2020 Annual Report

Continental
RESOURCES

LETTER FROM THE EXECUTIVE CHAIRMAN & CEO

2020 was a year for the history books in more ways than one. In the face of extreme business and social instability and some of the most unprecedented challenges we have seen in decades, Continental again showed what we can accomplish. Thanks to our capital discipline, strong entrepreneurial spirit and skillset, low cost, nimble operations, the strength and optionality of our assets, we excelled in 2020. As a result we are now set for an even stronger and resilient future.

None of this would have been possible without the hard work and dedication of our outstanding workforce. Our employees returned safely to the office last May, as soon as it was practical, and have been hard at work in pursuit of opportunities for our shareholders.

2020 demonstrated our unwavering commitment to delivering free cash flow and returns to shareholders. In a year with a worldwide pandemic, negative oil prices, and 20 million barrels of supply and demand imbalance, Continental delivered on the following:

- ✓ *Our fifth consecutive year of free cash flow. We are one of only a very few of our peers to accomplish this track record. We said we would generate $200 million. Through excellent outperformance, we generated nearly 40% more at $275 million.*
- ✓ *We targeted and achieved significant well cost improvement in the Bakken and Oklahoma. All-in well costs were reduced by 13% and 6%, respectively.*
- ✓ *We captured and sold 98.3% of our produced gas and delivered our best year of safety performance as part of our continued focus on ESG stewardship.*
- ✓ *We further developed our next generation ESG program.*

2020 highlighted the continued need for industry consolidation. We continue to consider organic and bolt on asset acquisitions the most efficient way for this to occur for Continental. This approach yielded 195,000 net acres, 550 well locations, and over 450 million BOE of net risked resource potential, including our recent acquisition of Powder River Basin assets without the disruptive cultural consequences of a corporate merger.

Operationally, our results were strong relative to our guidance for the year, underscoring Continental's ability to deliver on what we say. For perspective, we said capital expenditures would be at or below $1.2 billion. We spent approximately 3% less at $1.16 billion. We achieved our production guidance on oil and delivered 160,500 barrels of oil per day versus guidance of 155,000 to 165,000. We exceeded our production guidance on natural gas and delivered 837.5 million cubic feet a day versus guidance of 800 million to 820 million. Our operations teams did a superb job of managing our production expense per BOE at $3.27 versus our guidance of $3.50 to $3.75. The operational execution and capital discipline we saw in 2020 is only the beginning.

As we look ahead to 2021, we are excited to share our strategy and value proposition. We remain committed to our goal of delivering strong returns to shareholders through dividends, debt reduction and/or stock buybacks. In 2021 we expect this return to be in excess of 40% of cash flow through debt reduction and dividends. While the future reinstatement of dividends in 2021 will require Board approval, the Board has indicated its desire to return a dividend as soon as prudently possible.

We are projecting our sixth consecutive year of positive free cash flow in 2021 with approximately $1 billion at $52 WTI. We are targeting approximately $1 billion of debt reduction in 2021 to approximately $4.5 billion of total debt by year-end. Looking beyond 2021, our ultimate total debt target remains between $2 billion to $3 billion, which is driven by our organic free cash flow.

We will continue to focus on our low-cost leadership and are projecting cost improvements consistent with 2020. We expect to deliver strong asset performance across all of our basins, including our recently announced assets in the oil-weighted Powder River Basin.

Lastly, we are committed to our strong ESG stewardship and will publish our 2020 ESG report around midyear 2021. Across every level of the company, our teams remain keenly focused on sustainability, our environmental impact and our role in society and corporate governance. With more than 80% of company shares controlled by employees, the team at Continental acts, thinks and operates like owners because we are owners. The same can be said for our ESG program. We will continue to be a leader in efforts to responsibly fuel a better world as we serve and support the communities in which we operate.

Through what was surely an unprecedented year, thank you, our shareholders, for believing in Continental. As the world continues to get back to normal, we will see market demand strengthen and solid fundamentals return to commodity prices. In 2021, Continental will continue its executional excellence while focusing on shareholder returns and maximizing free cash flow. We will continue to make the world a better place while doing our part to protect our nation's energy independence and national security.

Harold Hamm
Executive Chairman

Bill Berry
Chief Executive Officer

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, 2020

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	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(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:

Title of each class	Trading symbol(s)	Name of each exchange on which registered
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 ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐
	Emerging growth company ☐

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2020 was approximately $1.4 billion, based upon the closing price of $17.53 per share as reported by the New York Stock Exchange on such date.

365,193,888 shares of our $0.01 par value common stock were outstanding on January 31, 2021.

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 2021, 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 for 2018, 2019, and 2020 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. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma.

"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, or share repurchases;
- 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 consequent 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, and production of crude oil and natural gas 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. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The 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 65% of our crude oil and natural gas revenues for the year ended December 31, 2020. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. Approximately 48% of our proved reserves as of December 31, 2020 are located in the North region. Our operations in the South region comprised 45% of our crude oil and natural gas production, 35% of our crude oil and natural gas revenues, and 52% of our proved reserves as of and for the year ended December 31, 2020.

We focus our activities in large new or developing crude oil and natural gas plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. 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.

As of December 31, 2020, our proved reserves were 1,104 MMBoe, with proved developed reserves representing 627 MMBoe, or 57%, of our total proved reserves. The standardized measure of our discounted future net cash flows totaled $4.65 billion at December 31, 2020. For 2020, we generated crude oil and natural gas revenues of $2.56 billion and operating cash flows of $1.42 billion. Crude oil accounted for 53% of our total production and 86% of our crude oil and natural gas revenues for 2020. Our total production averaged 300,090 Boe per day for 2020, a decrease of 12% compared to 2019.

The table below summarizes our total proved reserves, PV-10 (non-GAAP) and net producing wells as of December 31, 2020, average daily production for the quarter ended December 31, 2020 and the reserve-to-production index in 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, 2020				Average daily production for fourth quarter 2020 (Boe per day)	Percent of total	Annualized reserve/ production index (2)
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells			
North Region:							
Bakken field							
North Dakota Bakken	483,238	43.8%	$2,235	1,631	177,802	52.4%	7.4
Montana Bakken	25,754	2.3%	128	254	5,339	1.6%	13.2
Red River units							
Cedar Hills	17,670	1.6%	142	130	5,323	1.6%	9.1
Other Red River units	932	0.1%	7	116	1,467	0.4%	1.7
South Region:							
SCOOP	478,196	43.3%	2,139	463	107,060	31.6%	12.2
STACK	97,967	8.9%	241	299	42,281	12.4%	6.3
Other	5	— %	1	2	35	— %	0.4
Total	1,103,762	100.0%	$4,893	2,895	339,307	100.0%	8.9

(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 $239 million. 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 Annualized Reserve/Production Index is the number of years that estimated proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2020 production into estimated proved reserve volumes as of December 31, 2020.

Business Environment and Outlook

In March 2020, the World Health Organization declared a global pandemic related to the proliferation of COVID-19 (novel coronavirus). The ensuing economic turmoil caused by the pandemic resulted in a significant reduction in global and domestic demand for crude oil due to, among other things, changes in consumer behavior and restrictions implemented by governments to mitigate the pandemic. This demand destruction contributed to an unprecedented decline in crude oil prices, with West Texas Intermediate benchmark prices reaching all-time lows in April 2020. In response to the significant reduction in crude oil prices, we began voluntarily curtailing our production in April 2020 and ultimately curtailed approximately 55% of our operated crude oil production and associated natural gas in the 2020 second quarter. Additionally, in light of the challenges facing our business and industry, we implemented cost saving initiatives and significantly reduced our operated rig and completion crew counts in order to preserve our assets and better align our capital spending with expected available cash flows, resulting in a $1.5 billion, or 56%, decrease in our non-acquisition capital spending in 2020 compared to 2019. These actions, coupled with historically low crude oil prices, resulted in a material reduction in our production, revenues, and cash flows in 2020 compared to 2019.

Crude oil prices began to stabilize in mid-2020 and generally improved in the second half of 2020 in response to the gradual lifting of COVID-19 restrictions, the resumption of economic activity, and the resulting increase in crude oil demand. In July 2020 we began to gradually restore our curtailed production and subsequently brought our remaining curtailed production back online in September 2020. As a result of our resumed production, coupled with strategic well completion activities in late 2020, our total average production improved to 339,307 Boe per day for the 2020 fourth quarter, representing a 14% increase compared to the third quarter of 2020, yet still remaining 7% lower than the fourth quarter of 2019.

Despite the gradual improvement in crude oil prices in the second half of 2020, we continued our commitment to operating in a disciplined, capital efficient manner. Improved revenues from higher commodity prices coupled with our tempered spending resulted in the generation of cash flows in excess of operating and capital needs in the second half of 2020 that allowed for a $210 million net reduction in our total debt at December 31, 2020 compared to June 30, 2020. Additionally, despite production curtailments during the year, we continued to drive our per-unit production expenses lower to $3.27 per Boe for 2020 compared to $3.58 per Boe for 2019.

We remain committed to the responsible stewardship of our assets and continue to focus on maximizing cash flows, further reducing debt, delivering low-cost capital efficient operations, and generating shareholder value. The depth and quality of our asset base, the commodity optionality provided by our significant amount of acreage held by production, and our financial strength allow us to be adaptable in a variety of price environments. We remain flexible as we monitor and adapt to market conditions.

For 2021, our primary business strategies will focus on generating shareholder value by:

- Continuing to exercise capital and operational discipline to maximize cash flow generation;
- Reducing outstanding debt;
- Capitalizing on commodity optionality afforded to us by our crude oil and natural gas assets; and
- Maintaining low-cost operations.

Our Business Strategies

Despite volatility and uncertainty in commodity prices, our business strategies continue to be focused on generating shareholder value by finding and developing crude oil and natural gas reserves at low costs and attractive rates of return. The principal elements of this strategy include:

Growing and sustaining our premier portfolio of assets in a disciplined manner to maximize cash flow generation. We hold a portfolio of leasehold acreage, drilling opportunities, uncompleted wells, perpetually owned minerals, and water infrastructure assets in certain premier U.S. resource plays with varying access to crude oil, natural gas, and natural gas liquids. Our capital programs are designed to allocate investments to projects that provide the best opportunities to generate cash flows in excess of operating and capital requirements, capitalize on movements in strip pricing between crude oil and natural gas, convert our undeveloped acreage to acreage held by production, harvest our inventory of uncompleted wells, and improve hydrocarbon recoveries and rates of return on capital employed. We are strongly aligned with shareholders and our strategic vision is predicated on our desire to generate shareholder value through various means.

Reducing outstanding debt. Maintaining a strong balance sheet, ample liquidity, and financial flexibility are key components of our business strategy. A cornerstone of our 2021 plan is to maximize cash flow generation to pay down debt. In 2021 and beyond we will continue our focus on paying down debt and preserving financial flexibility and ample liquidity as we manage the risks facing our industry.

Capitalizing on commodity optionality afforded to us by our crude oil and natural gas assets. We have a deep inventory of both oil and gas assets across the Bakken and Oklahoma that allow us to be responsive to, and benefit from, changes in oil and gas commodity price fundamentals. This commodity optionality provides an inherent advantage to Continental. Not only do we have the ability to shift capital between our Bakken and Oklahoma assets, but within Oklahoma we have the ability to shift capital between oil-weighted or gas-weighted projects depending on which commodity has a stronger price outlook. We also have direct access to multiple premium markets from our Oklahoma assets, which allow us to pursue either oil or gas markets as prices and fundamentals warrant. For 2021, we plan to remain flexible and responsive with our drilling and completion programs to capitalize on relative movements in oil and gas prices.

Maintaining low-cost operations. Our culture is defined by our low cost operations and in 2020 we again delivered low cost industry leadership despite the challenges facing our business. We continue to manage our business in the volatile commodity price environment by focusing on improving operating and capital efficiencies and reducing costs by exploiting technical innovations, pad and row development opportunities, and other means. Our key operating areas are characterized by large acreage positions in select unconventional resource plays with multiple stacked geologic formations that provide repeatable drilling opportunities and resource potential. We operate a significant portion of our wells and leasehold acreage and believe the concentration of our operated assets allows us to leverage our technical expertise and manage the development of our properties to enhance operating efficiencies and economies of scale. Our operational excellence has allowed us to achieve and maintain enviable low-cost operations.

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 359,300 net undeveloped acres and 1.23 million net developed acres under lease as of December 31, 2020 concentrated in certain premier U.S. resource plays that provide optionality and access to crude oil, natural gas, and natural gas liquids. We are among the largest leaseholders in the Bakken, SCOOP and STACK plays. Being an early entrant in these plays has allowed us to capture significant acreage positions in core parts of the plays.

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, 2020, we operated properties comprising 88% 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 Executive Chairman, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our 8 executive officers have an average of 41 years of oil and gas industry experience.

Financial Position and Liquidity. We have a credit facility with lender commitments totaling $1.5 billion that matures in April 2023. We had approximately $1.33 billion of borrowing availability on our credit facility at December 31, 2020 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.

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, 2020. 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 $4.65 billion at December 31, 2020. Our reserve estimates as of December 31, 2020 are based primarily on a reserve report prepared by Ryder Scott. In preparing its report, Ryder Scott evaluated properties representing approximately 93% of our PV-10 and 95% of our total proved reserves as of December 31, 2020. 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, 2020 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2020 through December 2020, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas ($34.34 per Bbl for crude oil and $1.17 per Mcf for natural gas adjusted for location and quality differentials). These average prices are significantly lower than 2019 levels, which resulted in significant downward price-related revisions to proved reserves in 2020. Additionally, in 2020 we reduced the scope of our future drilling programs in response to the reduction in consumer demand and lower prices prompted by the COVID-19 pandemic, which resulted in the removal of PUD reserves no longer scheduled to be drilled within five years of initial booking. These revisions are further discussed below and contributed to significant decreases in our proved reserves, Standardized Measure, and PV-10 in 2020 compared to 2019.

The following table summarizes our estimated proved reserves by commodity and reserve classification as of December 31, 2020.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	271,904	2,023,293	609,119	$3,962.5
Proved developed non-producing	10,002	49,718	18,288	110.8
Proved undeveloped	215,069	1,567,713	476,355	819.4
Total proved reserves	496,975	3,640,724	1,103,762	$4,892.7
Standardized Measure (1)				$4,653.6

(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 $239 million. 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, 2020.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North Region:						
Bakken field						
North Dakota Bakken	170,498	550,159	262,191	159,674	368,239	221,047
Montana Bakken	12,114	25,573	16,377	7,330	12,281	9,377
Red River units						
Cedar Hills	17,670	—	17,670	—	—	—
Other Red River units	932	—	932	—	—	—
South Region:						
SCOOP	69,955	1,073,955	248,947	46,263	1,097,920	229,249
STACK	10,732	423,320	81,285	1,802	89,273	16,682
Other	5	4	5	—	—	—
Total	281,906	2,073,011	627,407	215,069	1,567,713	476,355

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

	Year Ended December 31,		
MBoe	2020	2019	2018
Proved reserves at beginning of year	1,619,265	1,522,365	1,330,995
Revisions of previous estimates	(504,874)	(148,848)	(269,253)
Extensions, discoveries and other additions	91,387	365,034	565,030
Production	(109,833)	(124,244)	(108,839)
Sales of minerals in place	—	(1,840)	(8,011)
Purchases of minerals in place	7,817	6,798	12,443
Proved reserves at end of year	1,103,762	1,619,265	1,522,365

Revisions of previous estimates. 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 our 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 the 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 of 43 MMBo and 31 Bcf (totaling 48 MMBoe) 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 in the Bakken, SCOOP, and STACK plays. Proved reserve additions in the Bakken totaled 41 MMBoe, 160 MMBoe, and 251 MMBoe for 2020, 2019, and 2018, respectively, while reserve additions in SCOOP totaled 49 MMBoe, 186 MMBoe, and 186 MMBoe for 2020, 2019, and 2018, respectively. Additionally, reserve additions in STACK totaled 1 MMBoe, 19 MMBoe, and 128 MMBoe in 2020, 2019, and 2018, respectively. See the subsequent section titled *Summary of Crude Oil and Natural Gas Properties and Projects* for a discussion of our 2020 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. We had no individually significant acquisitions of proved reserves in the past three years.

Proved Undeveloped Reserves

All of our PUD reserves at December 31, 2020 are located in the Bakken, SCOOP, and STACK plays, our most active development areas, with those plays comprising 48%, 48%, and 4%, respectively, of our total PUD reserves at year-end 2020. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2020. Our PUD reserves at December 31, 2020 include 98 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 (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves at December 31, 2019	423,782	2,928,354	911,841
Revisions of previous estimates	(210,569)	(1,326,177)	(431,599)
Extensions and discoveries	37,605	271,611	82,874
Sales of minerals in place	—	—	—
Purchases of minerals in place	496	5,363	1,390
Conversion to proved developed reserves	(36,245)	(311,438)	(88,151)
Proved undeveloped reserves at December 31, 2020	215,069	1,567,713	476,355

Revisions of previous estimates. As previously discussed, in 2020 we removed 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 our future drilling programs based on adverse market conditions, reduced demand, and lower prices caused by the COVID-19 pandemic. Of these removals, 31 MMBo and 90 Bcf (totaling 46 MMBoe) was related to Bakken properties, 18 MMBo and 224 Bcf (totaling 56 MMBoe) was related to SCOOP properties, and 31 Bcf (5 MMBoe) was related to STACK properties. Additionally, changes in economics, performance, and other factors resulted in downward PUD reserve revisions of 29 MMBo and 172 Bcf (totaling 58 MMBoe) in 2020. The significant decreases in average crude oil and natural gas prices in 2020 resulting from the COVID-19 pandemic and other factors resulted in downward price revisions of 145 MMBo and 813 Bcf (totaling 280 MMBoe). Finally, changes in ownership interests, operating costs, anticipated production, and other factors resulted in net upward revisions for PUD reserves of 13 MMBo and 6 Bcf (totaling 14 MMBoe) in 2020.

Extensions and discoveries. Extensions and discoveries were primarily due to successful drilling activities and continual refinement of our drilling programs in the Bakken and SCOOP plays. PUD reserve additions in the Bakken totaled 27 MMBo and 56 Bcf (totaling 36 MMBoe) in 2020, while SCOOP PUD reserve additions totaled 11 MMBo and 216 Bcf (totaling 47 MMBoe).

Sales of minerals in place. We had no individually significant dispositions of PUD reserves in 2020.

Purchases of minerals in place. We had no individually significant acquisitions of PUD reserves in 2020.

Conversion to proved developed reserves. In 2020, we developed approximately 12% of our PUD locations and 10% of our PUD reserves booked as of December 31, 2019 through the drilling and completion of 328 gross (149 net) development wells at an aggregate capital cost of approximately $439 million incurred in 2020.

Our original capital budget for 2020 was $2.65 billion, which was reduced to $1.2 billion in March 2020 in response to the sudden, unprecedented decrease in crude oil prices resulting from the COVID-19 pandemic and other factors. Due to economic uncertainty from the pandemic, we significantly reduced our drilling and completion activities from previously planned levels in order to preserve financial flexibility and better align our spending with expected available cash flows. These factors adversely impacted our conversion of PUD reserves to proved developed reserves in 2020.

Development plans. We have acquired substantial leasehold positions in the Bakken, SCOOP and STACK plays. Our drilling programs to date in those 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 316 gross (121 net) operated and non-operated locations at December 31, 2020 and represent 20% of our PUD reserves at that date. The costs to drill our uncompleted wells were incurred prior to December 31, 2020 and only the remaining completion costs are included in future development plans.

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $732 million in 2021, $734 million in 2022, $889 million in 2023, $1.1 billion in 2024, and $448 million in 2025. 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, 2020 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, 2020. We had no PUD reserves at December 31, 2020 that remain undeveloped 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, 93% of our PV-10 and 95% of our total proved reserves as of December 31, 2020 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 36 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.

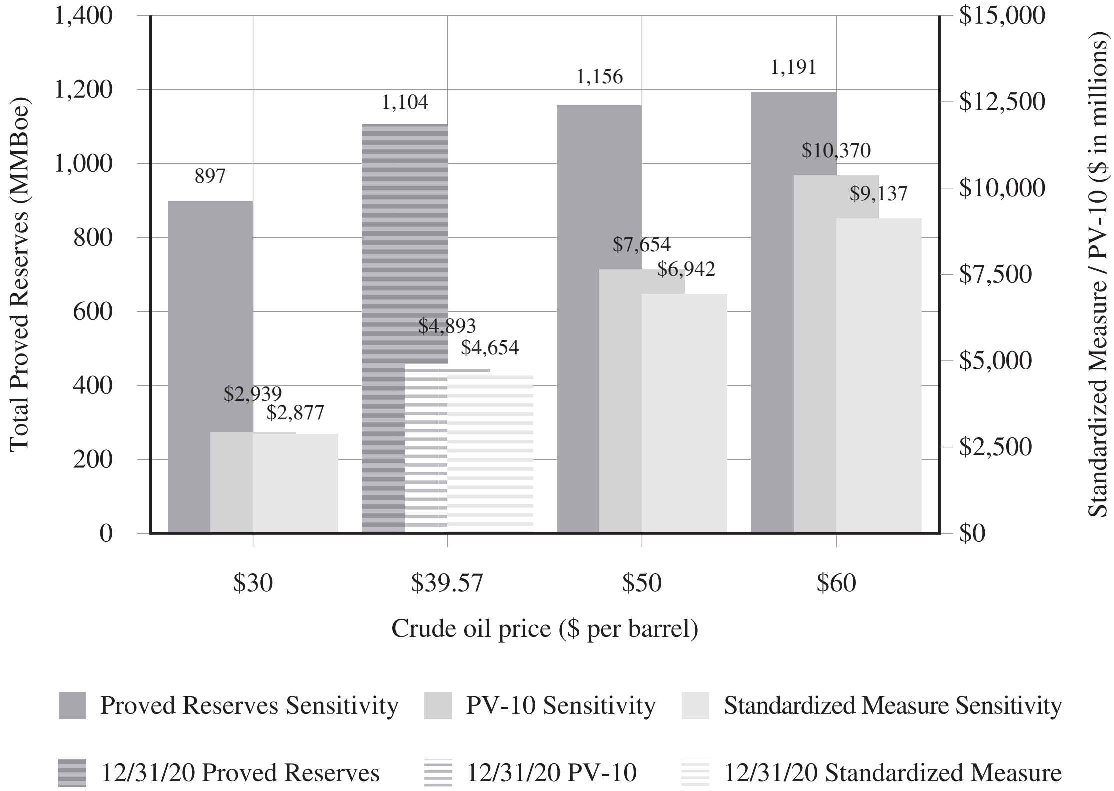
Proved Reserves, Standardized Measure, and PV-10 Sensitivities

Our year-end 2020 proved reserves, Standardized Measure, and PV-10 estimates were prepared using 2020 average first-day-of-the-month prices of $39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas ($34.34 per Bbl for crude oil and $1.17 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, 2020 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.

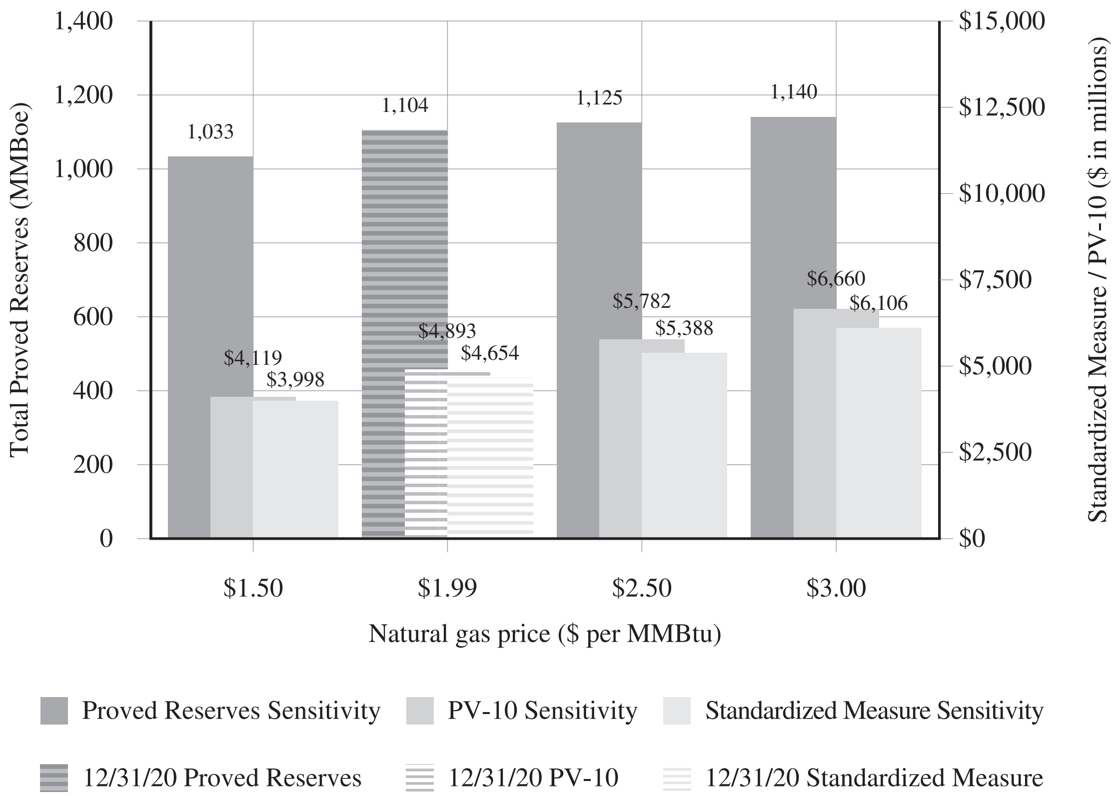
The crude oil price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain crude oil price scenarios, with natural gas prices being held constant at the 2020 average first-day-of-the-month price of $1.99 per MMBtu.

Price Sensitivities - Crude Oil



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 2020 average first-day-of-the-month price of $39.57 per Bbl.

Price Sensitivities - Natural Gas



Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2020:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	949,852	563,260	105,095	61,248	1,054,947	624,508
Montana Bakken	170,412	136,153	33,795	25,789	204,207	161,942
Red River units	155,249	138,064	19,455	10,112	174,704	148,176
Other	80,326	54,095	29,569	25,725	109,895	79,820
South Region:						
SCOOP	276,618	166,327	183,840	107,459	460,458	273,786
STACK	265,736	146,078	88,139	45,489	353,875	191,567
Other	34,247	20,790	28,940	12,364	63,187	33,154
East Region	734	670	77,547	71,159	78,281	71,829
Total	1,933,174	1,225,437	566,380	359,345	2,499,554	1,584,782

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2020 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.

	2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	34,287	23,193	31,849	19,034	4,160	2,143
Montana Bakken	1,480	1,480	12,182	10,311	5,697	5,580
Other	—	—	—	—	17,847	17,847
South Region:						
SCOOP	36,475	16,265	35,631	22,773	26,068	12,927
STACK	31,465	19,241	11,541	7,696	4,259	3,114
Other	4,889	744	8,987	6,063	2,942	2,592
East Region	969	370	4,856	3,732	5,968	5,272
Total	109,565	61,293	105,046	69,609	66,941	49,475

Drilling Activity

During the three years ended December 31, 2020, we participated in the drilling and completion of exploratory and development wells as set forth in the table below. As previously discussed, we significantly reduced our drilling and completion activities in 2020 in response to reduced crude oil prices, which resulted in a significant decrease in the number of wells completed during 2020 compared to prior years.

	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	1	—	2	1.6	4	1.0
Natural gas	1	—	4	1.8	9	4.6
Dry holes	1	0.9	—	—	—	—
Total exploratory wells	3	0.9	6	3.4	13	5.6
Development wells:						
Crude oil	300	115.5	615	222.9	636	213.7
Natural gas	31	15.9	68	9.7	151	39.1
Dry holes	—	—	—	—	—	—
Total development wells	331	131.4	683	232.6	787	252.8
Total wells	334	132.3	689	236.0	800	258.4

As of December 31, 2020, there were 459 gross (156 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 2021 in our key operating areas. Our 2021 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 decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures.

The following table provides information regarding well counts and budgeted capital expenditures for 2021.

	2021 Plan		
	Gross wells (1)	Net wells (1)	Capital expenditures (in millions) (2)
North Region	229	94	$ 732
South Region	120	57	380
Total exploration and development	349	151	$1,112
Land			85
Mineral acquisitions attributable to Continental (3)			13
Capital facilities, workovers, water infrastructure, and other			186
Seismic			4
2021 capital budget attributable to Continental			$1,400
Mineral acquisitions attributable to Franco-Nevada (3)			52
Total 2021 capital budget			$1,452

(1) Represents operated and non-operated wells expected to have first production in 2021.
(2) Represents total capital expenditures for operated and non-operated wells expected to have first production in 2021 and wells spud that will be in the process of drilling, completing or waiting on completion as of year-end 2021. Amounts exclude our pending acquisition of properties in the Powder River Basin of Wyoming for $215 million as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 12. Commitments and Contingencies.*
(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 16. 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 2021 planned spending, or $13 million, and Franco-Nevada will fund the remaining 80%, or $52 million.

North Region

Our properties in the North region represented 48% of our total proved reserves as of December 31, 2020 and 56% of our average daily Boe production for the fourth quarter of 2020. Our principal producing properties in the North region are located in the Bakken field.

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, 2020, we controlled one of the largest leasehold positions in the Bakken with approximately 1.3 million gross (786,500 net) acres under lease.

Our total Bakken production averaged 183,141 Boe per day for the fourth quarter of 2020, down 6% from the 2019 fourth quarter. For the year ended December 31, 2020, our average daily Bakken production decreased 19% compared to 2019, reflecting our reduction in drilling and completion activities and the impact of voluntary production curtailments during the year. In 2020, we participated in the drilling and completion of 188 gross (77 net) wells in the Bakken compared to 379 gross (124 net) wells in 2019. Our 2020 activities in the Bakken focused on ongoing multi-zone unit development in core areas of the play.

Our Bakken properties represented 46% of our total proved reserves at December 31, 2020 and 54% of our average daily Boe production for the 2020 fourth quarter. Our total proved Bakken field reserves as of December 31, 2020 were 509 MMBoe, a decrease of 39% compared to December 31, 2019 primarily due to downward reserve revisions prompted by significantly reduced commodity prices and resulting changes in drilling plans. Our inventory of proved undeveloped drilling locations in the Bakken totaled 849 gross (404 net) wells as of December 31, 2020.

For 2021, our budget for exploration and development capital expenditures in the North region is $732 million. In 2021, we expect to have first production on 229 gross (94 net) operated and non-operated wells in the North region. We plan to average approximately seven operated rigs and three well completion crews in the North region in 2021. Our 2021 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.

South Region

Our properties in the South region represented 52% of our total proved reserves as of December 31, 2020 and 44% of our average daily Boe production for the fourth quarter of 2020. Our principal producing properties in the South region are located in the SCOOP and STACK areas of Oklahoma.

SCOOP

The SCOOP play extends across Garvin, Grady, Stephens, Carter, McClain and Love counties in Oklahoma and contains crude oil and condensate-rich fairways as delineated by numerous industry wells. We are a leading producer, leasehold owner and operator in the SCOOP play. As of December 31, 2020, we controlled one of the largest leasehold positions in SCOOP with approximately 460,500 gross (273,800 net) acres under lease.

SCOOP represented 43% of our total proved reserves as of December 31, 2020 and 32% of our average daily Boe production for the fourth quarter of 2020. Production in SCOOP averaged 107,060 Boe per day during the fourth quarter of 2020, down 4% compared to the 2019 fourth quarter. For the year ended December 31, 2020, average daily production in SCOOP increased 16% compared to 2019, reflecting additional drilling and completion activities in our Project SpringBoard which exceeded the impact of production curtailments in the play during the year. We participated in the drilling and completion of 123 gross (46 net) wells in SCOOP during 2020 compared to 207 gross (93 net) wells in 2019. Our total proved SCOOP field reserves as of December 31, 2020 were 478 MMBoe, a decrease of 17% compared to December 31, 2019 primarily due to downward reserve revisions prompted by significantly reduced commodity prices and resulting changes in drilling plans. Our inventory of proved undeveloped drilling locations in SCOOP totaled 262 gross (164 net) wells as of December 31, 2020.

STACK

The STACK play is located in the Anadarko Basin of Oklahoma and is characterized by stacked geologic formations with major targets in the Meramec, Osage, and Woodford formations. As of December 31, 2020, we controlled one of the largest leasehold positions in STACK with approximately 353,900 gross (191,600 net) acres under lease.

Our STACK properties represented 9% of our total proved reserves as of December 31, 2020 and 12% of our average daily Boe production for the fourth quarter of 2020. Production in STACK averaged 42,281 Boe per day during the fourth quarter of 2020, down 18% from the 2019 fourth quarter. For the year ended December 31, 2020, average daily production in STACK decreased 30% compared to 2019, reflecting our reduction in drilling and completion activities and the impact of voluntary production curtailments during the year. We participated in the drilling and completion of 22 gross (8 net) wells in STACK during 2020 compared to 103 gross (19 net) wells in 2019. Proved reserves in STACK decreased 46% year-over-year to 98 MMBoe as of December 31, 2020 primarily due to downward reserve revisions prompted by significantly reduced commodity prices and resulting changes in drilling plans. Our inventory of proved undeveloped drilling locations in STACK totaled 25 gross (9 net) wells as of December 31, 2020.

For 2021, our aggregate budget for exploration and development capital expenditures in the South region is $380 million. In 2021, we expect to have first production on 120 gross (57 net) operated and non-operated wells in the South region. We plan to average approximately four operated rigs and two well completion crews in the South region in 2021. Our 2021 activities will focus on continued row development in Project SpringBoard in the SCOOP play and ongoing 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.

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, 2020, 2019 and 2018 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2020.

	Year ended December 31,		
	2020	2019	2018
Net production volumes:			
Crude oil (MBbls)			
North Dakota Bakken	40,052	52,420	45,775
SCOOP	12,585	11,679	6,918
Total Company	58,745	72,267	61,384
Natural gas (MMcf)			
North Dakota Bakken	97,532	98,186	78,448
SCOOP	136,410	111,436	99,397
Total Company	306,528	311,865	284,730
Crude oil equivalents (MBoe)			
North Dakota Bakken	56,308	68,784	58,849
SCOOP	35,320	30,252	23,484
Total Company	109,833	124,244	108,839
Average net sales prices (1):			
Crude oil ($/Bbl)			
North Dakota Bakken	$ 33.53	$ 50.96	$ 58.37
SCOOP	37.88	54.92	62.74
Total Company	34.71	51.82	59.19
Natural gas ($/Mcf)			
North Dakota Bakken	$ 0.23	$ 1.28	$ 3.33
SCOOP	1.64	2.36	3.41
Total Company	1.04	1.77	3.01
Crude oil equivalents ($/Boe)			
North Dakota Bakken	$ 24.24	$ 40.66	$ 49.83
SCOOP	19.90	29.80	32.88
Total Company	21.47	34.56	41.25
Average costs per Boe:			
Production expenses ($/Boe)			
North Dakota Bakken	$ 4.35	$ 4.28	$ 4.40
SCOOP	1.06	1.21	1.34
Total Company	3.27	3.58	3.59
Production taxes ($/Boe)	$ 1.75	$ 2.88	$ 3.25
General and administrative expenses ($/Boe)	$ 1.79	$ 1.57	$ 1.69
DD&A expense ($/Boe)	$ 17.12	$ 16.25	$ 17.09

(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 2020:

	Fourth Quarter 2020 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	122,291	333,070	177,802
Montana Bakken	4,137	7,209	5,339
Red River units			
Cedar Hills	5,323	—	5,323
Other Red River units	1,464	17	1,467
South Region:			
SCOOP	36,415	423,871	107,060
STACK	6,995	211,715	42,281
Other	14	129	35
Total	176,639	976,011	339,307

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, 2020. 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 field						
North Dakota Bakken	4,708	1,631	—	—	4,708	1,631
Montana Bakken	394	254	—	—	394	254
Red River units						
Cedar Hills	136	130	—	—	136	130
Other Red River units	130	116	—	—	130	116
South Region:						
SCOOP	620	316	488	147	1,108	463
STACK	416	157	436	142	852	299
Other	1	1	22	1	23	2
Total	6,405	2,605	946	290	7,351	2,895

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 defects, 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 defects 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, 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 purchase 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 our operated natural gas production to midstream customers at our lease locations based on market prices in the field where the sales occur. 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. We currently take certain processed residue gas volumes in kind in lieu of monetary settlement, but we do not currently take NGL volumes. 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.

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. 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 and complex 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 crude oil and natural gas 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, the U.S. Congress and federal and state legislators and agencies frequently revise environmental laws, rules and regulations and with party control of Congress shifting in January 2021, there is potential for the Biden Administration to pursue new legislation and regulatory initiatives that revise the permitting or leasing policies pursued under the Trump Administration that could adversely affect the oil and gas industry. Moreover, President Biden has issued, and may continue to issue, executive orders in pursuit of his regulatory agenda. Any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the crude oil and natural gas industry or restrict, delay or ban oil and gas permitting or leasing on federal lands 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 that apply to our operations.

Air emissions and climate change. 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, including the potential effects of carbon dioxide, methane and other identified “greenhouse gas” emissions on the environment and climate worldwide, generally referred to as “climate change.” For example, since 2015 the U.S. Environmental Protection Agency (“EPA”) under the Obama Administration has made revisions to the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone, making the standard stricter. Since that time, the EPA under the Trump Administration has issued attainment and nonattainment designations and, on December 31, 2020, published notice of a final action, upon conducting a periodic review of the ozone standard, electing to retain the 2015 ozone NAAQS in 2020 without revision on a going-forward basis. However, this December 2020 final action is subject to legal challenge, and the NAAQS may be subject to further revision under the Biden Administration. State implementation of the revised NAAQS for ground-level ozone could result in stricter permitting requirements, a delay or prohibition on our ability to obtain such permits, or result in increased expenditures for pollution control equipment, the costs of which could be significant.

With respect to climate change and the control of greenhouse gas emissions, 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 restrict or eliminate future emissions. 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 operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements. For example, in 2016 the EPA under the Obama Administration finalized new regulations (New Source Performance Standard Subpart OOOOa, commonly referred to as “Quad Oa”) setting methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities. However, in recent years following the beginning of the Trump Administration in 2017, the EPA has undertaken several measures to delay implementation of the methane standards. Recently, in September 2020, the EPA issued its final policy and technical amendments to the 2016 final rule. The policy amendments, effective September 14, 2020, notably removed the transmission and storage sector from the regulated source category and rescinded methane and volatile organic compound requirements for the remaining sources that were established by former President Obama’s Administration, whereas the technical amendments, effective November 16, 2020, included changes to fugitive emissions monitoring and repair schedules for gathering and boosting compressor stations and low-production wells, recordkeeping and reporting requirements, and more. Various states and industry and environmental groups are separately challenging both the original 2016 standards and the EPA’s September 2020 final rules and on January 20, 2021, President Biden issued an executive order that, among other things, directed the EPA to reconsider the technical amendments and issue a proposed rule suspending, revising or rescinding those amendments by no later than

September 2021. A reconsideration of the September 2020 policy amendments is expected to follow. The January 20, 2021 executive order also directed the establishment of new methane and volatile organic compound standards applicable to existing oil and gas operations, including the production, transmission, processing and storage segments. 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 for nations to limit their greenhouse gas emissions through individually-determined reduction goals every five years after 2020. While the United States withdrew from the Paris Agreement under the Trump Administration, on January 20, 2021 President Biden issued an executive order recommitting the United States to the Paris Agreement and calling for the federal government to begin formulating the United States’ nationally determined emissions reduction goal under the agreement. With the United States recommitting to the Paris Agreement, executive orders may be issued or federal legislation or regulatory initiatives may be adopted to achieve the agreement’s goals, which could require us to incur increased costs to comply with such requirements.

In addition, increasing concern over the threat of climate change arising from greenhouse gas emissions has given rise to a series of political, litigation, and financial risks associated with the production and processing of hydrocarbons and emission of greenhouse gases. In addition to recommitting the United States to the Paris Agreement, on January 20, 2021, the Acting Secretary of the U.S. Department of the Interior issued an order, effective immediately, that suspends new crude oil and natural gas leases and drilling permits on non-Indian federal lands and waters for a period of 60 days. Building on this suspension, President Biden issued an executive order on January 27, 2021 that suspends new leasing activities for oil and gas exploration and production on non-Indian federal lands and offshore waters pending completion of a comprehensive study of federal oil and gas permitting and leasing practices that take into consideration potential climate and other impacts associated with oil and gas activities on such lands and waters. As of December 31, 2020, we held approximately 41,800 net undeveloped acres on federal lands.

The January 20, 2021 and January 27, 2021 executive orders do not apply to existing leases and the January 27, 2021 order further directs applicable agencies to eliminate subsidies for the oil and gas sector. Legal challenges to these orders are expected, with at least one industry group already filing a lawsuit in January 2021 in Wyoming federal district court and seeking to have the moratorium on leasing declared invalid. 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. There are also increasing financial risks for oil and gas producers, as stockholders and bondholders currently invested in energy companies 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 issues and some of them may elect not to provide funding for energy companies. Limitation of investments in and financings for oil and gas producers could result in reduced access to capital, higher costs of capital and the restriction, delay, or cancellation of development and production activities.

While we cannot predict the outcome of legislative or regulatory initiatives related to climate change, we anticipate that initiatives to reduce greenhouse gas emissions will continue to develop. The adoption of state or federal legislation or regulatory programs to reduce greenhouse gas emissions, including methane and carbon dioxide, could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Additionally, political, litigation, and financial risks may result in restrictions or cancellations in development and production activities, liability for infrastructure damages due to climate changes, or increases in the cost of consuming hydrocarbons and thereby reducing demand for crude oil and natural gas. Moreover, the increased competitiveness of alternative energy sources (such as wind, solar, geothermal, tidal and biofuels) could reduce demand for hydrocarbons, including the oil and gas we produce, which could lead to a reduction in our revenues. Also, there is the possibility that financial institutions will be required to adopt policies that limit funding for energy companies as President Biden recently signed an executive order calling for the development of a climate finance plan and, separately, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Finally, increasing concentrations of greenhouse gas in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, rising sea levels and other climatic events. Consequently, one or more of these developments could have an adverse effect on our business, financial condition, results of operations, and cash flows.

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. 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 continue to strive to reduce natural gas flaring as much as practicable, 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. The Wyoming decision is expected to be appealed. Moreover, the BLM under a Biden Administration could seek to pursue regulatory initiatives that regulate hydraulic fracturing activities on federal lands.

While the U.S. Congress has from time to time considered but refused to adopt federal regulation of hydraulic fracturing, there is a possibility that a Biden Administration will pursue such legislation. In addition to pursuing the revision of existing laws and regulations, President Biden has issued, and may continue to issue, additional executive orders in pursuit of his regulatory agenda with regards to limiting hydraulic fracturing.

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 in Oklahoma 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, 2020, we employed 1,201 people, all of which were employed in the United States, with 716 employees being located at our corporate headquarters in Oklahoma City, Oklahoma and 485 employees located in our field offices located in Oklahoma, North Dakota, South Dakota, and Montana. 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 any employee or contractor working on one of our locations who observes and reports 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 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 three years and measured 0.40 for 2020, a 53% 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, creating the Continental Leadership Learning Center which offers numerous different instructor-led programs which foster employee development and acquiring 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.

In response to the COVID-19 pandemic, commencing in the first quarter of 2020, we have taken, and continue to take, proactive measures to protect the health and safety of our employees. These measures have included the implementation of a voluntary testing program to provide our employees and their household members with reliable and timely test results when public testing options were limited and restricted, maintaining social 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, suspending employee business travel, requiring employees to complete daily self-screening questionnaires, performing temperature checks, frequently and extensively disinfecting common areas, performing rigorous contact tracing protocols, 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 recognize that a diverse workforce provides the best opportunity to obtain unique perspectives, experiences, ideas, and solutions to help our business succeed. To that end, 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. Further, we forbid retaliation against any individual who reports, claims, or makes a charge of discrimination or harassment, fraud, unethical conduct, or a violation of our Company policies. To sustain and promote an inclusive culture, we 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 require all employees to complete periodic training sessions on various aspects of our Code of Business Conduct and Ethics and other corporate policies through an annual acknowledgement and certification process. We evaluate ways to enhance awareness of diversity and inclusion on an ongoing basis in an effort to continue improving our approach.

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. For example, during 2020 the NYMEX West Texas Intermediate ("WTI") crude oil and Henry Hub natural gas spot prices ranged from negative \$36.98 to positive \$63.27 per barrel and \$1.33 to \$3.14 per MMBtu, respectively. Commodity prices will likely remain volatile and unpredictable in 2021 and beyond. A significant portion of our future crude oil and 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 weather 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 emission limitations or other environmental protection efforts; 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. For example, OPEC and certain other oil exporting nations have previously agreed to take measures, including production cuts, to support crude oil prices. However, in March 2020, members of OPEC and Russia were unable to agree on production levels and, in response, Saudi Arabia announced it would significantly increase production and cut the prices at which it sold crude oil. These actions, coupled with the economic impact and uncertainty from the COVID-19 pandemic, led to a sudden and drastic decrease in crude oil prices in March 2020, which materially impacted our business, results of operations, and cash flows. It is not certain what impact current or future agreements or disagreements among these parties will have on crude oil prices, particularly in light of the significant decrease in crude oil demand resulting from the COVID-19 pandemic. There can be no assurance that OPEC members and other oil exporting nations will comply with agreed-upon production cuts, agree to further production cuts 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 COVID-19 pandemic has negatively impacted, and will likely 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.

We began to experience material decreases in our revenues in the first quarter of 2020, which negatively impacted our business, financial condition, results of operations, cash flows and outlook during 2020. The adverse effects of COVID-19 included or may in the future include the following:

- Historically low 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;
- Our ability to repay or refinance indebtedness, increase our credit facility commitments, borrow money, or raise capital;
- Disruptions in energy industry supply chains;
- 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 extent to which COVID-19 and depressed crude oil prices impacts our results of operations, financial position and liquidity will depend on future developments, which are uncertain and cannot be predicted, including but not limited to, the availability of effective treatments and vaccines, the ultimate duration of the pandemic, and how quickly and to what extent normal economic and operating conditions can resume. Therefore, the degree and duration of the adverse financial impact of the pandemic cannot be reasonably estimated at this time.

Our producing properties are located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A significant portion of our producing properties is located in the Bakken field of North Dakota and Montana, with that area comprising 53% of our crude oil and natural gas production and 61% of our crude oil and natural gas revenues for the year ended December 31, 2020. Approximately 46% of our estimated proved reserves were located in the Bakken as of December 31, 2020. Additionally, our properties in Oklahoma comprised 45% of our crude oil and natural gas production and 35% of our crude oil and natural gas revenues for the year ended December 31, 2020. Approximately 52% of our estimated proved reserves were located in Oklahoma as of December 31, 2020.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) our reliance on a limited number of pipelines to deliver our production to markets, (ii) the prices of crude oil and natural gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints; (iii) the availability of rigs, completion crews, waste water disposal wells, equipment, field services, water, supplies, and labor; (iv) the availability of processing and refining facilities; and (v) infrastructure capacity. In addition, our operations in the Bakken field and Oklahoma may be adversely affected by severe weather events such as floods, blizzards, extreme cold, ice storms, drought, and tornadoes, which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests, cyber attacks, or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 weather 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, 2020.

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, 2020, average prices used to calculate our estimated proved reserves were $39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas ($34.34 per Bbl for crude oil and $1.17 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, 2021 and February 1, 2021 averaged $51.04 per barrel and $2.53 per MMBtu, respectively. See *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, 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, 2020, approximately 43% 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, 2020 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $3.9 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 2020, 107 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 primarily due to a reduction in the scope of our future drilling programs based on adverse market conditions, reduced demand, and lower prices caused by the COVID-19 pandemic.

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 50% of our total net undeveloped acreage at December 31, 2020. At that date, we had leases representing 61,293 net acres expiring in 2021, 69,609 net acres expiring in 2022, and 49,475 net acres expiring in 2023.

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 weather, 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.

On July 6, 2020, the U.S. District Court for the District of Columbia ruled that the U.S. Army Corps of Engineers ("Corps"), which had previously issued an easement near tribal lands allowing the Dakota Access Pipeline ("DAPL") to cross a water body, had failed to adequately consider the environmental impacts under the National Environmental Protection Act ("NEPA") arising out of such pipeline crossing this water body, and directed the Corps to prepare a new environmental impact statement ("EIS") as well as ordering the owners of DAPL to shut down the pipeline pending completion of the EIS. The DAPL is owned and operated by a third party and carries Bakken-produced crude oil from North Dakota to Illinois. The pipeline owner sought an emergency stay of the shut-down order from the U.S. Court of Appeals for the District of Columbia Circuit (the "Appeals Court"). On July 14, 2020, the Appeals Court issued a temporary administrative stay of such order, which has allowed the pipeline to continue operating. On January 26, 2021, the Appeals Court affirmed that part of the lower court decision vacating the Corps' easement while it prepares a new EIS, but reversed the lower court's order to shut down the pipeline because the lower court had not properly evaluated such a move under an applicable NEPA factoring test established under case law. As stated by the Appeals Court, the Corps is within its authority to shut down the pipeline and the Appeals Court would expect the Corps to make that decision "promptly." On February 9, 2021, the Corps, through the Department of Justice, sought a delay of the proceedings to give lawyers time to brief the new presidential administration on the background of the DAPL matter. Accordingly, the continued operation of DAPL in the future is uncertain. The Company utilizes DAPL to transport a portion of its North region crude oil production to ultimate markets on the U.S. gulf coast. Currently, the Company is committed to transport 3,550 barrels per day on the pipeline through February 2026 and has an additional commitment to transport an incremental 26,450 barrels per day for 7 years effective upon the pending completion of a DAPL expansion project which is estimated to occur in the second half of 2021. 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 $1.40 billion for capital expenditures attributable to us in 2021 of which approximately $1.11 billion is allocated to exploration and development activities. We may adjust our 2021 capital spending plans upward or downward depending on market conditions. Our 2021 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 $1.5 billion that matures in April 2023. 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, causing periodic shortages and/or higher costs. Such 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, 2020, non-operated properties represented 14% of our estimated proved developed reserves, 10% of our estimated proved undeveloped reserves, and 12% 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 will likely continue to make acquisitions of oil and gas properties, divest assets, and enter into joint development arrangements. The successful acquisition of producing properties requires an assessment of several factors, including but not limited to:

- recoverable reserves;
- future crude oil and natural gas prices and location and quality differentials;
- the quality of the title to acquired properties;
- future development costs, operating costs and property taxes; and
- potential environmental and other liabilities.

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.

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. In addition, certain cyber incidents, such as surveillance of our systems and those of our business associates, may remain undetected for an extended period.

A cyber attack involving our information systems and related infrastructure, and/or that of our business associates, 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.

While the Company has 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 weather events and natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe weather 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 have a material adverse effect on our operations or the operations of third party service providers. The consequences of such events may include the evacuation of personnel; damage to and disruption of drilling rigs or transportation, processing, storage, refining, and export facilities; 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.

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 5. Derivative Instruments* for a summary of our commodity derivative positions as of December 31, 2020. 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, 2020. 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 liquidate derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program or other business opportunities.

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, 2020, we had $160 million of outstanding borrowings on our credit facility and our consolidated net debt to total capitalization ratio, as defined, was 0.42 to 1.00.

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 ($561 million in receivables at December 31, 2020) and our joint interest and other receivables ($144 million at December 31, 2020). 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 new leasing and permitting on federal lands and waters; elimination of subsidies for the oil and gas sector; 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—In previous years, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and gas exploration and production companies. Such proposed changes have included: (i) a repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of deductions for intangible drilling and exploration and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. With President Biden taking office and the control of Congress shifting in January 2021, there is an increased risk of the enactment of legislation that alters, eliminates, or defers these or other tax deductions utilized within our industry, which 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.

Climate change activism, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy could reduce the demand for the crude oil and natural gas we produce.

Climate change activism, 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. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for further discussion relating to climate change and emission of greenhouse gases, climate change activism, energy conservation measures or initiatives that stimulate demand for alternative forms of energy. 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 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 attention to environmental, social, and corporate governance matters may impact our business.

Companies across all industries are facing increasing scrutiny from stakeholders related to their environmental, social, and corporate governance ("ESG") practices. These 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. 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 Executive Chairman beneficially owns approximately 81% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our Company.

As of December 31, 2020, Harold G. Hamm, our Executive Chairman, beneficially owned approximately 81% of our outstanding common shares. As a result, Mr. Hamm has 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 could cause, delay or prevent a change of control of our Company. The interests of Mr. Hamm 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 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, 2020.

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

On April 15, 2020, Casillas Petroleum Resource Partners II, LLC filed a petition against the Company in the District Court of Tulsa County, State of Oklahoma alleging the Company breached a Purchase and Sale Agreement ("PSA") to purchase oil and gas interests in Oklahoma for $200 million. The Company asserted the PSA was terminated due to Casillas' breach of the PSA and denied the allegations. On October 16, 2020, the parties entered into a settlement agreement to amend and supplement the terms of the PSA, close on the transaction contemplated by the PSA for a negotiated amount, and settle all disputes involved in the litigation or that could have been raised in the litigation. The parties subsequently dismissed their respective claims in the litigation.

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 January 29, 2021, the number of record holders of our common stock was 1,223. On January 29, 2021, after inquiry, management believes that the number of beneficial owners of our common stock is 55,192. On January 29, 2021, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $19.69 per share.

In May 2019, our Board of Directors approved the initiation of a dividend payment program and on June 3, 2019 the Company announced its first quarterly cash dividend of $0.05 per share, which was paid on November 21, 2019. On January 27, 2020 our Board of Directors approved a cash dividend of $0.05 per share for the first quarter of 2020, which was paid on February 21, 2020. To preserve cash in response to the significant reduction in crude oil prices and economic uncertainty resulting from the COVID-19 pandemic, in April 2020 the Company's quarterly dividend was suspended by the Board of Directors. 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, 2020:

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, 2020 to October 31, 2020				
Repurchases for tax withholdings (2)	9,292	$12.40	—	—
November 1, 2020 to November 30, 2020				
Repurchases for tax withholdings (2)	11,297	$14.06	—	—
December 1, 2020 to December 31, 2020				
Repurchases for tax withholdings (2)	—	$ —	—	—
Total for the quarter	20,589	$ —	—	—

(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. The share repurchase program may be modified, suspended, or terminated by our Board of Directors at any time. No share repurchases were made by the Company under the program during the three months ended December 31, 2020. The total dollar value of shares that may yet be purchased under the program totaled $682.9 million as of December 31, 2020.

(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.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2020 relating to equity compensation plans:

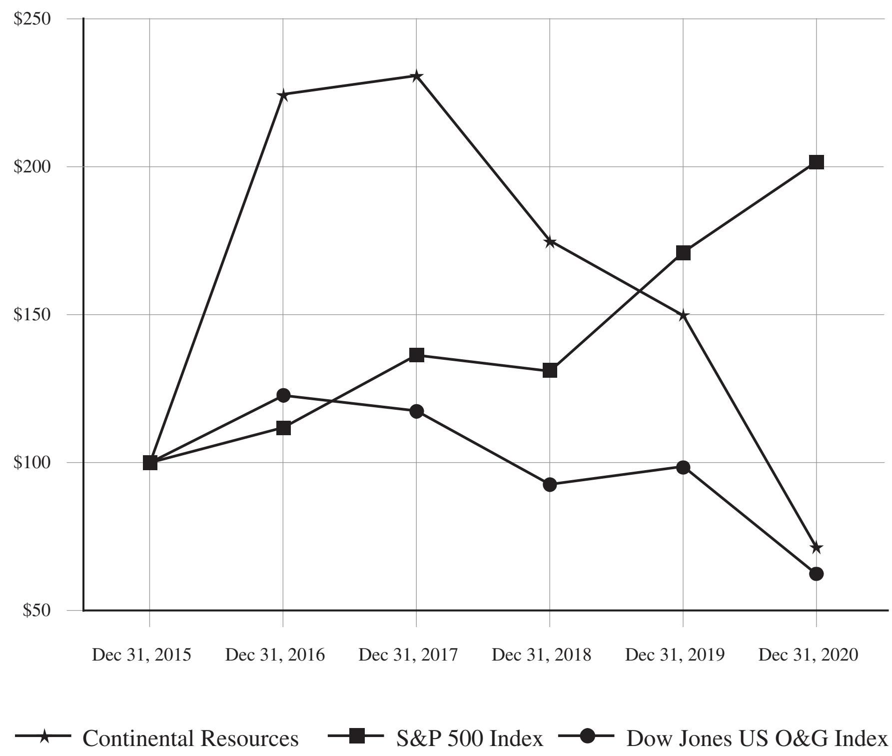
	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	10,768,301
Equity Compensation Plans Not 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, 2015 through December 31, 2020. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2015 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 6. Selected Financial Data

This section presents selected consolidated financial data for the years ended December 31, 2016 through 2020. The selected financial data presented below is not intended to replace our consolidated financial statements. The following financial data has been derived from our audited consolidated financial statements for such periods. You should read the following selected financial data in connection with *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements and related notes included elsewhere in this report. The selected consolidated results are not necessarily indicative of results to be expected in future periods. Operating and financial results attributable to noncontrolling interests are not material relative to the Company's consolidated results and are not separately presented below.

	Year Ended December 31,				
	2020	2019	2018	2017	2016
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales (1)	$ 2,555,434	$ 4,514,389	$ 4,678,722	$ 2,982,966	$ 2,026,958
Gain (loss) on derivative instruments, net	(14,658)	49,083	(23,930)	91,647	(71,859)
Total revenues	2,586,470	4,631,947	4,709,586	3,120,828	1,980,273
Net income (loss) (2)	(605,561)	774,473	989,700	789,447	(399,679)
Net income (loss) attributable to Continental Resources (2)(3)	(596,869)	775,641	988,317	789,447	(399,679)
Net income (loss) per share attributable to Continental Resources: (2)(3)					
Basic	$ (1.65)	$ 2.09	$ 2.66	$ 2.13	$ (1.08)
Diluted	$ (1.65)	$ 2.08	$ 2.64	$ 2.11	$ (1.08)
Cash dividends per common share	$ 0.05	$ 0.05	—	—	—
Production volumes					
Crude oil (MBbl)	58,745	72,267	61,384	50,536	46,850
Natural gas (MMcf)	306,528	311,865	284,730	228,159	195,240
Crude oil equivalents (MBoe)	109,833	124,244	108,839	88,562	79,390
Average costs per unit					
Production expenses ($/Boe)	$ 3.27	$ 3.58	$ 3.59	$ 3.66	$ 3.65
Production taxes (% of net oil and gas revenues)	8.2%	8.3%	7.9%	7.0%	7.0%
DD&A ($/Boe)	$ 17.12	$ 16.25	$ 17.09	$ 18.89	$ 21.54
General and administrative expenses ($/Boe)	$ 1.79	$ 1.57	$ 1.69	$ 2.16	$ 2.14
Proved reserves at December 31					
Crude oil (MBbl)	496,975	760,187	757,096	640,949	643,228
Natural gas (MMcf)	3,640,724	5,154,471	4,591,614	4,140,281	3,789,818
Crude oil equivalents (MBoe)	1,103,762	1,619,265	1,522,365	1,330,995	1,274,864
Other financial data (in thousands)					
Net cash provided by operating activities	$ 1,422,304	$ 3,115,688	$ 3,456,008	$ 2,079,106	$ 1,125,919
Net cash used in investing activities	$ (1,511,358)	$ (2,771,956)	$ (2,860,172)	$ (1,808,845)	$ (532,965)
Net cash (used in) provided by financing activities	$ 97,124	$ (587,108)	$ (356,934)	$ (243,034)	$ (587,773)
Total capital expenditures	$ 1,363,034	$ 2,809,192	$ 2,928,746	$ 2,035,254	$ 1,110,256
Balance Sheet data at December 31 (in thousands)					
Total assets	$14,633,098	$15,727,907	$15,297,947	$14,199,651	$13,811,776
Long-term debt, including current portion	$ 5,532,418	$ 5,326,514	$ 5,768,349	$ 6,353,691	$ 6,579,916
Total equity	$ 6,422,725	$ 7,108,351	$ 6,421,861	$ 5,131,203	$ 4,301,996

(1) In years prior to 2018, we generally presented our revenues net of costs incurred to transport our production to market. For 2020, 2019, and 2018, crude oil and natural gas sales are presented gross of certain transportation expenses as a result of our January 1, 2018 adoption of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. We adopted the new rules using a modified retrospective transition approach whereby the rules were prospectively applied beginning January 1, 2018 and prior period results were not adjusted to conform to the current presentation. The change in presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on our results of operations, net income, or cash flows.

(2) Results for 2017 include the remeasurement of the Company's deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share).

(3) Excludes results attributable to noncontrolling interests. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 16. Noncontrolling Interests* for a discussion of the arrangements that give rise to the separate presentation of results attributable to Continental and noncontrolling interests in our financial statements.

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, as well as the selected consolidated financial data 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.

Our operating results for 2020 discussed below were impacted by the economic effects from the COVID-19 pandemic on crude oil demand and prices and may not be indicative of future results. Given the economic uncertainty from the pandemic and ongoing volatility in commodity prices, it is difficult to predict the extent to which the pandemic or other factors will have on the Company's performance in 2021 and beyond.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development and production of crude oil and natural gas. 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. Our operations are primarily focused on exploration and development activities in the Bakken field of North Dakota and Montana and the SCOOP and STACK areas of Oklahoma. Our common stock trades on the New York Stock Exchange under the symbol "CLR" and our corporate internet website is www.clr.com.

Business Environment and Outlook

Crude oil prices decreased to historically low levels in April 2020 due primarily to reduced global and domestic demand for crude oil caused by the impact of the COVID-19 pandemic and resulting changes in consumer behavior and restrictions implemented by governments to mitigate the pandemic. In response to the significant reduction in crude oil prices, we began voluntarily curtailing our production in April 2020 and ultimately curtailed approximately 55% of our operated crude oil production and associated natural gas in the 2020 second quarter. Additionally, in light of the challenges facing our business and industry, we implemented cost saving initiatives and significantly reduced our operated rig and completion crew counts in order to preserve our assets and better align our capital spending with expected available cash flows, resulting in a $1.5 billion, or 56%, decrease in our non-acquisition capital spending in 2020 compared to 2019. These actions, coupled with historically low crude oil prices, resulted in a material reduction in our production, revenues, and cash flows in 2020 compared to 2019.

Crude oil prices began to stabilize in mid-2020 and generally improved in the second half of 2020 in response to the gradual lifting of COVID-19 restrictions, the resumption of economic activity, and the resulting increase in crude oil demand. In July 2020 we began to gradually restore our curtailed production and subsequently brought our remaining curtailed production back online in September 2020. As a result of our resumed production, coupled with strategic well completion activities in late 2020, our total average production improved to 339,307 Boe per day for the 2020 fourth quarter, representing a 14% increase compared to the third quarter of 2020, yet still remaining 7% lower than the fourth quarter of 2019.

Despite the gradual improvement in crude oil prices in the second half of 2020, we continued our commitment to operating in a disciplined, capital efficient manner. Improved revenues from higher commodity prices coupled with our tempered spending resulted in the generation of cash flows in excess of operating and capital needs in the second half of 2020 that allowed for a $210 million net reduction in our total debt at December 31, 2020 compared to June 30, 2020. Additionally, despite production curtailments during the year, we continued to drive our per-unit production expenses lower to $3.27 per Boe for 2020 compared to $3.58 per Boe for 2019.

We remain committed to the responsible stewardship of our assets and continue to focus on maximizing cash flows, further reducing debt, delivering low-cost capital efficient operations, and generating shareholder value. The depth and quality of our asset base, the commodity optionality provided by our significant amount of acreage held by production, and our financial strength allow us to be adaptable in a variety of price environments. We remain flexible as we monitor and adapt to market conditions. See the subsequent section titled *Liquidity and Capital Resources* for additional discussion of our financial condition.

Financial and Operating Metrics

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.

	Year ended December 31,		
	2020	2019	2018
Average daily production:			
Crude oil (Bbl per day)	160,505	197,991	168,177
Natural gas (Mcf per day)	837,509	854,424	780,083
Crude oil equivalents (Boe per day)	300,090	340,395	298,190
Average net sales prices: (1)			
Crude oil ($/Bbl)	$ 34.71	$ 51.82	$ 59.19
Natural gas ($/Mcf)	$ 1.04	$ 1.77	$ 3.01
Crude oil equivalents ($/Boe)	$ 21.47	$ 34.56	$ 41.25
Crude oil net sales price discount to NYMEX ($/Bbl)	$ (5.80)	$ (5.15)	$ (5.27)
Natural gas net sales price discount to NYMEX ($/Mcf)	$ (1.10)	$ (0.86)	$ (0.09)
Production expenses ($/Boe)	$ 3.27	$ 3.58	$ 3.59
Production taxes (% of net crude oil and natural gas sales)	8.2%	8.3%	7.9%
DD&A ($/Boe)	$ 17.12	$ 16.25	$ 17.09
Total general and administrative expenses ($/Boe)	$ 1.79	$ 1.57	$ 1.69

(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.

In thousands, except sales price data	Year Ended December 31, 2020	2019	2018
Crude oil and natural gas sales	$ 2,555,434	$ 4,514,389	$ 4,678,722
Gain (loss) on derivative instruments, net	(14,658)	49,083	(23,930)
Crude oil and natural gas service operations	45,694	68,475	54,794
Total revenues	2,586,470	4,631,947	4,709,586
Operating costs and expenses	(3,140,362)	(3,374,535)	(3,115,866)
Other expenses, net	(220,859)	(270,250)	(296,918)
Income (loss) before income taxes	(774,751)	987,162	1,296,802
(Provision) benefit for income taxes	169,190	(212,689)	(307,102)
Net income (loss)	(605,561)	774,473	989,700
Net income (loss) attributable to noncontrolling interests	(8,692)	(1,168)	1,383
Net income (loss) attributable to Continental Resources	$ (596,869)	$ 775,641	$ 988,317
Diluted net income (loss) per share attributable to Continental Resources	$ (1.65)	$ 2.08	$ 2.64
Production volumes:			
Crude oil (MBbl)	58,745	72,267	61,384
Natural gas (MMcf)	306,528	311,865	284,730
Crude oil equivalents (MBoe)	109,833	124,244	108,839
Sales volumes:			
Crude oil (MBbl)	58,793	72,136	61,332
Natural gas (MMcf)	306,528	311,865	284,730
Crude oil equivalents (MBoe)	109,881	124,113	108,787

Year ended December 31, 2020 compared to the year ended December 31, 2019

Below is a discussion of changes in our results of operations for 2020 compared to 2019. A discussion of changes in our results of operations for 2019 compared to 2018 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, 2019 as filed with the SEC on February 26, 2020.

Production

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

Boe production per day	Fourth Quarter 2020	Fourth Quarter 2019	% Change	Year Ended December 31, 2020	2019	% Change
Bakken	183,141	194,156	(6%)	158,604	194,691	(19%)
SCOOP	107,060	111,829	(4%)	96,503	82,882	16%
STACK	42,281	51,628	(18%)	38,003	54,587	(30%)
All other	6,825	7,728	(12%)	6,980	8,235	(15%)
Total	339,307	365,341	(7%)	300,090	340,395	(12%)

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

	Year Ended December 31,					
	2020		2019			Volume
	Volume	Percent	Volume	Percent	Volume decrease	percent decrease
Crude oil (MBbl)	58,745	53%	72,267	58%	(13,522)	(19%)
Natural gas (MMcf)	306,528	47%	311,865	42%	(5,337)	(2%)
Total (MBoe)	109,833	100%	124,244	100%	(14,411)	(12%)

	Year Ended December 31,					
	2020		2019			Volume
	MBoe	Percent	MBoe	Percent	Volume decrease	percent decrease
North Region	60,591	55%	74,028	60%	(13,437)	(18%)
South Region	49,242	45%	50,216	40%	(974)	(2%)
Total	109,833	100%	124,244	100%	(14,411)	(12%)

The 19% decrease in crude oil production in 2020 compared to 2019 was primarily due to a 12,763 MBbls, or 24%, decrease in Bakken oil production along with a 1,315 MBbls, or 37%, decrease in STACK oil production due to the previously described production curtailments and limited drilling and completion activities undertaken in response to the adverse commodity price environment during the year. These decreases were partially offset by a 906 MBbls, or 8%, increase in crude oil production in SCOOP due to new well completions over the past year in our oil-weighted Project SpringBoard, which exceeded the impact of production curtailments in the play.

Our production curtailments and limited drilling and completion activities in 2020 also impacted our natural gas production, leading to a 28,202 MMcf, or 29%, decrease in STACK natural gas production and a 1,501 MMcf, or 1%, decrease in Bakken natural gas production in 2020 compared to 2019. These decreases were partially offset by a 24,974 MMcf, or 22%, increase in SCOOP natural gas production in conjunction with the previously described increase in SCOOP crude oil production in 2020.

We have a deep inventory of both oil and gas assets that allow us to be responsive to changes in oil and gas commodity price fundamentals. In the second quarter of 2020 we strategically shifted our rigs to gas-weighted areas in Oklahoma to capitalize on improvements in market prices for natural gas. These actions contributed to an increase in our natural gas production as a percentage of total production from 42% in 2019 to 47% in 2020 and an increase in our South region production as a percentage of total production from 40% in 2019 to 45% in 2020.

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 2020 totaled $2.36 billion, a 45% decrease compared to net sales of $4.29 billion for 2019 due to significant decreases in net sales prices and sales volumes as discussed below.

Total sales volumes for 2020 decreased 14,232 MBoe, or 11%, compared to 2019, reflecting reduced sales from the previously described production curtailments in the current year. For 2020, our crude oil sales volumes decreased 18% compared to 2019, while our natural gas sales volumes decreased 2%.

Our crude oil net sales prices averaged $34.71 per barrel for 2020, a decrease of 33% compared to $51.82 per barrel for 2019 due to significantly reduced market prices and wider price differentials. The differential between NYMEX West Texas Intermediate calendar month crude oil prices and our realized crude oil net sales prices averaged $5.80 per barrel in 2020 compared to $5.15 per barrel in 2019. The increased differential reflects changes in supply and demand fundamentals and economic effects from COVID-19 that impacted location differentials and price realizations in the first and second quarters of 2020 compared to the prior year. Our crude oil net sales price differential to NYMEX averaged $5.20 per barrel for the fourth quarter of 2020.

Our natural gas net sales prices averaged $1.04 per Mcf for 2020, a 41% decrease compared to $1.77 per Mcf for 2019 due to significantly reduced market prices and lower price realizations. The discount between our net sales prices and NYMEX Henry Hub calendar month natural gas prices weakened to $1.10 per Mcf for 2020 compared to $0.86 per Mcf for 2019. We sell the majority of our operated natural gas production to midstream customers at lease locations based on market prices in the field where the sales occur. The field markets are impacted by residue gas and natural gas liquids ("NGLs") prices at secondary, downstream markets. NGL prices decreased in 2020 compared to 2019 levels in conjunction with decreased crude oil prices and other factors, resulting in reduced price realizations for our natural gas sales stream relative to benchmark prices. As a result of the decrease in prices, under certain of our arrangements on operated properties the contractual pricing adjustments applied by midstream customers exceeded the sales consideration we were entitled to receive, resulting in a net payment owed by us to the customers. Additionally, in some instances on non-operated properties the costs incurred by the outside operator exceeded the consideration we were entitled to receive, resulting in a net payment owed by us to the outside operator. The net amounts paid or payable under these arrangements on operated and non-operated properties totaled $42.9 million for 2020, and are reflected as a reduction of natural gas revenues and net sales prices. Nearly all of such amounts were associated with our North region natural gas production.

Derivatives. Changes in market prices during 2020 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $14.7 million for the year, representing $28.2 million of cash losses partially offset by $13.5 million of unsettled non-cash gains. For 2019, we recognized positive revenue adjustments of $49.1 million resulting from changes in market prices that had a favorable 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 decreased $22.8 million, or 33%, from $68.5 million for 2019 to $45.7 million for 2020 due to reduced water handling activities resulting from our curtailment of production and reduced completion activities during the year. The decreased activities also resulted in a reduction in service-related expenses compared to the prior period.

Operating Costs and Expenses

Production expenses. Production expenses decreased $85.3 million, or 19%, to $359.3 million for 2020 compared to $444.6 million for 2019. This decrease resulted from reduced service costs being incurred in conjunction with production curtailments and cost control efforts, operating efficiency gains, and a higher portion of our production coming from wells in Oklahoma which typically have lower operating costs compared to wells in the Bakken, all of which led to a reduction in our production expenses to $3.27 per Boe for 2020 compared to $3.58 per Boe for 2019. Despite our production curtailments, we achieved sequential reductions in our per-Boe production expenses each quarter during 2020 and, as a result of our efficient operations and low-cost production growth in Oklahoma late in the year, our production expenses decreased to a notably low $2.80 per Boe for the 2020 fourth quarter.

Production taxes. Production taxes decreased $165.3 million, or 46%, to $192.7 million for 2020 compared to $358.0 million for 2019 due to a 43% decrease in crude oil and natural gas sales. Our production taxes as a percentage of net crude oil and natural gas sales averaged 8.2% for 2020, consistent with 8.3% for 2019.

Exploration expenses. Exploration expenses, which consist primarily of exploratory geological and geophysical costs and dry hole costs that are expensed as incurred, increased $3.0 million, or 21%, to $17.7 million for 2020 compared to $14.7 million for 2019 due to changes in the timing and extent of our exploration-related activities. The 2020 period includes $6.3 million of dry hole costs recognized in the first quarter associated with an unsuccessful exploratory well with no comparable dry hole costs incurred in 2019.

Depreciation, depletion, amortization and accretion ("DD&A"). Total DD&A decreased $136.4 million, or 7%, to $1.88 billion for 2020 compared to $2.02 billion for 2019 due to an 11% decrease in total sales volumes, the impact of which was partially offset by an increase 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.

	Year ended December 31,	
$/Boe	2020	2019
Crude oil and natural gas properties	$16.84	$16.03
Other equipment	0.19	0.15
Asset retirement obligation accretion	0.09	0.07
Depreciation, depletion, amortization and accretion	$17.12	$16.25

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.

Downward revisions of proved reserves at year-end 2020 prompted by the significant decrease in average commodity prices and other factors resulted in an increase in our DD&A rate for crude oil and natural gas properties compared to 2019. As a result of these downward revisions, our DD&A increased to $19.01 per Boe for the 2020 fourth quarter compared to $16.45 per Boe for the 2019 fourth quarter, which contributed to the overall increase in our DD&A rate for the full year of 2020.

NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2021 and February 1, 2021 averaged $51.04 per barrel and $2.53 per MMBtu, respectively, which are notably higher than average prices in 2020. If commodity prices remain at current levels for an extended period, upward price-related revisions of proved reserves may occur in the future, which may be significant and could result in a decrease in our DD&A rate relative to the 2020 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 increased $191.7 million to $277.9 million for 2020 compared to $86.2 million for 2019, primarily reflecting higher proved property impairments as described below.

Impairments of proved oil and gas properties totaled $182.6 million for 2020, of which $181.0 million was recognized in the 2020 first quarter and $1.6 million was recognized in the 2020 third quarter, resulting from the significant decrease in commodity prices that indicated the carrying values for certain fields were not recoverable. The impairments were recognized on legacy properties in the Red River Units ($168.1 million) and various non-core properties in the North and South regions ($14.5 million). Additionally, in response to decreased crude oil prices, we recognized a $24.5 million impairment in the 2020 first quarter to reduce the value of our crude oil inventory to estimated net realizable value at the time of impairment. There were no significant proved property impairments recognized in 2019.

Impairments of unproved properties decreased $11.7 million, or 14%, to $70.8 million in 2020 compared to $82.5 million in 2019 due to a reduction in the balance of unamortized leasehold costs over the past year.

General and administrative ("G&A") expenses. G&A expenses totaled $196.6 million for 2020, consistent with $195.3 million for 2019 due to offsetting changes in equity compensation expenses and other G&A charges as described below.

Total G&A expenses include non-cash charges for equity compensation of $64.6 million and $52.0 million for 2020 and 2019, respectively, the increase of which was due to additional grants of restricted stock awards coupled with higher forfeitures of unvested stock in 2019 that resulted in lower equity compensation expense for that period.

G&A expenses other than equity compensation totaled $132.0 million for 2020, a decrease of $11.3 million, or 8%, compared to $143.3 million for 2019. This decrease was primarily due to a reduction in employee benefits and other efforts to reduce spending in response to significantly reduced commodity prices and economic turmoil from the COVID-19 pandemic, partially offset by lower overhead recoveries from joint interest owners driven by reduced drilling, completion, and production activities.

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

	Year ended December 31,	
$/Boe	2020	2019
General and administrative expenses	$1.20	$1.15
Non-cash equity compensation	0.59	0.42
Total general and administrative expenses	$1.79	$1.57

The increase in equity compensation expenses on a per-Boe basis in 2020 was driven by an 11% decrease in total sales volumes with no similar reduction in equity compensation expenses, as such expenses continue to be recognized irrespective of sales volumes.

Interest expense. Interest expense decreased $11.2 million, or 4%, to $258.2 million for 2020 compared to $269.4 million for 2019 primarily due to a decrease in our weighted average interest rate from changes in the mix of outstanding debt between periods driven by the redemption or repurchase of senior notes over the past year using available cash and lower-rate credit facility borrowings. Our weighted average interest rate amounted to 4.3% for 2020 compared to 4.5% for 2019.

Gain (loss) on extinguishment of debt. In 2020 we redeemed or repurchased a portion of our outstanding 2022 Notes, 2023 Notes, and 2024 Notes and recognized net gains totaling $35.7 million upon the redemptions and repurchases. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt* for additional discussion.

Income Taxes. For 2020 and 2019 we provided for income taxes at a combined federal and state tax rate of 24.5% of pre-tax income generated by our operations in the United States. We recorded an income tax benefit of $169.2 million and an income tax provision of $212.7 million for 2020 and 2019, respectively, which resulted in effective tax rates of 21.8% and 21.5%, respectively, after taking into account the application of statutory tax rates, permanent taxable differences, tax effects from equity compensation, valuation allowances, tax effects from the 2019 sale of our Canadian operations, and other items. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Income Taxes* for a summary of the sources and tax effects of items comprising our income tax provision and resulting effective tax rates for 2020 and 2019.

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. In light of the challenges facing our business and industry, we remain committed to operating in a responsible manner to preserve financial flexibility, liquidity, and the strength of our balance sheet. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from potential sales of assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

At January 31, 2021, we had approximately $1.13 billion of borrowing availability under our credit facility after considering outstanding borrowings and letters of credit. Our credit facility, which is unsecured and has no borrowing base subject to redetermination, does not mature until April 2023. Further, we have no senior note maturities in the next 12 months, with our earliest scheduled maturity being our $230.8 million of 2022 Notes due in September 2022.

Based on our planned capital spending, 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 in the ordinary course of business other contractual cash commitments to third parties pursuant to the various agreements subsequently described under the heading *Contractual Obligations*, 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 to preserve liquidity and financial flexibility if needed to fund our operations.

Cash Flows

Cash flows from operating activities

Net cash provided by operating activities totaled $1.42 billion and $3.12 billion for 2020 and 2019, respectively, reflecting a significant decrease in our operating cash flows due to the previously described decrease in market prices and our voluntary curtailment of production in the second and third quarters which adversely impacted our 2020 operating results. As a result of our resumed production and improved commodity prices late in the year, our net cash provided by operating activities increased to $487.5 million for the fourth quarter of 2020, an improvement of $196.3 million, or 67%, compared to $291.2 million of operating cash flows generated in the third quarter of 2020.

Cash flows used in investing activities

Net cash used in investing activities totaled $1.51 billion and $2.77 billion for 2020 and 2019, respectively, reflecting the significant decrease in our drilling and completion activities in 2020 prompted by the decrease in crude oil prices and economic uncertainty from the COVID-19 pandemic.

Cash flows from financing activities

Net cash provided by financing activities for 2020 totaled $97.1 million, primarily consisting of $1.48 billion of net proceeds received from our November 2020 issuance of 5.75% senior notes due 2031, $105.0 million of net credit facility borrowings, and net proceeds of $26.0 million from new term loans executed during the year. These increases were partially offset by $1.34 billion of senior note repurchases and redemptions during the year 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.

Net cash used in financing activities for 2019 totaled $587.1 million primarily resulting from a $441.8 million net reduction in total outstanding debt due in part to our partial redemption of 2022 Notes in September 2019. Additionally, $18.4 million of cash was used to fund our inaugural dividend payment in November 2019 and $190.2 million of cash was used to repurchase shares of our common stock. These cash outflows were partially offset by $109.1 million of contributions received from noncontrolling interests, primarily from Franco-Nevada for the funding of its share of mineral acquisition costs incurred by The Mineral Resources Company II.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows and availability under our credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments for at least the next 12 months.

Our 2021 capital budget is reflective of the current commodity price environment and, based on our current expectations of commodity prices and costs, is expected to be funded from operating cash flows. Any cash flow deficiencies 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, although uncertainties existing in the financial markets as a result of the COVID-19 pandemic and other factors may increase the expense and difficulty of completing a bank or capital markets financing. Additionally, the terms available to the Company in connection with such a financing transaction may be less favorable than those enjoyed by the Company prior to the COVID-19 pandemic, although the degree, if any, by which such terms may change cannot be predicted at this time. 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.

In March 2020, our corporate credit rating was downgraded by Standard & Poor's Ratings Services ("S&P") in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. Such downgrade negatively impacted our cost of capital and increased our borrowing costs under our credit facility. Also in March 2020, our corporate credit ratings were reaffirmed by both Moody's Investor Services and Fitch Ratings. Such ratings are subject to ongoing review and adjustment.

Credit facility

We have an unsecured credit facility, maturing in April 2023, with aggregate lender commitments totaling $1.5 billion. The commitments are from a syndicate of 14 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of January 31, 2021, we had $360 million of outstanding borrowings and $1.13 billion of borrowing availability on our credit facility.

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, such as the downgrade by S&P that occurred in March 2020 in response to weakened oil and gas industry conditions, do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants.
The downgrade of our credit rating did, however, trigger a 0.25% increase in our credit facility's interest rate and prompted a 0.05% increase in the rate of commitment fees paid on unused borrowing availability.

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 7. Long-Term Debt* for a discussion of how this ratio is calculated pursuant to our revolving credit agreement.

We were in compliance with our credit facility covenants at December 31, 2020 and expect to maintain compliance. At December 31, 2020, our consolidated net debt to total capitalization ratio was 0.42 to 1.00. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing to a material extent if needed to support our business.

At December 31, 2020, our total debt would have needed to independently increase by approximately $8.4 billion above the existing level at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $4.5 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at December 31, 2020 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Future Capital Requirements

Senior notes

In January 2021, we redeemed an additional $400 million principal amount of our outstanding 2022 Notes using proceeds from lower-rate credit facility borrowings. Our outstanding senior note obligations now total $5.0 billion at January 31, 2021. We have no senior note maturities in the next 12 months, with our earliest scheduled maturity being our $230.8 million of remaining 2022 Notes due in September 2022. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. 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 *Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt.*

We were in compliance with our senior note covenants at December 31, 2020 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, such as the downgrade by S&P that occurred in March 2020, do not trigger additional senior note covenants.

Mineral acquisition 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"). Under the relationship, the parties have committed to spend up to a remaining aggregate total of $153 million to acquire mineral interests. Continental agreed 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 predetermined production targets, while Franco-Nevada will fund 80% of future acquisitions and will be entitled to receive between 50% and 75% of TMRC II's revenues. Based upon production targets achieved to date, Continental is currently earning 50% of TMRC II's revenues and such allocation is expected to continue through at least year-end 2021.

Capital expenditures

2020

Our original capital budget for 2020 was $2.65 billion, excluding acquisitions, which was reduced to $1.2 billion in March 2020 in response to the significant decrease in crude oil prices resulting from the COVID-19 pandemic and other factors. We significantly reduced our drilling and completion activities in order to preserve our assets and better align our spending with expected available cash flows. As a result of these actions, our non-acquisition capital spending was reduced by 56% in 2020 compared to 2019.

For the year ended December 31, 2020, we invested $1.16 billion in our capital program excluding $204.0 million of unbudgeted acquisitions and excluding $133.9 million of capital costs associated with reduced accruals for capital expenditures as compared to December 31, 2019. Our 2020 capital expenditures were allocated as follows by quarter:

In millions	1Q 2020	2Q 2020	3Q 2020	4Q 2020	Total 2020
Exploration and development	$544.0	$155.8	$120.9	$151.0	$ 971.7
Land costs (1)	39.9	8.9	6.1	3.5	58.4
Capital facilities, workovers and other corporate assets	63.0	25.8	22.4	13.5	124.7
Seismic	3.8	0.3	—	0.1	4.2
Capital expenditures, excluding acquisitions	$650.7	$190.8	$149.4	$168.1	$1,159.0
Acquisitions of producing properties	19.3	0.1	4.0	37.1	60.5
Acquisitions of non-producing properties	10.6	—	0.1	132.8	143.5
Total acquisitions (2)	29.9	0.1	4.1	169.9	204.0
Total capital expenditures	$680.6	$190.9	$153.5	$338.0	$1,363.0

(1) Full year 2020 amount includes $24 million of mineral acquisitions made by TMRC II, of which $19 million was recouped from Franco-Nevada.

(2) The 2020 fourth quarter amount includes our October 2020 acquisition of undeveloped leasehold and producing properties in the SCOOP play for $162.8 million and excludes the $21.5 million escrow deposit paid on December 31, 2020 associated with a pending property acquisition as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 12. Commitments and Contingencies.*

2021 Capital Budget

In 2021, we will remain committed to operating in a disciplined, capital-efficient manner in light of continued volatility in commodity prices. Our 2021 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.

In millions	2021 Budget
Exploration and development	$1,112
Land costs	85
Mineral acquisitions attributable to Continental (1)	13
Capital facilities, workovers, water infrastructure, and other corporate assets	186
Seismic	4
2021 capital budget attributable to Continental	$1,400
Mineral acquisitions attributable to Franco-Nevada (1)	52
Total 2021 capital budget (2)	$1,452

(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 2021 planned spending, or $13 million, and Franco-Nevada will fund the remaining 80%, or $52 million.

(2) Excludes the Company's pending acquisition of properties in the Powder River Basin of Wyoming for $215 million discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 12. Commitments and Contingencies.*

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, 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 decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures. 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 competitive terms.

Contractual Obligations

The following table presents our contractual obligations and commitments as of December 31, 2020.

	Payments due by period				
In thousands	Total	Less than 1 year (2021)	Years 2 and 3 (2022-2023)	Years 4 and 5 (2024-2025)	More than 5 years
Credit facility borrowings (1)	$ 160,000	$ —	$ 160,000	$ —	$ —
Senior Notes (1)(2)	5,391,407	—	1,280,407	911,000	3,200,000
Notes payable (3)	24,696	2,245	4,736	5,082	12,633
Interest payments and commitment fees (4)	2,316,057	266,929	482,793	346,997	1,219,338
Asset retirement obligations (5)	179,676	2,482	22,760	1,141	153,293
Operating leases and other (6)	33,236	15,514	7,536	1,428	8,758
Drilling rig commitments (7)	14,099	14,099	—	—	—
Transportation and processing commitments (8)	1,450,873	226,804	513,243	364,819	346,007
Total contractual obligations	$9,570,044	$528,073	$2,471,475	$1,630,467	$4,940,029

(1) On January 5, 2021, we redeemed $400 million principal amount of our outstanding 2022 Notes using proceeds from borrowings on our credit facility. Such activity is not reflected in the table above.
(2) Amounts represent scheduled maturities of our senior note obligations at December 31, 2020 and do not reflect any discount or premium at which the senior notes were issued or any debt issuance costs.
(3) Represents future principal payments on two 10-year amortizing notes payable secured by the Company's corporate office building and its interest in parking facilities in Oklahoma City, Oklahoma and does not reflect any debt issuance costs. Principal and interest are payable monthly through the loans' maturity dates in May 2030.
(4) Interest payments include scheduled cash interest payments on the senior notes and notes payable, as well as estimated interest payments and commitment fees on unused borrowing availability under our credit facility assuming the $1.33 billion of availability as of December 31, 2020 continues through the April 2023 maturity date of the facility.
(5) Amounts represent estimated discounted costs for future dismantlement and abandonment of our crude oil and natural gas properties. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies* for additional discussion of our asset retirement obligations.
(6) Amounts primarily represent commitments for electric infrastructure, surface use agreements, office buildings and equipment, communication towers, field equipment, and purchase obligations mainly related to software services. A portion of these costs will be borne by other interest owners. Due to variations in well ownership, our net share of these costs cannot be determined with certainty. These amounts include minimum payment obligations on enforceable commitments with durations in excess of one year with a

discounted present value totaling $6.4 million that qualify as leases and were recognized on our balance sheet at December 31, 2020 in accordance with ASC Topic 842.

(7) Amounts represent operating day-rate commitments under drilling rig contracts with various terms extending to May 2021. A portion of these costs will be borne by other interest owners, the amount of which cannot be determined with certainty. These amounts include minimum payment obligations with a discounted present value totaling $2.0 million that qualify as leases and were recognized on our balance sheet at December 31, 2020 in accordance with ASC Topic 842.

(8) We have entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. These commitments require us to pay per-unit transportation or processing charges regardless of the amount of capacity used. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. A portion of these costs will be borne by other interest owners, the amount of which cannot be determined with certainty. These commitments do not qualify as leases under ASC Topic 842 and are not recognized on our balance sheet.

On December 31, 2020, we executed a definitive agreement to acquire undeveloped leasehold and producing properties in the Powder River Basin of Wyoming for $215 million of cash. Closing of the acquisition is scheduled to occur on or around March 4, 2021. This pending acquisition remains subject to the completion of customary due diligence procedures and closing conditions and is not reflected in the table above.

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. As of December 31, 2020, we were committed to deliver the following fixed quantities of natural gas production.

Year Ending December 31,	Natural Gas Bcf
2021	107
2022	37
2023	34
2024	34
2025	18
2026	15

Derivative Instruments

See *Note 5. Derivative Instruments* in *Part II, Item 8. Notes to Consolidated Financial Statements* for a summary of derivative instruments in place as of December 31, 2020. Between January 1, 2021 and February 12, 2021 we entered into additional derivative instruments as summarized below. The hedged volumes reflected below represent an aggregation of multiple contracts. The crude oil derivative instruments will be settled based on NYMEX West Texas Intermediate pricing and natural gas derivative instruments will be settled based on NYMEX Henry Hub pricing.

Natural gas derivatives

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
April 2021—December 2021		
Swaps—Henry Hub	64,120,000	$2.88

Crude oil derivatives

			Collars			
			Floors		Ceilings	
Period and Type of Contract	Bbls	Swaps Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
March 2021—December 2021						
NYMEX Roll Swaps	6,885,000	$ 0.39				
January 2021—May 2021						
Swaps—WTI	5,310,000	$52.50				
March 2021—April 2021						
Collars—WTI	915,000		$45.00 - $50.00	$47.46	$53.80 - $55.10	$54.44

Dividend payments

To preserve cash in response to the significant reduction in crude oil prices and economic uncertainty resulting from the COVID-19 pandemic, in April 2020 the Company's quarterly dividend was suspended by the Board of Directors.

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. Through December 31, 2020, we had repurchased and retired a cumulative total of approximately 13.8 million shares at an aggregate cost of $317.1 million since the inception of the 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. To preserve cash in the current environment, we do not expect to engage in significant share repurchase activity in the near term.

Senior note repurchases

As discussed in *Note 7. Long-Term Debt* and *Note 21. Subsequent Event* in *Part II, Item 8. Notes to Consolidated Financial Statements*, in 2020 and early 2021 we repurchased a portion of our outstanding senior notes. From time to time we may seek to execute additional repurchases of our senior notes for cash in open market transactions, privately negotiated transactions, or otherwise. Such repurchases 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 8. 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, 2020, 2019, and 2018, net downward revisions and removals of our proved reserves totaled approximately 505 MMBoe, 149 MMBoe, and 269 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, 2020, our proved reserves totaled 1,104 MMBoe as determined using 12-month average first-day-of-the-month prices of $39.57 per barrel for crude oil and $1.99 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, 2021 and February 1, 2021 averaged $51.04 per barrel and $2.53 per MMBtu, respectively.

Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were increased to $50 per barrel our proved reserves at December 31, 2020 could increase by approximately 52 MMBoe, or 5%, representing a 7% increase in proved developed producing reserves averaged with a 2% increase in PUD reserves. If the increase in proved reserves under this oil price sensitivity existed throughout 2020, our DD&A expense for 2020 would have decreased by an estimated 7%.

Holding all other factors constant, if natural gas prices used in our year-end reserve estimates were increased to $2.50 per MMBtu our proved reserves at December 31, 2020 could increase by approximately 21 MMBoe, or 2%, representing a 3% increase in proved developed producing reserves averaged with a 1% increase in PUD reserves. If the increase in proved reserves under this gas price sensitivity existed throughout 2020, our DD&A expense for 2020 would have decreased by an estimated 3%.

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 Reserve, 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 8. 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.

Impairment provisions for proved properties totaled $207.1 million for 2020. Commodity price assumptions used for the year-end December 31, 2020 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2025 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, 2020, the publicly available forward commodity strip prices for the year 2025 used in our fourth quarter impairment calculations averaged $44.82 per barrel for crude oil and $2.52 per Mcf for natural gas. If forward commodity prices materially decrease from current levels for an extended period, additional 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 for our deferred tax asset balances, we consider, among other factors, current financial position, results of operations, projected future taxable income, reversal of existing deferred tax liabilities against deferred tax assets, whether the carryforward period is so brief that it would limit realization of the tax benefit, 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, after valuation allowances, will ultimately be realized. We will continue to evaluate both the positive and negative evidence on a quarterly basis in determining the need for additional valuation allowances with respect to our deferred tax assets. In 2020, we determined it was more likely than not that a portion of our Oklahoma net operating loss carryforward would not be utilized before expiration, and a valuation allowance of $14.5 million was established during the year for the deferred tax asset associated with such net operating loss carryforward.

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.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resources.

New Accounting Pronouncements

See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Allowance for Credit Losses* for a discussion of the new credit loss accounting standard adopted on January 1, 2020.

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. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for a 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. In particular, in January 2021 President Biden issued executive orders that, among other things, suspend new permitting and leasing activities for oil and gas exploration and production on federal lands and establish new greenhouse gas emission standards for the oil and gas sector. President Biden may continue to issue additional executive orders in pursuit of his regulatory agenda and, with control of Congress shifting in January 2021, 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.

Inflation

As a result of the low commodity price environment in recent years, the number of providers of services, equipment, and materials have decreased in the regions where we operate. If commodity prices show signs of diminished volatility and sustained recovery, industry drilling and completion activities are likely to increase and we may face shortages of service providers, equipment, and materials. Such shortages could result in increased competition which may lead to 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 8. 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 2020, 2019, and 2018.

Total Company	Year Ended December 31, 2020			Year Ended December 31, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$2,199,976	$355,458	$2,555,434	$3,929,994	$584,395	$4,514,389	$3,792,594	$886,128	$4,678,722
Less: Transportation expenses	(158,989)	(37,703)	(196,692)	(191,998)	(33,651)	(225,649)	(162,312)	(29,275)	(191,587)
Net crude oil and natural gas sales (non-GAAP)	$2,040,987	$317,755	$2,358,742	$3,737,996	$550,744	$4,288,740	$3,630,282	$856,853	$4,487,135
Sales volumes (MBbl/MMcf/MBoe)	58,793	306,528	109,881	72,136	311,865	124,113	61,332	284,730	108,787
Net sales price (non-GAAP)	$ 34.71	$ 1.04	$ 21.47	$ 51.82	$ 1.77	$ 34.56	$ 59.19	$ 3.01	$ 41.25

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 2020, 2019, and 2018 as presented in *Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Production and Price History.*

North Dakota Bakken	Year Ended December 31, 2020			Year Ended December 31, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$1,469,450	$24,714	$1,494,164	$2,826,136	$128,426	$2,954,562	$2,797,771	$263,388	$3,061,159
Less: Transportation expenses	(127,036)	(2,580)	(129,616)	(157,076)	(2,530)	(159,606)	(128,287)	(2,291)	(130,578)
Net crude oil and natural gas sales (non-GAAP)	$1,342,414	$22,134	$1,364,548	$2,669,060	$125,896	$2,794,956	$2,669,484	$261,097	$2,930,581
Sales volumes (MBbl/MMcf/MBoe)	40,040	97,532	56,295	52,374	98,186	68,738	45,735	78,448	58,810
Net sales price (non-GAAP)	$ 33.53	$ 0.23	$ 24.24	$ 50.96	$ 1.28	$ 40.66	$ 58.37	$ 3.33	$ 49.83

SCOOP	Year Ended December 31, 2020			Year Ended December 31, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$486,076	$246,125	$732,201	$640,097	$277,230	$917,327	$435,798	$351,021	$786,819
Less: Transportation expenses	(5,275)	(21,909)	(27,184)	(3,539)	(14,795)	(18,334)	(4,039)	(11,741)	(15,780)
Net crude oil and natural gas sales (non-GAAP)	$480,801	$224,216	$705,017	$636,558	$262,435	$898,993	$431,759	$339,280	$771,039
Sales volumes (MBbl/MMcf/MBoe)	12,694	136,410	35,429	11,592	111,436	30,164	6,882	99,397	23,447
Net sales price (non-GAAP)	$ 37.88	$ 1.64	$ 19.90	$ 54.92	$ 2.36	$ 29.80	$ 62.74	$ 3.41	$ 32.88

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, 2020, our PV-10 totaled approximately $4.89 billion. The standardized measure of our discounted future net cash flows was approximately $4.65 billion at December 31, 2020, representing a $239 million 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, 2020, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $645 million for each $10.00 per barrel change in crude oil prices at December 31, 2020 and $356 million for each $1.00 per Mcf change in natural gas prices at December 31, 2020.

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. 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 liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. 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 natural gas derivative instruments at December 31, 2020 was a net asset of $13.7 million. An assumed increase in the forward prices used in the December 31, 2020 valuation of our natural gas derivatives of $1.00 per MMBtu would change our derivative valuation to a net liability of approximately $27 million at December 31, 2020. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our derivative asset to approximately $63 million at December 31, 2020.

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 ($561 million in receivables at December 31, 2020) and our joint interest and other receivables ($144 million at December 31, 2020).

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; however, we could experience increased exposure to credit losses in the future, which may be material, if the adverse economic effects of the COVID-19 pandemic persist for an extended period.

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 $25 million at December 31, 2020, 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 redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial; however, we could experience increased exposure to credit losses in the future, which may be material, if the adverse economic effects of the COVID-19 pandemic persist for an extended period.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any 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. In March 2020, our corporate credit rating was downgraded by S&P in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. The downgrade caused the interest rate on our credit facility borrowings to increase by 0.25% and also prompted a 0.05% increase in the rate of commitment fees paid on unused borrowing availability. 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 $360 million of variable rate borrowings outstanding on our credit facility at January 31, 2021. 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 $0.9 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, 2020:

In thousands	2021	2022	2023	2024	2025	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)(2)	$ —	$630,782	$649,625	$911,000	$ —	$3,200,000	$5,391,407
Weighted-average interest rate	—	5.0%	4.5%	3.8%	— %	5.1%	4.8%
Notes payable:							
Principal amount (1)	$2,245	$ 2,326	$ 2,410	$ 2,495	$2,587	$ 12,633	$ 24,696
Interest rate	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
Variable rate debt:							
Credit facility:							
Principal amount (2)	$ —	$ —	$160,000	$ —	$ —	$ —	$ 160,000
Weighted-average interest rate	—	—	1.9%	—	—	—	1.9%

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

(2) On January 5, 2021, we redeemed $400 million principal amount of our outstanding 2022 Notes using proceeds from borrowings on our credit facility. Such activity is not reflected in the table above.

Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

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, 2020 and 2019, the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 16, 2021 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 and of proved and unproved crude oil and natural gas reserves for the assessment / measurement of impairment of proved crude oil and natural gas properties (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. 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 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.

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 / measurement of impairment 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.
- 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; and
- 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.

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
February 16, 2021

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

In thousands, except par values and share data	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 47,470	$ 39,400
Receivables:		
Crude oil and natural gas sales	561,127	726,876
Joint interest and other	143,829	317,018
Allowance for credit losses	(2,462)	(2,407)
Receivables, net	702,494	1,041,487
Derivative assets	15,303	—
Inventories	72,157	109,536
Prepaid expenses and other	15,121	16,592
Total current assets	852,545	1,207,015
Net property and equipment, based on successful efforts method of accounting	13,737,292	14,497,726
Operating lease right-of-use assets	8,557	9,128
Other noncurrent assets	34,704	14,038
Total assets	$14,633,098	$15,727,907
Liabilities and equity		
Current liabilities:		
Accounts payable trade	$ 361,704	$ 629,264
Revenues and royalties payable	327,029	470,264
Accrued liabilities and other	167,013	230,368
Derivative liabilities	227	—
Current portion of operating lease liabilities	2,588	3,695
Current portion of long-term debt	2,245	2,435
Total current liabilities	860,806	1,336,026
Long-term debt, net of current portion	5,530,173	5,324,079
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,620,154	1,787,125
Asset retirement obligations, net of current portion	177,194	151,774
Derivative liabilities, noncurrent	1,584	—
Operating lease liabilities, net of current portion	5,839	5,433
Other noncurrent liabilities	14,623	15,119
Total other noncurrent liabilities	1,819,394	1,959,451
Commitments and contingencies (Note 12)		
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; 365,220,435 shares issued and outstanding at December 31, 2020; 371,074,036 shares issued and outstanding at December 31, 2019;	3,652	3,711
Additional paid-in capital	1,205,148	1,274,732
Retained earnings	4,847,646	5,463,224
Total shareholders' equity attributable to Continental Resources	6,056,446	6,741,667
Noncontrolling interests	366,279	366,684
Total equity	6,422,725	7,108,351
Total liabilities and equity	$14,633,098	$15,727,907

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

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

In thousands, except per share data	Year Ended December 31, 2020	2019	2018
Revenues:			
Crude oil and natural gas sales	$2,555,434	$4,514,389	$4,678,722
Gain (loss) on derivative instruments, net	(14,658)	49,083	(23,930)
Crude oil and natural gas service operations	45,694	68,475	54,794
Total revenues	2,586,470	4,631,947	4,709,586
Operating costs and expenses:			
Production expenses	359,267	444,649	390,423
Production taxes	192,718	357,988	353,140
Transportation expenses	196,692	225,649	191,587
Exploration expenses	17,732	14,667	7,642
Crude oil and natural gas service operations	18,294	33,230	21,639
Depreciation, depletion, amortization and accretion	1,880,959	2,017,383	1,859,327
Property impairments	277,941	86,202	125,210
General and administrative expenses	196,572	195,302	183,569
Net (gain) loss on sale of assets and other	187	(535)	(16,671)
Total operating costs and expenses	3,140,362	3,374,535	3,115,866
Income (loss) from operations	(553,892)	1,257,412	1,593,720
Other income (expense):			
Interest expense	(258,240)	(269,379)	(293,032)
Gain (loss) on extinguishment of debt	35,719	(4,584)	(7,133)
Other	1,662	3,713	3,247
	(220,859)	(270,250)	(296,918)
Income (loss) before income taxes	(774,751)	987,162	1,296,802
(Provision) benefit for income taxes	169,190	(212,689)	(307,102)
Net income (loss)	(605,561)	774,473	989,700
Net income (loss) attributable to noncontrolling interests	(8,692)	(1,168)	1,383
Net income (loss) attributable to Continental Resources	$ (596,869)	$ 775,641	$ 988,317
Net income (loss) per share attributable to Continental Resources:			
Basic	$ (1.65)	$ 2.09	$ 2.66
Diluted	$ (1.65)	$ 2.08	$ 2.64
Comprehensive income (loss):			
Net income (loss)	$ (605,561)	$ 774,473	$ 989,700
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	—	140	108
Release of cumulative translation adjustments	—	(555)	—
Total other comprehensive income (loss), net of tax	—	(415)	108
Comprehensive income (loss)	(605,561)	774,058	989,808
Comprehensive income (loss) attributable to noncontrolling interests	(8,692)	(1,168)	1,383
Comprehensive income (loss) attributable to Continental Resources	$ (596,869)	$ 775,226	$ 988,425

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								
In thousands, except share data	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
Balance at December 31, 2017	375,219,769	$3,752	$1,409,326	$ 307	$ —	$3,717,818	$5,131,203	$ —	$5,131,203
Net Income	—	—	—	—	—	988,317	988,317	1,383	989,700
Other comprehensive income, net of tax	—	—	—	108	—	—	108	—	108
Equity transaction costs (see Note 16)	—	—	(4,838)	—	—	—	(4,838)	—	(4,838)
Stock-based compensation	—	—	47,223	—	—	—	47,223	—	47,223
Restricted stock:									
Granted	1,390,914	14	—	—	—	—	14	—	14
Repurchased and canceled	(310,822)	(3)	(16,888)	—	—	—	(16,891)	—	(16,891)
Forfeited	(278,286)	(3)	—	—	—	—	(3)	—	(3)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	277,238	277,238
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(1,893)	(1,893)
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 ($0.05 per share)	—	—	—	—	—	(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 income (loss)	—	—	—	—	—	(596,869)	(596,869)	(8,692)	(605,561)
Cumulative effect adjustment from adoption of ASU 2016-13 (see Note 9)	—	—	—	—	—	(137)	(137)	—	(137)
Cash dividends declared ($0.05 per share)	—	—	—	—	—	(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

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

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

In thousands	Year Ended December 31, 2020	2019	2018
Cash flows from operating activities:			
Net income (loss)	$ (605,561)	$ 774,473	$ 989,700
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	1,882,458	2,019,704	1,859,118
Property impairments	277,941	86,202	125,210
Non-cash (gain) loss on derivatives, net	(13,492)	15,612	(13,009)
Stock-based compensation	64,613	52,044	47,236
Provision (benefit) for deferred income taxes	(166,971)	212,689	314,878
Net (gain) loss on sale of assets and other	187	(535)	(16,671)
(Gain) loss on extinguishment of debt	(35,719)	4,584	7,133
Other, net	16,970	10,408	16,705
Changes in assets and liabilities:			
Accounts receivable	332,128	(33,619)	94,765
Inventories	12,859	(21,204)	7,735
Other current assets	1,471	(4,459)	(3,539)
Accounts payable trade	(133,977)	(36,359)	9,274
Revenues and royalties payable	(143,260)	69,195	24,010
Accrued liabilities and other	(66,071)	(36,467)	(4,162)
Other noncurrent assets and liabilities	(1,272)	3,420	(2,375)
Net cash provided by operating activities	1,422,304	3,115,688	3,456,008
Cash flows from investing activities:			
Exploration and development	(1,408,149)	(2,783,149)	(2,840,880)
Purchase of producing crude oil and natural gas properties	(81,994)	(51,558)	(31,579)
Purchase of other property and equipment	(23,994)	(25,983)	(42,171)
Proceeds from sale of assets	2,779	88,734	54,458
Net cash used in investing activities	(1,511,358)	(2,771,956)	(2,860,172)
Cash flows from financing activities:			
Credit facility borrowings	2,052,000	1,216,000	2,024,000
Repayment of credit facility	(1,947,000)	(1,161,000)	(2,212,000)
Proceeds from issuance of Senior Notes	1,485,000	—	—
Redemption and repurchase of Senior Notes	(1,343,250)	(500,000)	(400,000)
Premium and costs on redemption of Senior Notes	(25,173)	(4,167)	(6,700)
Proceeds from other debt	26,000	—	—
Repayment of other debt	(6,679)	(2,352)	(2,286)
Debt issuance costs	(4,368)	—	(5,535)
Equity transaction costs	—	—	(4,838)
Contributions from noncontrolling interests	27,116	109,137	267,920
Distributions to noncontrolling interests	(13,809)	(14,164)	(604)
Repurchase of common stock	(126,906)	(190,239)	—
Repurchase of restricted stock for tax withholdings	(7,347)	(21,943)	(16,891)
Dividends paid on common stock	(18,460)	(18,380)	—
Net cash provided by (used in) financing activities	97,124	(587,108)	(356,934)
Effect of exchange rate changes on cash	—	27	(55)
Net change in cash and cash equivalents	8,070	(243,349)	238,847
Cash and cash equivalents at beginning of period	39,400	282,749	43,902
Cash and cash equivalents at end of period	$ 47,470	$ 39,400	$ 282,749

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

Continental Resources, Inc. and Subsidiaries
Notes to 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 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 certain of its key operating areas. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

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, 2020, the Company had cash deposits in excess of federally insured amounts of approximately $46.0 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's method for determining its allowance for credit losses was changed upon its January 1, 2020 adoption of ASU 2016-13 as subsequently discussed in *Note 9. Allowance for Credit Losses*. The Company's allowance for credit losses, as accounted for under legacy U.S. GAAP in effect as of December 31, 2019, was determined by considering a number of factors, including the length of time accounts are past due, the Company's history of losses, and the customer or working interest owner's ability to pay. 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 $2.5 million and $2.4 million as of December 31, 2020 and 2019, respectively. See *Note 9. 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, 2020, sales to the Company's two largest purchasers accounted for approximately 13% and 12% 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 2020. 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.

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, 2020 and 2019 consisted of the following:

	December 31,	
In thousands	2020	2019
Tubular goods and equipment	$13,671	$ 14,880
Crude oil	58,486	94,656
Total	$72,157	$109,536

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, repairs, and costs of injection 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:

Service property and equipment	Useful Lives In Years
Automobiles and aircraft	5-10
Machinery and equipment	6-10
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, 2018 through December 31, 2020:

In thousands	2020	2019	2018
Asset retirement obligations at January 1	$153,673	$141,360	$114,406
Accretion expense	9,393	8,443	6,985
Revisions (1)	10,743	(1,762)	13,075
Plus: Additions for new assets	7,048	8,392	9,070
Less: Plugging costs and sold assets	(1,181)	(2,760)	(2,176)
Total asset retirement obligations at December 31	$179,676	$153,673	$141,360
Less: Current portion of asset retirement obligations at December 31 (2)	2,482	1,899	4,374
Non-current portion of asset retirement obligations at December 31	$177,194	$151,774	$136,986

(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 is included in the caption "Accrued liabilities and other" in the consolidated balance sheets.

As of December 31, 2020 and 2019, net property and equipment on the consolidated balance sheets included $56.1 million and $55.8 million, respectively, of net asset retirement costs.

Asset impairment

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 $45.8 million and $40.0 million (net of accumulated amortization of $87.4 million and $73.7 million) relating to its long-term debt at December 31, 2020 and 2019, respectively. Unamortized capitalized costs associated with the Company's Notes and note payable totaled $42.5 million and $35.3 million at December 31, 2020 and 2019, 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 $3.3 million and $4.7 million at December 31, 2020 and 2019, respectively, and are reflected in "Other noncurrent assets" on the consolidated balance sheets.

For the years ended December 31, 2020, 2019 and 2018, the Company recognized amortization expense associated with capitalized debt issuance costs of $7.8 million, $8.3 million and $9.3 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 5. 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 6. 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, 2020 and 2019.

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. 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.

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, 2020, 2019 and 2018.

In thousands, except per share data	Year ended December 31, 2020	2019	2018
Net income (loss) attributable to Continental Resources (numerator)	$(596,869)	$775,641	$988,317
Weighted average shares (denominator):			
Weighted average shares—basic	361,538	370,699	371,854
Non-vested restricted stock (1)	—	1,839	2,984
Weighted average shares—diluted	361,538	372,538	374,838
Net income (loss) per share attributable to Continental Resources:			
Basic	$ (1.65)	$ 2.09	$ 2.66
Diluted	$ (1.65)	$ 2.08	$ 2.64

(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 10. Income Taxes* and *Note 17. 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, net of tax” in the consolidated statements of comprehensive income (loss).

Adoption of new accounting pronouncement

On January 1, 2020 the Company adopted Accounting Standards Update (“ASU”) 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. See *Note 9. Allowance for Credit Losses* for discussion of the adoption impact and the applicable disclosures required by the new standard.

New accounting pronouncements not yet adopted at December 31, 2020

In December 2019, the Financial Accounting Standards Board issued ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes.* This standard eliminates 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 clarifies certain aspects of the existing guidance, among other things. The standard became effective for interim and annual periods beginning after December 15, 2020 and shall be applied on either a prospective basis, a retrospective basis for all periods presented, or a modified retrospective basis through a cumulative-effect adjustment to retained earnings depending on which aspects of the new standard are applicable to an entity. The Company adopted the new standard on January 1, 2021 on a prospective basis, which did not have a material impact on its financial position, results of operations, or cash flows.

Note 2. 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.

In thousands	Year ended December 31, 2020	2019	2018
Supplemental cash flow information:			
Cash paid for interest	$256,633	$267,421	$270,927
Cash paid for income taxes	4	229	—
Cash received for income tax refunds (1)	9,600	107	7,893
Non-cash investing activities:			
Asset retirement obligation additions and revisions, net	17,791	6,630	22,145

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

As of December 31, 2020 and 2019, the Company had $128.8 million and $262.7 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, 2020 and 2019, the Company had $0.1 million and $5.6 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, 2020 and 2019, the Company had $1.0 million and $1.5 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.

On January 1, 2019 the Company adopted ASU 2016-02, *Leases (Topic 842)*, which resulted in the non-cash recognition of offsetting right-of-use assets and lease liabilities totaling approximately $19 million upon adoption. See *Note 11. Leases* for additional information on right-of-use assets obtained in exchange for new operating lease liabilities for the years ended December 31, 2020 and 2019.

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2020 and 2019.

In thousands	December 31, 2020	2019
Proved crude oil and natural gas properties	$ 27,726,954	$ 26,611,429
Unproved crude oil and natural gas properties	368,256	319,592
Service properties, equipment and other	414,066	336,439
Total property and equipment	28,509,276	27,267,460
Accumulated depreciation, depletion and amortization	(14,771,984)	(12,769,734)
Net property and equipment	$ 13,737,292	$ 14,497,726

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2020 and 2019:

In thousands	December 31, 2020	December 31, 2019
Prepaid advances from joint interest owners	$ 25,209	$ 50,021
Accrued compensation	47,985	61,483
Accrued production taxes, ad valorem taxes and other non-income taxes	40,818	59,057
Accrued interest	50,009	56,953
Current portion of asset retirement obligations	2,482	1,899
Other	510	955
Accrued liabilities and other	$167,013	$230,368

Note 5. Derivative Instruments

From time to time the Company enters into crude oil and natural gas swap and collar 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 of derivative contracts 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 6. Fair Value Measurements*.

At December 31, 2020 the Company had outstanding derivative contracts as set forth in the tables below.

Natural gas derivatives

			Collars			
			Floors		Ceilings	
Period and Type of Contract	MMBtus	Swaps Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
January 2021—March 2021						
Swaps—Henry Hub	10,800,000	$2.90				
Collars—Henry Hub	22,500,000		$2.65 - $3.00	$2.78	$3.31 - $4.00	$3.69
April 2021—June 2021						
Swaps—Henry Hub	3,609,000	$2.59				
Collars—Henry Hub	13,650,000		$2.50 - $2.60	$2.58	$3.06 - $3.43	$3.24
July 2021—September 2021						
Swaps—Henry Hub	3,069,000	$2.59				
Collars—Henry Hub	13,800,000		$2.50 - $2.60	$2.58	$3.06 - $3.43	$3.24

Crude oil derivatives

Period and Type of Contract	Bbls	Floor Price	Ceiling Price
January 2021			
Collar—WTI	465,000	$41.60	$50.00

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 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.

	Year ended December 31,		
In thousands	2020	2019	2018
Cash received (paid) on derivatives:			
Crude oil fixed price swaps	$(31,179)	$ —	$ —
Natural gas fixed price swaps	1,071	58,836	(36,939)
Natural gas collars	1,958	5,859	—
Cash received (paid) on derivatives, net	(28,150)	64,695	(36,939)
Non-cash gain (loss) on derivatives:			
Crude oil collars	(227)	—	—
Natural gas fixed price swaps	2,043	(10,130)	7,527
Natural gas collars	11,676	(5,482)	5,482
Non-cash gain (loss) on derivatives, net	13,492	(15,612)	13,009
Gain (loss) on derivative instruments, net	$(14,658)	$ 49,083	$(23,930)

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.

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, 2020, all at fair value. The Company had no outstanding commodity derivative instruments at December 31, 2019.

	December 31,	
In thousands	2020	2019
Commodity derivative assets:		
Gross amounts of recognized assets	$15,900	$—
Gross amounts offset on balance sheet	(597)	—
Net amounts of assets on balance sheet	15,303	—
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(2,408)	—
Gross amounts offset on balance sheet	597	—
Net amounts of liabilities on balance sheet	$ (1,811)	$—

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

In thousands	December 31, 2020	December 31, 2019
Derivative assets	$15,303	$—
Derivative assets, noncurrent	—	—
Net amounts of assets on balance sheet	15,303	—
Derivative liabilities	(227)	—
Derivative liabilities, noncurrent	(1,584)	—
Net amounts of liabilities on balance sheet	(1,811)	—
Total derivative assets, net	$13,492	$—

Note 6. 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.

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 table summarizes the valuation of derivative instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2020. The Company had no outstanding commodity derivative instruments at December 31, 2019.

	Fair value measurements at December 31, 2020 using:			
In thousands	Level 1	Level 2	Level 3	Total
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, 2020, the Company's commodity price assumptions were based on forward NYMEX strip prices through year-end 2025 and were then escalated at 3% per year thereafter. Operating cost assumptions were based on current costs escalated at 3% per year beginning in 2022.

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.

For the years ended December 31, 2020, 2019, and 2018, 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, $3.7 million, and $18.0 million for 2020, 2019, and 2018 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 and 2018 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, 2020, 2019, and 2018, 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).

	Year ended December 31,		
In thousands	2020	2019	2018
Proved property and inventory impairments	$207,119	$ 3,745	$ 18,037
Unproved property impairments	70,822	82,457	107,173
Total	$277,941	$86,202	$125,210

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 7. Long-Term Debt* for discussion of the changes in the Company's outstanding debt during the year ended December 31, 2020.

	December 31, 2020		December 31, 2019	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Credit facility	$ 160,000	$ 160,000	$ 55,000	$ 55,000
Notes payable	24,590	24,700	5,351	5,400
5% Senior Notes due 2022	630,470	632,900	1,099,165	1,108,700
4.5% Senior Notes due 2023	646,943	669,900	1,491,339	1,571,400
3.8% Senior Notes due 2024	906,922	939,500	994,310	1,034,200
4.375% Senior Notes due 2028	990,746	1,024,400	989,661	1,063,700
5.75% Senior Notes due 2031	1,480,879	1,651,900	—	—
4.9% Senior Notes due 2044	691,868	689,600	691,688	742,000
Total debt	$5,532,418	$5,792,900	$5,326,514	$5,580,400

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.

The fair values of the 5% Senior Notes due 2022 ("2022 Notes"), the 4.5% Senior Notes due 2023 ("2023 Notes"), the 3.8% Senior Notes due 2024 ("2024 Notes"), the 4.375% Senior Notes due 2028 ("2028 Notes"), the 5.75% Senior Notes due 2031, and the 4.9% Senior Notes due 2044 ("2044 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 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $43.7 million and $33.9 million at December 31, 2020 and 2019, respectively, consists of the following.

In thousands	December 31, 2020	December 31, 2019
Credit facility	$ 160,000	$ 55,000
Notes payable	24,590	5,351
5% Senior Notes due 2022	630,470	1,099,165
4.5% Senior Notes due 2023	646,943	1,491,339
3.8% Senior Notes due 2024	906,922	994,310
4.375% Senior Notes due 2028	990,746	989,661
5.75% Senior Notes due 2031	1,480,879	—
4.9% Senior Notes due 2044	691,868	691,688
Total debt	5,532,418	5,326,514
Less: Current portion of long-term debt	2,245	2,435
Long-term debt, net of current portion	$5,530,173	$5,324,079

Credit Facility

The Company has an unsecured credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion. The Company had $160 million of outstanding borrowings on its credit facility at December 31, 2020.

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, 2020 was 1.9%.

The Company had approximately $1.33 billion of borrowing availability on its credit facility at December 31, 2020 after considering outstanding borrowings and letters of credit. The Company incurs commitment fees based on currently assigned credit ratings of 0.25% 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, 2020.

Senior Notes

In November 2020, the Company issued $1.5 billion of 5.75% Senior Notes due 2031 and received total net proceeds of $1.49 billion after deducting the initial purchasers' fees. The 2031 Notes were sold at par in a private placement transaction exempt from the registration requirements of the Securities Act to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The Company used the net proceeds from the offering to finance the partial repurchases of its 2022 Notes and 2023 Notes in November 2020 as further discussed below, to repay a portion of the borrowings outstanding on its credit facility, and for general corporate purposes.

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, 2020.

	2022 Notes (1)	2023 Notes	2024 Notes	2028 Notes	2031 Notes	2044 Notes
Face value (in thousands)	$630,782	$649,625	$911,000	$1,000,000	$1,500,000	$700,000
Maturity date	Sep 15, 2022	April 15, 2023	June 1, 2024	January 15, 2028	January 15, 2031	June 1, 2044
Interest payment dates	Mar 15, Sep 15	April 15, Oct 15	June 1, Dec 1	Jan 15, July 15	Jan 15, Jul 15	June 1, Dec 1
Make-whole redemption period (2)	—	Jan 15, 2023	Mar 1, 2024	Oct 15, 2027	Jul 15, 2030	Dec 1, 2043

(1) The Company has the option to redeem all or a portion of its remaining 2022 Notes at the decreasing redemption prices specified in the indenture governing the 2022 Notes plus any accrued and unpaid interest to the date of redemption.

(2) 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, 2020.

The senior notes are obligations of Continental Resources, Inc. Additionally, three of the Company's wholly-owned 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's other subsidiaries, whose assets, equity, and results of operations attributable to the Company are not material, do not guarantee the senior notes.

Retirement of Senior Notes

2020

In March 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 $33.4 million face value of its 2023 Notes at an aggregate cost of $19.5 million and $7.0 million face value of its 2024 Notes at an aggregate cost of $3.8 million, in each case, including accrued and unpaid interest to the repurchase dates.

In April 2020, the Company repurchased an additional $17.0 million face value of its 2023 Notes at an aggregate cost of $9.8 million and an additional $82.0 million face value of its 2024 Notes at an aggregate cost of $43.1 million, in each case, including accrued and unpaid interest to the repurchase dates.

The repurchased notes were canceled by the Company. The Company recognized pre-tax gains on extinguishment of debt in the 2020 first quarter related to the March 2020 repurchases totaling $17.6 million and additional pre-tax gains on extinguishment of debt in the 2020 second quarter related to the April 2020 repurchases totaling $47.0 million, which included the pro-rata write-off of deferred financing costs and unamortized debt discount associated with the notes. The gains are reflected in the caption “Gain (loss) on extinguishment of debt” in the consolidated statements of comprehensive income (loss).

In November 2020, the Company repurchased $469.2 million of its 2022 Notes using proceeds from the previously described issuance of new 2031 Notes. 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 was $475.0 million. The Company recorded a pre-tax loss on extinguishment of debt related to the repurchase of $1.4 million, which included the premium and pro-rata write-off of deferred financing costs and unamortized debt premium associated with the notes.

See *Note 21. Subsequent Event* for discussion of the Company’s additional redemption of 2022 Notes subsequent to December 31, 2020.

In November 2020, the Company also repurchased $800.0 million of its 2023 Notes using proceeds from the previously described issuance of new 2031 Notes. 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 was $828.0 million. The Company recorded a pre-tax loss on extinguishment of debt related to the repurchase of $27.4 million, which included the premium and pro-rata write-off of deferred financing costs 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.

2018

In August 2018, the Company redeemed $400 million of its original outstanding $2.0 billion of 2022 Notes. The redemption price was equal to 101.667% 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 $415.1 million. The Company recorded a pre-tax loss on extinguishment of debt related to the redemption of $7.1 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, $2.2 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, 2020 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 8. 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 $159.0 million, $192.0 million, and $162.3 million for the years ended December 31, 2020, 2019, and 2018, 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 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, totaled $25.6 million for operated properties for the year ended December 31, 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. The Company currently takes certain processed residue gas volumes in kind in lieu of monetary settlement, but does not currently take NGL volumes. 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 $37.7 million, $33.7 million, and $29.3 million for the years ended December 31, 2020, 2019, and 2018, 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 totaled $17.3 million for the year ended December 31, 2020.

Revenues from derivative instruments—See *Note 5. 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.

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.

	Year ended December 31,								
	2020			2019			2018		
In thousands	North Region	South Region	Total	North Region	South Region	Total	North Region	South Region	Total
Crude oil revenues:									
Operated properties	$1,264,149	$537,961	$1,802,110	$2,365,574	$ 786,652	$3,152,226	$2,330,711	$ 603,070	$2,933,781
Non-operated properties	362,952	34,914	397,866	727,068	50,700	777,768	790,435	68,378	858,813
Total crude oil revenues	1,627,101	572,875	2,199,976	3,092,642	837,352	3,929,994	3,121,146	671,448	3,792,594
Natural gas revenues:									
Operated properties (1)	28,086	301,486	329,572	109,668	411,464	521,132	214,741	547,247	761,988
Non-operated properties (2)	720	25,166	25,886	25,188	38,075	63,263	60,738	63,402	124,140
Total natural gas revenues	28,806	326,652	355,458	134,856	449,539	584,395	275,479	610,649	886,128
Crude oil and natural gas sales	$1,655,907	$899,527	$2,555,434	$3,227,498	$1,286,891	$4,514,389	$3,396,625	$1,282,097	$4,678,722
Timing of revenue recognition									
Goods transferred at a point in time	$1,655,907	$899,527	$2,555,434	$3,227,498	$1,286,891	$4,514,389	$3,396,625	$1,282,097	$4,678,722
Goods transferred over time	—	—	—	—	—	—	—	—	—
	$1,655,907	$899,527	$2,555,434	$3,227,498	$1,286,891	$4,514,389	$3,396,625	$1,282,097	$4,678,722

(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.

All of the Company's outstanding crude oil sales contracts at December 31, 2020 are 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.

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, 2020, 2019, and 2018 related to performance obligations satisfied in prior reporting periods were not material.

Note 9. Allowance for Credit Losses

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. This standard changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard replaced the previously required incurred loss approach with a forward-looking expected credit loss model for accounts receivable and other financial instruments measured at amortized cost. The standard became effective for reporting periods beginning after December 15, 2019. The Company adopted the new standard on January 1, 2020 using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the effective date. The Company's cumulative effect adjustment resulted in a $0.1 million decrease in retained earnings and corresponding decrease in receivables via the recognition of an incremental allowance for credit losses at January 1, 2020.

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." Presented below are applicable disclosures required by ASU 2016-13 for each portfolio segment.

Historically, the Company's credit losses on receivables have been immaterial. The Company's aggregate allowance for credit losses totaled $2.5 million and $2.4 million at December 31, 2020 and 2019, respectively, which is reported as "Allowance for credit losses" in the consolidated balance sheets. Aggregate credit loss expenses totaled $1.8 million, $1.6 million, and $0.5 million for the years ended December 31, 2020, 2019, and 2018, 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, 2020 and December 31, 2019. 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 year ended December 31, 2020.

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.

The Company's allowance for credit losses on joint interest receivables totaled $2.5 million and $2.4 million at December 31, 2020 and 2019, 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 year ended December 31, 2020.

Note 10. Income Taxes

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

	Year ended December 31,		
In thousands	2020	2019	2018
Current income tax provision (benefit):			
United States federal (1)	$ (2,248)	$ —	$ (7,781)
Various states	29	—	5
Total current income tax provision (benefit)	(2,219)	—	(7,776)
Deferred income tax provision (benefit):			
United States federal	(148,828)	191,328	282,947
Various states	(18,143)	21,361	31,931
Total deferred income tax provision (benefit)	(166,971)	212,689	314,878
Provision (benefit) for income taxes	$(169,190)	$212,689	$307,102
Effective tax rate	21.8%	21.5%	23.7%

(1) The current federal income tax benefits represent alternative minimum tax refunds.

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, valuation allowances, and other tax items as reflected in the table below.

	Year ended December 31,		
In thousands, except tax rates	2020	2019	2018
Income (loss) before income taxes	$(774,751)	$987,162	$1,296,802
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	(162,698)	207,304	272,328
Items impacting the effective tax rate:			
State and local income taxes, net of federal benefit	(24,808)	31,967	45,920
Tax (benefit) deficiency from stock-based compensation	4,927	(7,971)	(259)
Sale of Canadian subsidiary and assets	—	(16,860)	—
Other, net	(1,085)	(1,751)	(10,887)
Valuation allowance	14,474	—	—
Provision (benefit) for income taxes	$(169,190)	$212,689	$ 307,102
Effective tax rate	21.8%	21.5%	23.7%

In 2020, the Company determined it was more likely than not that a portion of its Oklahoma net operating loss ("NOL") carryforward would not be utilized prior to expiration, and a valuation allowance of $14.5 million was established during the year for the deferred tax asset associated with such NOL carryforward. The Company will continue to evaluate both the positive and negative evidence on a quarterly basis in determining the need for additional valuation allowances 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, 2020 and 2019 are reflected in the table below.

	December 31,	
In thousands	2020	2019
Deferred tax assets		
United States net operating loss carryforwards	$ 579,781	$ 550,086
Equity compensation	12,900	13,157
Other	10,691	18,466
Total deferred tax assets	603,372	581,709
Valuation allowance	(14,474)	—
Total deferred tax assets, net of valuation allowance	588,898	581,709
Deferred tax liabilities		
Property and equipment	(2,204,378)	(2,367,137)
Other	(4,674)	(1,697)
Total deferred tax liabilities	(2,209,052)	(2,368,834)
Deferred income tax liabilities, net	$(1,620,154)	$(1,787,125)

As of December 31, 2020, the Company had federal and state net operating loss carryforwards of $1.9 billion and $3.8 billion, respectively. The Company's federal net operating loss carryforwards were generated in tax years prior to 2018 and expire between 2035 and 2037. The Company's net operating loss carryforward in Oklahoma totaled $2.8 billion at December 31, 2020, which will begin to expire in 2028. The Company's net operating loss carryforward in North Dakota totaled $870 million at December 31, 2020, which will begin to expire in 2035. 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 2017.

Note 11. Leases

The Company's lease liabilities recognized on the balance sheet as a lessee totaled $8.4 million as of December 31, 2020 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 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.

In thousands	Amount
Drilling rig commitments	$2,025
Surface use agreements	4,928
Field equipment	928
Other	546
Total	$8,427

Drilling rig commitments reflected above represent minimum payment obligations expected to be incurred on enforceable commitments with durations in excess of one year at the inception of the lease.

Minimum future commitments by year for the Company's operating leases as of December 31, 2020 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.

In thousands	Amount
2021	$ 2,911
2022	865
2023	811
2024	537
2025	429
Thereafter	6,230
Total operating lease liabilities, at undiscounted value	$11,783
Less: Imputed interest	(3,356)
Total operating lease liabilities, at discounted present value	$ 8,427
Less: Current portion of operating lease liabilities	(2,588)
Operating lease liabilities, net of current portion	$ 5,839

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.

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

Prior to the January 1, 2019 adoption of ASU 2016-02, the Company's operating lease obligations, as defined and accounted for under legacy U.S. GAAP in effect as of December 31, 2018, primarily represented leases for surface use agreements, office buildings and equipment, communication towers, and field equipment. Lease payments associated with legacy operating leases for the year ended December 31, 2018 totaled $2.0 million, a portion of which was capitalized and/or billed to other interest owners. At December 31, 2018, the minimum future rental commitments under legacy operating leases having enforceable lease terms in excess of one year are reflected in the table below. Such commitments are reflected at undiscounted values and were not required to be recognized on the Company's balance sheet under legacy U.S. GAAP in effect as of December 31, 2018.

In thousands	Total amount as of December 31, 2018
2019	$ 1,535
2020	1,042
2021	833
2022	805
2023	745
Thereafter	6,795
Total obligations as of December 31, 2018	$11,755

Note 12. Commitments and Contingencies

Included below is a discussion of certain future commitments of the Company as of December 31, 2020.

Drilling rig commitments—As of December 31, 2020, the Company has drilling rig contracts with various terms extending to May 2021. Future operating day-rate commitments as of December 31, 2020 total approximately $14.1 million, all of which will be incurred in 2021. A portion of these future costs will be borne by other interest owners. Such future commitments include minimum payment obligations with a discounted present value totaling $2.0 million that are required to be recognized on the Company's balance sheet at December 31, 2020 in accordance with ASC Topic 842 as discussed in *Note 11. Leases*.

Other lease commitments—The Company has various other lease commitments primarily associated with surface use agreements and field equipment. See *Note 11. Leases* for additional information.

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, 2020 under the arrangements amount to approximately $1.45 billion, of which $227 million is expected to be incurred in 2021, $256 million in 2022, $257 million in 2023, $221 million in 2024, $143 million in 2025, and $346 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.

Pending property acquisition—On December 31, 2020, the Company executed a definitive agreement to acquire undeveloped leasehold and producing properties in the Powder River Basin of Wyoming for $215 million of cash. Closing of the acquisition is scheduled to occur on or around March 4, 2021 and remains subject to the completion of customary due diligence procedures and closing conditions. Upon execution of the agreement, the Company paid an escrow deposit of $21.5 million, which is reflected in the caption "Other noncurrent assets" on the consolidated balance sheet at December 31, 2020.

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, 2020 and 2019, the Company had recognized a liability within "Other noncurrent liabilities" of $7.7 million and $8.7 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.

Note 13. 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 $0.2 million, $0.4 million, and $0.5 million and received payments from these affiliates of $0.3 million, $0.3 million, and $0.2 million during the years ended December 31, 2020, 2019, and 2018, respectively, relating to the operations of the respective properties. At December 31, 2020 and 2019, approximately $18,000 and $127,000, 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, 2020 and 2019, approximately $18,000 and $35,000, 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 2020, 2019, and 2018, the Company charged affiliates approximately $8,100, $17,600, and $12,900, respectively, for use of its corporate aircraft crews, fuel, and reimbursement of expenses and received approximately $9,500, $18,900, and $14,400 from affiliates in 2020, 2019, and 2018, respectively, in connection with such items. The Company was charged approximately $120,000, $303,000, and $598,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2020, 2019, and 2018 and paid $158,000, $426,000, and $529,000 to the affiliates in 2020, 2019, and 2018, respectively. At December 31, 2019, approximately $1,400 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, 2019, approximately $38,000 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 14. 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 $64.6 million, $52.0 million, and $47.2 million for the years ended December 31, 2020, 2019, and 2018, 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, 2020, the Company had 10,768,301 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, if any, subject to forfeiture. Restricted stock grants generally vest over periods ranging from 1 to 3 years.

A summary of changes in non-vested restricted shares from December 31, 2017 to December 31, 2020 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2017	4,026,110	$35.63
Granted	1,390,914	52.71
Vested	(1,116,329)	46.19
Forfeited	(278,286)	38.06
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

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 2020, 2019, and 2018 was approximately $27.5 million, $79.7 million, and $61.0 million, respectively. As of December 31, 2020, there was approximately $66 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.3 years.

Note 15. 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. As of December 31, 2019, the Company had repurchased and retired approximately 5.6 million shares at an aggregate cost of $190.2 million. During the three months ended March 31, 2020, the Company repurchased and retired approximately 8.2 million additional shares of its common stock at an aggregate cost of $126.9 million. No share repurchases have been made subsequent to March 31, 2020. Through December 31, 2020, the Company has repurchased and retired a cumulative total of approximately 13.8 million shares at an aggregate cost of $317.1 million since the inception of its $1 billion share repurchase program in June 2019.

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 payment

In May 2019 the Company's Board of Directors approved the initiation of a dividend payment program and on June 3, 2019 the Company announced its first quarterly cash dividend of $0.05 per share on its outstanding common stock, which amounted to $18.4 million and was paid on November 21, 2019 to shareholders of record on November 7, 2019.

On January 27, 2020 the Company declared a quarterly cash dividend of $0.05 per share on its outstanding common stock, which amounted to $18.4 million and was paid on February 21, 2020 to shareholders of record as of February 7, 2020.

To preserve cash in response to the significant reduction in crude oil prices and economic uncertainty resulting from the COVID-19 pandemic, in April 2020 the Company's quarterly dividend was suspended by the Board of Directors.

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 years ended December 31, 2019, and 2018:

In thousands	Year ended December 31, 2019	2018
Beginning accumulated other comprehensive income, net of tax	$ 415	$307
Foreign currency translation adjustments	140	108
Release of cumulative translation adjustments (1)	(555)	—
Income taxes (2)	—	—
Other comprehensive income (loss), net of tax	(415)	108
Ending accumulated other comprehensive income, net of tax	$ —	$415

(1) In conjunction with the Company's sale of its Canadian operations in 2019, the cumulative translation adjustments were released. See *Note 17. 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 16. 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. Additionally, at closing 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 $355.1 million and $356.9 million at December 31, 2020 and 2019, respectively. In 2018, Continental incurred $4.8 million of costs associated with the above transaction, which were recognized as a reduction of "Additional paid-in capital" within shareholders' equity attributable to Continental.

Joint ownership arrangement

In December 2018, Continental entered into an arrangement with a third party to jointly acquire 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 $11.2 million and $9.8 million at December 31, 2020 and 2019, respectively.

Note 17. Property Acquisitions and Dispositions

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 insignificant amounts of production and proved reserves.

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.

2018

During 2018, the Company sold non-strategic properties in various areas for cash proceeds totaling $54.5 million. The Company recognized pre-tax gains on the transactions totaling $16.7 million. The disposed properties represented an immaterial portion of the Company's production and proved reserves.

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, 2020, 2019 and 2018.

	Year ended December 31,		
In thousands	2020	2019	2018
Crude oil and natural gas sales	$ 2,555,434	$ 4,514,389	$ 4,678,722
Production expenses	(359,267)	(444,649)	(390,423)
Production taxes	(192,718)	(357,988)	(353,140)
Transportation expenses	(196,692)	(225,649)	(191,587)
Exploration expenses	(17,732)	(14,667)	(7,642)
Depreciation, depletion, amortization and accretion	(1,859,893)	(1,997,854)	(1,839,241)
Property impairments	(277,941)	(86,202)	(125,210)
Income tax (provision) benefit (1)	83,427	(323,025)	(434,047)
Results from crude oil and natural gas producing activities	$ (265,382)	$ 1,064,355	$ 1,337,432

(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, 2020, 2019 and 2018 are presented below:

	Year ended December 31,		
In thousands	2020	2019	2018
Property acquisition costs:			
Proved	$ 60,494	$ 51,558	$ 31,579
Unproved	201,919	312,680	329,586
Total property acquisition costs	262,413	364,238	361,165
Exploration Costs	48,282	50,143	81,015
Development Costs	1,053,532	2,388,582	2,478,327
Total	$1,364,227	$2,802,963	$2,920,507

Costs incurred above include asset retirement costs and revisions thereto of $18.1 million, $6.7 million and $25.8 million for the years ended December 31, 2020, 2019 and 2018, respectively.

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, 2020 and 2019 are as follows:

In thousands	December 31, 2020	December 31, 2019
Proved crude oil and natural gas properties	$ 27,726,954	$ 26,611,429
Unproved crude oil and natural gas properties	368,256	319,592
Total	28,095,210	26,931,021
Less accumulated depreciation, depletion and amortization	(14,622,376)	(12,635,247)
Net capitalized costs	$ 13,472,834	$ 14,295,774

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:

In thousands	Year ended December 31, 2020	2019	2018
Balance at January 1	$ 6,257	$ 3,959	$ 31,356
Additions to capitalized exploratory well costs pending determination of proved reserves	32,880	28,280	45,088
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(72)	(23,200)	(72,347)
Capitalized exploratory well costs charged to expense	(6,328)	(2,782)	(138)
Balance at December 31	$32,737	$ 6,257	$ 3,959
Number of gross wells	16	11	16

As of December 31, 2020, 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 95%, 91%, and 98% of the Company's total proved reserves as of December 31, 2020, 2019, and 2018, 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 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, 2020, 2019, and 2018 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, 2020, 2019, and 2018 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, 2017	640,949	4,140,281	1,330,995
Revisions of previous estimates	(76,994)	(1,153,555)	(269,253)
Extensions, discoveries and other additions	253,066	1,871,777	565,030
Production	(61,384)	(284,730)	(108,839)
Sales of minerals in place	(2,154)	(35,142)	(8,011)
Purchases of minerals in place	3,613	52,983	12,443
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. 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 our 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 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 the 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.

Revisions for 2018 are comprised of (i) the removal of 74 MMBo and 960 Bcf (totaling 234 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to changes in development plans, (ii) downward revisions of 21 MMBo and 216 Bcf (totaling 57 MMBoe) from the removal of PUD reserves due to changes in anticipated well densities and other factors, (iii) upward price revisions of 21 MMBo and 31 Bcf (totaling 26 MMBoe) due to an increase in average crude oil and natural gas prices in 2018 compared to 2017, and (iv) net downward revisions of 2 MMBo and 11 Bcf (totaling 4 MMBoe) 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 in the Bakken, SCOOP, and STACK plays. For 2020, proved reserve additions in the Bakken totaled 30 MMBo and 69 Bcf (totaling 41 MMBoe) and reserve additions in SCOOP totaled 12 MMBo and 223 Bcf (totaling 49 MMBoe). Additionally, 2020 proved reserve additions in STACK totaled 4 Bcf (totaling 1 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. There were no individually significant acquisitions of proved reserves in the three years reflected in the table above.

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, 2020, 2019 and 2018:

	December 31,		
	2020	2019	2018
Proved Developed Reserves			
Crude oil (MBbl)	281,906	336,405	347,825
Natural Gas (MMcf)	2,073,011	2,226,117	1,964,289
Total (MBoe)	627,407	707,424	675,206
Proved Undeveloped Reserves			
Crude oil (MBbl)	215,069	423,782	409,271
Natural Gas (MMcf)	1,567,713	2,928,354	2,627,325
Total (MBoe)	476,355	911,841	847,159
Total Proved Reserves			
Crude oil (MBbl)	496,975	760,187	757,096
Natural Gas (MMcf)	3,640,724	5,154,471	4,591,614
Total (MBoe)	1,103,762	1,619,265	1,522,365

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.

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, 2020, 2019, and 2018. 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.

	December 31,		
In thousands	2020	2019	2018
Future cash inflows	$21,334,235	$ 49,893,470	$ 61,510,432
Future production costs	(7,750,834)	(15,309,672)	(16,139,001)
Future development and abandonment costs	(3,950,752)	(10,033,887)	(9,706,114)
Future income taxes (1)	(724,569)	(3,351,657)	(6,012,439)
Future net cash flows	8,908,080	21,198,254	29,652,878
10% annual discount for estimated timing of cash flows	(4,254,515)	(10,736,613)	(13,968,061)
Standardized measure of discounted future net cash flows	$ 4,653,565	$ 10,461,641	$ 15,684,817

(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, 2020, 2019, and 2018.

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $34.34, $51.95, and $61.20 per barrel at December 31, 2020, 2019, and 2018, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $1.17, $2.02, and $3.22 per Mcf at December 31, 2020, 2019, and 2018, 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.

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.

	December 31,		
In thousands	2020	2019	2018
Standardized measure of discounted future net cash flows at January 1	$10,461,641	$15,684,817	$10,470,177
Extensions, discoveries and improved recoveries, less related costs	187,981	1,649,322	5,162,635
Revisions of previous quantity estimates	(2,952,489)	(1,564,503)	(3,522,428)
Changes in estimated future development and abandonment costs	4,760,286	1,401,513	1,063,089
Purchases (sales) of minerals in place, net	53,742	49,330	(9,192)
Net change in prices and production costs	(6,912,031)	(6,591,347)	4,224,473
Accretion of discount	1,183,993	1,865,034	1,183,347
Sales of crude oil and natural gas produced, net of production costs	(1,806,758)	(3,486,103)	(3,743,572)
Development costs incurred during the period	863,101	1,557,121	1,134,153
Change in timing of estimated future production and other	(2,325,024)	(1,690,779)	1,324,365
Change in income taxes	1,139,123	1,587,236	(1,602,230)
Net change	(5,808,076)	(5,223,176)	5,214,640
Standardized measure of discounted future net cash flows at December 31	$ 4,653,565	$10,461,641	$15,684,817

Note 20. Quarterly Financial Data (Unaudited)

The Company's unaudited quarterly financial data for 2020 and 2019 is summarized below.

	Quarter ended			
In thousands, except per share data	March 31	June 30	September 30	December 31
2020				
Total revenues (1)	$ 880,801	$ 175,659	$ 692,370	$ 837,640
Gain (loss) on derivative instruments, net (1)	$ —	$ (7,782)	$ (17,853)	$ 10,977
Property impairments (2)	$ 222,529	$ 23,929	$ 18,518	$ 12,965
Loss from operations	$ (193,588)	$ (296,776)	$ (31,895)	$ (31,633)
Gain (loss) on extinguishment of debt (3)	$ 17,631	$ 46,942	$ —	$ (28,854)
Net loss	$ (186,784)	$ (242,131)	$ (81,583)	$ (95,063)
Net loss attributable to Continental Resources	$ (185,664)	$ (239,286)	$ (79,422)	$ (92,497)
Net loss per share attributable to Continental Resources:				
Basic	$ (0.51)	$ (0.66)	$ (0.22)	$ (0.26)
Diluted	$ (0.51)	$ (0.66)	$ (0.22)	$ (0.26)
2019				
Total revenues (1)	$1,124,234	$1,208,382	$1,104,197	$1,195,134
Gain (loss) on derivative instruments, net (1)	$ (1,124)	$ 53,448	$ 1,195	$ (4,436)
Property impairments (2)	$ 25,316	$ 21,339	$ 20,199	$ 19,348
Income from operations	$ 304,965	$ 379,847	$ 278,724	$ 293,876
Gain (loss) on extinguishment of debt (3)	$ —	$ —	$ (4,584)	$ —
Net income (4)	$ 186,493	$ 236,450	$ 157,422	$ 194,108
Net income attributable to Continental Resources (4)	$ 186,976	$ 236,557	$ 158,162	$ 193,946
Net income per share attributable to Continental Resources: (4)				
Basic	$ 0.50	$ 0.63	$ 0.43	$ 0.53
Diluted	$ 0.50	$ 0.63	$ 0.43	$ 0.53

(1) Gains and losses on natural gas derivative instruments are reflected in "Total revenues" on both the consolidated statements of comprehensive income (loss) and this table of unaudited quarterly financial data. Commodity price fluctuations each quarter can result in significant swings in mark-to-market gains and losses, which affects comparability between periods.
(2) Property impairments have been shown separately to illustrate the impact on quarterly results attributable to write downs of the Company's assets. Commodity price fluctuations each quarter can result in significant changes in estimated future cash flows and resulting impairments, which affects comparability between periods.
(3) See *Note 7. Long-Term Debt* for discussion of the gains and losses recognized by the Company upon the partial redemptions and repurchases of its senior notes in 2019 and 2020.
(4) In the fourth quarter of 2019, the Company sold its Canadian subsidiary and associated properties and a $16.9 million ($0.05 per basic and diluted share) decrease in income tax expense and corresponding increase in net income was recognized as discussed in *Note 10. Income Taxes*.

Note 21. Subsequent Event

Redemption of 2022 Notes

On January 5, 2021, the Company redeemed an additional $400 million principal amount of its outstanding 2022 Notes using proceeds from lower-rate borrowings on its credit facility. At January 31, 2021, the remaining outstanding principal amount of 2022 Notes totaled $230.8 million and outstanding credit facility borrowings totaled $360 million.

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, 2020 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 2020 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 2020 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, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ William B. Berry
Chief Executive Officer

/s/ John D. Hart
Senior Vice President, Chief Financial Officer and Treasurer

February 16, 2021

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, 2020, 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, 2020, 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, 2020, and our report dated February 16, 2021 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 16, 2021

Item 9B. Other Information

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 2021 (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.

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.

4.4 Indenture dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.2 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.

4.5 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.

4.6 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.

4.7 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.

4.8	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.
4.9	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.
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 as of April 9, 2018 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., Merrill Lynch, Pierce, Fenner & Smith Incorporated, TD Securities (USA) LLC and Mizuho Bank, Ltd., as Joint Lead Arrangers and Joint Bookrunners, Compass Bank, Citibank, N.A., Export Development Canada, ING Bank, JPMorgan Chase Bank, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A., as Co-Documentation Agents 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 April 12, 2018 and incorporated herein by reference.
10.7†	Summary of Non-Employee Director Compensation approved as of July 30, 2020 to be effective October 1, 2020 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended September 30, 2020 (Commission File No. 001-32886) filed November 5, 2020 and incorporated herein by reference.
10.8†	Description of cash bonus plan updated as of February 12, 2019 filed as Exhibit 10.4 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.

10.9†	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*	Consent of Ryder Scott Company, L.P.
31.1*	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)
31.2*	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)
32**	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)
99*	Report of Ryder Scott Company, L.P., Independent Petroleum Engineers and Geologists
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: **Chief Executive Officer**
Date: **February 16, 2021**

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.

Signature	Title	Date
/s/ HAROLD G. HAMM **Harold G. Hamm**	Executive Chairman and Director	February 16, 2021
/s/ WILLIAM B. BERRY **William B. Berry**	Chief Executive Officer and Director (principal executive officer)	February 16, 2021
/s/ JOHN D. HART **John D. Hart**	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 16, 2021
/s/ SHELLY LAMBERTZ **Shelly Lambertz**	Director	February 16, 2021
/s/ LON MCCAIN **Lon McCain**	Director	February 16, 2021
/s/ JOHN T. MCNABB II **John T. McNabb II**	Director	February 16, 2021
/s/ MARK E. MONROE **Mark E. Monroe**	Director	February 16, 2021
/s/ TIMOTHY G. TAYLOR **Timothy G. Taylor**	Director	February 16, 2021

BOARD OF DIRECTORS

Harold G. Hamm

William B. Berry

Mark E. Monroe

Shelly Lambertz

Lon McCain

John T. McNabb II

Tim Taylor

EXECUTIVE OFFICERS & SENIOR VICE PRESIDENTS

Harold G. Hamm
Executive Chairman

William B. Berry
Chief Executive Officer

Jack H. Stark
President & Chief Operating Officer

Jeff B. Hume
Vice Chairman of Strategic Growth Initiatives

Eric S. Eissenstat
Sr. Vice President, General Counsel, Chief Risk Officer and Secretary

John D. Hart
Sr. Vice President, Chief Financial Officer & Chief Strategy Officer

Pat Bent
Sr. Vice President, Operations

Shelly Lambertz
Chief Culture Officer & Sr. Vice President of Human Resources

Robert Hagens
Sr. Vice President, Land

Blu Hulsey
Sr. Vice President, HSE and Government and Regulatory Affairs

Kristin Thomas
Sr. Vice President, Public Relations

NYSE SYMBOL

CLR

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CORPORATE HEADQUARTERS

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