, performance, and other factors, (iii) downward price revisions of 24 MMBo and 118 Bcf (totaling 43 MMBoe) due to a decrease in average crude oil and natural gas prices in 2019 compared to 2018, and (iv) net downward revisions for oil reserves of 9 MMBo and net upward revisions for natural gas reserves of 139 Bcf (netting to 14 MMBoe of upward revisions) due to changes in ownership interests, operating costs, anticipated production, and other factors.

Extensions, discoveries and other additions. Extensions, discoveries and other additions for each of the three years reflected in the table above were due to successful drilling and completion activities and continual refinement of our drilling programs. For 2021, proved reserve additions in the Bakken totaled 140 MMBo and 375 Bcf (totaling 202 MMBoe) and proved reserve additions in Oklahoma totaled 25 MMBo and 860 Bcf (totaling 169 MMBoe).

Sales of minerals in place. There were no individually significant dispositions of proved reserves in the three years reflected in the table above.

Purchases of minerals in place. Purchases for 2021 primarily represent acquisitions of proved reserves in the Permian Basin and Powder River Basin as discussed in *Note 2. Property Acquisitions and Dispositions*. Proved reserves acquired in the Permian Basin in 2021 totaled 149 MMBo and 326 Bcf (totaling 203 MMBoe) and proved reserves acquired in the Powder River Basin totaled 26 MMBo and 46 Bcf (totaling 34 MMBoe). There were no individually significant acquisitions of proved reserves in 2019 or 2020.

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped crude oil and natural gas reserves of the Company as of December 31, 2021, 2020 and 2019:

	December 31,		
	2021	2020	2019
Proved Developed Reserves			
Crude oil (MBbl)	424,153	281,906	336,405
Natural Gas (MMcf)	2,901,147	2,073,011	2,226,117
Total (MBoe)	907,678	627,407	707,424
Proved Undeveloped Reserves			
Crude oil (MBbl)	369,377	215,069	423,782
Natural Gas (MMcf)	2,209,532	1,567,713	2,928,354
Total (MBoe)	737,632	476,355	911,841
Total Proved Reserves			
Crude oil (MBbl)	793,530	496,975	760,187
Natural Gas (MMcf)	5,110,679	3,640,724	5,154,471
Total (MBoe)	1,645,310	1,103,762	1,619,265

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves expected to be recovered from new wells on undrilled acreage or from existing wells that require relatively major capital expenditures to recover, including most wells where drilling has occurred but the wells have not been completed. Natural gas is converted to barrels of crude oil equivalent using a conversion factor of six thousand cubic feet per barrel of crude oil based on the average equivalent energy content of natural gas compared to crude oil.

Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using the 12-month unweighted average of the first-day-of-the-month commodity prices, the costs in effect at December 31 of each year and a 10% discount factor. The Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the crude oil and natural gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, the estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

The following table sets forth the standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves as of December 31, 2021, 2020, and 2019. Discounted future net cash flows attributable to noncontrolling interests are not material relative to the Company's consolidated amounts and are not separately presented below.

<i>In thousands</i>	December 31,		
	2021	2020	2019
Future cash inflows	\$ 67,034,046	\$ 21,334,235	\$ 49,893,470
Future production costs	(18,837,000)	(7,750,834)	(15,309,672)
Future development and abandonment costs	(7,751,678)	(3,950,752)	(10,033,887)
Future income taxes (1)	(7,862,849)	(724,569)	(3,351,657)
Future net cash flows	32,582,519	8,908,080	21,198,254
10% annual discount for estimated timing of cash flows	(15,946,126)	(4,254,515)	(10,736,613)
Standardized measure of discounted future net cash flows	\$ 16,636,393	\$ 4,653,565	\$ 10,461,641

- (1) Estimated future income taxes were calculated by applying existing statutory tax rates, including any known future changes, to the estimated pre-tax net cash flows related to proved crude oil and natural gas reserves, giving effect to any permanent taxable differences and tax credits, less the tax basis of the properties involved. The U.S. federal statutory tax rate utilized in estimating future income taxes was 21% at December 31, 2021, 2020, and 2019.

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was \$62.19, \$34.34, and \$51.95 per barrel at December 31, 2021, 2020, and 2019, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was \$3.46, \$1.17, and \$2.02 per Mcf at December 31, 2021, 2020, and 2019, respectively. Future cash flows are reduced by estimated future costs to develop and produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions. The expected tax benefits to be realized from the utilization of net operating loss carryforwards and tax credits are used in the computation of future income tax cash flows.

Continental Resources, Inc. and Subsidiaries
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The changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are presented below for each of the past three years.

<i>In thousands</i>	December 31,		
	2021	2020	2019
Standardized measure of discounted future net cash flows at January 1	\$ 4,653,565	\$ 10,461,641	\$ 15,684,817
Extensions, discoveries and improved recoveries, less related costs	2,985,056	187,981	1,649,322
Revisions of previous quantity estimates	816,674	(2,952,489)	(1,564,503)
Changes in estimated future development and abandonment costs	706,168	4,760,286	1,401,513
Purchases (sales) of minerals in place, net	3,408,365	53,742	49,330
Net change in prices and production costs	9,396,945	(6,912,031)	(6,591,347)
Accretion of discount	489,273	1,183,993	1,865,034
Sales of crude oil and natural gas produced, net of production costs	(4,757,483)	(1,806,758)	(3,486,103)
Development costs incurred during the period	683,212	863,101	1,557,121
Change in timing of estimated future production and other	1,871,903	(2,325,024)	(1,690,779)
Change in income taxes	(3,617,285)	1,139,123	1,587,236
Net change	11,982,828	(5,808,076)	(5,223,176)
Standardized measure of discounted future net cash flows at December 31	\$ 16,636,393	\$ 4,653,565	\$ 10,461,641

Note 20. Subsequent Events

Acquisition Agreement

On January 24, 2022, the Company executed a definitive agreement to acquire oil and gas properties in the Powder River Basin for \$450 million of cash, subject to customary closing price adjustments. The properties include approximately 172,000 net leasehold acres and producing properties with production totaling approximately 16,000 barrels of oil equivalent per day based on two-stream reporting. Closing of the acquisition is expected to occur in late March 2022 and remains subject to the completion of customary due diligence procedures and closing conditions.

Increase in Share Repurchase Program

On February 8, 2022, the Company's Board of Directors approved an increase in the size of the Company's existing share repurchase program from \$1.0 billion to \$1.5 billion, inclusive of cumulative amounts repurchased to date. As of the date of this filing, the Company has repurchased a cumulative \$441.1 million of its common stock, leaving approximately \$1.06 billion of authorized repurchasing capacity under the modified program. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.

Dividend Declaration

On February 9, 2022, the Company declared a quarterly cash dividend of \$0.23 per share on its outstanding common stock, which will be paid on March 4, 2022 to shareholders of record as of February 22, 2022.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no changes in accountants or any disagreements with accountants.

Item 9A. Controls and Procedures**Evaluation of Disclosure Controls and Procedures**

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded the Company's disclosure controls and procedures were effective as of December 31, 2021 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our 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 our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our consolidated 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our consolidated 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.

Based on our evaluation under the framework in *Internal Control—Integrated Framework (2013)*, the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ William B. Berry
President and Chief Executive Officer

/s/ John D. Hart
Chief Financial Officer and Executive Vice President of Strategic Planning

February 14, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the “Company”) as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). 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 the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Company as of and for the year ended December 31, 2021, and our report dated February 14, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company’s management is responsible 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 Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 14, 2022

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held in May 2022 (the “Annual Meeting”) and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 201(d) of Regulation S-K with respect to securities authorized for issuance under equity compensation plans is disclosed in *Part II, Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Equity Compensation Plan Information* and is incorporated herein by reference. Other applicable information required as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The consolidated financial statements of Continental Resources, Inc. and Subsidiaries and the Report of Independent Registered Public Accounting Firm are included in Part II, Item 8 of this report. Reference is made to the accompanying Index to Consolidated Financial Statements.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes thereto.

(3) Index to Exhibits

The exhibits required to be filed or furnished pursuant to Item 601 of Regulation S-K are set forth below.

- 2.1 Purchase and Sale Agreement, dated November 1, 2021, by and among Continental Resources, Inc., Parsley Energy, LLC, Parsley Energy, L.P., Parsley Minerals, LLC, Parsley Energy Operations, LLC and, solely for the limited purposes set forth in the Agreement, Pioneer Natural Resources Company filed as Exhibit 2.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 5, 2021 and incorporated herein by reference.
- 3.1 Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendments filed on June 15, 2015 and May 21, 2020 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarter ended June 30, 2020 (Commission File No. 001-32886) filed August 3, 2020 and incorporated herein by reference.
- 3.2 Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company's Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
- 4.1 Registration Rights Agreement dated as of May 18, 2007 by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust filed as Exhibit 4.1 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference.
- 4.2 Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 4.3 Description of Capital Stock filed as Exhibit 4.3 to the Company's Form 10-K for the year ended December 31, 2020 (Commission File No. 001-32886) filed February 16, 2021 and incorporated herein by reference.
- 4.4 Registration Rights Agreement dated as of August 13, 2012 among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, and Jeffrey B. Hume filed as Exhibit 4.6 to the Company's Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
- 4.5 Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Form 10-Q for the quarter ended March 31, 2018 (Commission File No. 001-32886) filed May 2, 2018 and incorporated herein by reference.
- 4.6 Indenture dated as of May 19, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2014 and incorporated herein by reference.
- 4.7 Indenture dated as of December 8, 2017 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 12, 2017 and incorporated herein by reference.

- 4.8 Indenture dated as of November 25, 2020 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 25, 2020 and incorporated herein by reference.
- 4.9 Indenture dated as of November 22, 2021 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 22, 2021 and incorporated herein by reference.
- 10.1† Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.2† Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.3† Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended September 30, 2018 (Commission File No. 001-32886) filed October 29, 2018 and incorporated herein by reference.
- 10.4† First Amendment to the Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2014 (Commission File No. 001-32886) filed May 8, 2014 and incorporated herein by reference.
- 10.5† Second Amendment to the Continental Resources, Inc. Deferred Compensation Plan adopted and effective as of May 23, 2014 filed as Exhibit 10.15 to the Company's Registration Statement on Form S-4 (Commission File No. 333-196944) filed June 20, 2014 and incorporated herein by reference.
- 10.6 Revolving Credit Agreement dated October 29, 2021 among Continental Resources, Inc., as borrower, and its subsidiaries Banner Pipeline Company L.L.C., CLR Asset Holdings, LLC and The Mineral Resources Company as guarantors, MUFG Union Bank, N.A., as Administrative Agent, MUFG Union Bank, N.A., BofA Securities, Inc., Mizuho Bank, Ltd., TD Securities (USA) LLC, U.S. Bank National Association, Royal Bank of Canada, Wells Fargo Securities, LLC, and Truist Securities, Inc. as Joint Lead Arrangers and Joint Bookrunners, and the other lenders named therein filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 3, 2021 and incorporated herein by reference.
- 10.7† Summary of Non-Employee Director Compensation approved and effective as of May 19, 2021, filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended June 30, 2021 (Commission File No. 001-32886) filed August 2, 2021 and incorporated herein by reference.
- 10.8† Description of cash bonus plan updated as of March 16, 2021 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2021 (Commission File No. 001-32886) filed April 28, 2021 and incorporated herein by reference.
- 10.9† Amended and Restated Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2019 (Commission File No. 001-32886) filed April 29, 2019 and incorporated herein by reference.
- 10.10† First Amendment to the Amended and Restated Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.10 to the Company's Form 10-K for the year ended December 31, 2019 (Commission File No. 001-32886) filed February 26, 2020 and incorporated herein by reference.
- 10.11† Amended and Restated Form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended March 31, 2019 (Commission File No. 001-32886) filed April 29, 2019 and incorporated herein by reference.
- 10.12† Amended and Restated Form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.3 to the Company's Form 10-Q for the quarter ended March 31, 2019 (Commission File No. 001-32886) filed April 29, 2019 and incorporated herein by reference.
- 21* Subsidiaries of Continental Resources, Inc.
- 23.1* Consent of Grant Thornton LLP.

23.2*	<u>Consent of Ryder Scott Company, L.P.</u>
31.1*	<u>Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)</u>
31.2*	<u>Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)</u>
32**	<u>Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)</u>
99*	<u>Report of Ryder Scott Company, L.P., Independent Petroleum Engineers and Geologists</u>
101.INS*	Inline XBRL Instance Document - the Inline XBRL Instance Document does not appear in the Interactive Data file because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith

** Furnished herewith

† Management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Signatures

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

CONTINENTAL RESOURCES, INC.

By: /s/ WILLIAM B. BERRY
Name: **William B. Berry**
Title: **President and Chief Executive Officer**
Date: **February 14, 2022**

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

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ HAROLD G. HAMM</u> Harold G. Hamm	Chairman of the Board and Director	February 14, 2022
<u>/s/ WILLIAM B. BERRY</u> William B. Berry	President, Chief Executive Officer, and Director (principal executive officer)	February 14, 2022
<u>/s/ JOHN D. HART</u> John D. Hart	Chief Financial Officer and Executive Vice President of Strategic Planning (principal financial and accounting officer)	February 14, 2022
<u>/s/ SHELLY LAMBERTZ</u> Shelly Lambertz	Executive Vice President, Chief Culture and Administrative Officer and Director	February 14, 2022
<u>/s/ LON MCCAIN</u> Lon McCain	Director	February 14, 2022
<u>/s/ JOHN T. MCNABB II</u> John T. McNabb II	Director	February 14, 2022
<u>/s/ MARK E. MONROE</u> Mark E. Monroe	Director	February 14, 2022
<u>/s/ TIMOTHY G. TAYLOR</u> Timothy G. Taylor	Director	February 14, 2022

SUBSIDIARIES OF CONTINENTAL RESOURCES, INC.

20 Broadway Associates LLC, an Oklahoma limited liability company

Banner Pipeline Company, L.L.C., an Oklahoma limited liability company

CLR Asset Holdings, LLC, an Oklahoma limited liability company

SFPG, LLC, an Oklahoma limited liability company*

The Mineral Resources Company, an Oklahoma corporation

The Mineral Resources Company II, LLC, a Delaware limited liability company*

Jagged Peak Energy LLC, a Delaware limited liability company

Parsley SoDe Water LLC, a Delaware limited liability company

* Ownership is less than 100%.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 14, 2022, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Continental Resources, Inc. on Form 10-K for the year ended December 31, 2021. We consent to the incorporation by reference of said reports in the Registration Statements of Continental Resources, Inc. on Form S-8 (File No. 333-188787) and on Form S-3ASR (File No. 333-233089).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 14, 2022

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the use of its name and to the reference of its report dated January 5, 2022, relating to proved crude oil and natural gas reserves and future net revenues of Continental Resources, Inc. as of December 31, 2021, in the Annual Report of Continental Resources, Inc. on Form 10-K for the year ended December 31, 2021. We hereby consent to the incorporation by reference of said report in the Registration Statements of Continental Resources, Inc. on Form S-8 (File No. 333-188787) and on Form S-3ASR (File No. 333-233089).

Very truly yours,

/s/ RYDER SCOTT COMPANY, L.P.

Ryder Scott Company, L.P.

Denver, Colorado
February 14, 2022

**Certification of the Company's Chief Executive Officer Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)**

I, William B. Berry, certify that:

1. I have reviewed this report on Form 10-K for the period ended December 31, 2021 of Continental Resources, Inc. ("Registrant");
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 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 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:
 - (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 14, 2022

/s/ William B. Berry

William B. Berry
President and Chief Executive Officer

**Certification of the Company's Chief Financial Officer Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)**

I, John D. Hart, certify that:

1. I have reviewed this report on Form 10-K for the period ended December 31, 2021 of Continental Resources, Inc. ("Registrant");
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 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 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:
 - (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 14, 2022

/s/ John D. Hart

John D. Hart

**Chief Financial Officer and Executive Vice President of Strategic
Planning**

**Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)**

Pursuant to 18 U.S.C. Section 1350, the undersigned officers of Continental Resources, Inc. (the "Company") hereby certify that the Company's Report on Form 10-K for the year ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William B. Berry

William B. Berry
President and Chief Executive Officer
February 14, 2022

/s/ John D. Hart

John D. Hart
Chief Financial Officer
and Executive Vice President of Strategic Planning
February 14, 2022



633 17TH STREET, SUITE 1700

DENVER, COLORADO 80202

TELEPHONE (303) 339-8110

January 5, 2022

Continental Resources, Inc.
20 North Broadway
Oklahoma City, Oklahoma 73102

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Continental Resources, Inc. (Continental) as of December 31, 2021. The subject properties are located in the states of Louisiana, Montana, North Dakota, New Mexico, Oklahoma, South Dakota, Texas, and Wyoming. The reserves and income data were estimated 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 third party study, completed on January 5, 2022 and presented herein, was prepared for public disclosure by Continental in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of Continental's total net proved reserves as of December 31, 2021. Based on information provided by Continental, the third party estimate conducted by Ryder Scott addresses 97 percent of the total proved developed net liquid hydrocarbon reserves, 97 percent of the total proved developed net gas reserves, 99 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 99 percent of the total proved undeveloped net gas reserves of Continental. When put in discounted cash flow terms, the reserves values evaluated represent 98 percent of Continental's total proved FNI discounted at 10 percent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on 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, 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 and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Continental Resources, Inc.

As of December 31, 2021

	Proved			
	Developed		Undeveloped	Total Proved
	Producing	Non-Producing		
<u>Net Reserves</u>				
Oil/Condensate – MBarrels	405,218	7,843	366,642	779,703
Gas - MMCF	2,777,529	36,273	2,196,697	5,010,499
<u>Income Data (\$M)</u>				
Future Gross Revenue	\$ 32,264,996	\$ 558,012	\$ 28,058,105	\$ 60,881,113
Deductions	8,994,492	191,201	12,351,619	21,537,312
Future Net Income (FNI)	\$ 23,270,504	\$ 366,811	\$ 15,706,486	\$ 39,343,801
Discounted FNI @ 10%	\$ 12,923,342	\$ 202,918	\$ 6,969,622	\$ 20,095,882

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (\$M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Continental. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, recompletion costs, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 74 percent and gas reserves account for the remaining 26 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discounted Future Net Income (\$M)	
As of December 31, 2021	
Discount Rate Percent	Total Proved
5	\$26,553,995
15	\$16,218,666
20	\$13,633,049
25	\$11,786,948

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein 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 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 the behind pipe and shut-in status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." 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 Continental's request, this report addresses only the proved reserves attributable to the properties evaluated 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, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Continental'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 detailed study of the properties in which Continental 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 for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

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

All of the proved developed non-producing and undeveloped reserves included herein 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 Continental or which we have obtained from public data sources that were available through October 2021. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions 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 making this evaluation.

Continental has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Continental with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, 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 Continental. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. 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 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 Continental. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our 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/or recompleting wells and/or 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/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein 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.

Continental furnished us with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices 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 for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property 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 in the preparation of this report were furnished to us by Continental. The differentials furnished to us 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 Continental to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America	Oil/Condensate	WTI Cushing	\$66.56/BBL	\$62.20/BBL
	Gas	Henry Hub	\$3.598/MMBTU	\$3.46/MCF

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

Costs

Operating costs for the leases and wells in this report were furnished by Continental and are based on the operating expense reports of Continental and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Continental. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Continental and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Continental’s estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Continental’s estimate.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Continental’s plans to develop these reserves as of December 31, 2021. The implementation of Continental’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Continental’s management. As the result of our inquiries during the course of preparing this report, Continental has informed us that the development activities included herein have been subjected to and received the internal approvals required by Continental’s management at the appropriate local, regional and/or 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 Continental. Continental has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Continental 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 Continental were held constant throughout the life of the properties.

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 Continental. 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 study, 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 evaluation 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 study, 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 Continental.

Continental makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Continental 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 Continental, of the references to our name, as well as to the references to our third party report for Continental, which appears in the December 31, 2021 annual report on Form 10-K of Continental. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Continental.

We have provided Continental 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 Continental 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.
TBPE Firm Registration No. F-1580

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

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. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at <https://www.ryderscott.com/company/employees/denver-employees>.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson 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.