2019 ANNUAL REPORT

Continental
RESOURCES

CHAIRMAN'S LETTER

2019 was another great year for Continental Resources, building on the momentum of 2018.

We delivered on our promise of being the most efficient producer of oil and gas in our peer group, and our goal of delivering sustainable, cash flow positive growth for the company.

The American Energy Renaissance continued unabated, as America achieved energy independence for the first time in decades, becoming a net exporter of oil and natural gas. Continental played an important role in making that happen.

Financially, it was a very good year. We produced $776 million of net income and a total debt reduction of $442 million.

Beyond the financials, we took another step to strengthen the future of the company. At the end of 2019, I made plans to step up to my new role as Executive Chairman, and to name Bill Berry as the new Chief Executive Officer of Continental Resources. This move frees me up to take on other large issues for both the industry and the company.

Bill's appointment became effective January 1, 2020. He brings a wealth of expertise and experience, nearly 40 years in the making. It would be hard to find a better resume or a more impressive track record of success. Bill has served on our board for 5 years and has been a long-time confidant to me and an invaluable advisor to our management team.

2019 was also a record year for production. Our deep oil inventory in the Bakken in North Dakota and the SCOOP and STACK in Oklahoma, helped us reach an output of 340,395 BOE a day for the year.

Our teams were outstanding. Our production growth year over year was 14% higher.
Perhaps best of all, we lowered our production expenses to $3.58 per BOE, among the lowest, if not the lowest, among our domestic peers.

We continued our mineral royalty relationship with Franco-Nevada, a creative example of how we intend to enhance shareholder value to position the company for continued growth. As we said last year, we believe this business model and this relationship will continue to grow into what is potentially a multi-billion-dollar enterprise.

In addition to minerals, we pursued strategic opportunities for our water infrastructure assets.
In 2019, we divested a water gathering and recycling system in Oklahoma for $85 million.
Our remaining water infrastructure assets in the Bakken and Oklahoma have an estimated value of $1.5 billion. We are continuing to look at ways to monetize a portion of these assets to create future shareholder value.

Other important highlights of the year included:

- ✓ *Meeting or exceeding all of our guidance*
- ✓ *Oil production grew 18% year over year*
- ✓ *Generated free cash flow of approximately $600 million*
- ✓ *We returned $190 million in stock buybacks*
- ✓ *We reduced net debt by $200 million*
- ✓ *We initiated a quarterly dividend*
- ✓ *Made a series of strategic trades, bolt-on acquisitions and leasing in Continental-dominated areas for approximately $165 million, adding up to 370 additional gross operated locations to our inventory*
- ✓ *All of the above was achieved within our planned capital expenditures*

I would also like to highlight Continental's continued commitment to ESG. Take, for example, the role we have played in helping America become the world's leading energy producer. One of its important virtues is C02 emissions in the U.S. have decreased by nearly 15% since 2006, thanks to the abundance of economic clean-burning natural gas.

We have always been, and will always be, strong stewards of the environment, our resources and the communities we do business in. Again, an example: We are one of the best in the industry when it comes to gas capture, with a 98% capture rate. Our goal is to have best in class ESG. You can find our ESG reporting philosophy posted on our website, www.clr.com, and our full 2019 sustainability report will be available in the second quarter of 2020.

Finally, we believe Continental Resources is uniquely positioned for success, despite the recent disruptions caused by the Saudis-Russian price war on America and the effects Covid-19 are having on the world economy. While the near-term marketplace is clearly in flux, when the world emerges to its new normal, we believe we are well suited to take advantage of the opportunities and challenges to come. We are the lowest cost operator among our oil-weighted peers thanks to the quality of our assets, our operations and our people. We have a well-established track record of exploration success which will serve us well in this adverse environment.

As we look to 2020 and beyond, our mission remains the same: Deliver results in the most efficient and profitable manner possible, counting on our teams to deliver the right rock, with the right density, at the right cost. We know no other way.

Harold Hamm
Executive Chairman

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, 2019

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 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, 2019 was approximately $3.5 billion, based upon the closing price of $42.09 per share as reported by the New York Stock Exchange on such date.

371,541,200 shares of our $0.01 par value common stock were outstanding on February 7, 2020.

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 2020, 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.

Table of Contents

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 and 2019 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. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays.

“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;
- 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 or dividend payments;
- general economic conditions;
- 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.

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.

A substantial portion of our operations is located in the North region, with that region comprising 60% of our crude oil and natural gas production and 71% of our crude oil and natural gas revenues for the year ended December 31, 2019. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. Approximately 53% of our proved reserves as of December 31, 2019 are located in the North region. Our operations in the South region continue to expand with our increased activity in Oklahoma and that region comprised 40% of our crude oil and natural gas production, 29% of our crude oil and natural gas revenues, and 47% of our proved reserves as of and for the year ended December 31, 2019.

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, 2019, our proved reserves were 1,619 MMBoe, with proved developed reserves representing 707 MMBoe, or 44%, of our total proved reserves. The standardized measure of our discounted future net cash flows totaled $10.5 billion at December 31, 2019. For 2019, we generated crude oil and natural gas revenues of $4.51 billion and operating cash flows of $3.12 billion. Crude oil accounted for 58% of our total production and 87% of our crude oil and natural gas revenues for 2019. Our total production averaged 340,395 Boe per day for 2019, a 14% increase compared to 2018.

The table below summarizes our total proved reserves, PV-10 (non-GAAP) and net producing wells as of December 31, 2019, average daily production for the quarter ended December 31, 2019 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, 2019				Average daily production for fourth quarter 2019 (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	795,091	49.1%	$ 6,739	1,545	188,178	51.5%	11.6
Montana Bakken	38,979	2.4%	304	259	5,978	1.6%	17.9
Red River units							
Cedar Hills	24,957	1.5%	332	130	5,757	1.6%	11.9
Other Red River units	2,952	0.2%	33	116	1,861	0.5%	4.3
Other	27	— %	—	2	15	— %	4.9
South Region:							
SCOOP	575,664	35.6%	3,766	406	111,829	30.6%	14.1
STACK	181,501	11.2%	665	330	51,628	14.1%	9.6
Other	94	— %	1	2	95	0.1%	2.7
Total	1,619,265	100.0%	$11,840	2,790	365,341	100.0%	12.1

(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 $1.4 billion. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for further discussion.

(2) The 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 2019 production into estimated proved reserve volumes as of December 31, 2019.

Business Environment and Outlook

Our industry is impacted by volatility and uncertainty in commodity prices. Crude oil prices remained volatile throughout 2019, with West Texas Intermediate crude oil benchmark prices ranging from approximately $46 to $66 per barrel, and price volatility has continued into early 2020. Our leadership team has significant experience with operating in challenging commodity price environments. With our portfolio of high quality assets and strong balance sheet, we are well-positioned to manage the ongoing challenges and price volatility facing our industry.

For 2020, our primary business strategies will focus on:

- Continuing to increase shareholder value through free cash flow generation and shareholder capital return initiatives;
- Generating corporate returns on capital employed that compete with the broader market through operational excellence, technical innovations, pad and row development, optimized completion methods, well productivity, and strategic mineral ownership;

- Continuing to exercise disciplined capital spending to maintain financial flexibility and ample liquidity; and
- Stock repurchases and/or reducing outstanding debt using available operating cash flows, proceeds from asset dispositions, or joint development arrangements.

Our Business Strategies

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

Growing and sustaining a premier portfolio of assets focused on increasing shareholder value through free cash flow generation and shareholder capital return initiatives. We are focused on increasing shareholder value and returns. 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. We pursue opportunities to develop our existing properties as well as explore for new resource plays where significant reserves may be economically developed. Our capital programs are designed to allocate investments to projects that provide opportunities to deliver production growth at low costs while generating cash flows in excess of operating and capital requirements, harvest our inventory of uncompleted wells, convert our undeveloped acreage to acreage held by production, and improve hydrocarbon recoveries and rates of return on capital employed.

Our assets and execution generated strong free cash flows in 2018 and 2019 and we plan to remain focused on generating cash flow positive growth for the foreseeable future. Accordingly, in 2019 we initiated a strategy to increase shareholder value and returns that included the commencement of a $1 billion share repurchase program and the payment of a quarterly dividend. Through year-end 2019 we had executed $190.2 million of share repurchases and we paid our first cash dividend of $0.05 per share in November 2019. We are strongly aligned with shareholders and our strategic vision is predicated on our desire to increase shareholder value through dividends, share repurchases, continued debt reduction, and other means.

Generating corporate returns on capital employed that compete with the broader market through operational excellence, technical innovations, pad and row development, optimized completions, well productivity, and strategic mineral ownership. We are focused on generating strong corporate returns on capital employed that compete with the broader market. We continue to manage our business in the volatile commodity price environment by focusing on improving operating 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.

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 develop our water gathering, recycling, and disposal infrastructure which allows 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 increase shareholder returns.

Maintaining capital discipline, financial flexibility, and a strong balance sheet. Maintaining capital discipline, a strong balance sheet, ample liquidity, and financial flexibility are key components of our business strategy. In

2019, we reduced our total debt by $442 million, or 8%. We are targeting further debt reduction using available cash, operating cash flows, or proceeds from potential sales of non-strategic assets and joint development opportunities and will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry.

Focusing on organic growth through disciplined capital investments. Although we consider various growth opportunities, including property acquisitions, our primary focus is on organic growth through leasing and drilling in our core areas where we can exploit our extensive inventory of repeatable drilling opportunities to achieve attractive rates of return.

Our Business Strengths

We have a number of strengths we believe will help us successfully execute our business strategies, including the following:

Large acreage inventory. We held approximately 458,500 net undeveloped acres and 1.23 million net developed acres under lease as of December 31, 2019 concentrated in certain premier U.S. resource plays. 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, 2019, we operated properties comprising 86% 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.

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 9 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 no outstanding borrowings on the facility at January 31, 2020. 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, 2019. Proved reserves attributable to noncontrolling interests are immaterial and are not separately presented herein. The standardized measure of our discounted future net cash flows totaled approximately $10.5 billion at December 31, 2019. Our reserve estimates as of December 31, 2019 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 91% of our total proved reserves as of December 31, 2019. 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, 2019 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2019 through December 2019, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($51.95 per Bbl for crude oil and $2.02 per Mcf for natural gas adjusted for location and quality differentials).

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	327,840	2,204,104	695,190	$ 7,942.2
Proved developed non-producing	8,565	22,013	12,234	158.1
Proved undeveloped	423,782	2,928,354	911,841	3,739.6
Total proved reserves	760,187	5,154,471	1,619,265	$11,839.9
Standardized Measure (1)				$10,461.6

(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 $1.4 billion. See *Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for further discussion.

The following table provides additional information regarding our estimated proved crude oil and natural gas reserves by region as of December 31, 2019.

	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	213,379	695,294	329,261	323,675	852,931	465,830
Montana Bakken	16,663	35,898	22,646	12,839	20,964	16,333
Red River units						
Cedar Hills	24,957	—	24,957	—	—	—
Other Red River units	2,952	—	2,952	—	—	—
Other	27	—	27	—	—	—
South Region:						
SCOOP	66,012	1,010,565	234,440	79,008	1,573,293	341,224
STACK	12,374	484,039	93,047	8,260	481,166	88,454
Other	41	321	94	—	—	—
Total	336,405	2,226,117	707,424	423,782	2,928,354	911,841

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

	Year Ended December 31,		
MBoe	2019	2018	2017
Proved reserves at beginning of year	1,522,365	1,330,995	1,274,864
Revisions of previous estimates	(148,848)	(269,253)	(82,012)
Extensions, discoveries and other additions	365,034	565,030	240,206
Production	(124,244)	(108,839)	(88,562)
Sales of minerals in place	(1,840)	(8,011)	(15,197)
Purchases of minerals in place	6,798	12,443	1,696
Proved reserves at end of year	1,619,265	1,522,365	1,330,995

Revisions of previous estimates. 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 our drilling programs and reallocation of capital to areas providing the greatest opportunities to improve efficiencies, recoveries, and rates of return, (ii) downward revisions of 38 MMBo and 278 Bcf (totaling 85 MMBoe) from the removal of PUD reserves due to changes in economics, performance, and other factors, (iii) downward price revisions of 24 MMBo and 118 Bcf (totaling 43 MMBoe) due to a decrease in average crude oil and natural gas prices in 2019 compared to 2018, and (iv) net downward revisions for oil reserves of 9 MMBo and net upward revisions for natural gas reserves of 139 Bcf (netting to 14 MMBoe of upward revisions) due to changes in ownership interests, operating costs, anticipated production, and other factors.

Extensions, discoveries and other additions. Extensions, discoveries and other additions for each of the three years reflected in the table above were due to successful drilling and completion activities and continual refinement of our drilling programs in the Bakken, SCOOP, and STACK plays. Proved reserve additions in the Bakken totaled 160 MMBoe, 251 MMBoe, and 148 MMBoe for 2019, 2018, and 2017, respectively, while reserve additions in SCOOP totaled 186 MMBoe, 186 MMBoe, and 53 MMBoe for 2019, 2018, and 2017, respectively. Additionally, reserve additions in STACK totaled 19 MMBoe, 128 MMBoe, and 39 MMBoe in 2019, 2018, and 2017, respectively. See the subsequent section titled *Summary of Crude Oil and Natural Gas Properties and Projects* for a discussion of our 2019 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, 2019 are located in the Bakken, SCOOP, and STACK plays, our most active development areas, with those plays comprising 53%, 37%, and 10%, respectively, of our total PUD reserves at year-end 2019. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2019. Our PUD reserves at December 31, 2019 include 91 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, 2018	409,271	2,627,325	847,159
Revisions of previous estimates	(72,759)	(443,343)	(146,650)
Extensions and discoveries	151,441	1,143,773	342,070
Sales of minerals in place	(739)	(1,980)	(1,069)
Purchases of minerals in place	471	11,298	2,354
Conversion to proved developed reserves	(63,903)	(408,719)	(132,023)
Proved undeveloped reserves at December 31, 2019	423,782	2,928,354	911,841

Revisions of previous estimates. As previously discussed, in 2019 we removed 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 our drilling programs. Of these removals, 12 MMBo and 39 Bcf (totaling 19 MMBoe) was related to Bakken properties, 4 MMBo and 56 Bcf (totaling 13 MMBoe) was related to SCOOP properties, and 1 MMBo and 13 Bcf (totaling 3 MMBoe) was related to STACK properties. Additionally, changes in economics, performance, and other factors resulted in downward PUD reserve revisions of 38 MMBo and 278 Bcf (totaling 85 MMBoe) in 2019. Decreases in average crude oil and natural gas prices in 2019 resulted in downward price revisions of 11 MMBo and 67 Bcf (totaling 22 MMBoe). Finally, changes in ownership interests, operating costs, anticipated production, and other factors resulted in net downward revisions for oil PUD reserves of 6 MMBo and net upward revisions for natural gas PUD reserves of 9 Bcf (totaling a net downward revision of 5 MMBoe) in 2019.

Extensions and discoveries. Extensions and discoveries were due to successful drilling activities and continual refinement of our drilling programs in the Bakken, SCOOP and STACK plays. PUD reserve additions in the Bakken totaled 107 MMBo and 261 Bcf (totaling 150 MMBoe) in 2019, while SCOOP PUD reserve additions totaled 43 MMBo and 793 Bcf (totaling 176 MMBoe) and STACK PUD reserve additions totaled 1 MMBo and 90 Bcf (totaling 16 MMBoe).

Sales of minerals in place. We had no individually significant dispositions of PUD reserves in 2019.

Purchases of minerals in place. We had no individually significant acquisitions of PUD reserves in 2019.

Conversion to proved developed reserves. In 2019, we developed approximately 20% of our PUD locations and 16% of our PUD reserves booked as of December 31, 2018 through the drilling and completion of 480 gross (217 net) development wells at an aggregate capital cost of $1.1 billion incurred in 2019.

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 386 gross (138 net) operated and non-operated locations at December 31, 2019 and represent 10% of our PUD reserves at that date. The costs to drill our uncompleted wells were incurred prior to December 31, 2019 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 $1.8 billion in 2020, $2.2 billion in 2021, $2.0 billion in 2022, $2.3 billion in 2023, and $1.7 billion in 2024. 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, 2019 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, 2019. We had no PUD reserves at December 31, 2019 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 91% of our total proved reserves as of December 31, 2019 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 35 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.

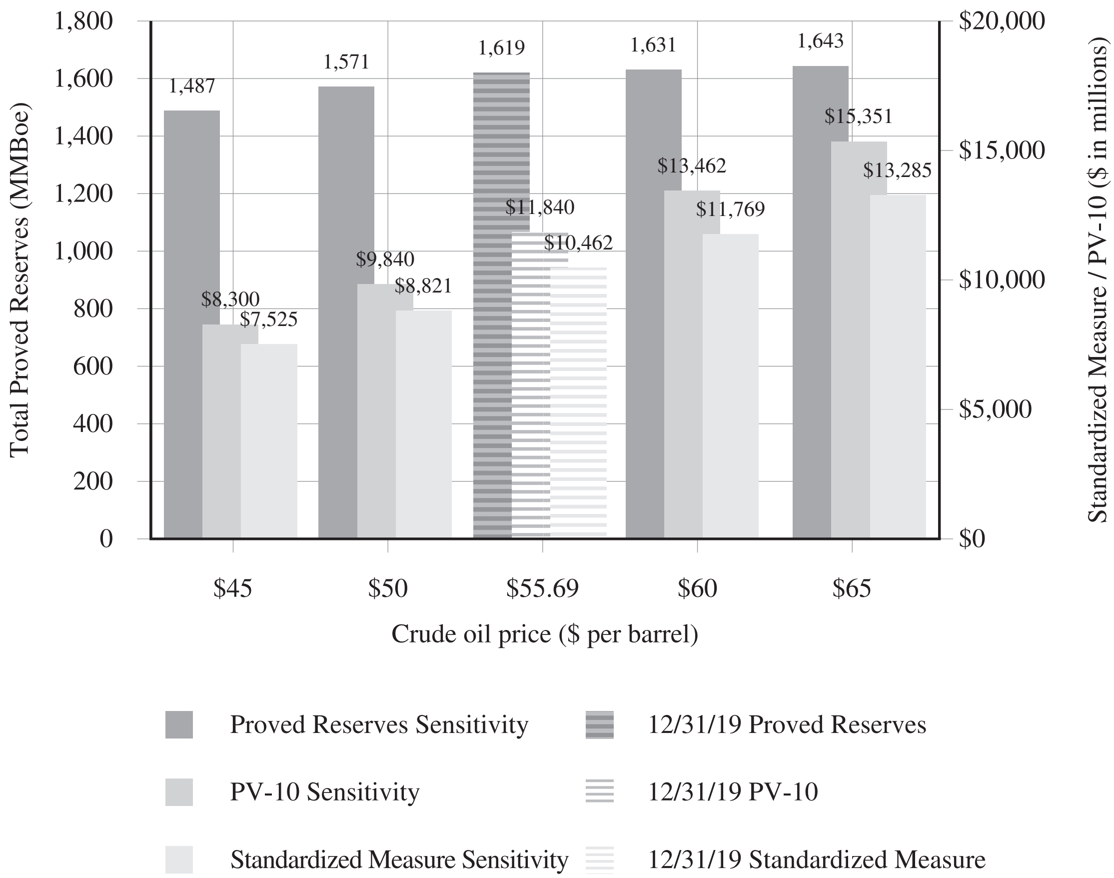
Proved Reserves, Standardized Measure, and PV-10 Sensitivities

Our year-end 2019 proved reserves, Standardized Measure, and PV-10 estimates were prepared using 2019 average first-day-of-the-month prices of $55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($51.95 per Bbl for crude oil and $2.02 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, 2019 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 demonstrate the impact that changing commodity prices may have on estimated proved reserves, Standardized Measure, and PV-10 and there is no assurance these outcomes will be realized.

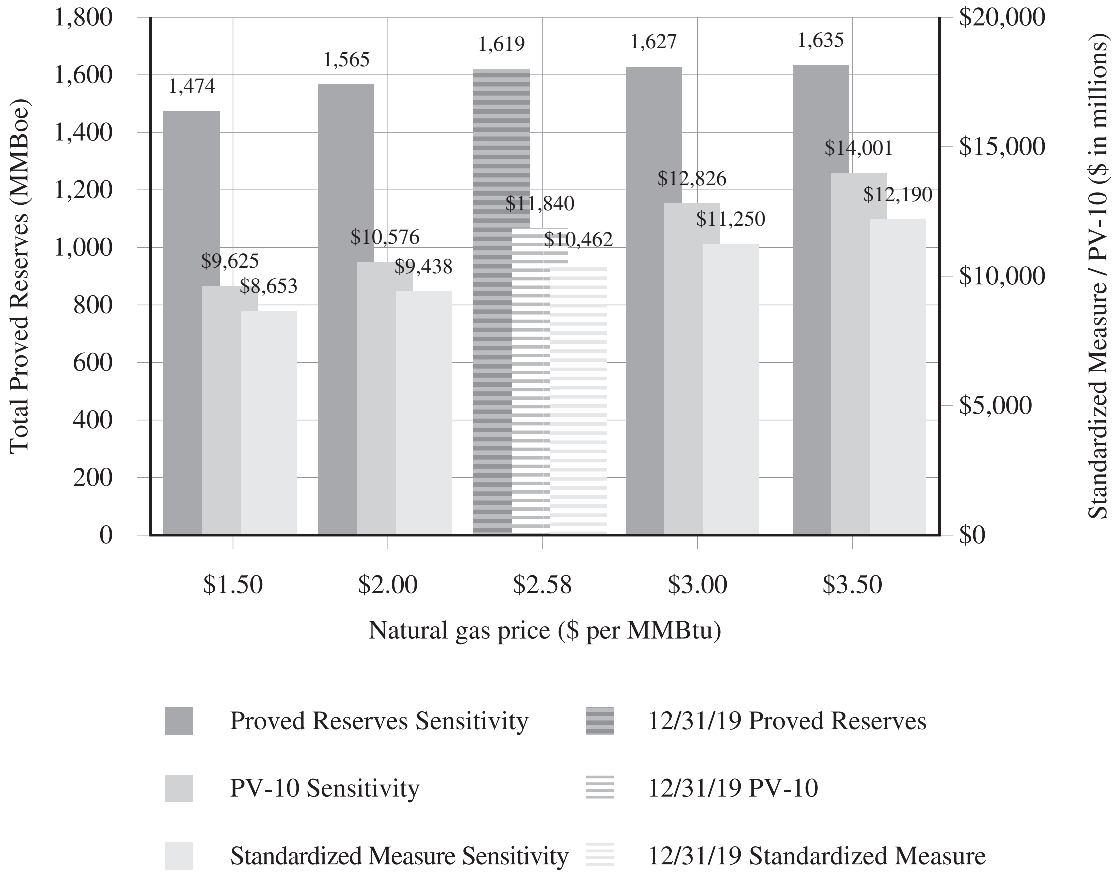
The crude oil price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain crude oil price scenarios, with natural gas prices being held constant at the 2019 average first-day-of-the-month price of $2.58 per MMBtu.

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 2019 average first-day-of-the-month price of $55.69 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, 2019:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	952,366	564,681	129,920	81,590	1,082,286	646,271
Montana Bakken	172,247	137,972	34,730	25,913	206,977	163,885
Red River units	157,915	140,025	17,467	8,272	175,382	148,297
Other	83,070	58,229	51,623	44,834	134,693	103,063
South Region:						
SCOOP	267,796	159,367	184,200	101,880	451,996	261,247
STACK	264,535	143,981	128,705	77,944	393,240	221,925
Other	35,052	21,129	54,379	22,085	89,431	43,214
East Region	968	881	104,015	96,022	104,983	96,903
Total	1,933,949	1,226,265	705,039	458,540	2,638,988	1,684,805

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2019 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.

	2020		2021		2022	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	29,054	18,724	32,282	23,099	27,967	18,201
Montana Bakken	—	—	1,480	1,480	12,182	10,311
Other	3,755	1,343	17,217	17,217	—	—
South Region:						
SCOOP	55,908	29,469	33,633	16,621	31,304	20,979
STACK	53,933	33,714	27,210	19,884	9,855	8,554
Other	30,887	12,129	2,954	748	9,227	6,623
East Region	11,730	10,172	969	370	4,856	3,732
Total	185,267	105,551	115,745	79,419	95,391	68,400

Drilling Activity

During the three years ended December 31, 2019, we drilled and completed exploratory and development wells as set forth in the table below:

	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	2	1.6	4	1.0	34	9.0
Natural gas	4	1.8	9	4.6	9	3.1
Dry holes	—	—	—	—	—	—
Total exploratory wells	6	3.4	13	5.6	43	12.1
Development wells:						
Crude oil	615	222.9	636	213.7	474	175.4
Natural gas	68	9.7	151	39.1	91	26.8
Dry holes	—	—	—	—	—	—
Total development wells	683	232.6	787	252.8	565	202.2
Total wells	689	236.0	800	258.4	608	214.3

As of December 31, 2019, there were 509 gross (190 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 2020 in our key operating areas. Our 2020 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 2020.

	2020 Plan		
	Gross wells (1)	Net wells (1)	Capital expenditures (in millions) (2)
North Region	406	154	$1,368
South Region	254	91	843
Total exploration and development	660	245	$2,211
Land (3)			202
Capital facilities, workovers and other corporate assets			235
Seismic			2
Total 2020 capital budget			$2,650

(1) Represents operated and non-operated wells expected to have first production in 2020.

(2) Represents total capital expenditures for operated and non-operated wells expected to have first production in 2020 and wells spud that will be in the process of drilling, completing or waiting on completion as of year-end 2020.

(3) Includes $125 million of planned spending for mineral acquisitions under our relationship with Franco-Nevada Corporation described in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests*. With a carry structure in place, Continental will recoup $100 million, or 80%, of such acquisition spending from Franco-Nevada.

North Region

Our properties in the North region represented 53% of our total proved reserves as of December 31, 2019 and 55% of our average daily Boe production for the fourth quarter of 2019. 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, 2019, we controlled one of the largest leasehold positions in the Bakken with approximately 1.3 million gross (810,200 net) acres under lease.

Our total Bakken production averaged 194,156 Boe per day for the fourth quarter of 2019, up 6% from the 2018 fourth quarter. For the year ended December 31, 2019, our average daily Bakken production increased 16% over 2018, reflecting additional drilling and completion activities. In 2019, we participated in the drilling and completion of 379 gross (124 net) wells in the Bakken compared to 496 gross (169 net) wells in 2018. Our 2019 activities in the Bakken focused on ongoing multi-zone unit development of high rate-of-return areas in the play.

Our Bakken properties represented 52% of our total proved reserves at December 31, 2019 and 53% of our average daily Boe production for the 2019 fourth quarter. Our total proved Bakken field reserves as of December 31, 2019 were 834 MMBoe, an increase of 5% compared to December 31, 2018 primarily due to reserves added from our drilling and development program and continued improvement in recoveries driven by operating efficiencies and advances in optimized completion designs. Our inventory of proved undeveloped drilling locations in the Bakken totaled 1,997 gross (944 net) wells as of December 31, 2019.

For 2020, our budget for exploration and development capital expenditures in the North region is $1.37 billion. In 2020, we expect to have first production on 406 gross (154 net) operated and non-operated wells in the North region. We plan to average approximately nine operated rigs and four well completion crews in the North region throughout 2020. Our 2020 drilling and completion activities in the Bakken will focus on ongoing 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 achieve sustainable and repeatable results. Notably, in 2020 we plan to ramp up development activities on our 10-square mile Long Creek Bakken Unit in Williams County, North Dakota, with production from the project beginning in late 2020 and increasing into 2021. This unit is another high impact oil project for the Company that was formed to capitalize on our dominant ownership position in the area and will be exploited using row development to maximize efficiencies and value, much like our SpringBoard project in SCOOP described below.

South Region

Our properties in the South region represented 47% of our total proved reserves as of December 31, 2019 and 45% of our average daily Boe production for the fourth quarter of 2019. 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, 2019, we controlled one of the largest leasehold positions in SCOOP with approximately 452,000 gross (261,200 net) acres under lease.

SCOOP represented 36% of our total proved reserves as of December 31, 2019 and 31% of our average daily Boe production for the fourth quarter of 2019. Production in SCOOP averaged 111,829 Boe per day during the fourth quarter of 2019, up 66% compared to the 2018 fourth quarter. For the year ended December 31, 2019, average daily production in SCOOP increased 29% compared to 2018, reflecting increased drilling and completion activities in our Project SpringBoard play described below. We participated in the drilling and completion of 207 gross (93 net) wells in SCOOP during 2019 compared to 148 gross (48 net) wells in 2018, which helped generate a 25% increase in proved reserves during the year to 576 MMBoe as of December 31, 2019. Our inventory of proved undeveloped drilling locations in SCOOP totaled 577 gross (287 net) wells as of December 31, 2019.

Our 2019 activities in SCOOP were focused on ongoing row development of leasehold in our oil-weighted Project SpringBoard play. SpringBoard is a large, multi-year, crude oil project controlled and operated by Continental that covers approximately 73 square miles of contiguous leasehold in Grady County, Oklahoma where we are concurrently developing three stacked reservoirs in the Springer, Sycamore, and Woodford formations. These reservoirs are being developed in rows to maximize efficiencies and rates of return through the orderly sequencing of drilling and completion activities. This row development strategy allows us to realize significant cost savings. In addition to cost saving benefits, our SpringBoard production benefits from access to premium sales markets through existing pipeline infrastructure, making our SpringBoard sales price realizations among the best in the Company. Additionally, water pipeline and recycling facilities are in place to allow for uninterrupted flow back and recycling capabilities to support timely completion activities in the project.

To date, Project SpringBoard has outperformed our production targets due to operational efficiency gains and strong well performance, which allowed us to reduce our rig count in Oklahoma in 2019 while still achieving our production growth objectives. This outperformance had a meaningful impact on our oil-weighted production growth during the year and contributed to a 69% increase in crude oil production from our SCOOP properties in 2019 compared to 2018.

STACK

STACK is a significant resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage, and Woodford formations. As of December 31, 2019, we controlled one of the largest leasehold positions in STACK with approximately 393,200 gross (221,900 net) acres under lease. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma where we believe the reservoirs are typically thicker and deliver superior production rates relative to normal-pressured areas of the STACK petroleum system.

Our STACK properties represented 11% of our total proved reserves as of December 31, 2019 and 14% of our average daily Boe production for the fourth quarter of 2019. Production in STACK averaged 51,628 Boe per day during the fourth quarter of 2019, down 18% over the 2018 fourth quarter due to changes in the timing of initial production from new well completions between periods. For the year ended December 31, 2019, average daily production in STACK decreased 3% from 2018 due to moderated drilling and completion activities resulting from a greater allocation of capital to other areas during the year. We participated in the drilling and completion of 103 gross (19 net) wells in STACK during 2019 compared to 154 gross (40 net) wells in 2018. Proved reserves in STACK decreased 21% year-over-year to 182 MMBoe as of December 31, 2019 due primarily to the removal of PUD reserves from changes in economics, performance, and other factors. Our inventory of proved undeveloped drilling locations in STACK totaled 156 gross (52 net) wells as of December 31, 2019.

Highlighting our 2019 activity in the STACK play was the completion of the Reba Jo and Schulte units, which consisted of 14 total wells targeting two separate benches in the Meramec formation in the STACK over-pressured oil window. These combined units delivered outstanding initial production results with initial 24-hour production averaging 4,092 Boe per day per well, ranking the wells amongst the best in Company history.

For 2020, our aggregate budget for exploration and development capital expenditures in the South region is $843 million. In 2020, we expect to have first production on 254 gross (91 net) operated and non-operated wells in the South region. We plan to average approximately 11 operated rigs and three well completion crews in the South region throughout 2020. Our 2020 activities in SCOOP will focus on continued row development in Project SpringBoard and achieving operational and technical advancements aimed at further improving capital efficiencies and rates of return. Our 2020 activities in STACK will focus on continued development of oil and liquids-rich assets in the over-pressured windows of the play and improving capital efficiencies, recoveries, and rates of return.

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, 2019, 2018 and 2017 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2019.

	Year ended December 31,		
	2019	2018	2017
Net production volumes:			
Crude oil (MBbls)			
North Dakota Bakken	52,420	45,775	35,964
SCOOP	11,679	6,918	5,726
Total Company	72,267	61,384	50,536
Natural gas (MMcf)			
North Dakota Bakken	98,186	78,448	59,232
SCOOP	111,436	99,397	98,563
Total Company	311,865	284,730	228,159
Crude oil equivalents (MBoe)			
North Dakota Bakken	68,784	58,849	45,836
SCOOP	30,252	23,484	22,153
Total Company	124,244	108,839	88,562
Average net sales prices (1):			
Crude oil ($/Bbl)			
North Dakota Bakken	$ 50.96	$ 58.37	$ 45.21
SCOOP	54.92	62.74	47.96
Total Company	51.82	59.19	45.70
Natural gas ($/Mcf)			
North Dakota Bakken	$ 1.28	$ 3.33	$ 2.97
SCOOP	2.36	3.41	3.26
Total Company	1.77	3.01	2.93
Crude oil equivalents ($/Boe)			
North Dakota Bakken	$ 40.66	$ 49.83	$ 39.32
SCOOP	29.80	32.88	26.93
Total Company	34.56	41.25	33.65
Average costs per Boe:			
Production expenses ($/Boe)			
North Dakota Bakken	$ 4.28	$ 4.40	$ 4.40
SCOOP	1.21	1.34	1.01
Total Company	3.58	3.59	3.66
Production taxes ($/Boe)	$ 2.88	$ 3.25	$ 2.35
General and administrative expenses ($/Boe)	$ 1.57	$ 1.69	$ 2.16
DD&A expense ($/Boe)	$ 16.25	$ 17.09	$ 18.89

(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 for 2018 and 2019.

The following table sets forth information regarding our average daily production by region for the fourth quarter of 2019:

	Fourth Quarter 2019 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	139,527	291,910	188,178
Montana Bakken	4,581	8,379	5,978
Red River units			
Cedar Hills	5,757	3	5,757
Other Red River units	1,861	—	1,861
Other	13	11	15
South Region:			
SCOOP	44,399	404,582	111,829
STACK	10,071	249,341	51,628
Other	40	330	95
Total	206,249	954,556	365,341

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, 2019. 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	4,611	1,545	—	—	4,611	1,545
Montana Bakken	406	259	—	—	406	259
Red River units						
Cedar Hills	136	130	—	—	136	130
Other Red River units	130	116	—	—	130	116
Other	2	2	—	—	2	2
South Region:						
SCOOP	510	271	471	135	981	406
STACK	418	171	472	159	890	330
Other	1	1	22	1	23	2
Total	6,214	2,495	965	295	7,179	2,790

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 and Major Customers

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 balance of production primarily transported by truck either directly to a refinery or 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 dedication. 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 monthly interruptible packaged volume deals, short 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.

For the year ended December 31, 2019, sales to Valero Energy Corporation and its affiliates accounted for approximately 13% of our total crude oil and natural gas revenues. No other purchaser accounted for more than 10% of our total crude oil and natural gas revenues for 2019. The loss of any single purchaser will not have a material adverse effect on our operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

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, which can be particularly important in the areas in which we operate. 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 create new competitive conditions that 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 on us and other industry participants. 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. In general, pipeline rates must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. Intrastate crude oil and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. 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 costs of ocean going freight are expected to initially increase as the shipping industry adapts to the new regulations, which may have far reaching consequences for domestic and global economies through increased consumer prices and other effects. Although preparatory efforts have been undertaken by the shipping industry and fuel oil suppliers to comply with the new rules that went into effect on January 1, 2020, the ultimate long-term impact of the IMO regulations remains 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 also restrict the rate of crude oil and natural gas production below a rate otherwise possible. 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 any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the crude oil and natural gas industry 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, the occurrence of restrictions, delays or cancellations in the permitting or performance of projects, the issuance of orders enjoining performance of some or all of our operations, and potential litigation. 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 may 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, in October 2015 the U.S. Environmental Protection Agency ("EPA") revised the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and 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 June 2016 the EPA 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. Following the change in U.S. presidential administrations in 2016, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. 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, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

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 fossil fuels and emission of greenhouse gases, including pledges made by certain candidates seeking the office of the President of the United States in 2020 to ban hydraulic fracturing of oil and natural gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Litigation risks are also increasing, as a number of cities, local governments, 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 as a result, or alleging 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 fossil fuel producers, as stockholders and bondholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional investors who provide financing to fossil fuel energy companies also have become more attentive to sustainability issues and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for fossil fuel energy 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, incurring liability for infrastructure damages as a result of climate changes, or increases in the cost of consuming hydrocarbons and thereby reducing demand for the crude oil and natural gas we produce. 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, particularly with respect to the flaring of natural gas from our operated well sites in the Bakken field of North Dakota. North Dakota statutes permit 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 addressing measures 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 88% of the natural gas produced from a field, and beginning November 1, 2020 the target capture rate increases to 91%. 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 of such flexibility 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 policy in the event an operator not meeting the gas capture percentage goals 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 may be dependent upon 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 and 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 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. It has not been our practice to 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 2015, the BLM issued 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 subsequently rescinded the rules in 2017. Litigation challenging the BLM's rescission has been filed by certain states and environmental groups and remains ongoing. As of December 31, 2019, we held approximately 60,300 net undeveloped acres on federal land, representing approximately 13% of our total net undeveloped acres.

From time to time, legislation has been introduced, but not enacted, in the U.S. Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain candidates running for the office of President of the United States in 2020 have pledged to ban hydraulic fracturing and, on January 28, 2020, one of those candidates introduced Senate Bill 3247 that, if enacted as proposed, would ban hydraulic fracturing nationwide by 2025.

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. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or imposed moratoria on the use of injection wells. 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 believe 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. Although we believe our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you the passage of more stringent laws or regulations in the future will not materially impact 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 (“OSHA”) and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA 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.

Employees

As of December 31, 2019, we employed 1,260 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of independent contractors to perform various field and other services.

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 “For 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.

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 2019 the NYMEX West Texas Intermediate ("WTI") crude oil and Henry Hub natural gas spot prices ranged from approximately $46 to $66 per barrel and $1.75 to $4.25 per MMBtu, respectively. Commodity prices will likely remain volatile and unpredictable in 2020 and beyond. Our future crude oil and natural gas production is unhedged as of December 31, 2019 and is directly 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 producing nations;
- the nature and extent of domestic and foreign governmental laws, regulations, and taxation, including environmental laws and regulations governing the imposition of trade restrictions and tariffs;
- 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;
- technological advances affecting energy production and consumption;

- the effect of worldwide energy conservation and 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 the 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.

Volatility in the financial markets or in global economic factors, 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 health epidemic originating in China, 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 increasing levels of 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.

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 57% of our crude oil and natural gas production and 68% of our crude oil and natural gas revenues for the year ended December 31, 2019. Approximately 52% of our estimated proved reserves were located in the Bakken as of December 31, 2019. Additionally, our properties in Oklahoma comprised 40% of our crude oil and natural gas production and 28% of our crude oil and natural gas revenues for the year ended December 31, 2019. Approximately 47% of our estimated proved reserves were located in Oklahoma as of December 31, 2019.

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) 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; (ii) the availability of rigs, completion crews, waste water disposal wells, equipment, field services, water, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Bakken field and Oklahoma may be adversely affected by severe weather events such as floods, blizzards, 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.

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

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. We have budgeted $2.65 billion for capital expenditures in 2020 of which approximately $2.21 billion is allocated to exploration and development activities. We may adjust our 2020 capital spending plans upward or downward depending on market conditions. Our 2020 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.

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.

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, 2019.

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, 2019, average prices used to calculate our estimated proved reserves were $55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($51.95 per Bbl for crude oil and $2.02 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, 2020 and February 1, 2020 averaged $56.31 per barrel and $1.95 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, 2019, approximately 56% 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, 2019 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $10.0 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 2019, 35 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.

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 55% of our total net undeveloped acreage at December 31, 2019. At that date, we had leases representing 105,551 net acres expiring in 2020, 79,419 net acres expiring in 2021, and 68,400 net acres expiring in 2022.

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.

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.

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 historically 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 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.

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.

We are subject to complex federal, state and local laws and regulations 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. Following is a discussion of certain significant laws, rules and regulations that affect us in the areas in which we operate. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* for further discussion of these and other regulations that affect us.

Air emissions and climate change—Federal, state and local laws and regulations have been and may be enacted to address concerns about the potential effects of emissions of regulated air pollutants, including carbon dioxide, methane and other identified "greenhouse gas" emissions on the environment and climate worldwide, generally referred to as "climate change." See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Air emissions and climate change* for further discussion of the impact of regulated air pollutants including greenhouse gases on our operations. The implementation of, and compliance with, laws and regulations that impose more stringent standards for greenhouse gas emissions from the oil and natural gas sector or otherwise restrict the areas in which oil and natural gas may be produced could limit our ability to obtain permits in order to develop and produce our reserves and result in increased costs of compliance or costs of consuming hydrocarbons, and thereby reduce demand for the crude oil, natural gas, and natural gas liquids we produce, which could lower the value of our reserves and have a material adverse effect on our business, financial condition, results of operations and cash flows. Additionally, political, litigation, and financial risks may result in our restricting or cancelling development or production activities, incurring liability for infrastructure damages as a result of climate changes, or impairing our ability to continue to operate in an economic manner, which also could reduce demand for our products. One or more of these developments could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Hydraulic fracturing—Hydraulic fracturing is an important and commonly used process in the completion of crude oil and natural gas wells in low-permeability formations. In recent years there has been public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to induce seismic events. As a result, several federal and state enacted and proposed laws and regulations have emerged which have increased, and have the potential to further increase, the regulatory burden imposed on hydraulic fracturing. While no federal legislation has been enacted to provide for regulation of hydraulic fracturing, certain candidates running for the office of President of the United States in 2020 have pledged to ban hydraulic fracturing and, on January 28, 2020, one of those candidates introduced Senate Bill 3247 that, if enacted as proposed, would ban hydraulic fracturing nationwide by 2025. States in which we operate have adopted laws and regulations imposing more stringent permitting, disclosure, and well construction and reclamation requirements on hydraulic fracturing activities. Local governments also have sought to adopt ordinances within their jurisdictions regulating or prohibiting the time, place and manner of hydraulic fracturing activities. The adoption of any future federal, state or local law or implementing regulation imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process, or the discovery of groundwater contamination or other adverse environmental effects directly connected to hydraulic fracturing, could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. In the event regulations are adopted to prohibit or significantly limit the use of hydraulic fracturing in states or federal lands in which we operate, it would have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves in our strategic plays. The inability to achieve a satisfactory economic return could cause us to curtail or discontinue our exploration and development plans, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Waste water disposal—Our business depends on the ability to dispose of waste water from oil and gas activities. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or imposed moratoria on the use of injection wells. In addition, concerns have been raised in recent years about the potential for seismic events to occur from the use of injection wells. Rules and regulations have been developed in Oklahoma to address these concerns by limiting or eliminating the ability to use disposal wells in certain locations or increasing the cost of disposal. Complying with existing or new laws, regulations, and permit requirements governing the disposal of waste water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. The enactment of legislation in the future that eliminates or defers these or other tax deductions utilized within our industry could adversely affect our business, financial condition, results of operations and cash flows.

Dodd-Frank Act derivative regulations—From time to time, we may use derivative instruments to manage commodity price risk. 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. 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. Certain aspects of the Dodd-Frank rulemaking have been repealed or have not been finalized and the ultimate effect of the 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. Strict liability or joint and several liability may be imposed under certain laws, 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 and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

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 a change in U.S. presidential administrations, 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. The lending and investment practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists and foreign citizenry concerned about climate change. These lobbying efforts have resulted in, and may yet result in, financial institutions, funds, and other sources of capital restricting or eliminating their investment in crude oil and natural gas activities. Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods or other climatic events. If any such effects were to occur as a result of climate change or otherwise, they 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.

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. In addition, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, securing long-term transportation and processing capacity, marketing hydrocarbons, attracting and retaining quality personnel, and raising additional capital, which 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, 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. Such events may result in significant destruction of infrastructure, businesses, and homes and could disrupt the distribution and supply of crude oil and natural gas products in the impacted regions. 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.

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 seismic data, reserves information, strategic information, or other sensitive or proprietary information owned by us or by third parties could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production-related infrastructure could result in a loss of production or accidental discharge;
- a cyber attack on third party transportation, processing, storage, refining, or export facilities could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- a cyber attack involving commodity exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- corruption of our financial or operating data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- a cyber attack could result in unauthorized access to and release of personal or confidential information maintained by the Company.

Any of the above events 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.

The Company has established cyber security systems and controls intended to monitor threats, identify incidents and assess their impact, protect information, and mitigate data loss. The Company has also established disclosure controls and procedures in tandem with incident response protocols, including regular assessment of threats and incidents by a security oversight committee comprised of members of senior management and information technology personnel. These systems, controls, and procedures are intended to provide information about cyber security incidents so that such information can be timely processed and reported to the appropriate personnel; however, these systems, controls, and procedures may not identify all risks and threats we face, or may fail to protect data or mitigate the adverse effects of data loss. Our senior management makes materiality assessments and disclosure decisions and has implemented procedures to prohibit insider trading on the basis of material nonpublic information about cyber incidents; however, we cannot guarantee all of these efforts will be effective. Although we maintain systems, controls, and procedures to address cyber security risks, such measures cannot eliminate cyber security threats and incidents, and there remains a risk that we will experience a cyber breach, attack, or data loss incident and suffer adverse effects.

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.

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.

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, 2019, non-operated properties represented 16% of our estimated proved developed reserves, 13% of our estimated proved undeveloped reserves, and 14% 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, safety 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.

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, 2019, we had $55 million of outstanding borrowings on our credit facility and our consolidated net debt to total capitalization ratio, as defined, was 0.40 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.

We may be adversely affected by changes in LIBOR reporting practices, the method in which LIBOR is determined, or the use of alternative reference rates.

It is expected the London Interbank Offered Rate ("LIBOR") will be discontinued as a reference rate for financial contracts by the end of 2021. Financial regulators and institutions have proposed replacing the LIBOR reference rate with a Secured Overnight Financing Rate ("SOFR"). SOFR is a measure of the cost of borrowing cash overnight, collateralized by U.S. Treasury securities, and is based on observable U.S. Treasury-backed repurchase transactions.

Certain types of borrowings under our revolving credit facility, which matures in April 2023, are derived from the LIBOR reference rate. Our revolving credit agreement includes general provisions governing the establishment of an alternate rate of interest to the LIBOR-based rate that gives consideration to the then prevailing market convention for determining a rate of interest for comparable syndicated loans. At this time, the impact on the Company's borrowing costs, if any, under an alternative reference rate scenario is uncertain. Additionally, it remains uncertain whether and to what extent banks will continue to provide LIBOR submissions, whether LIBOR rates will cease to be published or supported before or after 2021, or whether any additional reforms to LIBOR may be enacted.

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 ($727 million in receivables at December 31, 2019) and our joint interest and other receivables ($315 million at December 31, 2019). 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.

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

Although our future crude oil and natural gas production is unhedged as of December 31, 2019, from time to time we may enter into derivative instruments for a potentially significant portion of our production to achieve more predictable cash flows and reduce our exposure to adverse fluctuations in commodity prices. We do not designate our derivative instruments, if any, as hedges for accounting purposes and we record all derivatives on our balance sheet at fair value. Changes in the fair value of any such 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, if any, 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 Executive Chairman beneficially owns approximately 77% 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, 2019, Harold G. Hamm, our Executive Chairman, beneficially owned approximately 77% 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.

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 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 of assets, and enter into joint development arrangements. Suitable acquisition properties, buyers of our assets, or joint development counterparties may not be available on terms and conditions we find acceptable or not at all.

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.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2019.

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. MD&A—Delivery Commitments* and is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various legal proceedings incidental to our 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. While the outcome of these legal matters cannot be predicted with certainty, we do not expect them to have a material effect on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange and trades under the symbol "CLR." As of January 31, 2020, the number of record holders of our common stock was 1,272. On February 13, 2020, after inquiry, management believes that the number of beneficial owners of our common stock is 58,849. On January 31, 2020, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $27.22 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. The Company intends to continue paying a quarterly dividend; however, any payment of future dividends will be at the discretion of our Board of Directors and will depend on, among other things, our future earnings, financial condition, cash flows, capital requirements, levels of indebtedness, prevailing business conditions and other considerations our Board of Directors may deem relevant.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2019:

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, 2019 to October 31, 2019				
Share repurchase program (1)	640,000	$28.55	640,000	$809.8
November 1, 2019 to November 30, 2019				
Repurchases for tax withholdings (2)	10,214	$31.45		
December 1, 2019 to December 31, 2019				
Repurchases for tax withholdings (2)	1,468	$33.38		
Total	651,682	$28.61	640,000	

(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.

(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, 2019 relating to equity compensation plans:

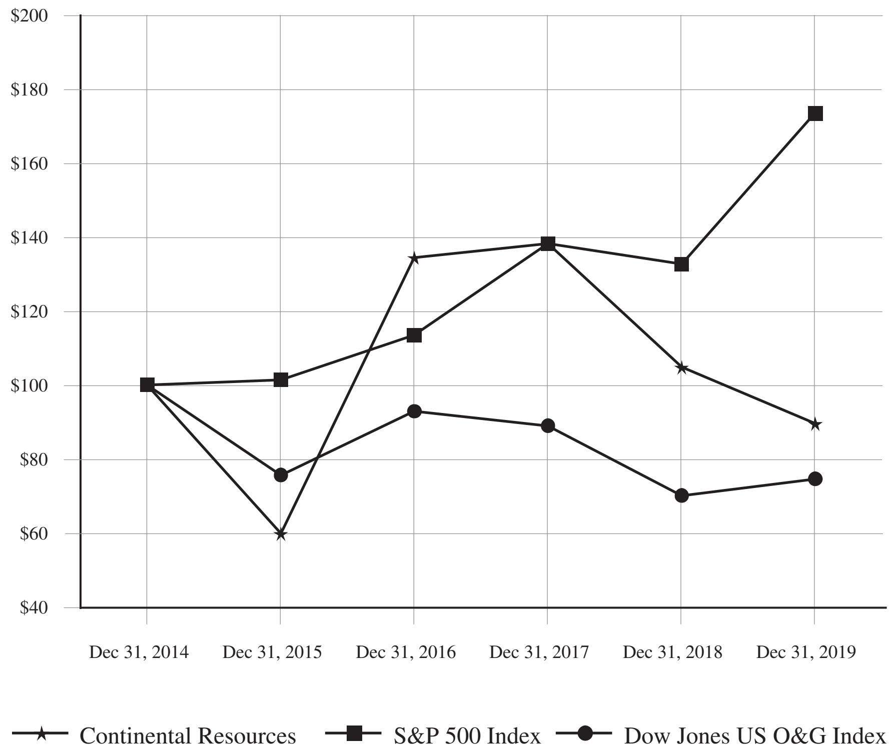
	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	13,036,804
Equity Compensation Plans Not 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, 2014 through December 31, 2019. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2014 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, 2015 through 2019. 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 immaterial and are not separately presented below.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales (1)	$ 4,514,389	$ 4,678,722	$ 2,982,966	$ 2,026,958	$ 2,552,531
Gain (loss) on crude oil and natural gas derivatives, net (2)	49,083	(23,930)	91,647	(71,859)	91,085
Total revenues	4,631,947	4,709,586	3,120,828	1,980,273	2,680,167
Net income (loss) (3)	774,473	989,700	789,447	(399,679)	(353,668)
Net income (loss) attributable to Continental Resources (3)(4)	775,641	988,317	789,447	(399,679)	(353,668)
Net income (loss) per share attributable to Continental Resources: (3)(4)					
Basic	$ 2.09	$ 2.66	$ 2.13	$ (1.08)	$ (0.96)
Diluted	$ 2.08	$ 2.64	$ 2.11	$ (1.08)	$ (0.96)
Cash dividends per common share	$ 0.05	—	—	—	—
Production volumes					
Crude oil (MBbl)	72,267	61,384	50,536	46,850	53,517
Natural gas (MMcf)	311,865	284,730	228,159	195,240	164,454
Crude oil equivalents (MBoe)	124,244	108,839	88,562	79,390	80,926
Average costs per unit					
Production expenses ($/Boe)	$ 3.58	$ 3.59	$ 3.66	$ 3.65	$ 4.30
Production taxes (% of net oil and gas revenues)	8.3%	7.9%	7.0%	7.0%	7.8%
DD&A ($/Boe)	$ 16.25	$ 17.09	$ 18.89	$ 21.54	$ 21.57
General and administrative expenses ($/Boe)	$ 1.57	$ 1.69	$ 2.16	$ 2.14	$ 2.34
Proved reserves at December 31					
Crude oil (MBbl)	760,187	757,096	640,949	643,228	700,514
Natural gas (MMcf)	5,154,471	4,591,614	4,140,281	3,789,818	3,151,786
Crude oil equivalents (MBoe)	1,619,265	1,522,365	1,330,995	1,274,864	1,225,811
Other financial data (in thousands)					
Net cash provided by operating activities	$ 3,115,688	$ 3,456,008	$ 2,079,106	$ 1,125,919	$ 1,857,101
Net cash used in investing activities	$ (2,771,956)	$ (2,860,172)	$ (1,808,845)	$ (532,965)	$ (3,046,247)
Net cash (used in) provided by financing activities	$ (587,108)	$ (356,934)	$ (243,034)	$ (587,773)	$ 1,187,189
Total capital expenditures	$ 2,809,192	$ 2,928,746	$ 2,035,254	$ 1,110,256	$ 2,564,301
Balance Sheet data at December 31 (in thousands)					
Total assets	$15,727,907	$15,297,947	$14,199,651	$13,811,776	$14,919,808
Long-term debt, including current portion	$ 5,326,514	$ 5,768,349	$ 6,353,691	$ 6,579,916	$ 7,117,788
Total equity	$ 7,108,351	$ 6,421,861	$ 5,131,203	$ 4,301,996	$ 4,668,900

(1) In years prior to 2018, we generally presented our revenues net of costs incurred to transport our production to market. For 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 new revenue recognition and presentation rules as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues.* 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 have not been 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 for 2019 and 2018.

(2) Crude oil and natural gas derivative instruments are not designated as hedges for accounting purposes and, therefore, changes in the fair value of the instruments are shown separately from crude oil and natural gas sales.

(3) In 2019, we sold our Canadian subsidiary and associated properties which resulted in a decrease in income tax expense and corresponding increase in net income via the recognition of an income tax benefit of $16.9 million ($0.05 per basic and diluted share). See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Income taxes* for further discussion. Additionally, 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). Results for 2017 also include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

(4) Excludes results attributable to noncontrolling interests. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. 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. Our operating results for the periods discussed below may not be indicative of future performance. Results attributable to noncontrolling interests are immaterial and are not separately presented or discussed below.

For additional discussion of crude oil and natural gas reserve information, please see *Part I, Item 1. Business—Crude Oil and Natural Gas Operations.* The following discussion and analysis includes forward-looking statements and should be read in conjunction with *Part I, Item 1A. Risk Factors* in this report, along with *Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995* at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development 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.

2019 Highlights

In 2019, Continental remained focused on increasing shareholder value by generating significant free cash flows, operating in a capital-efficient and disciplined manner, maintaining low-cost operations, further reducing debt, generating competitive corporate returns, and initiating a shareholder capital return strategy. Highlights of the Company's 2019 results are summarized below.

- Increased our total production by 14% in 2019 compared to 2018.
- Through efficiency gains, achieved production growth objectives while using fewer rigs and completion crews and reducing non-acquisition capital expenditures by 6% compared to 2018.
- Crude oil production increased 18% over 2018 driven by an increased focus on developing our oil-weighted assets in the Bakken field and Project SpringBoard play in SCOOP.
- Increased our proved reserves by 6% in 2019 to 1,619 MMBoe at December 31, 2019 despite downward reserve revisions driven by lower commodity prices and other factors.
- Initiated a total shareholder return strategy prompted by strong free cash flow generation that includes an ongoing share repurchase program of up to $1 billion and a quarterly dividend. Executed $190.2 million of share repurchases since the June 2019 inception of the repurchase program and paid first dividend of $0.05 per share in November 2019.
- Further reduced debt by redeeming $500 million of our 5% Senior Notes due 2022 in September 2019. Debt reduction efforts in 2018 and 2019 generated a $23.7 million, or 8%, decrease in interest expense in 2019 compared to 2018.
- Enhanced corporate returns through further expansion of our mineral ownership portfolio with $130 million of mineral acquisitions in 2019. The Company funded 20% of the acquisitions and expects to receive 50% of the mineral revenues.
- Continued to achieve efficiency gains and cost savings through operational excellence, resulting in exceptionally low oil-weighted production expenses of $3.58 per Boe and G&A expenses of $1.57 per Boe for 2019.

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,		
	2019	2018	2017
Average daily production:			
Crude oil (Bbl per day)	197,991	168,177	138,455
Natural gas (Mcf per day)	854,424	780,083	625,093
Crude oil equivalents (Boe per day)	340,395	298,190	242,637
Average net sales prices: (1)			
Crude oil ($/Bbl)	$ 51.82	$ 59.19	$ 45.70
Natural gas ($/Mcf)	$ 1.77	$ 3.01	$ 2.93
Crude oil equivalents ($/Boe)	$ 34.56	$ 41.25	$ 33.65
Crude oil net sales price discount to NYMEX ($/Bbl)	$ (5.15)	$ (5.27)	$ (5.50)
Natural gas net sales price discount to NYMEX ($/Mcf)	$ (0.86)	$ (0.09)	$ (0.16)
Production expenses ($/Boe)	$ 3.58	$ 3.59	$ 3.66
Production taxes (% of net crude oil and natural gas sales)	8.3%	7.9%	7.0%
DD&A ($/Boe)	$ 16.25	$ 17.09	$ 18.89
Total general and administrative expenses ($/Boe)	$ 1.57	$ 1.69	$ 2.16

(1) See the subsequent section titled *Non-GAAP Financial Measures* for a discussion and calculation of net sales prices, which are non-GAAP measures for 2019 and 2018.

Results of Operations

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

	Year Ended December 31,		
In thousands, except sales price data	2019	2018	2017
Crude oil and natural gas sales (1)	$ 4,514,389	$ 4,678,722	$ 2,982,966
Gain (loss) on natural gas derivatives, net	49,083	(23,930)	91,647
Crude oil and natural gas service operations	68,475	54,794	46,215
Total revenues	4,631,947	4,709,586	3,120,828
Operating costs and expenses (2)	(3,374,535)	(3,115,866)	(2,671,427)
Other expenses, net	(270,250)	(296,918)	(293,334)
Income before income taxes	987,162	1,296,802	156,067
(Provision) benefit for income taxes (3)	(212,689)	(307,102)	633,380
Net income	774,473	989,700	789,447
Net income (loss) attributable to noncontrolling interests	(1,168)	1,383	—
Net income attributable to Continental Resources	$ 775,641	$ 988,317	$ 789,447
Diluted net income per share attributable to Continental Resources (3)	$ 2.08	$ 2.64	$ 2.11
Production volumes:			
Crude oil (MBbl)	72,267	61,384	50,536
Natural gas (MMcf)	311,865	284,730	228,159
Crude oil equivalents (MBoe)	124,244	108,839	88,562
Sales volumes:			
Crude oil (MBbl)	72,136	61,332	50,628
Natural gas (MMcf)	311,865	284,730	228,159
Crude oil equivalents (MBoe)	124,113	108,787	88,655

(1) In years prior to 2018, we generally presented our revenues net of costs incurred to transport our production to market. For 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 new revenue recognition and presentation rules (ASU 2016-08) as discussed in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues.* We adopted the new rules using a modified retrospective transition approach whereby the rules were prospectively applied beginning January 1, 2018 and results prior to 2018 have not been 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 for 2019 and 2018.

(2) Net of gain on sale of assets of $0.5 million, $16.7 million, and $55.1 million for 2019, 2018, and 2017, respectively. The years of 2019 and 2018 include $225.6 million and $191.6 million, respectively, of transportation expenses that are presented gross of crude oil and natural gas sales as a result of our aforementioned adoption of ASU 2016-08 on January 1, 2018. The year 2017 includes a $59.6 million pre-tax loss accrual ($37.0 million after-tax, or $0.10 per diluted share) recognized in conjunction with the litigation settlement described in *Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Commitments and Contingencies—Litigation.*

(3) In 2019, we sold our Canadian subsidiary and associated properties which resulted in a decrease in income tax expense and corresponding increase in net income via the recognition of an income tax benefit totaling $16.9 million ($0.05 per diluted share). The year 2017 reflects the remeasurement of our 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 decrease in income tax expense and corresponding increase in net income via the recognition of an income tax benefit totaling $713.7 million ($1.91 per diluted share).

Year ended December 31, 2019 compared to the year ended December 31, 2018

Below is a discussion of changes in our results of operations for 2019 compared to 2018. A discussion of changes in our results of operations for 2018 compared to 2017 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, 2018 as filed with the SEC on February 19, 2019.

Production

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

	Fourth Quarter			Year Ended December 31,		
Boe production per day	2019	2018	% Change	2019	2018	% Change
Bakken	194,156	183,836	6%	194,691	167,800	16%
SCOOP	111,829	67,244	66%	82,882	64,339	29%
STACK	51,628	62,947	(18%)	54,587	56,055	(3%)
All other	7,728	9,974	(23%)	8,235	9,996	(18%)
Total	365,341	324,001	13%	340,395	298,190	14%

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

	Year Ended December 31,					
	2019		2018			
	Volume	Percent	Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	72,267	58%	61,384	56%	10,883	18%
Natural gas (MMcf)	311,865	42%	284,730	44%	27,135	10%
Total (MBoe)	124,244	100%	108,839	100%	15,405	14%

	Year Ended December 31,					
	2019		2018			
	MBoe	Percent	MBoe	Percent	Volume increase	Volume percent increase
North Region	74,028	60%	64,577	59%	9,451	15%
South Region	50,216	40%	44,262	41%	5,954	13%
Total	124,244	100%	108,839	100%	15,405	14%

The 18% increase in crude oil production in 2019 compared to 2018 was primarily due to a 6,510 MBbls, or 14%, increase in Bakken production due to additional wells being completed. Additionally, crude oil production from the SCOOP play increased 4,761 MBbls, or 69%, from the prior year due to new well completions in our oil-weighted Project SpringBoard.

The 10% increase in natural gas production in 2019 compared to 2018 was driven by a 19,831 MMcf, or 24%, increase in Bakken gas production in conjunction with the aforementioned increase in Bakken crude oil production in 2019. Additionally, natural gas production from the SCOOP play increased 12,039 MMcf, or 12%, in conjunction with the aforementioned increase in SCOOP crude oil production in 2019. These increases were partially offset by reduced production in various other areas from natural declines and limited natural gas drilling activities due to an increased focus on developing our oil-weighted assets offering better rates of return.

Revenues

Our revenues consist of sales of crude oil and natural gas, gains and losses resulting from changes in the fair value of our natural gas 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 2019 totaled $4.29 billion, a 4% decrease compared to net sales of $4.49 billion for 2018 due to a decrease in net sales prices partially offset by higher sales volumes as described below.

Total sales volumes for 2019 increased 15,326 MBoe, or 14%, compared to 2018, reflecting an increase in oil-weighted drilling and completion activities over the past year. For 2019, our crude oil sales volumes increased 18% compared to 2018, while our natural gas sales volumes increased 10%.

Our crude oil net sales prices averaged $51.82 per barrel for 2019, a decrease of 12% compared to $59.19 per barrel for 2018 due to lower crude oil market prices. The differential between NYMEX West Texas Intermediate calendar month crude oil prices and our realized crude oil net sales prices improved to $5.15 per barrel in 2019 compared to $5.27 per barrel in 2018.

Our natural gas net sales prices averaged $1.77 per Mcf for 2019, a 41% decrease compared to $3.01 per Mcf for 2018 due to lower market prices and reduced price realizations. The discount between our net sales prices and NYMEX Henry Hub calendar month natural gas prices weakened to $0.86 per Mcf for 2019 compared to $0.09

per Mcf for 2018. 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 ("NGL") prices at secondary, downstream markets. NGL prices in 2019 decreased significantly compared to 2018 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.

Derivatives. Changes in natural gas market prices during 2019 had an overall favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $49.1 million for the year, representing $64.7 million of cash gains partially offset by $15.6 million of non-cash losses. For 2018, we recognized negative revenue adjustments of $23.9 million resulting from changes in market prices that had an unfavorable impact on the fair value of our derivatives.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of crude oil reclaimed from waste products. Revenues associated with such activities increased $13.7 million, or 25%, from $54.8 million for 2018 to $68.5 million for 2019 due to an increase in water handling and disposal capabilities and activities compared to the prior year. The increased activities also resulted in higher service-related expenses compared to 2018. The continued growth in our water handling and disposal capabilities serves as another avenue for us to generate revenues and increase shareholder value.

Operating Costs and Expenses

Production expenses. Production expenses increased $54.2 million, or 14%, to $444.6 million for 2019 compared to $390.4 million for 2018 due to an increase in the number of producing wells and related 14% increase in sales volumes. Production expenses on a per-Boe basis averaged $3.58 for 2019, slightly improved from $3.59 per Boe recognized for 2018.

Production taxes. Production taxes increased $4.9 million, or 1%, to $358.0 million for 2019 compared to $353.1 million for 2018, despite lower revenues, due in part to legislation enacted in Oklahoma in 2018 that increased the state's production tax rate, effective July 1, 2018, from 2% to 5% for the first 36 months of production for wells commencing production after July 1, 2015. Additionally, the aforementioned increase in natural gas production volumes in North Dakota Bakken over the past year also contributed to the increase in production taxes. Natural gas production taxes in North Dakota are based on a per-Mcf rate applied to the quantity of volumes sold rather than being derived from the wellhead value of sales, which resulted in higher natural gas production taxes from increased North Dakota production despite lower revenues. As a result of these factors, our production taxes as a percentage of net crude oil and natural gas sales increased from 7.9% for 2018 to 8.3% for 2019.

Exploration expenses. Exploration expenses, which consist primarily of exploratory geological and geophysical costs that are expensed as incurred, increased $7.1 million, or 92%, to $14.7 million for 2019 compared to $7.6 million for 2018 due to an increase in the scope of our exploration-related activities in 2019 coupled with changes in the timing and amount of costs incurred by the Company and recouped from joint interest owners between periods.

Depreciation, depletion, amortization and accretion ("DD&A"). Total DD&A increased $158.1 million, or 9%, to $2.02 billion for 2019 compared to $1.86 billion for 2018 due to a 14% increase in total sales volumes, the impact of which was partially offset by a reduction 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	2019	2018
Crude oil and natural gas properties	$16.03	$16.84
Other equipment	0.15	0.18
Asset retirement obligation accretion	0.07	0.07
Depreciation, depletion, amortization and accretion	$16.25	$17.09

The reduction in our DD&A rate for crude oil and natural gas properties resulted from an increase in total proved developed reserves over which costs are depleted, along with improvements in drilling efficiencies and completion methods that have resulted in an increase in the quantity of proved reserves found and developed per dollar invested.

Property impairments. Property impairments decreased $39.0 million, or 31%, to $86.2 million for 2019 compared to $125.2 million for 2018, reflecting lower proved and unproved property impairments as described below.

Proved property impairments decreased to $3.7 million for 2019 compared to $18.0 million for 2018 due to changes in the nature and scope of drilling projects and commodity price fluctuations between periods, which impacted the timing and magnitude of impairments recognized in 2019 compared to 2018.

Impairments of unproved properties decreased $24.7 million, or 23%, to $82.5 million in 2019 compared to $107.2 million in 2018 due to a reduction in the balance of unamortized leasehold costs over the past year.

General and administrative ("G&A") expenses. Total G&A expenses increased $11.7 million, or 6%, to $195.3 million for 2019 compared to $183.6 million for 2018 due to higher corporate and personnel-related expenses associated with the growth in our operations over the past year. Total G&A expenses include non-cash charges for equity compensation of $52.0 million and $47.2 million for 2019 and 2018, respectively. G&A expenses other than equity compensation totaled $143.3 million for 2019, an increase of $6.9 million, or 5%, compared to $136.4 million for 2018.

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	2019	2018
General and administrative expenses	$1.15	$1.25
Non-cash equity compensation	0.42	0.44
Total general and administrative expenses	$1.57	$1.69

The decrease in G&A expenses on a per-Boe basis in 2019 was driven by a 14% increase in total sales volumes from new well completions with a less significant increase in G&A expenses.

Interest expense. Interest expense decreased $23.7 million, or 8%, to $269.4 million for 2019 compared to $293.0 million for 2018 due to a decrease in total outstanding debt. Our weighted average outstanding long-term debt balance for 2019 was $5.8 billion compared to $6.2 billion for 2018. The 2019 period includes $17.5 million of interest expense associated with the $500 million portion of our 2022 Notes that was redeemed in September 2019.

Income Taxes. For 2019 and 2018 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 income tax provisions of $212.7 million and $307.1 million for 2019 and 2018, respectively, which resulted in effective tax rates of 21.5% and 23.7%, respectively, after taking into account the application of statutory tax rates, permanent taxable differences, tax effects from the 2019 sale of our Canadian operations, tax effects from stock-based compensation, and other items. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Income Taxes* for a summary of the sources and tax effects of items comprising our income tax provision and resulting effective tax rates for 2019 and 2018.

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, in recent years asset dispositions and joint development arrangements have provided a source of cash flow for use in reducing debt and enhancing liquidity. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from additional potential sales of assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

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 for at least the next 12 months. Further, 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 $3.12 billion and $3.46 billion for 2019 and 2018, respectively. The decrease in operating cash flows was primarily due to a decrease in crude oil and natural gas commodity prices coupled with increases in production expenses and transportation expenses from higher sales volumes. The reduced cash flows from these factors were partially offset by lower interest expenses and higher cash gains on matured natural gas derivatives compared to 2018.

Cash flows used in investing activities

For 2019 and 2018, we had net cash flows used in investing activities of $2.77 billion and $2.86 billion, respectively, the decrease of which was due to a planned reduction in capital spending in 2019. These totals include cash capital expenditures of $2.86 billion and $2.91 billion, respectively, inclusive of exploration and development drilling, property acquisitions, mineral acquisitions, and leasing activities.

The use of cash for capital expenditures was partially offset by proceeds received from asset dispositions, which totaled $88.7 million and $54.5 million for 2019 and 2018, respectively. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 16. Property Dispositions* for a discussion of notable dispositions.

Cash flows used in financing activities

Net cash used in financing activities for 2019 totaled $587.1 million, primarily resulting from a $441.8 million 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 under our share repurchase program initiated in June 2019. These cash outflows were partially offset by $109.1 million of contributions received from noncontrolling interests, primarily from Franco-Nevada for its ownership interest in The Mineral Resources Company II, LLC ("TMRC II") and for funding of its share of mineral acquisition costs incurred by TMRC II as described below under the heading "Mineral acquisition relationship."

Net cash used in financing activities for 2018 totaled $356.9 million primarily resulting from a $585.4 million reduction in total outstanding debt using available cash flows from operations and proceeds from asset dispositions. Cash outflows for debt reduction were partially offset by $267.9 million of contributions received from noncontrolling interests, primarily from Franco-Nevada for its ownership interest in TMRC II and for funding of its share of certain mineral acquisition costs.

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, dividend payments, share repurchases, and commitments for at least the next 12 months. Our 2020 capital budget, based on our current expectations of commodity prices and costs, is expected to be funded from operating cash flows.

We currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. 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 the capital markets for additional financing or capital to take advantage of business opportunities that may arise. Further, we may sell assets or enter into strategic joint development opportunities in order to obtain funding if such transactions can be executed on satisfactory terms.

Revolving 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, 2020, we had no outstanding borrowings and $1.5 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 would not trigger a reduction in our current credit facility commitments, nor would such actions trigger a security requirement or change in covenants. Downgrades of our credit rating will, however, trigger increases in our credit facility's interest rates and commitment fees paid on unused borrowing availability under certain circumstances.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. See *Part II, Item 8. Notes to Consolidated Financial Statements—Note 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, 2019 and expect to maintain compliance for at least the next 12 months. At December 31, 2019, our consolidated net debt to total capitalization ratio was 0.40 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.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $5.3 billion at December 31, 2019. 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, 2019 and expect to maintain compliance for at least the next 12 months. 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 would 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 in the SCOOP and STACK plays through a minerals subsidiary named The Mineral Resources Company II, LLC ("TMRC II"). Under the relationship, the parties have committed, subject to satisfaction of agreed upon acreage development thresholds, to spend a remaining aggregate total of approximately $178 million through year-end 2021 to acquire mineral interests. 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 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 2020.

Capital expenditures

2019

For the year ended December 31, 2019, we invested $2.66 billion in our capital program excluding $147.4 million of unbudgeted acquisitions and excluding $54.8 million of capital costs associated with reduced accruals for capital expenditures as compared to December 31, 2018. Our 2019 capital expenditures were allocated as follows by quarter:

In millions	1Q 2019	2Q 2019	3Q 2019	4Q 2019	Total 2019
Exploration and development	$631.1	$569.7	$578.1	$467.8	$2,246.7
Land costs (1)	66.1	66.4	55.9	28.4	216.8
Capital facilities, workovers and other corporate assets	52.6	52.4	47.3	42.7	195.0
Seismic	0.4	0.3	0.2	2.4	3.3
Capital expenditures, excluding acquisitions	$750.2	$688.8	$681.5	$541.3	$2,661.8
Acquisitions of producing properties	15.8	4.7	28.8	2.3	51.6
Acquisitions of non-producing properties	—	79.8	10.7	5.3	95.8
Total acquisitions	15.8	84.5	39.5	7.6	147.4
Total capital expenditures	$766.0	$773.3	$721.0	$548.9	$2,809.2

(1) Full year 2019 amount includes $130 million of mineral acquisitions made by TMRC II, of which $104 million was recouped from Franco-Nevada.

2020 Capital Budget

In 2020, we will remain committed to operating in a disciplined, capital-efficient manner in light of continued volatility in commodity prices and have set our 2020 capital expenditures budget at $2.65 billion, flat with 2019 spending levels. Our 2020 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	2020 Budget
Exploration and development	$2,211
Land costs (1)	202
Capital facilities, workovers and other corporate assets	235
Seismic	2
Total 2020 capital budget	$2,650

(1) Includes $125 million of planned spending for mineral acquisitions by TMRC II. With a carry structure in place, Continental will recoup $100 million, or 80%, of such spending from Franco-Nevada.

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, 2019.

	Payments due by period				
In thousands	Total	Less than 1 year (2020)	Years 2 and 3 (2021-2022)	Years 4 and 5 (2023-2024)	More than 5 years
Revolving credit facility borrowings	$ 55,000	$ —	$ —	$ 55,000	$ —
Senior Notes (1)	5,300,000	—	1,100,000	2,500,000	1,700,000
Note payable (2)	5,377	2,435	2,942	—	—
Interest payments and commitment fees (3)	1,799,983	243,376	486,513	248,119	821,975
Asset retirement obligations (4)	153,673	1,899	19,216	72	132,486
Operating leases and other (5)	38,898	15,031	11,276	3,557	9,034
Drilling rig commitments (6)	64,345	64,345	—	—	—
Transportation and processing commitments (7)	2,197,157	290,647	661,843	629,371	615,296
Total contractual obligations	$9,614,433	$617,733	$2,281,790	$3,436,119	$3,278,791

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2019 and do not reflect any discount or premium at which the senior notes were issued or any debt issuance costs.

(2) Represents future principal payments on a 10-year amortizing note payable secured by the Company's corporate office building in Oklahoma City, Oklahoma and does not reflect any debt issuance costs. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022.

(3) Interest payments include scheduled cash interest payments on the senior notes and note payable, as well as estimated interest payments and commitment fees on unused borrowing availability under our credit facility assuming the $1.45 billion of availability as of December 31, 2019 continues through the April 2023 maturity date of the facility.

(4) 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.

(5) Amounts primarily represent commitments for electric infrastructure, surface use agreements, office buildings and equipment, communication towers, field equipment, sponsorship agreements, 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 $6.0 million that qualify as leases and were recognized on our balance sheet at December 31, 2019 in accordance with ASC Topic 842.

(6) Amounts represent operating day-rate commitments under drilling rig contracts with various terms extending to November 2020 to ensure rig availability in our key operating areas. 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 $3.2 million that qualify as leases and were recognized on our balance sheet at December 31, 2019 in accordance with ASC Topic 842.

(7) 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.

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, 2019, we were committed to deliver the following fixed quantities of natural gas production.

Year Ending December 31,	Natural Gas Bcf
2020	128
2021	53
2022	37
2023	34
2024	34
2025	18
2026	15

2020 Dividend Declaration

On January 27, 2020, the Company declared a quarterly cash dividend of $0.05 per share on the Company's outstanding common stock, which was paid on February 21, 2020 to shareholders of record as of February 7, 2020. This dividend payment, which amounted to $18.4 million, is not reflected in the December 31, 2019 *Contractual Obligations* table above.

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. We intend to purchase shares under the program opportunistically using available funds while maintaining sufficient liquidity to fund our operating needs, capital program, and dividend payments. As of December 31, 2019, we had repurchased and retired 5,646,553 shares under the program at an aggregate cost of $190.2 million. Our share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by our Board of Directors at any time.

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, 2019, 2018, and 2017, net downward revisions and removals of our proved reserves totaled approximately 149 MMBoe, 269 MMBoe, and 82 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, 2019, our proved reserves totaled 1,619 MMBoe as determined using 12-month average first-day-of-the-month prices of $55.69 per barrel for crude oil and $2.58 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, 2020 and February 1, 2020 averaged $56.31 per barrel and $1.95 per MMBtu, respectively.

Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were decreased to $45 per barrel our proved reserves at December 31, 2019 could decrease by approximately 132 MMBoe, or 8%, representing a 5% decrease in proved developed producing reserves averaged with a 10% decrease in PUD reserves. If the decrease in proved reserves under this oil price sensitivity existed throughout 2019, our DD&A expense for 2019 would have increased by an estimated 5%.

Holding all other factors constant, if natural gas prices used in our year-end reserve estimates were decreased to $1.50 per MMBtu our proved reserves at December 31, 2019 could decrease by approximately 145 MMBoe, or 9%, representing a 5% decrease in proved developed producing reserves averaged with an 11% decrease in PUD reserves. If the decrease in proved reserves under this gas price sensitivity existed throughout 2019, our DD&A expense for 2019 would have increased by an estimated 5%.

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. At December 31, 2019, we had no outstanding commodity derivative contracts. Historically, we have elected not to designate any of our price risk management activities as cash flow hedges. As a result, we marked our derivative instruments to fair value and recognized the changes in fair value in current earnings.

In determining the amounts to be recorded for outstanding derivative contracts, if any, 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 $3.7 million for 2019. Commodity price assumptions used for the year-end December 31, 2019 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2024 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, 2019, the publicly available forward commodity strip prices for the year 2024 used in our fourth quarter impairment calculations averaged $51.50 per barrel for crude oil and $2.49 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

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2019, we believe all deferred tax assets reflected in our consolidated balance sheets will ultimately be utilized. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly related to prevailing crude oil and natural gas prices). If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not that a deferred tax asset will not be utilized.

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax-paying companies. Our effective tax rate is affected by, among other things, permanent taxable differences, valuation allowances, and changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on current period earnings.

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 1. Organization and Summary of Significant Accounting Policies* for a discussion of the new lease accounting standard adopted on January 1, 2019 along with a discussion of accounting pronouncements not yet adopted.

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.

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 2019 and 2018.

Total Company	Year Ended December 31, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$3,929,994	$584,395	$4,514,389	$3,792,594	$886,128	$4,678,722
Less: Transportation expenses	(191,998)	(33,651)	(225,649)	(162,312)	(29,275)	(191,587)
Net crude oil and natural gas sales (non-GAAP)	$3,737,996	$550,744	$4,288,740	$3,630,282	$856,853	$4,487,135
Sales volumes (MBbl/MMcf/MBoe)	72,136	311,865	124,113	61,332	284,730	108,787
Net sales price (non-GAAP)	$ 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 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, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$2,826,136	$128,426	$2,954,562	$2,797,771	$263,388	$3,061,159
Less: Transportation expenses	(157,076)	(2,530)	(159,606)	(128,287)	(2,291)	(130,578)
Net crude oil and natural gas sales (non-GAAP)	$2,669,060	$125,896	$2,794,956	$2,669,484	$261,097	$2,930,581
Sales volumes (MBbl/MMcf/MBoe)	52,374	98,186	68,738	45,735	78,448	58,810
Net sales price (non-GAAP)	$ 50.96	$ 1.28	$ 40.66	$ 58.37	$ 3.33	$ 49.83

SCOOP	Year Ended December 31, 2019			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$640,097	$277,230	$917,327	$435,798	$351,021	$786,819
Less: Transportation expenses	(3,539)	(14,795)	(18,334)	(4,039)	(11,741)	(15,780)
Net crude oil and natural gas sales (non-GAAP)	$636,558	$262,435	$898,993	$431,759	$339,280	$771,039
Sales volumes (MBbl/MMcf/MBoe)	11,592	111,436	30,164	6,882	99,397	23,447
Net sales price (non-GAAP)	$ 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, 2019, our PV-10 totaled approximately $11.84 billion. The standardized measure of our discounted future net cash flows was approximately $10.46 billion at December 31, 2019, representing a $1.38 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at Standardized Measure. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas production. 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, 2019, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $753 million for each $10.00 per barrel change in crude oil prices at December 31, 2019 and $348 million for each $1.00 per Mcf change in natural gas prices at December 31, 2019.

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, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. Our future crude oil and natural gas production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

Changes in natural gas prices during the year ended December 31, 2019 had an overall favorable impact on the fair value of our derivative instruments. For the year ended December 31, 2019, we recognized cash gains on natural gas derivatives of $64.7 million which were partially offset by non-cash mark-to-market losses on natural gas derivatives of $15.6 million.

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 ($727 million in receivables at December 31, 2019) and our joint interest and other receivables ($315 million at December 31, 2019).

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

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $50 million at December 31, 2019, 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.

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 revolving 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. We had no outstanding borrowings on our credit facility at January 31, 2020. 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 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, 2019:

In thousands	2020	2021	2022	2023	2024	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$ —	$ —	$1,100,000	$1,500,000	$1,000,000	$1,700,000	$5,300,000
Weighted-average interest rate	—	—	5.0%	4.5%	3.8%	4.6%	4.5%
Note payable:							
Principal amount (1)	$2,435	$2,515	$ 427	$ —	$ —	$ —	$ 5,377
Interest rate	3.1%	3.1%	3.1%	—%	—%	—%	3.1%
Variable rate debt:							
Revolving credit facility:							
Principal amount	$ —	$ —	$ —	$ 55,000	$ —	$ —	$ 55,000
Weighted-average interest rate	—	—	—	3.3%	—	—	3.3%

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

Item 8. Financial Statements and Supplementary Data

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, 2019 and 2018, the related consolidated statements of comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 26, 2020 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 supporting 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 that (1) relates to accounts or disclosures that are material to the financial statements and (2) involves 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, assessment / measurement of potential impairment and certain required supplemental disclosures

  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, assess its oil and gas properties for potential impairment and certain required supplemental crude oil and gas information. To estimate the proved 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. In addition, the estimation of proved crude oil and natural gas reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved 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 potential impairment assessments / measurements. We identified the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion expense, assessment / measurement of potential impairment and certain required supplemental disclosures 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, assessment / measurement of potential impairment and certain required supplemental disclosures 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 proved crude oil and natural gas reserves could have a significant impact on the measurement of depletion expense or assessment / measurement of potential 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, assessment / measurement of potential impairment and certain required supplemental disclosures 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, assessing / measuring the Company's proved crude oil and gas properties for potential impairment and preparation of certain required disclosures of supplemental crude oil and natural gas information.
- 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 proved crude oil and natural gas reserve volumes, decline rates, and economically recoverable proved 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 proved 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, 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 models used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to 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; and
- Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
February 26, 2020

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

In thousands, except par values and share data	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 39,400	$ 282,749
Receivables:		
Crude oil and natural gas sales	726,876	644,107
Joint interest and other, net	314,611	368,308
Derivative assets	—	15,612
Inventories	109,536	88,544
Prepaid expenses and other	16,592	13,041
Total current assets	1,207,015	1,412,361
Net property and equipment, based on successful efforts method of accounting	14,497,726	13,869,800
Operating lease right-of-use assets	9,128	—
Other noncurrent assets	14,038	15,786
Total assets	$15,727,907	$15,297,947
Liabilities and equity		
Current liabilities:		
Accounts payable trade	$ 629,264	$ 717,723
Revenues and royalties payable	470,264	400,607
Accrued liabilities and other	230,368	266,819
Current portion of operating lease liabilities	3,695	—
Current portion of long-term debt	2,435	2,360
Total current liabilities	1,336,026	1,387,509
Long-term debt, net of current portion	5,324,079	5,765,989
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,787,125	1,574,436
Asset retirement obligations, net of current portion	151,774	136,986
Operating lease liabilities, net of current portion	5,433	—
Other noncurrent liabilities	15,119	11,166
Total other noncurrent liabilities	1,959,451	1,722,588
Commitments and contingencies (Note 11)		
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; 371,074,036 shares issued and outstanding at December 31, 2019; 376,021,575 shares issued and outstanding at December 31, 2018;	3,711	3,760
Additional paid-in capital	1,274,732	1,434,823
Accumulated other comprehensive income	—	415
Retained earnings	5,463,224	4,706,135
Total shareholders' equity attributable to Continental Resources	6,741,667	6,145,133
Noncontrolling interests	366,684	276,728
Total equity	7,108,351	6,421,861
Total liabilities and equity	$15,727,907	$15,297,947

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

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

In thousands, except per share data	Year Ended December 31, 2019	2018	2017
Revenues:			
Crude oil and natural gas sales	$4,514,389	$4,678,722	$2,982,966
Gain (loss) on natural gas derivatives, net	49,083	(23,930)	91,647
Crude oil and natural gas service operations	68,475	54,794	46,215
Total revenues	4,631,947	4,709,586	3,120,828
Operating costs and expenses:			
Production expenses	444,649	390,423	324,214
Production taxes	357,988	353,140	208,278
Transportation expenses	225,649	191,587	—
Exploration expenses	14,667	7,642	12,393
Crude oil and natural gas service operations	33,230	21,639	16,880
Depreciation, depletion, amortization and accretion	2,017,383	1,859,327	1,674,901
Property impairments	86,202	125,210	237,370
General and administrative expenses	195,302	183,569	191,706
Litigation settlement	—	—	59,600
Net gain on sale of assets and other	(535)	(16,671)	(53,915)
Total operating costs and expenses	3,374,535	3,115,866	2,671,427
Income from operations	1,257,412	1,593,720	449,401
Other income (expense):			
Interest expense	(269,379)	(293,032)	(294,495)
Loss on extinguishment of debt	(4,584)	(7,133)	(554)
Other	3,713	3,247	1,715
	(270,250)	(296,918)	(293,334)
Income before income taxes	987,162	1,296,802	156,067
(Provision) benefit for income taxes	(212,689)	(307,102)	633,380
Net income	774,473	989,700	789,447
Net income (loss) attributable to noncontrolling interests	(1,168)	1,383	—
Net income attributable to Continental Resources	$ 775,641	$ 988,317	$ 789,447
Net income per share attributable to Continental Resources:			
Basic	$ 2.09	$ 2.66	$ 2.13
Diluted	$ 2.08	$ 2.64	$ 2.11
Comprehensive income:			
Net income	$ 774,473	$ 989,700	$ 789,447
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	140	108	567
Release of cumulative translation adjustments	(555)	—	—
Total other comprehensive income (loss), net of tax	(415)	108	567
Comprehensive income	774,058	989,808	790,014
Comprehensive income (loss) attributable to noncontrolling interests	(1,168)	1,383	—
Comprehensive income attributable to Continental Resources	$ 775,226	$ 988,425	$ 790,014

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Equity

In thousands, except share data	Shareholders' equity attributable to Continental Resources: Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income (loss)	Treasury stock	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
Balance at December 31, 2016	374,492,357	$3,745	$1,375,290	$(260)	$ —	$2,923,221	$4,301,996	$ —	$4,301,996
Cumulative effect adjustment from adoption of ASU 2016-09	—	—	—	—	—	5,150	5,150	—	5,150
Net Income	—	—	—	—	—	789,447	789,447	—	789,447
Other comprehensive income, net of tax	—	—	—	567	—	—	567	—	567
Stock-based compensation	—	—	45,854	—	—	—	45,854	—	45,854
Restricted stock:									
Granted	1,585,870	16	—	—	—	—	16	—	16
Repurchased and canceled	(259,729)	(3)	(11,818)	—	—	—	(11,821)	—	(11,821)
Forfeited	(598,729)	(6)	—	—	—	—	(6)	—	(6)
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 15)	—	—	(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

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, 2019	2018	2017
Cash flows from operating activities:			
Net income	$ 774,473	$ 989,700	$ 789,447
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	2,019,704	1,859,118	1,670,838
Property impairments	86,202	125,210	237,370
Non-cash (gain) loss on derivatives, net	15,612	(13,009)	(58,031)
Stock-based compensation	52,044	47,236	45,868
Tax benefit from US tax reform legislation	—	—	(713,655)
Provision for deferred income taxes from operations	212,689	314,878	88,056
Litigation settlement	—	—	59,600
Gain on sale of assets, net	(535)	(16,671)	(55,124)
Loss on extinguishment of debt	4,584	7,133	554
Other, net	10,408	16,705	12,768
Changes in assets and liabilities:			
Accounts receivable	(33,619)	94,765	(329,811)
Inventories	(21,204)	7,735	14,517
Other current assets	(4,459)	(3,539)	1,038
Accounts payable trade	(36,359)	9,274	137,339
Revenues and royalties payable	69,195	24,010	158,982
Accrued liabilities and other	(36,467)	(4,162)	21,368
Other noncurrent assets and liabilities	3,420	(2,375)	(2,018)
Net cash provided by operating activities	3,115,688	3,456,008	2,079,106
Cash flows from investing activities:			
Exploration and development	(2,783,149)	(2,840,880)	(1,931,942)
Purchase of producing crude oil and natural gas properties	(51,558)	(31,579)	(8,446)
Purchase of other property and equipment	(25,983)	(42,171)	(12,810)
Proceeds from sale of assets	88,734	54,458	144,353
Net cash used in investing activities	(2,771,956)	(2,860,172)	(1,808,845)
Cash flows from financing activities:			
Credit facility borrowings	1,216,000	2,024,000	1,302,000
Repayment of credit facility	(1,161,000)	(2,212,000)	(2,019,000)
Proceeds from issuance of Senior Notes	—	—	990,000
Redemption of Senior Notes	(500,000)	(400,000)	—
Premium and costs on redemption of Senior Notes	(4,167)	(6,700)	—
Repayment of other debt	(2,352)	(2,286)	(502,214)
Debt issuance costs	—	(5,535)	(1,999)
Equity transaction costs	—	(4,838)	—
Contributions from noncontrolling interests	109,137	267,920	—
Distributions to noncontrolling interests	(14,164)	(604)	—
Repurchase of common stock	(190,239)	—	—
Repurchase of restricted stock for tax withholdings	(21,943)	(16,891)	(11,821)
Dividends paid on common stock	(18,380)	—	—
Net cash used in financing activities	(587,108)	(356,934)	(243,034)
Effect of exchange rate changes on cash	27	(55)	32
Net change in cash and cash equivalents	(243,349)	238,847	27,259
Cash and cash equivalents at beginning of period	282,749	43,902	16,643
Cash and cash equivalents at end of period	$ 39,400	$ 282,749	$ 43,902

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 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 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, 2019, the Company had cash deposits in excess of federally insured amounts of approximately $38.1 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 allowance for doubtful accounts, 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 doubtful accounts. Write-offs of noncollectable receivables have historically not been material. The Company's allowance for doubtful accounts totaled $2.4 million and $2.4 million as of December 31, 2019 and

2018, respectively, which is included in "Receivables—Joint interest and other, net" on the consolidated balance sheets. The Company's method for determining its allowance for doubtful accounts was changed upon its January 1, 2020 adoption of ASU 2016-13 as subsequently discussed under the caption *New accounting pronouncements not yet adopted at December 31, 2019—Credit Losses.*

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, 2019, sales to the Company's largest purchaser accounted for approximately 13% 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 2019. 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, 2019 and 2018 consisted of the following:

	December 31,	
In thousands	2019	2018
Tubular goods and equipment	$ 14,880	$14,623
Crude oil	94,656	73,921
Total	$109,536	$88,544

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, 2017 through December 31, 2019:

In thousands	2019	2018	2017
Asset retirement obligations at January 1	$141,360	$114,406	$ 96,178
Accretion expense	8,443	6,985	5,886
Revisions (1)	(1,762)	13,075	7,801
Plus: Additions for new assets	8,392	9,070	6,884
Less: Plugging costs and sold assets	(2,760)	(2,176)	(2,343)
Total asset retirement obligations at December 31	$153,673	$141,360	$114,406
Less: Current portion of asset retirement obligations at December 31 (2)	1,899	4,374	2,612
Non-current portion of asset retirement obligations at December 31	$151,774	$136,986	$111,794

(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, 2019 and 2018, net property and equipment on the consolidated balance sheets included $55.8 million and $57.7 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 note 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 $40.0 million and $51.2 million (net of accumulated amortization of $73.7 million and $62.5 million) relating to its long-term debt at December 31, 2019 and 2018, respectively. Unamortized capitalized costs associated with the Company's Notes and note payable totaled $35.3 million and $45.1 million at December 31, 2019 and 2018, 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 $4.7 million and $6.1 million at December 31, 2019 and 2018, respectively, and are reflected in "Other noncurrent assets" on the consolidated balance sheets.

For the years ended December 31, 2019, 2018 and 2017, the Company recognized amortization expense associated with capitalized debt issuance costs of $8.3 million, $9.3 million and $9.1 million, respectively, which are reflected in “Interest expense” on the consolidated statements of comprehensive income.

Derivative instruments

The Company recognizes its derivative instruments, if any, 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. Historically, the Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marked its derivative instruments to fair value and recognized the changes in fair value in the consolidated statements of comprehensive income under the caption “Gain (loss) on natural gas derivatives, net.”

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, 2019 and 2018.

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at period-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. The Company’s policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Earnings per share attributable to Continental Resources

Basic net income per share is computed by dividing net income 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 per share attributable to the Company for the years ended December 31, 2019, 2018 and 2017.

In thousands, except per share data	Year ended December 31, 2019	2018	2017
Net income attributable to Continental Resources (numerator) (1)	$775,641	$988,317	$789,447
Weighted average shares (denominator):			
Weighted average shares—basic	370,699	371,854	371,066
Non-vested restricted stock	1,839	2,984	2,702
Weighted average shares—diluted	372,538	374,838	373,768
Net income per share attributable to Continental Resources: (1)			
Basic	$ 2.09	$ 2.66	$ 2.13
Diluted	$ 2.08	$ 2.64	$ 2.11

(1) The Company sold its Canadian subsidiary and associated properties in 2019 which resulted in a decrease in income tax expense and corresponding increase in net income via the recognition of an income tax benefit of $16.9 million ($0.05 per basic and diluted share). See *Note 9. Income Taxes* for further discussion. Additionally, 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 decrease in income tax expense and corresponding increase in net income of $713.7 million ($1.92 per basic share and $1.91 per diluted share) for 2017. See *Note 9. Income Taxes* for further discussion. Results for 2017 also include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in *Note 11. Commitments and Contingencies*, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

Foreign currency translation

In 2014, the Company initiated operations in Canada through a wholly-owned Canadian subsidiary. The Company's operations in Canada are immaterial and were sold in the fourth quarter of 2019. See *Note 16. Property 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.

Adoption of new accounting pronouncement in 2019

On January 1, 2019 the Company adopted Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)*. See *Note 10. Leases* for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New accounting pronouncements not yet adopted at December 31, 2019

Credit losses—In June 2016, the Financial Accounting Standards Board ("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 interim and annual 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, which had an immaterial impact. Historically, the Company's credit losses on crude oil and natural gas sales receivables and joint interest receivables have been immaterial.

Income taxes—In December 2019, the FASB 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 is 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 is in the process of evaluating the new standard and is unable to estimate its financial impact, if any, at this time.

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.

	Year ended December 31,		
In thousands	2019	2018	2017
Supplemental cash flow information:			
Cash paid for interest	$267,421	$270,927	$281,058
Cash paid for income taxes	229	—	2
Cash received for income tax refunds	107	7,893	257
Non-cash investing activities:			
Asset retirement obligation additions and revisions, net	6,630	22,145	14,685

As of December 31, 2019 and 2018, the Company had $262.7 million and $317.5 million, respectively, of accrued capital expenditures included in "Net property and equipment" and "Accounts payable trade" in the consolidated balance sheets.

As of December 31, 2019 and 2018, the Company had $5.6 million and $9.3 million, respectively, of accrued contributions from noncontrolling interests included in "Receivables–Joint interest and other, net" and "Equity–Noncontrolling interests" in the condensed consolidated balance sheets.

As of December 31, 2019 and 2018, the Company had $1.5 million and $1.3 million, respectively, of accrued distributions to noncontrolling interests included in "Revenues and royalties payable" and "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. See *Note 10. Leases* for additional information.

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2019 and 2018.

In thousands	December 31, 2019	December 31, 2018
Proved crude oil and natural gas properties	$ 26,611,429	$ 24,060,625
Unproved crude oil and natural gas properties	319,592	291,564
Service properties, equipment and other	336,439	324,758
Total property and equipment	27,267,460	24,676,947
Accumulated depreciation, depletion and amortization	(12,769,734)	(10,807,147)
Net property and equipment	$ 14,497,726	$ 13,869,800

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2019 and 2018:

In thousands	December 31, 2019	December 31, 2018
Prepaid advances from joint interest owners	$ 50,021	$ 53,674
Accrued compensation	61,483	69,338
Accrued production taxes, ad valorem taxes and other non-income taxes	59,057	52,105
Accrued interest	56,953	64,483
Accrued litigation settlement (see Note 11)	—	19,753
Current portion of asset retirement obligations	1,899	4,374
Other	955	3,092
Accrued liabilities and other	$230,368	$266,819

Note 5. Derivative Instruments

Natural gas derivatives

From time to time the Company has entered into natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of natural gas production. At December 31, 2019, the Company had no outstanding commodity derivative contracts.

The Company recognizes its derivative instruments, if any, on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value of derivatives 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*.

Natural gas derivative gains and losses

Cash receipts and payments in the following table reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. The Company's natural gas derivatives were settled based upon reported NYMEX Henry Hub settlement prices. Non-cash gains and losses below represent the change in fair value of derivative instruments which continued to be held at period end, if any, and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

In thousands	Year ended December 31, 2019	2018	2017
Cash received (paid) on derivatives:			
Natural gas fixed price swaps	$ 58,836	$(36,939)	$ 40,095
Natural gas collars	5,859	—	(10,539)
Cash received (paid) on derivatives, net	64,695	(36,939)	29,556
Non-cash gain (loss) on derivatives:			
Natural gas fixed price swaps	(10,130)	7,527	18,960
Natural gas collars	(5,482)	5,482	43,131
Non-cash gain (loss) on derivatives, net	(15,612)	13,009	62,091
Gain (loss) on natural gas derivatives, net	$ 49,083	$(23,930)	$ 91,647

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", "Noncurrent derivative assets", "Derivative liabilities", and "Noncurrent derivative liabilities", 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 natural gas derivative assets and liabilities, as applicable, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value.

In thousands	December 31, 2019	2018
Commodity derivative assets:		
Gross amounts of recognized assets	$—	$16,789
Gross amounts offset on balance sheet	—	(1,177)
Net amounts of assets on balance sheet	—	15,612
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	—	(1,177)
Gross amounts offset on balance sheet	—	1,177
Net amounts of liabilities on balance sheet	$—	$ —

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

	December 31,	
In thousands	2019	2018
Derivative assets	$—	$15,612
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	—	15,612
Derivative liabilities	—	—
Noncurrent derivative liabilities	—	—
Net amounts of liabilities on balance sheet	—	—
Total derivative assets, net	$—	$15,612

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. The Company's policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Assets and liabilities measured at fair value on a recurring basis

The Company's derivative instruments, if any, 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, 2018. The Company had no outstanding commodity derivative instruments at December 31, 2019.

	Fair value measurements at December 31, 2018 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$10,130	$ —	$10,130
Collars	—	5,482	—	5,482
Total	$ —	$15,612	$ —	$15,612

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. The discounted cash flow method estimates future cash flows based on the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips adjusted for differentials, operating costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company at December 31, 2019 to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

Unobservable Input	Assumption
Future production	Future production estimates for each property
Forward commodity prices	Forward NYMEX strip prices through 2024 (adjusted for differentials), escalating 3% per year thereafter
Operating costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of properties	Up to 50 years
Discount rate	10%

Unobservable inputs to the fair value assessment are reviewed quarterly and are 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, 2019, 2018, and 2017, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Such impairments totaled $3.7 million and $18.0 million for 2019 and 2018, respectively, which reflect write-offs of various non-core properties in the North and South regions. Impairments of proved properties totaled $82.3 million for 2017, which reflect fair value adjustments in the Arkoma Woodford field ($81.2 million) and various non-core properties in the North and South regions ($1.1 million). The impaired properties in 2017 were written down to their estimated fair value at the time of impairment of $72 million.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2019, 2018, and 2017, 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.

	Year ended December 31,		
In thousands	2019	2018	2017
Proved property impairments	$ 3,745	$ 18,037	$ 82,340
Unproved property impairments	82,457	107,173	155,030
Total	$86,202	$125,210	$237,370

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.

	December 31, 2019		December 31, 2018	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Revolving credit facility	$ 55,000	$ 55,000	$ —	$ —
Note payable	5,351	5,400	7,700	7,700
5% Senior Notes due 2022	1,099,165	1,108,700	1,598,404	1,590,900
4.5% Senior Notes due 2023	1,491,339	1,571,400	1,488,960	1,476,300
3.8% Senior Notes due 2024	994,310	1,034,200	993,151	947,200
4.375% Senior Notes due 2028	989,661	1,063,700	988,617	942,800
4.9% Senior Notes due 2044	691,688	742,000	691,517	618,800
Total debt	$5,326,514	$5,580,400	$5,768,349	$5,583,700

The fair value of revolving 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 the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of the note payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of the note 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"), 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 $33.9 million and $39.4 million at December 31, 2019 and 2018, respectively, consists of the following.

	December 31,	
In thousands	2019	2018
Revolving credit facility	$ 55,000	$ —
Note payable	5,351	7,700
5% Senior Notes due 2022	1,099,165	1,598,404
4.5% Senior Notes due 2023	1,491,339	1,488,960
3.8% Senior Notes due 2024	994,310	993,151
4.375% Senior Notes due 2028	989,661	988,617
4.9% Senior Notes due 2044	691,688	691,517
Total debt	5,326,514	5,768,349
Less: Current portion of long-term debt	2,435	2,360
Long-term debt, net of current portion	$5,324,079	$5,765,989

Revolving credit facility

The Company has an unsecured credit facility, maturing in April 2023, with aggregate lender commitments totaling $1.5 billion. The Company had $55.0 million of outstanding borrowings on its credit facility at December 31, 2019. 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, 2019 was 3.3%.

The Company had approximately $1.45 billion of borrowing availability on its credit facility at December 31, 2019 and incurs commitment fees based on currently assigned credit ratings of 0.20% per annum on the daily average amount of unused borrowing availability.

The credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the credit facility covenants at December 31, 2019.

Senior notes

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, 2019.

	2022 Notes (1)	2023 Notes	2024 Notes	2028 Notes	2044 Notes
Face value (in thousands)	$1,100,000	$1,500,000	$1,000,000	$1,000,000	$700,000
Maturity date	Sep 15, 2022	April 15, 2023	June 1, 2024	January 15, 2028	June 1, 2044
Interest payment dates	March 15, Sep 15	April 15, Oct 15	June 1, Dec 1	Jan 15, July 15	June 1, Dec 1
Make-whole redemption period (2)	—	Jan 15, 2023	Mar 1, 2024	Oct 15, 2027	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 related to 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. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at December 31, 2019.

Three of the Company's wholly-owned subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, the value of whose assets, equity, and results of operations are minor, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company's other subsidiaries, the value of whose assets, equity, and results of operations attributable to the Company are minor, do not guarantee the senior notes.

Partial redemptions of senior notes

2019

In September 2019, the Company redeemed $500 million of its previously outstanding $1.6 billion of 5% Senior Notes due 2022. 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. The loss is reflected under the caption "Loss on extinguishment of debt" in the consolidated statements of comprehensive income.

2018

In August 2018, the Company redeemed $400 million of its original outstanding $2.0 billion of 5% Senior Notes due 2022. 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.

Note payable

In February 2012, 20 Broadway Associates LLC, a wholly-owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.4 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, 2019.

Note 8. Revenues

2018 adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received, allocate the consideration to each separate performance obligation, and recognize revenue as obligations are satisfied. Subsequently, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net),* pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis.

The Company adopted the new guidance on January 1, 2018 using a modified retrospective transition approach to all applicable contracts at the date of initial application, whereby the standard was applied for periods commencing on January 1, 2018 and results prior to 2018 were not adjusted to conform to current presentation. Adoption of the new guidance had no cumulative effect impact on the Company's retained earnings at January 1, 2018.

The new guidance does not have a material impact on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows, but does impact the Company's presentation of revenues and expenses under the gross-versus-net presentation guidance in ASU 2016-08. In years prior to 2018, the Company generally presented its revenues net of costs incurred to transport its production to market. Under the new guidance, revenues and transportation expenses associated with production originating from the Company's operated properties are now reported on a gross basis as further discussed below. The changes from net to gross presentation beginning on January 1, 2018 result in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company's results of operations, net income, or cash flows.

The following table reflects the change in presentation of revenues and applicable expenses on the Company's 2018 results under the new and previous guidance.

In thousands	Year ended December 31, 2018 New Standard	Prior Presentation	Change
Revenues:			
Crude oil and natural gas sales	$4,678,722	$4,487,135	$191,587
Loss on natural gas derivatives, net	(23,930)	(23,930)	—
Crude oil and natural gas service operations	54,794	54,794	—
Total revenues	$4,709,586	$4,517,999	$191,587
Operating costs and expenses:			
Transportation expenses	$ 191,587	$ —	$191,587
Net income	$ 989,700	$ 989,700	$ —

Revenue from contracts with customers

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 $192.0 million and $162.3 million for the years ended December 31, 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, 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 $33.7 million and $29.3 million for the years ended December 31, 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.

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,					
	2019			2018		
In thousands	North Region	South Region	Total	North Region	South Region	Total
Crude oil revenues:						
Operated properties	$2,365,574	$ 786,652	$3,152,226	$2,330,711	$ 603,070	$2,933,781
Non-operated properties	727,068	50,700	777,768	790,435	68,378	858,813
Total crude oil revenues	3,092,642	837,352	3,929,994	3,121,146	671,448	3,792,594
Natural gas revenues:						
Operated properties	109,668	411,464	521,132	214,741	547,247	761,988
Non-operated properties	25,188	38,075	63,263	60,738	63,402	124,140
Total natural gas revenues	134,856	449,539	584,395	275,479	610,649	886,128
Crude oil and natural gas sales	$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	$3,227,498	$1,286,891	$4,514,389	$3,396,625	$1,282,097	$4,678,722
Goods transferred over time	—	—	—	—	—	—
	$3,227,498	$1,286,891	$4,514,389	$3,396,625	$1,282,097	$4,678,722

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, 2019 are short-term in nature with contract terms of one year or less. 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, net", 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, 2019 and 2018 related to performance obligations satisfied in prior reporting periods were not material.

Note 9. Income Taxes

In December 2017, the Tax Cuts and Jobs Act was signed into law. The legislation contained several key changes to U.S. corporate tax laws, including a reduction of the corporate income tax rate from 35% to 21%, effective January 1, 2018. The legislation also included a variety of other changes such as the repeal of the alternative minimum tax; the introduction of new limitations on the tax deductibility of net operating losses, interest expenses, and executive compensation expenses; the acceleration of expensing of certain qualified property; and the introduction of new laws governing taxation of foreign earnings of U.S. entities, among others.

The Company recognizes the effect of tax law changes in the reporting period that includes the enactment date in accordance with U.S. GAAP. As a result, the Company remeasured its deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the corporate tax rate from 35% to 21% enacted into law in December 2017. This remeasurement resulted in a $713.7 million decrease in net deferred income tax liabilities and corresponding decrease in income tax expense as of and for the year ended December 31, 2017, which is reflected in the tables below. The Company's accounting for the effects of the tax rate change on its deferred tax balances as well as other relevant aspects of the Tax Cuts and Jobs Act was completed as of December 31, 2017 and no provisional amounts were recorded at that date that were later adjusted in 2018 or 2019.

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

	Year ended December 31,		
In thousands	2019	2018	2017
Current income tax provision (benefit):			
United States federal (1)	$ —	$ (7,781)	$ (7,781)
Various states	—	5	—
Total current income tax (benefit)	—	(7,776)	(7,781)
Deferred income tax provision (benefit):			
United States federal—taxation on operations	191,328	282,947	81,054
United States federal—effect of US tax reform	—	—	(713,655)
Various states	21,361	31,931	7,002
Total deferred income tax provision (benefit)	212,689	314,878	(625,599)
Provision (benefit) for income taxes	$212,689	$307,102	$(633,380)
Effective tax rate	21.5%	23.7%	(405.8%)

(1) The current federal income tax benefits for 2017 and 2018 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 and other tax items as reflected in the table below.

	Year ended December 31,		
In thousands, except rates	2019	2018	2017
Income before income taxes	$987,162	$1,296,802	$ 156,067
U.S. federal statutory tax rate	21.0%	21.0%	35.0%
Expected income tax provision based on US statutory tax rate	207,304	272,328	54,623
Items impacting the effective tax rate:			
State income taxes, net of federal benefit	31,967	45,920	4,682
Effect of US tax reform legislation	—	—	(713,655)
Tax benefit (deficiency) from stock-based compensation	(7,971)	(259)	3,932
Non-deductible compensation	8,282	2,932	13,813
Sale of Canadian subsidiary and assets	(16,860)	—	—
Other, net	(10,033)	(13,819)	3,225
Provision (benefit) for income taxes	$212,689	$ 307,102	$(633,380)
Effective tax rate	21.5%	23.7%	(405.8%)

The components of the Company's deferred tax assets and deferred tax liabilities as of December 31, 2019 and 2018 are reflected in the table below.

In thousands	December 31, 2019	December 31, 2018
Deferred tax assets		
United States net operating loss carryforwards	$ 550,086	$ 549,166
Canadian net operating loss carryforwards	—	19,633
Equity compensation	13,157	13,122
Other	18,466	13,622
Total deferred tax assets	581,709	595,543
Canadian valuation allowance	—	(19,633)
Total deferred tax assets, net of valuation allowance	581,709	575,910
Deferred tax liabilities		
Property and equipment	(2,367,137)	(2,144,767)
Other	(1,697)	(5,579)
Total deferred tax liabilities	(2,368,834)	(2,150,346)
Deferred income tax liabilities, net	$(1,787,125)	$(1,574,436)

As of December 31, 2019, the Company had federal and state net operating loss carryforwards of $1.9 billion and $3.3 billion, respectively. The federal net operating loss carryforward will begin expiring in 2035. The Company's net operating loss carryforward in Oklahoma totaled $2.3 billion at December 31, 2019, which will begin to expire in 2028. The Company's net operating loss carryforward in North Dakota totaled $872 million at December 31, 2019, which will begin to expire in 2035. Any available statutory depletion carryforwards will be recognized when realized. The Company files income tax returns in the U.S. federal, U.S. state and Canadian 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 2016.

In the fourth quarter of 2019, the Company sold its Canadian subsidiary and associated properties. The Company recognized immaterial valuation allowances for the years ended December 31, 2018 and 2017 against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary for which the Company did not expect to realize a benefit. Prior to the sale the cumulative valuation allowance recorded was $19.6 million. 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.

Note 10. Leases

In February 2016 the FASB issued ASU 2016-02, *Leases (Topic 842)*, which requires companies to recognize a right-of-use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than twelve months. The standard became effective for interim and annual reporting periods beginning after December 15, 2018. The Company adopted the new standard on January 1, 2019 on a prospective basis using the simplified transition method prescribed by ASU 2018-11, *Leases (Topic 842): Targeted Improvements.* Offsetting right-of-use assets and lease liabilities recognized by the Company on the January 1, 2019 adoption date totaled approximately $19 million, representing minimum payment obligations associated with drilling rig commitments, surface use agreements, equipment, and other leases with contractual durations in excess of one year. No cumulative-effect adjustment to retained earnings was recognized upon adoption of the new standard.

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

Presented below are disclosures required by the new lease standard. The amounts disclosed herein primarily represent costs associated with properties operated by the Company that are presented on a gross basis and do not reflect 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's lease liabilities recognized on the balance sheet as a lessee totaled $9.1 million as of December 31, 2019 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.

In thousands	Amount
Drilling rig commitments	$3,154
Surface use agreements	4,487
Field equipment	1,164
Other	323
Total	$9,128

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, 2019 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
2020	$ 3,999
2021	750
2022	734
2023	667
2024	411
Thereafter	5,755
Total operating lease liabilities, at undiscounted value	$12,316
Less: Imputed interest	(3,188)
Total operating lease liabilities, at discounted present value	$ 9,128
Less: Current portion of operating lease liabilities	(3,695)
Operating lease liabilities, net of current portion	$ 5,433

Additional information for the Company's operating leases is presented below. Lease costs are reflected at gross amounts and 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.

In thousands, except weighted average data	Year ended December 31, 2019
Lease costs:	
Operating lease costs	$ 11,130
Variable lease costs	11,930
Short-term lease costs	176,586
Total lease costs	$199,646
Other information:	
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 1,208
Operating cash flows from operating leases included in lease liabilities	804
Weighted average remaining lease term as of December 31, 2019 (in years)	11.5
Weighted average discount rate as of December 31, 2019	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 years ended December 31, 2018 and 2017 were $2.0 million and $1.9 million, respectively, 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 11. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2019.

Drilling commitments—As of December 31, 2019, the Company has drilling rig contracts with various terms extending to November 2020 to ensure rig availability in its key operating areas. Future operating day-rate commitments as of December 31, 2019 total approximately $64 million, all of which will be incurred in 2020. 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 $3.2 million that are required to be recognized on the Company's balance sheet at December 31, 2019 in accordance with ASC Topic 842 as discussed in *Note 10. Leases*.

Other lease commitments—The Company has various other lease commitments primarily associated with surface use agreements and field equipment. See *Note 10. 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, 2019 under the arrangements amount to approximately $2.20 billion, of which $291 million is expected to be incurred in 2020, $332 million in 2021, $330 million in 2022, $331 million in 2023, $298 million in 2024, and $615 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.

Litigation—In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition, as amended, alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and sought recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. The Company denied all allegations and denied that the case was properly brought as a class action. Due to the uncertainty of and burdens of litigation, in February 2018 the Company reached a settlement in connection with this matter, which was subsequently approved by the District Court of Garfield County, Oklahoma in June 2018. Under the settlement, the Company initially expected to make payments and incur costs associated with the settlement of approximately $59.6 million and accrued a loss for such amount at December 31, 2017 which, after making partial settlement payments in 2018, was reduced to $19.8 million at December 31, 2018. The Company has now satisfied substantially all of its monetary obligations under the settlement.

The Company is involved in various other 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, 2019 and 2018, the Company had recorded a liability in the consolidated balance sheets under the caption "Other noncurrent liabilities" of $8.7 million and $4.7 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 12. Related Party Transactions

Certain officers of the Company own or control entities that own working and royalty interests in wells operated by the Company. The Company paid revenues to these affiliates, including royalties, of $0.4 million, $0.5 million, and $0.5 million and received payments from these affiliates of $0.3 million, $0.2 million, and $0.3 million during the years ended December 31, 2019, 2018, and 2017, respectively, relating to the operations of the respective properties. At December 31, 2019 and 2018, approximately $127,000 and $67,000, respectively, was due from these affiliates relating to these transactions, which is included in "Receivables—Joint interest and other, net" on the consolidated balance sheets. At December 31, 2019 and 2018, approximately $35,000 and $41,000, 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 2019, 2018, and 2017, the Company charged affiliates approximately $17,600, $12,900, and $19,400, respectively, for use of its corporate aircraft crews, fuel, and reimbursement of expenses and received approximately $18,900, $14,400, and $18,600 from affiliates in 2019, 2018, and 2017, respectively, in connection with such items. The Company was charged approximately $303,000, $598,000, and $460,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2019, 2018, and 2017 and paid $426,000, $529,000, and $368,000 to the affiliates in 2019, 2018, and 2017, respectively. At December 31, 2019 and 2018, approximately $1,400 and $2,700, respectively, was due from an affiliate relating to these transactions, which is included in "Receivables—Joint interest and other, net" on the consolidated balance sheets. At December 31, 2019 and 2018, approximately $38,000 and $161,000, respectively, was due to an affiliate relating to these transactions, which is included in "Accounts payable trade" on the consolidated balance sheets.

Note 13. 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, was $52.0 million, $47.2 million, and $45.9 million for the years ended December 31, 2019, 2018 and 2017, respectively.

On March 26, 2019, the Company amended and restated its 2013 Plan and reserved 12,983,543 shares of common stock that may be issued pursuant to the amended plan. The 2013 Plan allows previously issued shares to be reissued if such shares are subsequently forfeited after issuance. As of December 31, 2019, the Company had 13,036,804 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 under the Company's dividend payment program discussed in *Note 14. Shareholders' Equity Attributable to Continental Resources*, 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, 2016 to December 31, 2019 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2016	3,913,634	$37.12
Granted	1,585,870	44.58
Vested	(874,665)	57.36
Forfeited	(598,729)	37.34
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

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 2019, 2018, and 2017 was approximately $79.7 million, $61.0 million, and $39.8 million, respectively. As of December 31, 2019, 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 1.2 years.

Note 14. Shareholders' Equity Attributable to Continental Resources

Share repurchase program

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 5,646,553 shares under the program at an aggregate cost of $190.2 million.

Under the program, the Company may repurchase shares from time to time at management's discretion in accordance with applicable securities laws, including through open market transactions, privately negotiated transactions or any combination thereof. In addition, shares may also be repurchased pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Exchange Act of 1934. The timing and amount of repurchases are subject to market conditions. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.

Dividend declaration

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.

Subsequent to December 31, 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.

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, net of tax" in the consolidated statements of comprehensive income. The following table summarizes the change in accumulated other comprehensive income (loss) for the years ended December 31, 2019, 2018, and 2017:

	Year ended December 31,		
In thousands	2019	2018	2017
Beginning accumulated other comprehensive income (loss), net of tax	$ 415	$307	$(260)
Foreign currency translation adjustments	140	108	567
Release of cumulative translation adjustments (1)	(555)	—	—
Income taxes (2)	—	—	—
Other comprehensive income (loss), net of tax	(415)	108	567
Ending accumulated other comprehensive income, net of tax	$ —	$415	$ 307

(1) In conjunction with the Company's sale of its Canadian operations in 2019, the cumulative translation adjustments were released. See *Note 16. Property 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 15. 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 in the SCOOP and STACK plays 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. In 2018 and

2019 Franco-Nevada made additional capital contributions to, and received revenue distributions from, TMRC II and the portion of Continental's consolidated net assets attributable to Franco-Nevada totaled $356.9 million and $266.8 million at December 31, 2019 and 2018, 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 $9.8 million and $9.9 million at December 31, 2019 and 2018, respectively.

Note 16. Property Dispositions

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.

2017

In October 2017, the Company sold non-core leasehold in the STACK play for cash proceeds totaling $63.5 million and recognized a $56.9 million pre-tax gain in 2017 associated with the transaction. The disposed properties represented an immaterial portion of the Company's production and proved reserves.

In September 2017, the Company sold properties in the Arkoma Woodford area for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold and producing properties with production totaling approximately 1,700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax loss of $3.5 million in 2017. The disposed properties represented an immaterial portion of the Company's proved reserves.

In September 2017, the Company sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.2 million pre-tax gain in 2017 associated with the transaction.

Note 17. 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, 2019, 2018 and 2017.

	Year ended December 31,		
In thousands	2019	2018	2017
Crude oil and natural gas sales (1)	$ 4,514,389	$ 4,678,722	$ 2,982,966
Production expenses	(444,649)	(390,423)	(324,214)
Production taxes	(357,988)	(353,140)	(208,278)
Transportation expenses (1)	(225,649)	(191,587)	—
Exploration expenses	(14,667)	(7,642)	(12,393)
Depreciation, depletion, amortization and accretion	(1,997,854)	(1,839,241)	(1,652,180)
Property impairments	(86,202)	(125,210)	(237,370)
Income tax (provision) benefit (2)	(323,025)	(434,047)	504,475
Results from crude oil and natural gas producing activities	$ 1,064,355	$ 1,337,432	$ 1,053,006

(1) For 2019 and 2018, crude oil and natural gas sales are presented gross of certain transportation expenses as a result of the Company's January 1, 2018 adoption of new revenue recognition and presentation rules as discussed in *Note 8. Revenues.* The rules were prospectively applied beginning January 1, 2018 and prior period results were not adjusted to conform to the current presentation.

(2) Income taxes reflect the application of a combined federal and state tax rate of 24.5% for 2019 and 2018 and a 38% combined tax rate for 2017 on pre-tax income generated by 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 the year. Further, the 2017 period includes the $713.7 million income tax benefit recognized upon the Company's remeasurement of its deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017.

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, 2019, 2018 and 2017 are presented below:

In thousands	Year ended December 31, 2019	2018	2017
Property acquisition costs:			
Proved	$ 51,558	$ 31,579	$ 8,446
Unproved	312,680	329,586	220,875
Total property acquisition costs	364,238	361,165	229,321
Exploration Costs	50,143	81,015	123,461
Development Costs	2,388,582	2,478,327	1,695,954
Total	$2,802,963	$2,920,507	$2,048,736

Costs incurred above include asset retirement costs and revisions thereto of $6.7 million, $25.8 million and $15.3 million for the years ended December 31, 2019, 2018 and 2017, 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, 2019 and 2018 are as follows:

In thousands	December 31, 2019	2018
Proved crude oil and natural gas properties	$ 26,611,429	$ 24,060,625
Unproved crude oil and natural gas properties	319,592	291,564
Total	26,931,021	24,352,189
Less accumulated depreciation, depletion and amortization	(12,635,247)	(10,680,870)
Net capitalized costs	$ 14,295,774	$ 13,671,319

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 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:

	Year ended December 31,		
In thousands	2019	2018	2017
Balance at January 1	$ 3,959	$ 31,356	$ 34,852
Additions to capitalized exploratory well costs pending determination of proved reserves	28,280	45,088	79,451
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(23,200)	(72,347)	(81,035)
Capitalized exploratory well costs charged to expense	(2,782)	(138)	(1,912)
Balance at December 31	$ 6,257	$ 3,959	$ 31,356
Number of gross wells	11	16	37

As of December 31, 2019, the Company had no significant exploratory well costs that were suspended one year beyond the completion of drilling.

Note 18. 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 91%, 98%, and 96% of the Company's total proved reserves as of December 31, 2019, 2018, and 2017, 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, 2019, 2018 and 2017 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, 2019, 2018 and 2017 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, 2016	643,228	3,789,818	1,274,864
Revisions of previous estimates	(77,779)	(25,390)	(82,012)
Extensions, discoveries and other additions	129,895	661,867	240,206
Production	(50,536)	(228,159)	(88,562)
Sales of minerals in place	(4,365)	(64,989)	(15,197)
Purchases of minerals in place	506	7,134	1,696
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. 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.

Revisions for 2017 are comprised of (i) the removal of 89 MMBoe of PUD reserves not scheduled to be drilled within five years of initial booking due to changes in development plans, (ii) upward price revisions of 42 MMBoe due to an increase in average crude oil and natural gas prices in 2017 compared to 2016, (iii) downward revisions of 30 MMBoe due to changes in anticipated production performance, and (iv) net downward revisions of 5 MMBoe due to changes in ownership interests, operating costs, 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 2019, proved reserve additions in the Bakken totaled 113 MMBo and 283 Bcf (totaling 160 MMBoe) and reserve additions in SCOOP totaled 47 MMBo and 830 Bcf (totaling 186 MMBoe). Additionally, 2019 proved reserve additions in STACK totaled 2 MMBo and 101 Bcf (totaling 19 MMBoe).

Sales of minerals in place. See *Note 16. Property Dispositions* for a discussion of notable dispositions in 2019, 2018 and 2017, none of which involved significant volumes of proved reserves.

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, 2019, 2018 and 2017:

	December 31,		
	2019	2018	2017
Proved Developed Reserves			
Crude oil (MBbl)	336,405	347,825	318,707
Natural Gas (MMcf)	2,226,117	1,964,289	1,699,161
Total (MBoe)	707,424	675,206	601,901
Proved Undeveloped Reserves			
Crude oil (MBbl)	423,782	409,271	322,242
Natural Gas (MMcf)	2,928,354	2,627,325	2,441,120
Total (MBoe)	911,841	847,159	729,094
Total Proved Reserves			
Crude oil (MBbl)	760,187	757,096	640,949
Natural Gas (MMcf)	5,154,471	4,591,614	4,140,281
Total (MBoe)	1,619,265	1,522,365	1,330,995

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, 2019, 2018 and 2017. 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	2019	2018	2017
Future cash inflows	$ 49,893,470	$ 61,510,432	$ 42,574,897
Future production costs	(15,309,672)	(16,139,001)	(11,159,362)
Future development and abandonment costs	(10,033,887)	(9,706,114)	(6,487,097)
Future income taxes (1)	(3,351,657)	(6,012,439)	(3,488,755)
Future net cash flows	21,198,254	29,652,878	21,439,683
10% annual discount for estimated timing of cash flows	(10,736,613)	(13,968,061)	(10,969,506)
Standardized measure of discounted future net cash flows	$ 10,461,641	$ 15,684,817	$ 10,470,177

(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, 2019, 2018, and 2017.

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $51.95, $61.20, and $47.03 per barrel at December 31, 2019, 2018 and 2017, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $2.02, $3.22, and $3.00 per Mcf at December 31, 2019, 2018 and 2017, 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	2019	2018	2017
Standardized measure of discounted future net cash flows at January 1	$15,684,817	$10,470,177	$ 5,510,223
Extensions, discoveries and improved recoveries, less related costs	1,649,322	5,162,635	1,462,629
Revisions of previous quantity estimates	(1,564,503)	(3,522,428)	(1,004,355)
Changes in estimated future development and abandonment costs	1,401,513	1,063,089	743,657
Purchases (sales) of minerals in place, net	49,330	(9,192)	(41,077)
Net change in prices and production costs	(6,591,347)	4,224,473	3,808,116
Accretion of discount	1,865,034	1,183,347	665,507
Sales of crude oil and natural gas produced, net of production costs	(3,486,103)	(3,743,572)	(2,450,474)
Development costs incurred during the period	1,557,121	1,134,153	1,045,875
Change in timing of estimated future production and other	(1,690,779)	1,324,365	948,519
Change in income taxes	1,587,236	(1,602,230)	(218,443)
Net change	(5,223,176)	5,214,640	4,959,954
Standardized measure of discounted future net cash flows at December 31	$10,461,641	$15,684,817	$10,470,177

Note 19. Quarterly Financial Data (Unaudited)

The Company's unaudited quarterly financial data for 2019 and 2018 is summarized below.

In thousands, except per share data	Quarter ended March 31	June 30	September 30	December 31
2019				
Total revenues (1)	$1,124,234	$1,208,382	$1,104,197	$1,195,134
Gain (loss) on natural gas derivatives, net (1)	$ (1,124)	$ 53,448	$ 1,195	$ (4,436)
Property impairments (2)	$ 25,316	$ 21,339	$ 20,199	$ 19,348
Gain (loss) on sale of assets, net (3)	$ 252	$ (364)	$ (535)	$ 1,182
Income from operations	$ 304,965	$ 379,847	$ 278,724	$ 293,876
Loss on extinguishment of debt (4)	$ —	$ —	$ (4,584)	$ —
Net income (5)	$ 186,493	$ 236,450	$ 157,422	$ 194,108
Net income attributable to Continental Resources (5)	$ 186,976	$ 236,557	$ 158,162	$ 193,946
Net income per share attributable to Continental Resources: (5)				
Basic	$ 0.50	$ 0.63	$ 0.43	$ 0.53
Diluted	$ 0.50	$ 0.63	$ 0.43	$ 0.53
2018				
Total revenues (1)	$1,141,028	$1,137,113	$1,282,151	$1,149,294
Gain (loss) on natural gas derivatives, net (1)	$ 10,174	$ (12,685)	$ (2,025)	$ (19,394)
Property impairments (2)	$ 33,784	$ 29,162	$ 23,770	$ 38,494
Gain on sale of assets, net (3)	$ 41	$ 6,710	$ 1,510	$ 8,410
Income from operations	$ 380,722	$ 391,276	$ 491,308	$ 330,414
Loss on extinguishment of debt (4)	$ —	$ —	$ (7,133)	$ —
Net income	$ 233,946	$ 242,464	$ 314,169	$ 199,121
Net income attributable to Continental Resources	$ 233,946	$ 242,464	$ 314,169	$ 197,738
Net income per share attributable to Continental Resources:				
Basic	$ 0.63	$ 0.65	$ 0.84	$ 0.53
Diluted	$ 0.63	$ 0.65	$ 0.84	$ 0.53

(1) Gains and losses on natural gas derivative instruments are reflected in "Total revenues" on both the consolidated statements of comprehensive income 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) Gains and losses on asset sales have been shown separately to illustrate the impact on quarterly results attributable to asset dispositions, which differ in significance from period to period and affect comparability. See *Note 16. Property Dispositions* for a discussion of notable dispositions.

(4) See *Note 7. Long-Term Debt* for discussion of the losses recognized by the Company upon the partial redemptions of its 2022 Notes in the 2019 third quarter and 2018 third quarter.

(5) 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 9. Income Taxes*.

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, 2019 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 2019 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 2019 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, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 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 26, 2020

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, 2019, 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, 2019, 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, 2019, and our report dated February 26, 2020 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 26, 2020

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 2020 (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 amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarter ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 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.
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 May 16, 2018 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended June 30, 2018 (Commission File No. 001-32886) filed August 7, 2018 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.
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 26, 2020**

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 26, 2020
/s/ WILLIAM B. BERRY **William B. Berry**	Chief Executive Officer and Director (principal executive officer)	February 26, 2020
/s/ JOHN D. HART **John D. Hart**	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 26, 2020
/s/ SHELLY LAMBERTZ **Shelly Lambertz**	Director	February 26, 2020
/s/ LON MCCAIN **Lon McCain**	Director	February 26, 2020
/s/ JOHN T. MCNABB II **John T. McNabb II**	Director	February 26, 2020
/s/ MARK E. MONROE **Mark E. Monroe**	Director	February 26, 2020
/s/ TIMOTHY G. TAYLOR **Timothy G. Taylor**	Director	February 26, 2020

BOARD OF DIRECTORS

Harold G. Hamm
William B. Berry
Mark E. Monroe
Shelly Lambertz
Lon McCain
John T. McNabb II
Timothy G. 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, CFO & Treasurer
Pat Bent
Sr. Vice President, Operations
Shelly Lambertz
Chief Culture Officer & Sr. Vice President of Human Resources
Ramiro Rangel
Sr. Vice President, Marketing
Steven K. Owen
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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