CENTENNIAL
RESOURCE DEVELOPMENT, INC.

2020 ANNUAL REPORT

LETTER TO SHAREHOLDERS

This is my first annual letter since assuming the role of Chief Executive Officer in April of 2020, and I am honored to lead and serve such a great company. Having been a member of Centennial's management team since its inception, I can personally attest to the quality and integrity of our employees, who have been working on your behalf every day. This is the primary reason why I am confident in Centennial's future growth and success, and I look forward to having you join us along the way.

During 2020, the world was suddenly and unexpectedly impacted by the coronavirus and ensuing global health pandemic. The crisis caused by COVID-19 severely weakened worldwide oil demand, which resulted in a steep decline in crude oil prices and a major disruption to the global oil and gas industry. In response, Centennial acted quickly and decisively to suspend our drilling and completions activity in order to protect the balance sheet and preserve liquidity.

During this period, we focused on reducing our cost structure and implemented numerous cost saving initiatives in the field that enhanced cash flow and capital efficiency. Additionally, we took action to reduce our aggregate amount of debt outstanding by completing a debt exchange with certain of our noteholders. This, coupled with other corporate finance initiatives, provided both debt reduction and significant financial flexibility to Centennial. Furthermore, in an effort to mitigate price volatility, we implemented a more systematic oil hedging program during 2020 to ensure future cash flows while also retaining exposure to potential upside in prices.

As global demand rebounded and oil prices strengthened, we resumed operational activity in the second half of the year. Currently, we expect to operate a two-rig drilling program in 2021. This plan will allow us to maintain full year average oil production volumes that are consistent with year-end 2020 levels, while generating free cash flow at current commodity prices and further reducing our debt. While the macro environment remains fragile pending the global recovery from COVID-19, we are cautiously optimistic that improving oil demand fundamentals are likely to support oil prices going forward.

In closing, I believe Centennial enjoyed a strong second-half of 2020 and that the Company is well positioned for 2021 and beyond. We continue to have high quality assets in the premier U.S. oil basin and management and operations teams with proven track records. Importantly, we have transitioned to a free cash flow generating company as a result of our expanded operating margins and structurally lower well costs and expect to organically reduce leverage over time. Furthermore, Centennial continues to be committed to best practices relating to environmental, social and governance issues and to being an employer where all employees feel valued, respected and included. Ultimately, we believe these facts, results and commitments will create additional long-term value for Centennial and its stakeholders, something which remains a top priority for the Company and its management and employees.

Thank you for investing in and supporting Centennial.

Sincerely,

Sean R. Smith
Chief Executive Officer

2020 ANNUAL REPORT

FORM 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2020

or

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-37697

CENTENNIAL RESOURCE DEVELOPMENT, INC.

(Exact name of registrant as specified in its charter)

Delaware	**47-5381253**
(State of Incorporation)	(I.R.S. Employer Identification No.)

1001 Seventeenth Street, Suite 1800

Denver, Colorado 80202

(Registrant's telephone number, including area code): (720) 499-1400

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, par value $0.0001 per share	CDEV	The NASDAQ Stock Market LLC

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 the filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. (See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act).

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
☐	☒	☐	☒	☐

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

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

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 30, 2020, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $162,307,533 based on the closing price of the shares of common stock on that date.

As of February 19, 2021, there were 278,916,306 shares of Class A Common Stock, par value $0.0001 per share outstanding.

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2021 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2020, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2020.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K, which are commonly used in the oil and natural gas industry:

Bbl. One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

Bbl/d. One Bbl per day.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

Btu. One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one-degree Fahrenheit.

Completion. The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to initiate production.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and location of oil or natural gas.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

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.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

ICE Brent. Brent crude oil traded on the Intercontinental Exchange, Inc. (ICE).

LIBOR. London Interbank Offered Rate.

MBbl. One thousand barrels of crude oil, condensate or NGLs.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGL. Natural gas liquids. These are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, that can be collectively removed from produced natural gas, separated in these substances and sold.

NYMEX. The New York Mercantile Exchange.

Operator. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Proved reserves. The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves or PUD. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion.

Realized price. The cash market price less differentials.

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

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

Royalty interest. An interest in an oil or gas property entitling the owner to shares of the production free of costs of exploration, development and production operations.

Spot market price. The cash market price without reduction for expected quality, location, transportation and demand adjustments.

Unproved reserves. Reserves attributable to unproved properties with no proved reserves.

Wellbore. The hole drilled by a drill bit that is equipped for oil and natural gas production once the well has been completed. Also called well or borehole.

Working interest. The interest in an oil and gas property (typically a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate is a grade of crude oil used as a benchmark in oil pricing.

GLOSSARY OF CERTAIN OTHER TERMS

The following are definitions of certain other terms that are used in this Annual Report:

Business Combination. The acquisition of approximately 89% of the outstanding membership interests in CRP from the Centennial Contributors, which closed on October 11, 2016, and the other transactions contemplated by the Contribution Agreement.

Centennial Contributors. The legacy owners of CRP, who sold approximately 89% of the outstanding membership interests in CRP to the Company in connection with the Business Combination. On April 2, 2020, the Centennial Contributors converted all of their remaining CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock, which eliminated their entire ownership interest in CRP.

The Company, We, Our or Us. (i) Centennial Resource Development, Inc. and its consolidated subsidiaries including CRP, following the closing of the Business Combination and (ii) Silver Run Acquisition Corporation prior to the closing of the Business Combination.

Class A Common Stock. Our Class A Common Stock, par value $0.0001 per share, also referred to as our Common Stock.

Class C Common Stock. Our Class C Common Stock, par value $0.0001 per share, which was issued to the Centennial Contributors in connection with the Business Combination, all of which have been converted for Class A Common Stock and are no longer outstanding.

Contribution Agreement. The Contribution Agreement, dated as of July 6, 2016, among the Centennial Contributors, CRP and NewCo, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, and the Joinder Agreement, dated as of October 7, 2016, by the Company.

CRP. Centennial Resource Production, LLC, a Delaware limited liability company.

CRP Common Units. The units representing common membership interests in CRP.

GMT Acquisition. The acquisition of certain undeveloped acreage and producing oil and natural gas properties of GMT Exploration Company LLC, which closed on June 8, 2017.

IPO. Our initial public offering of units, which closed on February 29, 2016.

NewCo. New Centennial, LLC, a Delaware limited liability company controlled by affiliates of Riverstone.

Private Placement Warrants. Our 8,000,000 outstanding warrants for the purchase of shares of Class A Common Stock, which were purchased by our Sponsor in a private placement simultaneously with the closing of our IPO.

Riverstone. Riverstone Investment Group LLC and its affiliates, including Silver Run Sponsor, LLC, a Delaware limited liability company, collectively.

Silverback. Silverback Exploration, LLC and Silverback Operating, LLC, collectively.

Silverback Acquisition. The acquisition of leasehold interests and related upstream assets in Reeves County, Texas from Silverback, which closed on December 28, 2016.

V*oting common stock*. Our Class A Common Stock and Class C Common Stock.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (the "Annual Report"), includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "goal," "plan," "target" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in *Item 1A. Risk Factors* in this Annual Report.

Forward-looking statements may include statements about:

- volatility of oil, natural gas and NGL prices or a prolonged period of low oil, natural gas or NGL prices and the effects of actions by, or disputes among or between, members of the Organization of Petroleum Exporting Countries ("OPEC"), such as Saudi Arabia, and other oil and natural gas producing countries, such as Russia, with respect to production levels or other matters related to the price of oil;
- the effects of excess supply of oil and natural gas resulting from the reduced demand caused by the Coronavirus Disease 2019 ("COVID-19") pandemic and the actions by certain oil and natural gas producing countries;
- our business strategy and future drilling plans;
- our reserves and our ability to replace the reserves we produce through drilling and property acquisitions;
- our drilling prospects, inventories, projects and programs;
- our financial strategy, liquidity and capital required for our development program;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- the marketing and transportation of our oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- cost of developing our properties;
- our anticipated rate of return;
- general economic conditions;
- weather conditions in the areas where we operate;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described in *Item 1A. Risk Factors* in this Annual Report.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

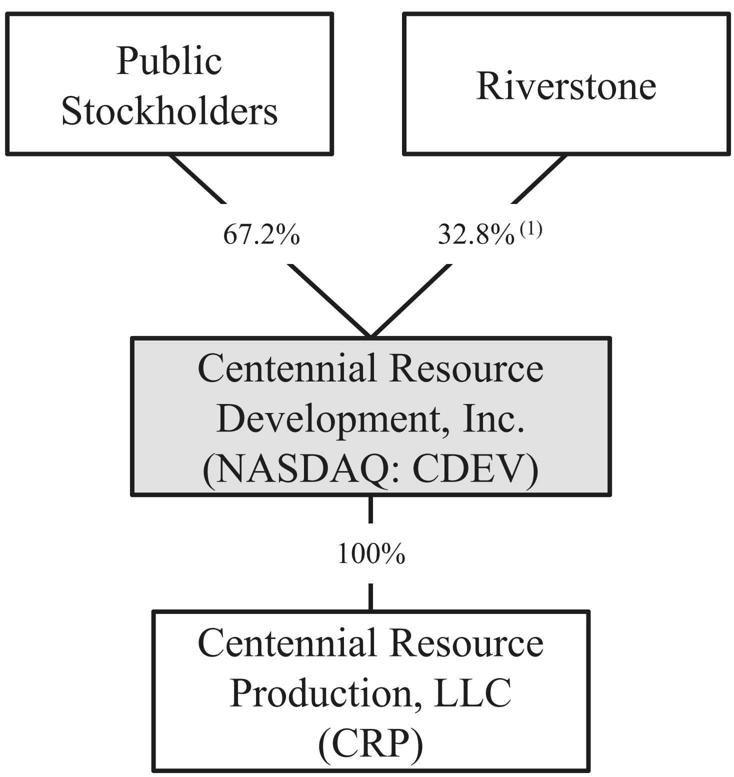
Centennial Resource Development, Inc. is an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Throughout this Annual Report, unless the context otherwise indicates, references to the "Company," "Centennial," "we," "us," or "our" refer to Centennial Resource Development, Inc. and its consolidated subsidiary, Centennial Resource Production, LLC ("CRP").

Our principal business objective is to increase shareholder value by building a premier development company focused on horizontal drilling in the Delaware Basin. We intend to grow our production and oil and natural gas reserves by developing our acreage with an increased focus on optimizing drilling and completion results, drilling extended laterals and managing costs, with an overall objective of improving our rates of return on all wells drilled and thereby funding our drilling and development capex entirely from cash flows from operations. We also intend to increase scale and grow production and reserves through selective acquisitions that meet our strategic and financial objectives.

Organizational Structure

On October 11, 2016, the acquisition of approximately 89% of the outstanding membership interests in CRP was consummated (the "Business Combination"). CRP is currently a wholly-owned subsidiary of Centennial Resource Development due to various equity transactions.

The following diagram illustrates the current ownership structure of the company as of December 31, 2020, including the voting interests of our equity holders:



(1) The above diagram excludes 8,000,000 outstanding Private Placement Warrants, each of which is exercisable for one share of Class A Common Stock at a price of $11.50 per share and will expire on October 11, 2021 (five years after the completion of the Business Combination) or earlier upon redemption or liquidation. As of December 31, 2020, Riverstone Investment Group LLC ("Riverstone") owns 6,826,502 Private Placement Warrants and Mark G. Papa, our former Chief Executive Officer and Chairman, owns 1,173,498.

Description of Our Properties

Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, and our properties consist of large, contiguous acreage blocks in West Texas and New Mexico. As a result, we are able to efficiently develop our drilling inventory and focus on maximizing returns to our stakeholders. We have established commercial production on our acreage using horizontal drilling from ten distinct zones: the Avalon Shale, 1st Bone Spring Sand, 2nd Bone Spring Sand, 2nd Bone Spring Shale, 3rd Bone Spring Sand, 3rd Bone Spring Shale, Upper Wolfcamp A, Lower Wolfcamp A, Wolfcamp B and Wolfcamp C. Our development drilling plan is comprised exclusively of horizontal drilling with an ongoing focus on optimizing completions, improving drilling results and managing costs.

As of December 31, 2020, we have leased or acquired approximately 81,657 net acres, 97% of which we operate. In addition, we own 1,472 net mineral acres in the Delaware Basin. Approximately 71% of our total acreage is located in Texas, primarily Reeves County, in the southern portion of the Delaware Basin and the remaining 29% is located in Lea County, New Mexico, in the northern portion of the Delaware Basin. Over 88% of our net acreage is held by production as of December 31, 2020. The relatively high proportion of our operated acreage that is held by production gives us significant operational control and capital spending flexibility. This allows us to execute our development program with significant control over the timing and allocation of capital expenditures and application of the optimal drilling and completion techniques to efficiently develop our resource base as evidenced by our operational flexibility executed in 2020.

During the first quarter of 2020, we operated a five-rig drilling program completing 22 gross operated wells and planned to operate a similar drilling and completion program for the remainder of the year. However, in response to significant market deterioration and declines in the oil and natural gas commodity prices, both stemming from the COVID-19 pandemic and tensions between members of OPEC and other important oil producing countries like Russia, we suspended our drilling program at the end of the first quarter of 2020. We continued with no rigs in operation until the end of the third quarter of 2020 when markets and commodity prices began to recover. During August of 2020, we also completed five gross operated wells that had been drilled but left uncompleted earlier in the year. We operated one drilling rig through the fourth quarter of 2020 and ended the year with two drilling rigs in operation. These operational decisions allowed us to preserve liquidity, conserve our reserve base and develop our properties during periods of higher economic opportunity. Refer to *Item 7, Management Discussion and Analysis of Financial Condition and Result of Operations* under Part II, Item 7 of this Annual Report for further discussion on the 2020 market conditions and our operational activity.

Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise, and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The pre-tax PV 10% amounts shown in the following table are not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated, due to a number of factors. The following table should be read along with *Item 1A. Risk Factors* in this Annual Report.

The following table summarizes estimated proved reserves, pre-tax PV 10%, and standardized measure of discounted future cash flows for the periods indicated:

	December 31, 2020	December 31, 2019	December 31, 2018
Proved developed reserves:			
Oil (MBbls)	70,716	74,842	63,317
Natural gas (MMcf)	279,556	237,791	180,542
NGL (MBbls)	31,672	32,743	23,093
Total proved developed reserves (MBoe)[1]	148,981	147,216	116,500
Proved undeveloped reserves:			
Oil (MBbls)	79,776	75,317	79,449
Natural gas (MMcf)	248,231	264,639	222,310
NGL (MBbls)	28,773	34,499	28,825
Total proved undeveloped reserves (MBoe)[1]	149,921	153,923	145,326
Total proved reserves:			
Oil (MBbls)	150,492	150,159	142,766
Natural gas (MMcf)	527,787	502,430	402,852
NGL (MBbls)	60,445	67,242	51,918
Total proved reserves (MBoe)[1]	298,902	301,139	261,826
Proved developed reserves %	50 %	49 %	44 %
Proved undeveloped reserves %	50 %	51 %	56 %
Reserve values (in millions):			
Standard measure of discounted future net cash flows	$ 1,184.7	$ 2,062.4	$ 2,479.9
Discounted future income tax expense	4.4	135.5	499.6
Total proved pre-tax PV 10%[2]	$ 1,189.1	$ 2,197.9	$ 2,979.5

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Total proved pre-tax PV 10% ("Pre-tax PV 10%") is a supplemental non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (the ''Standardized Measure''), which is the most directly comparable U.S. generally accepted accounting principles ("GAAP") financial measure. Pre-tax PV 10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe Pre-tax PV 10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our Pre-tax PV 10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, Pre-tax PV 10% is not a substitute for the Standardized Measure. Our Pre-tax PV 10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

Proved Undeveloped Reserves. Our proved undeveloped ("PUD") reserves decreased by 4.0 MMBoe on a net basis from December 31, 2019 to December 31, 2020, and the following table provides a reconciliation of the changes to our PUD reserves that occurred during the year:

(MBoe)	2020
Proved undeveloped reserves at January 1,	153,923
Transferred to proved developed reserves	(18,622)
Revisions to previous estimates	(37,471)
Extensions and discoveries	52,091
Proved undeveloped reserves at December 31,	149,921

During 2020, we spent $158.3 million in capital expenditures to convert 18.6 MMBoe of PUD reserves to proved developed reserves. Furthermore, we added 52.1 MMBoe of PUD reserves during the year through extensions and discoveries, which mainly related to new locations added based on our 2020 drilling results. The majority of these new PUD locations were on our New Mexico acreage within the 2nd and 3rd Bone Spring formations, and we also added locations in the Wolfcamp C and 3rd Bone Spring on our Texas acreage position. Total revisions to previous estimates reduced PUD reserves by a net amount of 37.5 MMBoe. Negative revisions during 2020 totaled 114.0 MMBoe and consisted of (i) 83.9 MMBoe of downward pricing adjustments, (ii) 25.4 MMBoe of negative revisions associated with PUD locations that were either reclassified to unproved reserves or removed due to changes in our active development program, and (iii) 4.0 MMBoe of reserves removed for PUD locations no longer expected to be developed within five years of their initial recording. These downward revisions were partially offset by 76.5 MMBoe of upward revisions primarily related to reductions to our operating costs and per-well capital expenditures realized during the year and applied to our reserve estimates. All of our PUD locations are scheduled to be drilled within five years of their initial booking. Our PUD to proved developed reserves conversion rate was 13% in 2020, which is lower than historical conversion rates due to our reduced 2020 drilling activity as previously discussed.

For additional information and for a discussion of material changes on our total proved reserves, see *Supplemental Information About Oil & Natural Gas Producing Activities*, Item 8. Financial Statements and Supplementary Data of this Annual Report.

Preparation of Reserve Estimates

Our proved reserves are estimated by an independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Reserve estimates are prepared in accordance with the definitions and regulations of the SEC and the Financial Accounting Standards Board (the "FASB") using a deterministic method, which includes decline curve analysis, production performance analysis, offset analogies, and in some cases a combination of these methodologies.

Controls over Reserve Estimation

We maintain adequate and effective internal controls over the reserve estimation process and the underlying data which the reserve estimates are based upon. Our reserves estimation process is coordinated by our internal reserves department, which consists of qualified petroleum engineers, and is overseen by our Vice President of Strategic Planning and Corporate Reserves. Reserve information, including models and other technical data, are stored on a secured database on our network. Certain non-technical inputs used in the reserves estimation process such as ownership interest percentages, oil and natural gas production, commodity prices, price differentials, operating and development costs and plug and abandonment estimates are obtained by other departments and are subject to our internal control process. Annually, our internal reserves department prepares a preliminary reserve database and meets with NSAI to discuss the assumptions and methods to be used in the year-end proved reserve estimation process and to review field performance and our future development plans. Following this review, the reserve database and supporting data is furnished to NSAI for their independent estimates and final report.

Qualifications of Responsible Technical Persons

Our Vice President of Strategic Planning and Corporate Reserves, Jeff Thompson, is responsible for overseeing the preparation of the reserves estimates. Mr. Thompson has held this position at Centennial since July 2017 and has over 15 years of relevant experience in reservoir engineering and reserve estimation. He holds a Bachelor of Science degree in petroleum engineering from the University of Oklahoma and is a Registered Professional Engineer in Oklahoma and member of the Society of Petroleum Engineers.

NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserve report incorporated herein are Mr. Neil H. Little and Mr. Edward C. Roy III. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. He graduated from Rice University with a Bachelor of Science Degree in Chemical Engineering and from University of Houston with a Master of Business Administration Degree. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University with a Bachelor of Science Degree in Geology and from Texas A&M University with a Master's Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Production

The following table sets forth information regarding net production of oil, natural gas and NGLs, and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2020	2019	2018
Net production:			
Oil (MBbls)	13,207	15,582	12,679
Natural gas (MMcf)	41,302	41,703	31,707
NGL (MBbls)	4,490	5,234	4,332
Total (MBoe)[1]	24,581	27,766	22,295
Average sales price (excluding effect of hedges):			
Oil (per Bbl)	$ 36.02	$ 52.02	$ 55.98
Natural gas (per Mcf)	1.13	1.07	1.97
NGL (per Bbl)	12.91	17.03	27.45
Total per BOE[1]	$ 23.61	$ 34.01	$ 39.97
Operating costs per Boe:			
Lease operating expenses	$ 4.45	$ 5.26	$ 3.74
Severance and ad valorem taxes	1.60	2.28	2.54
Gathering, processing and transportation expenses	2.90	2.62	2.58

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Productive Wells

As of December 31, 2020, we owned an approximate 75% average working interest in 534 gross (400 net) productive wells. Our wells are primarily oil wells (517 gross/387 net productive oil wells) that produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage

The following table sets forth information as of December 31, 2020 relating to our gross and net developed and undeveloped leasehold acreage. Developed acreage consists of acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Developed Acreage[3]		Undeveloped Acreage[3]		Total Acreage[3]	
Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
60,267	45,579	45,983	36,078	106,250	81,657

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(3) Does not include our 1,472 net mineral acres.

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2020, that will expire over the next five years unless production is established within the spacing units covering the acreage, the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates, or pursuant to other terms of the lease agreements.

2021		2022		2023		2024		2025	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
7,776	5,017	4,183	2,171	1,335	211	1,320	1,081	320	320

Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells placed on production, for the periods indicated. Productive wells are exploratory, development or extension wells that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are exploratory, development or extension wells that prove to be incapable of producing hydrocarbons in sufficient quantities to justify incurring the costs associated with completion as an oil or gas well.

	Year Ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive(1)	31	29.5	84	73.6	80	72.4
Dry(2)	1	1.0	2	2.0	—	—
	32	30.5	86	75.6	80	72.4
Exploratory Wells:						
Productive(1)	—	—	—	—	—	—
Dry	1	1.0	—	—	—	—
	1	1.0	—	—	—	—
Total	33	31.5	86	75.6	80	72.4

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

(2) The dry hole category includes wells that were unsuccessful due to mechanical issues that occurred during drilling.

As of December 31, 2020, we had 9 gross (8.4 net) operated wells in the process of drilling, completing or waiting on completion.

Delivery Commitments

The table below summarizes our firm sales agreements for crude oil and natural gas, both of which provide for gross firm sales over the contractual terms:

	Oil Volume Commitments[(1)(2)]		Gas Volume Commitments[(1)(3)]	
Period	**Total (Bbl)**	**Daily (Bbls/d)**	**Total (MMBtu)**	**Daily (MMBtu/d)**
2021	14,000,000	38,300	30,150,000	82,600
2022	18,250,000	50,000	12,450,000	41,000
2023	20,075,000	55,000	—	—
2024	10,980,000	30,100	—	—
2025	4,530,000	30,000	—	—
Total	67,835,000		42,600,000	

(1) Above volumes represent the total gross volumes we are required to deliver per these agreements, which gross volumes are not comparable to our net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation* in this Annual Report, as amounts therein are reflected net of all royalties, overriding royalties and production due to others.

(2) We are only required to physically deliver 30,000 Bbls/d of the total committed gross volumes of crude oil during the years 2021 through May 2025, and if these physical delivery commitments are not met, a financial obligation would arise. Failure to deliver the remainder of the committed gross volumes of crude oil under these agreements could result, and during 2020 did result, in a reduction of our future firm takeaway capacity at the purchasers' discretion in accordance with the terms of the agreements.

(3) We are not required to physically deliver these gross volumes over the terms of the agreements, but if the volumetric commitments are not met and the purchaser incurs financial damages, we are required to pay for any differences between the contracted prices and current market prices for replacement volumes bought by the purchaser.

We believe our current production and reserves are sufficient to fulfill these physical delivery commitments, and production under the agreements is not tied to any specific property. Therefore, if our production is not sufficient to satisfy the firm delivery commitments above, we believe we can purchase sufficient volumes in the market at index-related prices to satisfy our commitments. See also *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations*, in this Annual Report for discussion of our firm transportation commitments related to natural gas deliveries.

Title to Properties

We believe that we have satisfactory title to substantially all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, working and other outstanding interests customary in the industry. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Marketing and Customers

We market the majority of the production from properties we operate on account of both ourselves and that of the other working interest owners in these properties. We generally sell our oil, natural gas and NGL production to purchasers at prevailing market prices, which in certain cases are adjusted for contractual differentials, and the majority of our revenue contracts have terms greater than twelve months.

We normally sell production to a relatively small number of customers, as is customary in our business. The table below summarizes the purchasers that accounted for 10% or more of our total net revenues for the periods presented:

	Year Ended December 31,		
	2020	**2019**	**2018**
BP America	47 %	37 %	18 %
Shell Trading (US) Company	20 %	11 %	19 %
Eagleclaw Midstream Ventures, LLC	8 %	8 %	12 %
ExxonMobil Oil Corporation	4 %	26 %	— %

During these periods, no other purchaser accounted for 10% or more of our net revenues. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term. However, since crude oil and natural gas are fungible products with well-established markets and numerous purchasers and are based on current demand for oil and natural gas, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition or results of operations.

Competition

The oil and natural gas industry is a highly competitive environment. We compete with both major integrated and other independent oil and natural gas companies in all aspects of our business including exploring, developing and operating our properties as well as transporting and marketing our production. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect the supply and demand for oil and natural gas production, such as price fluctuations (including basis differentials), domestic and foreign political conditions, weather conditions, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources. 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 in a highly competitive environment.

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the areas of our production. The majority of our oil production is sold at the lease as it enters third-party gathering pipelines. The purchaser then transports the oil by pipeline or truck to a tank farm, another pipeline or a refinery. Our natural gas is either transported by gathering lines from the wellhead to a central delivery point and is then gathered by third-party lines to a gas processing facility or gathered by a third-party directly from the wellhead.

Regulation of the Oil and Natural Gas Industry

Our operations are subject to extensive federal, state and local laws and regulations. All of the jurisdictions in which we own or operate producing properties have statutory provisions regulating the development and production of oil and natural gas, including, but not limited to, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations including, but not limited to, the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings affecting the oil and natural gas industry are regularly considered by Congress, the states, regulatory authorities, including the Federal Energy Regulatory Commission ("FERC"), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Oil and Natural Gas

The production of oil, natural gas and NGLs is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in New Mexico and Texas, which regulate drilling and operating activities by, among other things, requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of New Mexico and Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, natural gas and NGLs that we can produce from our wells and to limit the number of wells or the locations where we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, New Mexico and Texas impose a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within their jurisdiction.

Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, and as a result we do not expect compliance with such regulatory requirements to affect our operations in any way that is of material difference from our competitors who are similarly situated. However, the failure to comply with these rules and regulations can result in substantial penalties.

Regulation of Sales and Transportation of Oil

Sales of oil, condensate and NGLs from our producing wells are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Sales of oil are affected by the availability, terms and conditions and cost of transportation services. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates the transportation in interstate commerce of crude oil, petroleum products, NGLs and other forms of liquid fuel under the Interstate Commerce Act.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We rely on third-party pipeline systems to transport the majority of crude oil produced by ours wells. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other oil producers and marketers with which we compete.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act of 1978 (the "NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act, which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 (the "NGA"), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The federal Energy Policy Act of 2005 (the "EP Act of 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amended the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provided FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increased FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. In January 2020, FERC issued a final rule increasing its maximum civil penalty authority under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of $1,291,894 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

We are required to observe such anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and those enforced by the US Commodity Futures Trading Commission (the "CFTC") under the Commodity Exchange Act, as amended (the "CEA") and CFTC regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce, as well as the market for financial instruments on such commodity, such as futures, options and swaps. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Natural gas gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states. Section 1(b) of the NGA exempts companies that provide natural gas gathering services from regulation by FERC as a “natural gas company” under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC’s determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, or vice versa, and depending on the scope of that decision, our costs of delivering gas to point-of-sale locations may increase. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. 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 within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action that FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, state and local laws and regulations governing the occupational safety and health aspects of our operations, the discharge of materials into the environment, and protection of the environment and natural resources (including threatened and endangered species and their habitats). Numerous governmental entities, including the U.S. Environmental Protection Agency (the “EPA”) and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things, (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentrations of various substances that can be released into the environment or injected into formations in connection with drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; (iv) require remedial measures to prevent or mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws, as amended from time to time, to which our business operations are or may be subject, and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Handling Wastes

The Resource Conservation and Recovery Act (“RCRA”) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and nonhazardous solid wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and other wastes associated with the exploration, development and production of oil, natural gas and NGLs, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree required the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes, or to sign a determination that revision of the regulations is not necessary. After undertaking its review, the EPA concluded in 2019 that it does not need to regulate exploration and production waste, and specifically "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy." The EPA concluded that states are adequately regulating exploration and production waste under the Subtitle D provisions of RCRA. However, any such change in the future could result in an increase in our, as well as the oil, natural gas and NGL exploration and production industry's, costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we may generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or the legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners or operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment, and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We may generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease or operate numerous properties that have been used for oil, natural gas and NGL exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Clean Water Act (the "CWA") and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other CWA requirements and analogous state laws and regulations.

The CWA also prohibits the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by permit. The EPA and the U.S. Army Corps of Engineers issued final rules attempting to clarify the federal jurisdictional reach over Waters of the United States in 2015 (the "WOTUS rule"). However, in 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to review the WOTUS rule and, if the agencies' reviews find that the rule does not meet the executive order's goal of promoting economic growth while reducing regulatory uncertainty, to initiate a new rulemaking to repeal or revise the rule. The EPA and the U.S. Army Corps of Engineers formally repealed the WOTUS rule in September 2019. In January 2020, the Trump administration published a final replacement rule, called the Navigable Waters Protection Rule, that purports to expressly define which categories of water may be federally regulated under the CWA. The

Navigable Waters Protection Rule is set to take effect 60 days from publication of the replacement rule in the Federal Register. Legal challenges to the Navigable Waters Protection Rule have been filed and are pending. As such, uncertainty remains with respect to future implementation of the rule. In addition, in an April 2020 decision defining the scope of the CWA, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. The U.S. Supreme Court rejected assertions by the EPA and the U.S. Army Corps of Engineers that groundwater should be totally excluded from CWA jurisdiction.

The process for obtaining permits under the CWA also has the potential to impact our operations. In April 2020, the U.S. District Court for the District of Montana vacated Nationwide Permit ("NWP") 12, the general permit issued by the U.S. Army Corps of Engineers for pipelines and utility projects. In May 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The U.S. Army Corps of Engineers appealed the decision to the U.S. Court of Appeals for the Ninth Circuit ("Ninth Circuit") and the litigation is ongoing. In July 2020, the U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. The stay is to remain in place pending disposition of the appeal currently pending before the Ninth Circuit. In January 2021, the U.S. Army Corps of Engineers released the final version of a rule renewing twelve of its NWPs, including NWP 12. The new rule splits NWP 12 into three parts; NWP 12 will continue to be available to oil and gas pipelines, while new NWP 57 will be available for electric utility line and telecommunications activities, and a new NWP 58 will be available for utility line activities for water and other substances. The new rule also eliminates preconstruction notice requirements for NWP 12 for several conditions that used to require such notice, but also now requires new oil and gas pipeline projects that exceed 250 miles in length to give preconstruction notice and obtain approval before proceeding. We cannot predict at this time whether and, if so, how the new rule will be implemented, because permits are issued by the local U.S. Army Corps of Engineers district offices. Moreover, in January 2021, the Biden administration issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies, and similar agency actions promulgated during the prior administration that may be inconsistent with the current administration's policies. If new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of CWA compliance, such projects could be significantly delayed, which could have an adverse impact on our operations.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (the "OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Subsurface Injections

In the course of our operations, we produce water in addition to natural gas, crude oil and NGLs. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control (the "UIC") program established under the federal Safe Drinking Water Act (the "SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near below-ground disposal wells used for the injection of natural gas- and oil-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety. These seismic events have also led to an increase in tort lawsuits filed against exploration and production companies, as well as the owners of underground injection wells. 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; however, these costs are commonly incurred by all oil, natural gas and NGL producers, and we do not believe that the costs associated with the disposal of produced water will affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Air Emissions

The federal Clean Air Act (the "CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of our projects. Recently, there has been increased regulation with respect to air emissions from the oil and natural gas sector. For example, the EPA promulgated rules in 2012 under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS"), and a separate set of requirements to address certain hazardous air pollutants frequently associated with oil and natural gas production and processing activities pursuant to the National Emissions Standards for Hazardous Air Pollutants program.

In June 2016, the EPA published final rules establishing new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA's final rules include NSPS to limit methane emissions from equipment and processes across the oil and natural gas source category. The rules also extend limitations on volatile organic compound ("VOC") emissions to sources that were unregulated under the previous NSPS at Subpart OOOO. Affected methane and VOC sources include hydraulically fractured (or re-fractured) oil and natural gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. In September 2018, the EPA proposed amendments to the 2016 rules that would reduce the 2016 rules' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 methane requirements and EPA's attempt to delay the implementation of the rule. Further, in August 2019, the EPA proposed two options for rescinding the Subpart OOOOa standards. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, several lawsuits have been filed challenging these amendments, and the amendments may be subject to reversal under the current administration. As discussed above, in January 2021, the administration issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies, and similar agency actions promulgated during the prior administration that may be inconsistent with the current administration's policies. The executive order specifically called on the EPA to consider a proposed rule suspending, revising or rescinding the September 2020 deregulatory amendments by September 2021. As a result, future implementation of the standards is uncertain at this time.

The Bureau of Land Management (the "BLM") also finalized rules (the "BLM methane rule") in November 2016 that seek to limit methane emissions from exploration and production activities on federal lands by imposing limitations on venting and flaring of natural gas, as well as requirements for the implementation of leak detection and repair programs for certain processes and equipment. After attempts by the Trump administration to delay implementation of the BLM methane rule, and legal challenges both to the BLM methane rule and the delays, the BLM issued a final rule in September 2018 rescinding many of the provisions of the 2016 BLM methane rule, including the requirement to implement leak detection and repair programs, and imposing certain new requirements in a manner the BLM considered would reduce unnecessary compliance obligations on the industry. In July 2020 a federal district court in California vacated the 2018 rescission rule. BLM filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit; however, the federal district court in California entered a final judgment vacating the September 2018 rescission rule in October 2020.

The EPA also finalized separate rules under the CAA in June 2016 regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In addition, in October 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standards for ground-level ozone from the current standard of 75 parts per billion ("ppb") for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. The final rule became effective on December 28, 2015. The EPA issued its anticipated area designations in November and December 2017. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 ppb rather than lower them further. However, as discussed above, that action could be subject to reversal following the administration's January 2021 executive order. States are expected to implement more stringent permitting and pollution control requirements as a result of this new final rule, which could apply to our operations.

Compliance with one or more of these and other air pollution control and permitting requirements and rules has the potential to delay the development of natural gas, oil and NGL projects and increase our costs of development and production, which costs could be significant.

Regulation of GHG Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") preconstruction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards that will typically be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from large GHG emission sources in the United States, including certain onshore and offshore natural gas, oil and NGL production sources, which include certain of our operations. As discussed above, federal regulatory action regarding GHG emissions from the oil and gas sector has focused on methane emissions; however, federal implementation of the finalized 2016 methane rule is uncertain at this time (as also discussed above).

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, no significant legislation has been adopted at the federal level. In the absence of such federal climate legislation, a number of state and regional cap-and-trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will take to achieve its GHG emissions targets. The Paris Agreement entered into force on November 4, 2016 upon achieving its threshold for ratification by signatory countries. A long-term goal of the Paris Agreement is to limit global warming to below two degrees Celsius by 2100 from temperatures in the pre-industrial era. However, the Paris Agreement does not impose any binding obligations on its participants. In November 2019, the Trump administration initiated the formal process for withdrawing from the Paris Agreement, which resulted in an effective exit date of November 2020. However, in its January 2021 executive order, the Biden administration initiated the process for rejoining the Paris Agreement.

The executive order also established an Interagency Working Group on the Social Cost of Greenhouse Gases ("Working Group"), which is called on to, among other things, develop methodologies for calculating the "social cost of carbon," "social cost of nitrous oxide," and "social cost of methane." Final recommendations from the Working Group are due no later than January 2022. A separate executive order targeting climate change, also issued by the current administration in January 2021, directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands and in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate actions to account for corresponding climate costs. The climate change executive order also directed the federal government to identify "fossil fuel subsidies" to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. Legal challenges to the executive orders have been filed.

Although it is not possible at this time to predict how new laws or regulations that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations, as well as delay or restrict our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the natural gas, oil and NGLs we produce and lower the value of our reserves. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil, natural gas and NGLs from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016, establishing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting (which are subject to revision, as discussed above); published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication version of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act ("TSCA") reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in March 2015, the BLM adopted rules establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands. In June 2016, a federal district court judge in Wyoming struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That ruling was appealed, but in September 2017 the U.S. Court of Appeals for the Tenth Circuit dismissed the appeal and remanded with directions to vacate the lower court's opinion, leaving the final rule in place. However, following the issuance of an executive order by President Trump to review rules related to the energy industry, the BLM initiated a rulemaking to rescind the final rule in December 2017. Shortly after the final rulemaking was issued, the state of California and several environmental groups filed lawsuits against the BLM, the Secretary of the Interior, and the Assistant Secretary for Land and Minerals Management, seeking an injunction and a declaration that the repeal violated numerous federal statutes. After the suits were filed, multiple industry groups and the state of Wyoming sought to intervene and transfer the case to federal court in Wyoming, which decided the initial legal challenge to the Obama administration's fracking regulations. A hearing was held in January 2020 to consider a motion for summary judgment in the case, and in March 2020, the court granted BLM's motion for summary judgment, upholding the agency's decision to rescind the hydraulic fracturing regulations finalized in the 2015 rule. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under certain limited circumstances."

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, the regulation of hydraulic fracturing has continued at the state level. For example, Wyoming has promulgated rules related to the public disclosure of substances used in hydraulic fluid, testing requirements for water wells near drilling sites and leak detection and repair requirements for fugitive emissions from oil and gas production facilities.

In the event that a new, federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Activities on Federal Lands and State Lands

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, are frequently subject to permitting delays. Operations on these lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. In January 2020, the White House Council on Environmental Quality ("CEQ") proposed changes to NEPA regulations designed to overhaul the system and speed up federal agencies' approval of projects. Among other things, the rule proposes to narrow the definition of "effects" to exclude the terms "direct," "indirect," and "cumulative" and redefine the term to be "reasonably foreseeable" and having "a reasonably close causal relationship to the proposed action or alternatives." In July 2020, CEQ issued a final rule implementing the January 2020 proposal. Such changes to the NEPA regulations, if they survive review following the January 2021 executive order, could have an effect on our operations and our ability to obtain governmental permits. We currently have exploration, development and production activities on federal lands. Our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of natural gas, oil and NGL projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in the Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

In addition, the New Mexico state legislature recently considered House Bill 206, which, if passed, would have enacted an Environmental Review Act comparable to NEPA. Specifically, the Environmental Review Act would require state governmental agencies at all levels to consider the qualitative, technical and economic factors relating to a project that may impact public health, ecosystems and the environment, the long-term as well as short-term benefits and costs of the proposed project, the cumulative impacts of the proposed project, and reasonable alternatives to proposed actions affecting the environment, communities or public health. If reconsidered and enacted in the future, the process contemplated by the Environmental Review Act has the potential, like NEPA, to delay or limit, or increase the cost of, the development of natural gas, oil and NGL projects in New Mexico, which costs could be substantial.

ESA and Migratory Birds

The federal Endangered Species Act ("ESA") and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of a 2011 settlement agreement, the U.S. Fish and Wildlife Service (the "FWS") was required to make a determination on listing of numerous species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The FWS did not meet that deadline. In August 2020, the FWS and the National Marine Fisheries Service issued three rules amending the implementation of the ESA regulations, among other things revising the process for listing species and designating critical habitat. A coalition of states and environmental groups has challenged the three rules and the litigation remains pending. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In addition, the federal government recently has issued indictments under the Migratory Bird Treaty Act ("MBTA") to several oil and natural gas companies after migratory birds were found dead near reserve pits associated with drilling activities. The Department of the Interior issued an opinion in December 2017 that would narrow certain protections afforded to migratory birds pursuant to the MBTA. In response to this opinion, two separate lawsuits were filed in May 2018 in the U.S. District Court for the Southern District of New York challenging the Department of the Interior's interpretation of the MBTA. In September 2018, eight states filed a similar suit in the U.S. District Court for the Southern District of New York. The litigation is ongoing. In February 2020, the FWS published a rule seeking to codify the December 2017 legal opinion. The FWS issued a draft rule in January 2021, which was set to take effect in February 2021. However, in response to the January 2021 executive order directing federal agencies to review actions taken by the prior administration, FWS has delayed implementation of the final rule by 30 days and opened the rule for additional public comment. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right-to-Know Act, comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other activities and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our development activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Human Capital Resources

We aim to attract top talent in the oil and gas sector and empower our employees to be innovators in our industry. As of December 31, 2020, we had 151 full-time employees. In addition, we hire independent contractors on an as needed basis but have no collective bargaining or employment agreements with our employees.

We believe that our employees give us a sustainable competitive advantage, and we understand the need to attract, retain and train the best team possible. We provide fair and competitive wages to assist in retention of our top talent, and our compensation programs are integrated with our overall business strategies to incentivize performance and maximize shareholder returns. We offer a variety of programs that are designed to retain our employees and also provide opportunities to grow their professional careers while continuing to deliver value to the company. Additionally, we have a comprehensive suite of benefits that provides our employees with various programs to meet their different needs including retirement, health and wellness plans.

We are committed to a diverse workforce because we believe employees with different backgrounds, experiences, interests and skillsets drive superior results. In terms of gender and racial distribution, approximately 38% of our employees identify as female and approximately 24% of our employees identify as non-white. We plan to continue to recruit and develop a diverse workforce to ensure that we remain an employer of choice delivering top-tier results.

We strive to promote a safe and healthy working environment with a focus on protecting our employees, contractors, the public and the environment in the communities in which we conduct our business. We provide frequent trainings and monthly safety meetings for all field employees and have excelled in health, safety and environmental performance maintaining zero employee recordable incidents due to illnesses or injuries at the workplace.

Offices

Our principal executive offices are located at 1001 Seventeenth Street, Suite 1800, Denver, Colorado 80202, and our telephone number is (720) 499-1400. We also have office space in Midland, Texas; Sugar Land, Texas; Pecos, Texas; and Jal, New Mexico.

Available Information

Our internet website address is www.cdevinc.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. Information on our website is not incorporated by reference into this Annual Report and should not be considered part of this document.

The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at www.sec.gov.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors together with all of the other information included in this Annual Report and our other reports filed with the SEC before investing in our securities. The occurrence of one or more of these risks could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

Risks Related to Commodity Prices

The COVID-19 pandemic and related governmental actions have and may continue to lead to an imbalance in expected supply and demand of oil and natural gas, which could negatively impact commodity prices and therefore our business, financial condition and results of operations.

The COVID-19 pandemic and various governmental actions taken to mitigate the impact of COVID-19 resulted in an unprecedented decline in demand for oil, natural gas and NGLs starting in 2020. The impact was exacerbated by Saudi Arabia significantly reducing export prices and increasing oil production in March 2020. As a result, there was a significant decline in commodity prices starting at the end of the first quarter of 2020. These commodity prices remained depressed for the remainder of 2020 as compared to average commodity prices over the last few years.

In late 2020 and early 2021, commitments made by the OPEC and other oil producing countries to reduce their crude oil production, taken together with U.S. producers substantially reducing drilling and producing activities, resulted in higher commodity prices, but commodity prices remain volatile. The remaining uncertainty around COVID-19, the efficacy of and timeframe for vaccinations, the emergence and spread of new strains of the virus, renewed actions by governments to combat the spread of the virus, including stay-at-home mandates and recommendations and general restrictions on travel, and other lingering risks and concerns relating to COVID-19, combined together, continue to impact actual and expected demand for oil and natural gas. To the extent oil producers fail to implement or sustain production cuts or take other actions that are sufficient to balance oil, natural gas and NGLs supply with expected demand, the excess supply could lead to a resurgence of commodity price declines. As the vast majority of our revenue and cash flow is generated from the sale of oil, natural gas and NGLs, lower commodity prices resulting from COVID-19 factors could materially and adversely affect our future business, financial condition and results of operations.

Commodity prices are volatile, and a sustained period of low commodity prices for oil, natural gas and NGLs could adversely affect our business, financial condition and results of operations.

The prices we receive for our oil, natural gas and NGLs heavily influence our revenue, cash flows, profitability, access to capital, future rate of growth and carrying value of our properties. Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to relatively minor changes in the actual and expected supply of and demand for oil, natural gas and NGLs and market uncertainty. In addition to the influence of the COVID-19 pandemic and related governmental actions, discussed above, oil, natural gas and NGL prices have historically been volatile and subject to fluctuations relating to a variety of additional factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the global supply of and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas and NGLs;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- political, economic and other conditions that affect perceived demand for oil, natural gas and NGLs, including trade tensions between the U.S. and other countries and global health pandemics, epidemics and concerns;
- the level of global exploration, development, production, and inventories;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the availability of refining and storage capacity;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- terrorist attacks targeting oil and natural gas related facilities and infrastructure;
- technological advances affecting fuel economy, energy supply and energy consumption;
- the effect of energy conservation measures, alternative fuel requirements and the price and availability of alternative fuels;

- laws, regulations and taxes in the U.S. and in foreign jurisdictions that impact the demand for oil, natural gas and NGLs;
- shareholder activism or activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize emissions of carbon dioxide and methane GHGs or otherwise;
- localized and global supply and demand fundamentals; and
- expectations about future commodity prices.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. From 2016 through 2020, the WTI spot price for oil averaged $51.21 per Bbl, which is down substantially from the $85.82 average for the prior five-year period. The Henry Hub average spot price from 2016 through 2020 of $2.65 per MMBtu similarly declined from $3.49 per MMBtu, which was the average for the prior five-year period. The commodity prices displayed even more dramatic volatility in 2020, during which the WTI spot price for oil briefly fell to a low of negative $37.63 per barrel on April 20, 2020 and the Henry Hub spot price reached a low of $1.33 on September 21, 2020. During these periods, NGLs, which are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, have suffered significant recent price declines.

A sustained or further extended decline in commodity prices may result in a shortfall in our expected revenues and cash flows and require us to reduce capital spending or borrow funds to cover any such shortfall. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods of low commodity prices for oil and natural gas and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone, moderate or eliminate our planned drilling and completions operations, or suspend production from current wells, which could result in the reduction of our expected production and some of our proved undeveloped reserves and related standardized measure. If we moderate or curtail our drilling, completion or production operations, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a sustained or further extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.

Accounting guidance requires that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. In 2020, we recognized an impairment of $591.8 million because of the depressed oil and natural gas commodity prices at the time we conducted the impairment analysis in the first quarter. While commodity prices improved in the subsequent quarters of 2020 and we did not recognize any further impairments directly relating to prevailing commodity prices, a sustained or further extended decline in commodity prices in the future could result in additional impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Risks Related to Our Reserves, Leases and Drilling Locations

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, seismic, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as commodity prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant inaccuracies in our interpretations of this technical data or in making our assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, commodity prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than our estimates and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. Our estimated proved reserves as of December 31, 2020, and related standardized measure were calculated under rules of the SEC using twelve-month trailing average benchmark prices of $36.04 per barrel of oil (WTI Posted) and $1.99 per MMBtu (Henry Hub spot), which may be substantially higher or lower than the available spot prices in 2021. For example, if the crude oil and natural gas prices used in our year-end reserve estimates were to increase or decrease by 10%, our proved reserve quantities at December 31, 2020 would increase by 4.5 MMBoe (2%) or decrease by 24.3 MMBoe (8%), respectively, and the pre-tax PV10% of our proved reserves would increase by $334.5 million (28%) or decrease by $327.7 million (28%), respectively.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future 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, particularly because competition in the oil and natural gas industry is intense, and many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. 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 would be materially and adversely affected.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of December 31, 2020, 50% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of December 31, 2020, over 88% of our total net acreage was held by production. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. Some of our leases also expire as to certain depths if continuous drilling obligations are not met. If our leases expire in whole or in part and we are unable to renew the leases, we will lose the right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

In 2020, given the weakness in realized oil prices at the end of the first quarter, we voluntarily shut-in a portion of our second quarter 2020 production volumes. In the future, we may again shut-in some or all of our production depending on market conditions, storage or transportation constraints and contractual obligations, and any prolonged shut-in of our wells could result in the expiration, in whole or in part, of the related leases, which could adversely affect our reserves, business, financial condition and results of operations.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, availability of gathering or transportation facilities, access to and availability of water sourcing and distribution systems, regulatory approvals, including permitting, and other factors. Because of these uncertain factors, we do not know if the numerous identified drilling locations will ever be drilled or if we will be able to produce natural gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or be economically viable. The use of micro-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 oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Risks Related to Our Operations

Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil and natural gas industry is capital-intensive. We make and expect to continue to make substantial capital expenditures related to development and acquisition projects. Historically, we have funded our capital expenditures with cash flows from operations, borrowings under CRP's revolving credit facility, proceeds from offering debt and equity securities and divestitures of non-core assets, and we intend to finance our future capital expenditures in a similar fashion. When we finance our capital expenditures through indebtedness a portion of our cash flows from operations must be used to pay interest and principal on the indebtedness, which reduces our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under CRP's revolving credit facility and to access the capital markets.

If our revenues or the borrowing base under CRP's revolving credit facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under CRP's revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties. This, in turn, could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations. Additionally, 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 will depend on the success of our development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. In addition to the risks we face in drilling for and producing oil and natural gas, some factors that may directly or indirectly negatively impact our scheduled operations:

- lack of available gathering or transportation facilities or delays in the constructing such facilities;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, qualified personnel, materials or resources;
- equipment failures, accidents or other unexpected operational events;
- delays imposed by or resulting from compliance with laws and regulations, including limitations resulting from wastewater disposal, emission of GHGs and limitations on hydraulic fracturing;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- natural disasters;
- personal injuries and death;
- terrorist attacks targeting oil and natural gas related facilities and infrastructure;
- limited availability of financing at acceptable terms;
- title problems;
- adverse weather conditions; and
- limitations in the market for oil and natural gas.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events, including those operating risks listed above, could materially and adversely affect our business, financial condition or results of operations. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include the following:

- landing a wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- spacing the wells appropriately to maximize production rates and recoverable reserves;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations;
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage; and
- the ability to prevent unintentional communication with other wells.

In addition, the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as anticipated, and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in Texas in past years. These drought conditions have led some local water districts to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. Where practicable, we strive to use recycled water for our hydraulic fracturing operations. If we are unable to obtain water from water suppliers or our recycling operations, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to recycle or dispose of the produced water we produce in an economical and environmentally safe manner.

Our operations could be impaired if we are unable to recycle or dispose of the water we produce in an economical and environmentally safe manner. Where practicable, we strive to recycle the produced water for our future oil and gas operations. Produced water that is not recycled generally gets disposed of in disposal wells that are operated by us or third-party contractors. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection of produced water resulting from oil and gas activities, which has led to increased public and governmental scrutiny of injection safety. For instance, in response to concerns regarding induced seismicity, regulators in Texas have adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity.

Another consequence of water disposal activities and seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells or commercial disposal wells to dispose of produced water. Increased regulation and attention given to water disposal and induced seismicity could also lead to greater opposition, including litigation, to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in limitations on disposal well volumes, disposal rates and pressures or locations, require us or our vendors to shut down or curtail the injection into disposal wells, or cause delays, interruptions or termination of our operations, which events could have a material adverse effect on our business, financial condition and results of operations.

Our producing properties are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, making us vulnerable to risks associated with operating in a single geographic area.

Our producing properties are geographically concentrated in the Delaware Basin, a sub-basin of the Permian Basin, primarily in West Texas and New Mexico. At December 31, 2020, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages, regional power outages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

The marketability of our production is dependent upon transportation and other facilities, most of which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.

The marketability of our oil, natural gas and NGLs production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil, natural gas and NGLs production is generally transported from the wellhead by gathering systems that are either owned by us or third-party midstream companies. In general, we do not control the transportation of our production and our access to transportation facilities may be limited or denied. In some instances, we have contractual guarantees relating to the transportation of our production through firm transportation arrangements, but third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents or other reasons. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or third-party midstream companies or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, natural gas and NGLs and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements, we may be required to shut in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, natural gas and NGLs produced from our fields, would materially and adversely affect our financial condition and results of operations.

We have entered into multi-year agreements with some of our suppliers, service providers and the purchasers of our oil and natural gas, which contain minimum volume commitments. Any failure by us to satisfy the minimum volume commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.

We have entered into certain multi-year supply and service agreements associated with water disposal. We also have various multi-year agreements that relate to the sale, transportation or gathering of our oil and natural gas and may in the future enter into multi-year agreements for contracts for drilling rigs or other services. Some of these agreements contain minimum volume commitments that we must satisfy or contractual penalties in the form of volume deficiencies or other remedies may apply. As of December 31, 2020, our aggregate long-term contractual obligation under these agreements was $12.8 million, which represents the gross minimum obligation but does not include amounts that may be due under certain contracts that contain variable pricing or volumetric components as the future obligations cannot be determined. Further information about these agreements can be found at *Note 13—Commitments and Contingencies*, Item 8. Financial Statements and Supplementary Data in this Annual Report. Any failure by us to satisfy the minimum volume commitments in these agreements could adversely affect our results of operations and financial position.

We depend upon a small number of significant purchasers for the sale of most of our oil, natural gas and NGL production.

We normally sell production to a relatively small number of customers, as is customary in our business. See *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, Item 8. Financial Statements and Supplementary Data in this Annual Report for significant purchasers that accounted for more than 10% of our revenues for the years ended December 31, 2020, 2019 and 2018. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of assets or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;

- future commodity prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. 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. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and purchase prices higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. In addition, debt agreements impose certain limitations on our ability to enter into mergers or combination transactions and our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. In addition, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages or cost increases could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue as commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

A security interruption or failure with respect to our information technology systems could harm our ability to effectively operate our business.

Our ability to effectively manage and operate our business depends significantly on information technology systems. The failure of these systems to operate effectively and support our operations, challenges in transitioning to upgraded or replacement systems, difficulty in integrating new or updated systems, or a breach in security of these systems could adversely impact the operations of our business.

Any breach of our network may result in the loss of valuable business data, misappropriation of our customers' or employees' personal information, or a disruption of our business, which could harm our customer relationships and reputation, and result in lost revenues, fines or lawsuits.

Moreover, we must comply with increasingly complex and rigorous regulatory standards enacted to protect business and personal data. Any failure to comply with these regulatory standards could subject us to legal and reputational risks. Misuse of or failure to secure personal information could also result in violation of data privacy laws and regulations, proceedings against us by governmental entities or others, damage to our reputation and credibility, and could have a negative impact on revenues and profits.

Risks Related to Our Derivative Transactions, Debt and Access to Capital

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

We enter into derivative instrument contracts for a portion of our oil and natural gas production from time to time. As of December 31, 2020, we had entered into derivative contracts covering a portion of our projected oil and gas production through early 2022 (refer to *Note 7—Derivative Instruments* under Part II, Item 8 of this Annual Report for a summary of our derivative instruments as of December 31, 2020). Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

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

- production is less than the volume covered by the derivative instruments;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of CRP's borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile commodity prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

Since our production is not fully hedged, and we are also exposed to fluctuations in oil, natural gas and NGL prices as it relates to the price we receive from the sale of our unhedged volumes. We intend to continue to hedge a portion of our production, but we may not be able to do so at favorable prices. Accordingly, our revenues and cash flows are subject to increased volatility with regard to these unhedged volumes, and a decline in commodity prices could materially and adversely affect our business, financial condition and results of operations.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on our outstanding debt.

As of December 31, 2020, we had approximately $1.1 billion of total long-term debt and additional borrowing capacity of $333.9 million under CRP's revolving credit facility (after giving effect to a $31.8 million availability blocker and $4.3 million of outstanding letters of credit), all of which would be secured if borrowed. Subject to the restrictions in the instruments governing CRP's outstanding indebtedness (including CRP's revolving credit facility and senior notes), CRP and its subsidiaries may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the instruments governing CRP's outstanding indebtedness do contain restrictions on the incurrence of additional indebtedness, these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

Our current and future level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limit management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

- make it more likely that a reduction in CRP's borrowing base following a periodic redetermination could require CRP to repay a portion of its then-outstanding bank borrowings;
- make us vulnerable to increases in interest rates as the indebtedness under CRP's revolving credit facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to our competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for CRP to satisfy its obligations under its debt and increase the risk that we may default on its debt obligations.

We may not be able to generate sufficient cash to service all of CRP's indebtedness and may be forced to take other actions to satisfy CRP's obligations under applicable debt instruments, which may not be successful.

CRP's ability to make scheduled payments on or to refinance its indebtedness depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit CRP to pay the principal, premium, if any, and interest on CRP's indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance CRP's indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require CRP to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm CRP's ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. The agreements governing CRP's indebtedness restrict CRP's ability to dispose of assets and CRP's use of the proceeds from such disposition. CRP may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit CRP to meet scheduled debt service obligations.

Restrictions in CRP's existing and future debt agreements could limit our growth and ability to engage in certain activities.

CRP's credit agreement and the indentures governing its senior notes contain a number of significant covenants, including restrictive covenants that may limit CRP's ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- make certain payments;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, CRP's credit agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of December 31, 2020, we were in full compliance with such financial ratios and covenants.

The restrictions in CRP's debt agreements may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive imposed on CRP.

If CRP is unable to comply with the restrictions and covenants in the agreements governing its indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that CRP has borrowed.

Any default under the agreements governing CRP's indebtedness that is not cured or waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make CRP unable to pay principal, premium, if any, and interest on such indebtedness. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on CRP's indebtedness, or if CRP otherwise fails to comply with the various covenants, including financial and operating covenants, in the agreements governing CRP's indebtedness, CRP could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under CRP's revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under CRP's revolving credit facility to avoid CRP being in default. If CRP breaches the covenants under its revolving credit facility and seeks a waiver, CRP may not be able to obtain a waiver from the required lenders. If this occurs, CRP would be in default under the revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

Any significant reduction in the borrowing base under CRP's revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

CRP's revolving credit facility limits the amounts CRP can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually in the spring and fall. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the loan. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of permitted senior unsecured notes CRP may issue in the future. In addition, CRP's credit agreement contains a minimum availability condition to borrowing equal to 25% of the aggregate principal amount of the Senior Secured Notes outstanding, which we refer to in this Annual Report as an availability blocker. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under CRP's revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. In connection with the fall 2020 semi-annual borrowing base redetermination, the borrowing base and elected commitments were reaffirmed at $700.0 million.

In the future, we may not be able to access adequate funding under CRP's revolving credit facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, CRP could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service CRP's indebtedness.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financing and trade credit and the terms of any financing or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. At December 31, 2020, we had $330.0 million in borrowings outstanding under CRP's revolving credit facility. Interest is calculated under the terms of CRP's credit agreement based on a LIBOR spread. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Risks Related to Legislative and Regulatory Initiatives

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the CAA that, among other things, require PSD preconstruction and Title V operating permits for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States, which include certain of our operations. Furthermore, in June 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule included first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. However, in September 2020, the EPA adopted deregulatory amendments to the 2016 standards intended to streamline implementation, reduce duplicative EPA and state requirements and decrease the burden of compliance. In particular, the amendments removed the transmission and storage segments from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. Although the amendments are now in effect, they may be subject to reversal under the new presidential administration. In January 2021, the administration issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies, and similar agency actions promulgated during the prior administration that may be inconsistent with the current administration's policies. The executive order specifically called on the EPA to consider a proposed rule suspending, revising or rescinding the September 2020 deregulatory amendments by September 2021. As such, future implementation is uncertain at this time. However, compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap-and-trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. The United States became one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, which requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. Although the previous administration withdrew the United States from the Paris Agreement, effective November 2020, the aforementioned executive order issued by the current administration in January 2021 commenced the process for reentering the Paris Agreement. The executive order also established a Working Group, which is called on to, among other things, develop methodologies for calculating the "social cost of carbon," "social cost of nitrous oxide," and "social cost of methane." Final recommendations from the Working Group are due no later than January 2022. A separate executive order targeting climate change, also issued by the current administration in January 2021 directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands and in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate actions to account for corresponding climate costs. The climate change executive order also directed the federal government to identify "fossil fuel subsidies" to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. Legal challenges to the executive orders have been filed. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA and other federal agencies have asserted regulatory authority over aspects of the process. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above-and-below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Conservation measures, technological advances and negative shift in market perception toward oil and natural gas industry could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. Additionally, the increased competitiveness of alternative energy sources (such as electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects.

The impact of the changing demand for oil and natural gas, together with a change in investor sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent, complex and evolving federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. In the states of New Mexico and Texas, as an example, governmental authorities are investigating the practice of flaring natural gas and it is possible that such states could implement additional volumetric or other restrictions on this practice which may require us to curtail or shut in production which otherwise is or would be flared due to the unavailability of acceptable delivery, transportation or processing arrangements. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations

Risks Related to Our Common Stock and Capital Structure

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in the oil and gas industry. Over the past years, equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain institutional investors, private equity companies, pension funds, university endowments and family foundations have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. Such developments could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Riverstone and its affiliates own a significant percentage of our outstanding voting common stock.

Riverstone and its affiliates beneficially own approximately 33% of our voting common stock as of December 31, 2020. As long as Riverstone and its affiliates own or control a significant percentage of outstanding voting power, they may have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our board of directors, any amendment of our third amended and restated certificate of incorporation (the "Charter") or our second amended and restated bylaws (the "Bylaws"), or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of Riverstone and its affiliates may not align with the interests of our other stockholders. Riverstone is in the business of making investments in companies and may acquire and hold interests in businesses that compete directly or indirectly with us. Riverstone and its affiliates may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our Charter provides that we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

Provisions contained in our Charter and Bylaws, as well as provisions of Delaware law, could impair a takeover attempt, which may adversely affect the market price of our Common Stock.

Our Charter and Bylaws contain provisions that could have the effect of delaying or preventing changes in control or changes in our management without the consent of our board of directors. These provisions include:

- a classified board of directors, with only approximately one-third of our board of directors elected each year;
- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;
- the exclusive right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director, which prevents stockholders from being able to fill vacancies on our board of directors;
- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;
- a prohibition on stockholder action by written consent, which forces stockholder action to be taken at an annual or special meeting of our stockholders;
- the requirement that an annual meeting of stockholders may be called only by the chairman of the board of directors, the chief executive officer, or the board of directors, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;
- limiting the liability of, and providing indemnification to, our directors and officers;
- controlling the procedures for the conduct and scheduling of stockholder meetings;
- providing that directors may be removed prior to the expiration of their terms by stockholders only for cause; and
- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

These provisions, alone or together, could delay hostile takeovers and changes in control of the Company or changes in our board of directors and management.

As a Delaware corporation, we are also subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law, which prevents some stockholders holding more than 15% of our outstanding voting common stock from engaging in certain business combinations without approval of the holders of substantially all of our outstanding voting common stock. Any provision of our Charter or Bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their securities and could also affect the price that some investors are willing to pay for our securities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment-related disputes. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

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

Common Stock

Our Common Stock is currently quoted on NASDAQ under the symbol "CDEV." As of February 19, 2021, there were 17 registered holders of record of our Common Stock.

Dividend Policy

We have not paid any cash dividends on our Common Stock to date. Our board of directors may from time to time consider whether or not to institute a dividend policy. It is our present intention to retain any earnings for use in our business operations and, accordingly, we do not anticipate the board of directors declaring any dividends in the near future.

ITEM 6. SELECTED FINANCIAL DATA

The following data should be read in conjunction with *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Annual report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this Annual Report. Our historical results are not necessarily indicative of future operating results.

The following table shows selected historical financial information for the periods and as of the dates indicated. The term "Successor" refers to Centennial after the acquisition of the outstanding membership interests in CRP on October 11, 2016 (the "Business Combination") and the consolidation of CRP subsequent to the Business Combination. The term "Predecessor" refers to CRP for periods prior to the Business Combination.

The selected historical financial information for the periods presented may not be comparable from period to period as a result of the following transactions:

- the GMT Acquisition completed in June 2017;
- the Silverback Acquisition completed in December 2016; and
- the Business Combination completed in October 2016.

	Successor					Predecessor
	Year Ended December 31,				October 11, 2016 through December 31, 2016	January 1, 2016 through October 10, 2016[1]
(in thousands, except per share data)	2020	2019	2018	2017		
Statements of Operations Data:						
Total revenues	$ 580,456	$ 944,330	$ 891,045	$ 429,902	29,717	$ 69,116
Net income (loss) attributable to Class A Common Stock	(682,837)	15,798	199,899	75,568	(8,081)	(218,724)
Income (loss) per share of Class A Common Stock:[2]						
Basic	$ (2.46)	$ 0.06	$ 0.76	$ 0.32	$ (0.05)	
Diluted	$ (2.46)	$ 0.06	$ 0.75	$ 0.32	$ (0.05)	
Cash Flows Data:						
Net cash provided by operating activities	$ 171,376	$ 564,173	$ 670,011	$ 259,918	$ 9,410	$ 51,740
Net cash used in investing activities	(326,323)	(932,989)	(1,068,664)	(992,306)	(1,749,733)	(101,434)
Net cash provided by financing activities	147,743	362,937	294,160	724,220	1,874,268	47,296

	Successor				
	December 31,				
(in thousands)	2020	2019	2018	2017	2016
Balance Sheet Data:					
Total assets	$ 3,827,425	$ 4,688,288	$ 4,260,021	$ 3,616,569	$ 2,651,642
Long-term debt, net	1,068,624	1,057,389	691,630	390,764	—
Total equity	2,603,961	3,270,701	3,243,869	3,003,972	2,552,935

(1) The selected historical consolidated financial information of CRP for the period from January 1, 2016 through October 10, 2016 was derived from the audited historical consolidated financial statements of CRP.

(2) No cash or stock dividends were declared or paid on our Common Stock during the periods presented.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" in this Annual Report. The following discussion and analysis contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, future market prices for oil, natural gas and NGLs, future production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes, continued and future impacts of COVID-19 and other uncertainties, as well as those factors discussed in "Cautionary Statement Concerning Forward-Looking Statements" and "Item 1A. Risk Factors" in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

We are an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. Our capital programs are focused on projects that we believe provide the highest return on capital.

Market Conditions

The recent worldwide outbreak of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19 have resulted in an unprecedented decline in the demand for oil and natural gas. In addition in March 2020, the decision by Saudi Arabia to drastically reduce export prices and increase oil production (the "Saudi-Russia oil price war") followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. As a result, there was a significant decline in commodity prices starting at the end of the first quarter of 2020. However, during the second quarter of 2020, OPEC and other oil producing countries agreed to reduce their crude oil production, while U.S. producers substantially reduced or suspended drilling activity and in most cases curtailed production due to low oil prices and poor economics. The oil production cuts by OPEC and other producing countries were agreed upon and continued during the remainder of 2020, and U.S. drilling activity remained low throughout the second half of 2020. These actions have aided in a partial recovery of global commodity prices. Specifically, WTI spot prices for crude oil fell to a low of negative $37.63 per barrel on April 20, 2020 (due to depressed demand and insufficient storage capacity, particularly at the WTI physical settlement location in Cushing, Oklahoma) and have since recovered to a high of $49.10 per barrel on December 18, 2020.

The oil and natural gas industry is cyclical, and it is likely that commodity prices, as well as commodity price differentials, will continue to be volatile due to fluctuations in global supply and demand, inventory levels, the continued effects of COVID-19, geopolitical events, weather conditions, global transition to alternative energy sources and other factors. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2018:

	2018				2019				2020			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude Oil (per Bbl)	$62.91	$68.07	$69.50	$58.81	$ 54.90	$ 59.81	$56.45	$ 56.94	$46.19	$ 28.00	$ 40.93	$ 42.66
Natural Gas (per MMBtu)	$ 3.08	$ 2.85	$ 2.93	$ 3.77	$ 2.88	$ 2.51	$ 2.33	$ 2.34	$ 1.88	$ 1.65	$ 1.95	$ 2.47

A sustained drop in oil, natural gas and NGL prices, such as those we have experienced during 2020, will not only decrease our revenues but can also reduce the amount of oil, natural gas and NGLs that we can produce economically and can therefore potentially lower our oil, natural gas and NGL reserve quantities.

Lower commodity prices (including our realized differentials) and lower futures curves for oil and gas prices, can also result in further impairments of our proved oil and natural gas properties or undeveloped acreage (such as the impairments discussed below under "Results of Operations") and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity and/or ability to finance planned capital expenditures. Lower realized prices may also reduce the borrowing base under CRP's credit agreement (such as the reduction discussed below under "Financing Highlights"), which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if any borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under the credit agreement. Additionally, the lower price environment and its impact to our operations could impact our ability to comply with the covenants under our credit agreement and senior notes.

COVID-19 Outbreak

The COVID-19 outbreak and its development into a pandemic in March 2020 have required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, contractors, suppliers and the communities in which we operate. Our operational employees have been and are currently able to work on site, while the vast majority of our non-operational employees have worked remotely or reported to our offices on a limited basis during 2020. We have taken various precautionary measures with respect to our operational employees, direct contractors and employees who returned to our offices or job sites during the year such as (i) requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site or office, (ii) self-quarantining any employees or contractors who have shown signs or symptoms of COVID-19 regardless of whether such person has been confirmed to be infected, (iii) imposing social distancing requirements on work sites and at our offices that are in accordance with the guidelines released by the Center for Disease Control (the "CDC") as well as local and state authorities, (iv) requiring all employees and contractors to have a fit-test for and wear KN-95 type respirators while in our offices and work sites, and (v) encouraging all employees and contractors to follow the CDC recommended preventive measures (including those mentioned above) to limit the spread of COVID-19. We have not experienced any operational disruptions (including disruptions from our suppliers or service providers) as a result of the COVID-19 outbreak.

2020 Highlights and Future Considerations

The changes in the macro environment and related volatility in commodity prices that occurred during 2020 discussed above have significantly impacted our results of operations for the year ended December 31, 2020, and we believe that our future operating results and near-term financial condition could continue to be impacted, until such time that oil supply and demand dynamics re-balance and stabilize.

Operational Highlights

We operated a five-rig drilling program during the majority of the first quarter of 2020, which enabled us to complete and bring online 26 gross operated wells with an average effective lateral length of approximately 7,000 feet during the first half of 2020. Due to the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment, in the second quarter of 2020, we suspended all drilling and completion activities in order to preserve capital. Specifically, we reduced our operated drilling rig program to zero rigs starting in April of 2020 and continued with no drilling rigs in operation until the end of the third quarter. In addition, given the weakness in realized oil prices, we voluntarily curtailed or shut-in approximately 20% of our production during the month of May, but we were able to bring the majority of this production back online in June as crude oil prices recovered, with minimal incremental cost.

We did not experience any further curtailments to our production during the remainder of 2020, and we recommenced drilling and completion activity in the third quarter of 2020. We completed an additional 5 gross operated wells during August of 2020 with an effective lateral length of approximately 9,000 feet, which were previously drilled during the first quarter of 2020. Further, we initiated a one-rig drilling program at the end of the third quarter, which we operated through the remainder of the year and added a second drilling rig in December. During the second half of 2020, we drilled six gross operated wells to total depth and began drilling an additional three gross operated wells, all of which we plan to complete in the first quarter of 2021.

Financing Highlights

On May 22, 2020, we completed an opportunistic private exchange of our debt pursuant to which $110.6 million aggregate principal amount of CRP's 5.375% senior unsecured notes due 2026 (the "2026 Senior Notes") and $143.7 million aggregate principal amount of CRP's 6.875% senior unsecured notes due 2027 (the "2027 Senior Notes" and, together with the 2026 Senior Notes, the "Senior Unsecured Notes") were validly tendered and exchanged by certain eligible bondholders for consideration consisting of $127.1 million aggregate principal amount (the "Debt Exchange") of newly issued 8.00% second lien senior secured notes due 2025 (the "Senior Secured Notes"). This transaction resulted in the removal of $127.1 million in aggregate principal amount of Senior Unsecured Notes from the long-term debt balance in our consolidated balance sheets.

On May 1, 2020, we entered into the second and third amendments to CRP's amended and restated credit agreement (the "Q2 2020 Amendments") with the lenders to our existing credit agreement. Pursuant to the Q2 2020 Amendments, the borrowing base and level of elected commitments were both reduced to $700.0 million from their previous amounts of $1.2 billion and $800.0 million, respectively. The Q2 2020 Amendments, which were approved by the lenders, permitted the issuance of the Senior Secured Notes in connection with the Debt Exchange, and they implemented an availability blocker of $31.8 million equal to 25% of the newly issued and outstanding Senior Secured Notes. Among other things, the Q2 2020 Amendments also suspended the total funded debt to EBITDAX ratio (as specified in the existing credit agreement) through year-end 2021 and introduced a new financial covenant testing the ratio of first lien debt to EBITDAX.

In connection with the credit facility's fall 2020 semi-annual redetermination process, the borrowing base and amount of elected commitments were reaffirmed at $700.0 million.

Results of Operations

For the Year Ended December 31, 2020 Compared to the Year Ended December 31, 2019

The following table provides the components of our net revenues and net production (net of all royalties, overriding royalties and production due to others) for the periods indicated, as well as each period's average prices and average daily production volumes:

	Year Ended December 31,		Increase/(Decrease)	
	2020	2019	$	%
Net revenues (in thousands):				
Oil sales	$ 475,694	$ 810,655	$ (334,961)	(41)%
Natural gas sales	46,776	44,556	2,220	5 %
NGL sales	57,986	89,119	(31,133)	(35)%
Oil and gas sales	$ 580,456	$ 944,330	$ (363,874)	(39)%
Average sales price:				
Oil (per Bbl)	$ 36.02	$ 52.02	$ (16.00)	(31)%
Effect of derivative settlements on average price (per Bbl)	(3.15)	(1.13)	(2.02)	(179)%
Oil net of hedging (per Bbl)	$ 32.87	$ 50.89	$ (18.02)	(35)%
Average NYMEX price for oil (per Bbl)	$ 39.44	$ 57.03	$ (17.59)	(31)%
Oil differential from NYMEX	(3.42)	(5.01)	1.59	32 %
Natural gas (per Mcf)	$ 1.13	$ 1.07	$ 0.06	6 %
Effect of derivative settlements on average price (per Mcf)	(0.12)	0.29	(0.41)	(141)%
Natural gas net of hedging (per Mcf)	$ 1.01	$ 1.36	$ (0.35)	(26)%
Average NYMEX price for natural gas (per Mcf)	$ 1.99	$ 2.52	$ (0.53)	(21)%
Natural gas differential from NYMEX	(0.86)	(1.45)	0.59	41 %
NGL (per Bbl)	$ 12.91	$ 17.03	$ (4.12)	(24)%
Net production:				
Oil (MBbls)	13,207	15,582	(2,375)	(15)%
Natural gas (MMcf)	41,302	41,703	(401)	(1)%
NGL (MBbls)	4,490	5,234	(744)	(14)%
Total (MBoe)(1)	24,581	27,766	(3,185)	(11)%
Average daily net production:				
Oil (Bbls/d)	36,084	42,692	(6,608)	(15)%
Natural gas (Mcf/d)	112,848	114,254	(1,406)	(1)%
NGL (Bbls/d)	12,269	14,338	(2,069)	(14)%
Total (Boe/d)(1)	67,161	76,072	(8,911)	(12)%

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the year ended December 31, 2020 were lower by $363.9 million, or 39%, compared to the year ended December 31, 2019. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Average realized sale prices for oil and NGLs decreased for the year ended December 31, 2020 as compared to 2019. The average price for oil before the effects of hedging decreased 31% and the average price for NGLs decreased 24% between periods. The 31% decrease in the average realized oil price was the result of lower NYMEX crude prices in 2020 (average NYMEX oil prices decreased 31%), which was minimally offset by improved oil differentials of $1.59 per Bbl during 2020. The

24% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products in 2020. Conversely, the average realized sales price of natural gas before the effects of hedging increased 6% in 2020 as compared to 2019. This increase was mainly due to improved gas differentials ($0.59 per Mcf), which was partially offset by lower average NYMEX gas prices (down $0.53 per Mcf) between periods. The improvement in gas differentials is the result of higher natural gas prices realized in West Texas as several producers shut-in wells and curtailed production in the Permian Basin during the year and as new pipelines have been placed into service. These pipelines have provided relief from the gas takeaway capacity constraints experienced in 2019. The market prices for oil, natural gas and NGLs have all been significantly impacted by lower demand globally for oil and gas as a result of COVID-19 as well as by supply disruptions from the Russia-Saudi oil price war early in 2020, which combined have resulted in significant price declines starting in March 2020 as discussed in the market conditions section above.

Net production volumes for oil, natural gas, and NGLs decreased 15%, 1% and 14%, respectively, between periods. The oil production volume decrease between periods was the result of (i) the temporary suspension of our drilling and completion activity during most of the second and third quarters of 2020, which resulted in only 31 new wells being completed and brought online during 2020 and added 2,849 MBbls of net oil production during the year ended December 31, 2020 as compared to 84 wells completed and brought online during 2019 adding 5,611 MBbls of net oil production during the year ended December 31, 2019; (ii) the curtailment of a portion of our production during the second quarter of 2020; and (iii) normal field production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, typically resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. However, during 2020, we flared significantly less wellhead gas as compared to 2019, resulting in a higher ratio of natural gas and NGL sales compared to oil sales in the period. In addition, for over half of 2020, the main processor of our raw gas operated in ethane-rejection as compared to operating in ethane-recovery during the majority of 2019. As a result, we sold an increased amount of natural gas from our wet gas stream and recovered fewer NGLs during the 2020 period, resulting in a lower decline in natural gas volumes (down 1%) as compared to the 14% decrease in NGL volumes between periods.

Operating Expenses. The following table sets forth selected operating expense data for the periods indicated:

	Year Ended December 31,		Increase/(Decrease)	
	2020	**2019**	**$**	**%**
Operating costs (in thousands):				
Lease operating expenses	$ 109,282	$ 145,976	$ (36,694)	(25)%
Severance and ad valorem taxes	39,417	63,200	(23,783)	(38)%
Gathering, processing, and transportation expense	71,309	72,834	(1,525)	(2)%
Operating costs per Boe:				
Lease operating expenses	$ 4.45	$ 5.26	$ (0.81)	(15)%
Severance and ad valorem taxes	1.60	2.28	(0.68)	(30)%
Gathering, processing, and transportation expense	2.90	2.62	0.28	11 %

Lease Operating Expenses. Lease operating expenses ("LOE") for the year ended December 31, 2020 decreased $36.7 million compared to the year ended December 31, 2019. Lower LOE for 2020 was primarily related to a $21.9 million decrease in workover expense between periods as a result of less workover activity and a $14.8 million decrease in well operating expenses associated with cost reduction initiatives, described below, as well as lower variable and semi-variable costs stemming from the 11% production decline between periods. These decreases were partially offset by LOE costs associated with our higher well count in 2020. We had 386 gross operated horizontal wells as of December 31, 2020 compared to 349 gross operated horizontal wells as of December 31, 2019. The net increase in well count was mainly the result of our drilling activity adding 31 gross operated wells in 2020, which was further adjusted for acquisitions and divestitures.

LOE on a per Boe basis decreased when comparing the year ended December 31, 2020 to the year ended December 31, 2019. LOE per Boe was $4.45 for the year ended December 31, 2020, which represents a decrease of $0.81 per Boe (or 15%) from 2019. This decrease in rate was mainly due to the lower level of workover activity discussed above as well as cost reduction initiatives we have undertaken such as (i) moving multiple wells off generators to more cost-efficient electrical line-power, (ii) switching wells away from electric submersible pumps ("ESPs") to more reliable and lower cost gas lift, and (iii) performing field reviews to reduce or eliminate various costs for contract labor, oilfield equipment and supplies. These decreases were partially offset by per BOE cost increases between periods associated with fixed and semi-variable costs that don't decrease at the same rate as declines in production such as monthly rental fees for compressors and other equipment, wellhead chemical costs, and water handling costs.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the year ended December 31, 2020 decreased $23.8 million compared to the year ended December 31, 2019. Severance taxes are primarily based on the market value of our production at the wellhead, while ad valorem taxes are generally based on the assessed taxable value of proved developed oil and natural gas properties and vary across the different counties in which we operate. Severance taxes for the year ended 2020 decreased $17.9 million compared to the same 2019 period primarily due to lower oil, natural gas and NGL revenues between periods. Ad valorem taxes decreased $5.9 million between periods due to lower tax assessments on our oil and gas reserve values. Severance and ad valorem taxes as a percentage of total net revenues remained consistent between periods at 6.8% and 6.7% for the years ended December 31, 2020 and 2019, respectively.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation costs ("GP&T") for the year ended December 31, 2020 decreased $1.5 million compared to the year ended December 31, 2019 due to an $8.3 million decrease in plant processing, transportation and gathering fees incurred between periods as a result of lower wellhead production in 2020. This was partially offset by a $6.5 million decrease in reimbursements (net of related fees) received from third parties for their usage of our available firm transportation capacity.

On a per Boe basis, GP&T increased 11% from $2.62 for the year ended December 31, 2019 to $2.90 per Boe for the year ended December 31, 2020. On a natural gas and NGLs volume basis (i.e. excluding crude oil barrels) the Boe rate likewise increased between periods from $5.98 to $6.27 for the year ended December 31, 2019 and 2020, respectively. These rate increases were mainly attributable to a lower amount of FT reimbursements (net of related fees) for the usage of our available FT capacity as referenced above.

Depreciation, Depletion, and Amortization. The following table summarizes our depreciation, depletion and amortization ("DD&A") for the periods indicated:

	Year Ended December 31,	
(in thousands, except per Boe data)	**2020**	**2019**
Depreciation, depletion and amortization	$ 358,554	$ 444,243
Depreciation, depletion and amortization per Boe	$ 14.59	$ 16.00

Our DD&A rate can fluctuate as a result of finding and development costs incurred, acquisitions, impairments, as well as changes in proved developed reserves and proved undeveloped reserves. For the year ended December 31, 2020, DD&A expense amounted to $358.6 million, a decrease of $85.7 million over 2019. The primary factor contributing to lower DD&A expense in 2020 was the decrease in our overall production volumes between periods, which decreased DD&A expense by $51.0 million for the year ended December 31, 2020, while lower DD&A rates between periods lowered DD&A expense by $34.7 million.

DD&A per Boe was $14.59 for the year ended December 31, 2020 compared to $16.00 in 2019. This decrease in DD&A rate was primarily due to (i) the proved property impairment recognized in the first quarter of 2020, which lowered the carrying value of our depletion base by $591.8 million and (ii) upward revisions to proved developed reserves of 18.3 MMBoe for the year ended December 31, 2020 related to lower operating costs that we realized during 2020, which were partially offset by downward revisions associated with lower SEC reserve pricing.

Impairment and Abandonment Expense. For the year ended December 31, 2020, $691.2 million of impairment and abandonment expense was incurred related to certain of our oil and gas properties. This expense consisted of (i) a $591.8 million non-cash impairment of our proved properties in the first quarter as a result of the depressed NYMEX oil and gas futures curves as of March 31, 2020; (ii) $78.8 million related to the amortization of leasehold expiration costs associated with individually insignificant unproved properties, and (iii) a $20.6 million non-cash impairment of other noncurrent assets, which represented advances paid to a third-party broker to acquire exploratory leasehold acres on our behalf, which acres are not currently included in our current development plan.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that the fair value of these assets may be below their carrying value. Fair values of our oil and natural gas properties are estimated using an income approach that is based on the discounted expected future net cash flows from these assets. These valuations are based on inputs which require significant judgment and include estimates of: (i) oil and gas reserves quantities; (ii) future production decline rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; and (v) a market participant-based weighted-average cost of capital discount rate.

We performed an impairment assessment of all our proved oil and gas properties as of March 31, 2020. Two of our fields were subject to impairment write-downs as quantified above, but the remaining five fields were not impaired due to their undiscounted cash flows exceeding their carrying values by 30% to over 100%. This impairment assessment was performed using commodity price futures curves as of March 31, 2020. If future oil, natural gas and NGL prices were to decline to lower levels, or other estimates impacting future net cash flows deteriorate (e.g. reserves, price differentials, future operating and/or development costs), our proved oil and gas properties could be subject to additional impairment write-downs in future periods. We did not recognize any additional impairment write-downs with respect to our proved oil and gas properties for the remainder of 2020.

For the year ended December 31, 2019, $47.2 million of impairment and abandonment expense was incurred related to undeveloped leasehold acreage. This expense consisted of (i) $19.1 million related to non-core acreage that expired during 2019 after efforts to extend, sell or trade these leases were unsuccessful, (ii) $16.6 million for impaired acreage following an acreage sale initiated in the first quarter of 2019, and (iii) $11.5 million related to the amortization of leasehold expiration costs associated with individually insignificant unproved properties.

Exploration and Other Expenses. The following table summarizes exploration and other expenses for the periods indicated:

	Year Ended December 31,	
(in thousands)	**2020**	**2019**
Geological and geophysical costs	$ 4,533	$ 8,424
Stock-based compensation - equity awards	1,433	2,682
Stock-based compensation - liability awards	90	—
Exploratory dry hole costs	6,615	—
Rig termination fees	3,046	284
Severance payments	722	—
Other expenses	1,916	—
Exploration and other expenses	$ 18,355	$ 11,390

Exploration and other expenses were $18.4 million for the year ended December 31, 2020 compared to $11.4 million for the year ended December 31, 2019. Exploration and other expenses mainly consists of topographical studies, geographical and geophysical ("G&G") projects, salaries and expenses of G&G personnel and includes other operating costs. The period over period increase was primarily related to (i) $6.6 million in exploratory dry hole costs incurred in 2020; (ii) $2.8 million in higher rig termination fees as a result of temporarily suspending drilling activity in 2020; and (iii) $1.7 million in environmental remediation costs incurred in 2020 associated with a recently acquired proved property. These increases were partially offset by (i) a $1.7 million decrease in G&G project and seismic costs incurred between periods, and (ii) $2.2 million in lower G&G personnel costs and $1.2 million in lower stock-based compensation in the 2020 period, both of which were associated with the lower headcount from our 2020 workforce reduction (as further described below under General and Administrative Expenses).

General and Administrative Expenses. The following table summarizes our general and administrative ("G&A") expenses for the periods indicated:

	Year Ended December 31,	
(in thousands)	**2020**	**2019**
Cash general and administrative expenses	$ 46,356	$ 52,841
Stock-based compensation - equity awards	19,533	26,315
Stock-based compensation - liability awards	3,512	—
Severance payments	3,466	—
General and administrative expenses	$ 72,867	$ 79,156

G&A expenses for the year ended December 31, 2020 were $72.9 million compared to $79.2 million for the year ended December 31, 2019. Lower G&A expenses incurred in 2020 were primarily the result of a reduction to our workforce and reduced salaries effective May 1, 2020 for employees that were retained. These two factors combined resulted in a $5.4 million decrease in payroll and other personnel related costs and a $6.8 million decrease in equity-based stock compensation expense between periods. In addition, in 2019 we incurred a $1.8 million charge for the settlement of a water disposal contract dispute that did not re-occur in 2020. These decreases were partially offset by 2020 charges related to (i) $3.5 million of nonrecurring severance payments paid to G&A employees who were included in our workforce reduction and (ii) $3.5 million in stock compensation expense related to liability awards granted to G&A employees in the third quarter of 2020 that we will settle in cash upon vesting. These liability stock-based awards are recorded at their respective fair values, and such fair values are re-measured each balance sheet date (refer to *Note 6—Stock-Based Compensation* under Part II, Item 8 of this Annual Report for additional information regarding the liability awards).

Other Income and Expense.

Interest Expense. The following table summarizes interest expense for the periods indicated:

(in thousands)	Year Ended December 31, 2020	2019
Credit facility	$ 12,973	$ 8,371
6.875% Senior Notes due 2027	28,368	27,309
5.375% Senior Notes due 2026	17,884	21,500
8.000% Senior Secured Notes due 2025	6,185	—
Amortization of debt issuance costs and debt discount	5,923	2,861
Interest capitalized	(2,141)	(4,050)
Total	$ 69,192	$ 55,991

Interest expense was $13.2 million higher for the year ended December 31, 2020 compared to the year ended December 31, 2019. Higher interest expense incurred during the year ended 2020 was mainly due to (i) $6.2 million in interest incurred on our new Senior Secured Notes issued in May of 2020 in connection with our Debt Exchange (refer to *Note 4—Long-Term Debt* under Part II, Item 8 of this Annual Report), (ii) $4.6 million in higher interest expense incurred on our credit facility borrowings, (iii) $3.1 million in higher amortization of debt issuance costs and the debt discount recognized in May 2020 in connection with our Debt Exchange and (iv) $1.9 million in lower capitalized interest due to our decreased capital spend in 2020. These increases were partially offset by lower interest expense incurred on our 2026 Senior Notes during the 2020 period, as $110.6 million of the 2026 Senior Notes were extinguished in our Debt Exchange transaction.

Our weighted average borrowings outstanding under our credit facility were $334.2 million during 2020 compared to $154.8 million in 2019. Our credit facility's weighted average effective interest rate (which is a LIBOR-based rate) was 3.3% for 2020 as compared to 3.7% during 2019 as a result of lower LIBOR in 2020.

Gain on exchange of debt. A gain of $143.4 million was recognized for the year ended December 31, 2020 related to our opportunistic Debt Exchange that was executed in the second quarter of 2020. This gain was determined based on the difference between the carrying value of the Senior Unsecured Notes extinguished less the fair value of our newly issued Senior Secured Notes on their date of issuance. Refer to *Note 4—Long-Term Debt* under Part II, Item 8 of this Annual Report for additional information regarding the gain on exchange of debt.

Net Gain (Loss) on Derivative Instruments. Net gains and losses are a function of (i) fluctuations in mark-to-market derivative fair values associated with changes in the forward price curves for the commodities underlying our hedge contracts outstanding and (ii) monthly settlements of our hedged derivative positions.

The following table presents gains and losses on our derivative instruments for the periods indicated:

(in thousands)	Year Ended December 31, 2020	2019
Realized cash settlement gains (losses)	$ (46,651)	$ (5,655)
Non-cash mark-to-market derivative gain (loss)	(17,884)	4,094
Total	$ (64,535)	$ (1,561)

Income Tax (Expense) Benefit: The following table summarizes our pre-tax income (loss) and income tax (expense) benefit for the periods indicated.

(in thousands)	Year Ended December 31, 2020	2019
Income (loss) before income taxes	$ (770,323)	$ 22,211
Income tax (expense) benefit	85,124	(5,797)

Our provision for income taxes for the years ended December 31, 2020 and 2019 differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax book income (loss) primarily due to (i) permanent differences; (ii) state income taxes; and (iii) any changes during the period in our deferred tax asset valuation allowance.

For the year ended December 31, 2020, we recognized a deferred tax asset valuation allowance of $77.0 million against net operating losses that we generated during the period, which are estimated as unlikely to be realized in future periods. This increase in valuation allowance was the primary factor reducing our income tax benefit for the year ended December 31, 2020 from the U.S. statutory rate to $85.1 million.

For the year ended December 31, 2019, we recognized a discrete permanent item of $1.7 million for lower deductions on stock awards that vested during the period, which was partially offset by a decrease in a projected permanent item of $0.8 million related to future stock compensation not expected to be deductible. These items were the primary factors increasing our income tax expense for the year ended December 31, 2019 from the U.S. statutory rate to $5.8 million.

For the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Refer to *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in the 2019 Annual Report on Form 10-K filed with the SEC for a discussion of the results of operations for the year ended December 31, 2019 compared to the year ended December 31, 2018.

Liquidity and Capital Resources

Overview

Our drilling and completion and land acquisition activities require us to make significant capital expenditures. Historically, our primary sources of liquidity have been cash flows from operations, borrowings under CRP's revolving credit facility, and proceeds from offerings of debt or equity securities. Future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly in March 2020 and have remained volatile since. These lower commodity prices negatively impact our operating cash flows and our ability to access debt or equity markets, and sustained low oil and natural gas prices could have a material and adverse effect on our liquidity position. To date, our primary use of capital has been for drilling and development capital expenditures and for the acquisition of oil and natural gas properties. The following table summarizes our capital expenditures ("capex") incurred during the year:

(in millions)	Year Ended December 31, 2020
Drilling and completion capital expenditures	$ 212.0
Facilities, infrastructure and other	38.2
Land	4.6
Total capital expenditures	$ 254.8

We continually evaluate our capital needs and compare them to our capital resources. As a result of the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment, we temporarily suspended all drilling and completion activities at the end of the first quarter of 2020 in order to preserve capital. Specifically, we reduced our operated drilling rig program to zero rigs starting in April of 2020 and continued with no drilling rigs in operation until the end of September 2020 when we resumed drilling activity with a one-rig program. Of our $212.0 million in drilling and completion capital expenditures incurred during the year ended December 31, 2020, approximately 70% was incurred during the first quarter of 2020. We operated one drilling rig during the entire fourth quarter, added a second drilling rig in late December 2020, and we plan to continue to operate a two rig program through 2021. We expect our total capex budget for 2021 to be between $260 million to $310 million, of which $250 million to $290 million is allocated to drilling, completion and facilities activity. We expect to fund our capex budget entirely from cash flows from operations given current commodity price levels. We were free cash flow positive during the second half of 2020 such that we were able to partially pay down borrowings under our credit agreement during the third and fourth quarters of 2020. Based upon current commodity prices, we expect to continue to pay down borrowings through expected free cash flow generation during 2021.

Because we are the operator of a high percentage of our acreage, we can control the amount and timing of our capital expenditures. We can choose to defer or accelerate a portion of our planned capex depending on a variety of factors, including but not limited to: prevailing and anticipated prices for oil and natural gas; oil storage or transportation constraints; the success of our drilling activities; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; seasonal conditions; property or land acquisition costs; and the level of participation by other working interest owners.

Given the weakness in realized oil prices, we voluntarily curtailed or shut-in a portion of our second quarter 2020 production volumes. Specifically, we curtailed approximately 20% of our production during the month of May but were able to bring the majority of our production back online in June as crude oil prices recovered. We did not experience any further curtailments of our production during the remainder of the year, but curtailments could occur in the future as a result of depressed market conditions, storage and transportation constraints and weather. Any decision in the future to curtail or shut-in our production or reduce our drilling and completion activity could adversely affect our business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures.

We cannot ensure that cash flows from operations will be available or other sources of needed capital on acceptable terms or at all. Further, our ability to access the public or private debt or equity capital markets at economic terms in the future will be affected by general economic conditions, the domestic and global oil and financial markets, our operational and financial performance, the value and performance of our debt or equity securities, prevailing commodity prices and other macroeconomic factors outside of our control.

Moreover, in order to manage our future financing cash outflows and improve our liquidity position, we completed the Debt Exchange with respect to our Senior Unsecured Notes in May 2020, which reduced the total principal amounts due of our aggregated secured and unsecured notes by $127.1 million and also reduced future interest payments.

Analysis of Cash Flow Changes

The following table summarizes our cash flows for the periods indicated:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Net cash provided by operating activities	$ 171,376	$ 564,173	$ 670,011
Net cash used in investing activities	(326,323)	(932,989)	(1,068,664)
Net cash provided by financing activities	147,743	362,937	294,160

Cash Flows from 2020 Compared to 2019. For the year ended December 31, 2020, we generated $171.4 million of cash from operating activities, a decrease of $392.8 million from 2019. Cash provided by operating activities decreased primarily due to lower realized prices for oil and NGLs, lower production volumes for crude oil, residue gas and NGLs, higher exploration and other expenses, interest payments, cash settlement losses on derivatives, and the timing of vendor payments during 2020 as compared to 2019. These declining factors were partially offset by higher realized natural gas prices, lower lease operating expenses, production taxes, GP&T costs, cash G&A expenses, and the timing of our receivable collections during 2020 as compared to the same 2019 period. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and on fluctuations in our operating costs periods.

For the year ended December 31, 2020, cash flows from operating activities, cash on hand, and net borrowings of $155.0 million under our credit facility were used to finance $318.5 million of drilling and development cash expenditures, to fund $8.5 million in oil and gas property acquisitions, and to finance $6.7 million of debt issuance and exchange costs.

Cash Flows from 2019 Compared to 2018. For the year ended December 31, 2019, we generated $564.2 million of cash from operating activities, a decrease of $105.8 million from 2018. Cash provided by operating activities decreased primarily due to lower realized prices for crude oil, natural gas and NGLs, higher lease operating expenses, severance and ad valorem taxes, GP&T costs, exploration expense, cash G&A expenses, interest payments, cash settlement losses from derivatives and the timing of our supplier payments during 2019. These declining factors were partially offset by higher crude oil, natural gas and NGL production volumes and the timing of our receivable collections during 2019 as compared to the 2018 period.

For the year ended December 31, 2019, cash flows from operating activities, cash on hand, proceeds from sales of oil and gas properties and proceeds from the issuance of our 2027 Senior Notes were used to repay net borrowings of $125.0 million under our credit facility, to finance $855.2 million of drilling and development capex, to fund $103.7 million in oil and gas property acquisitions and to purchase $8.9 million of other property and equipment.

Credit Agreement

CRP, our consolidated subsidiary, has a credit agreement with a syndicate of banks that provides for a five-year secured revolving credit facility, maturing on May 4, 2023 (the "Credit Agreement"). On May 1, 2020, CRP as borrower and we, as parent guarantor, entered into the Q2 2020 Amendments, which among other things established a new borrowing base of $700.0 million and a new level of elected commitments also $700.0 million. The Q2 2020 Amendments that the lenders approved permitted the issuance of the Senior Secured Notes in connection with the Debt Exchange (discussed below), and they implemented an availability blocker equal to 25% of the newly issued amount of Senior Secured Notes. As of December 31, 2020, we had $330.0 million in borrowings outstanding and $333.9 million in available borrowing capacity, which was net of $4.3 million in letters of credit outstanding and the availability blocker of $31.8 million. In connection with the Credit Agreement's fall 2020 semi-annual borrowing base redetermination, the borrowing base and amount of elected commitments were both reaffirmed at $700.0 million.

CRP's Credit Agreement contains restrictive covenants that limit its ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make or declare dividends; (v) enter into commodity hedges exceeding a specified percentage of our expected production; (vi) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (vii) incur liens; (viii) sell assets; and (ix) engage in transactions with affiliates.

CRP's credit agreement also requires it to maintain compliance with the following financial ratios:

(i) a current ratio, which is the ratio of CRP's consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0;

(ii) a first lien leverage ratio, as defined within the Credit Agreement as the ratio of first lien debt to EBITDAX for the rolling four fiscal quarter period, which may not exceed 2.75 to 1.00 beginning with the quarter ending June 30, 2020 and extending through the quarter ending December 31, 2021, after which the maximum ratio shall decrease to 2.50 to 1.00 for each of the quarters ending in 2022; and

(iii) a leverage ratio, as defined within the Credit Agreement as the ratio of total funded debt to consolidated EBITDAX for the rolling four fiscal quarter period. Pursuant to the Q2 2020 Amendments, the leverage ratio is suspended until March 31, 2022, at which time, the ratio may not exceed 5.00 to 1.00, with such maximum ratio declining at a rate of 0.25 for each succeeding quarter until March 31, 2023 when the ratio is set at not greater than 4.0 to 1.0.

CRP was in compliance with the covenants and applicable financial ratios described above as of December 31, 2020 and through the filing of this Annual Report.

For further information on the Credit Agreement, refer to *Note 4—Long-Term Debt* under Part II, Item 8 of this Annual Report.

Senior Unsecured Notes Debt Exchange and Senior Secured Notes

On May 22, 2020, CRP completed the Debt Exchange pursuant to which $110.6 million aggregate principal amount of CRP's 2026 Senior Notes and $143.7 million aggregate principal amount of CRP's 2027 Senior Notes were validly tendered and exchanged by certain eligible bondholders for consideration consisting of $127.1 million aggregate principal amount of newly issued Senior Secured Notes. The Senior Secured Notes bear interest at an annual rate of 8% and are due on June 1, 2025. Interest is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2020.

The Debt Exchange was accounted for as an extinguishment of debt in accordance with Financial Accounting Standards Board's Accounting Standard Codification Topic 470-50, *Modifications and Extinguishments*. As a result, a gain on the exchange of debt of $143.4 million was recognized in the consolidated statement of operations, which consisted of the carrying values of the Senior Unsecured Notes exchanged less the aggregate principal amount of new Senior Secured Notes issued, net of their associated debt discount of $21.0 million (which was based on the Senior Secured Notes' estimated fair value on the exchange date).

The Senior Secured Notes are guaranteed, subject to certain exceptions, by us and each of CRP's subsidiaries and are secured on a second-priority basis (subject in priority only to certain exceptions) by substantially all of CRP's and our assets, including deposit accounts and substantially all proved reserves and undeveloped acreage.

Senior Unsecured Notes

On November 30, 2017, CRP issued $400.0 million of 5.375% senior notes due 2026 and on March 15, 2019, CRP issued $500.0 million of 6.875% senior notes due 2027 in 144A private placements. The Senior Unsecured Notes are fully and unconditionally guaranteed on a senior unsecured basis by Centennial and each of CRP's current subsidiaries that guarantee CRP's revolving credit facility. In May 2020, a portion of the Senior Unsecured Notes were exchanged for Senior Secured Notes (see above discussion for details of the Debt Exchange).

The indentures governing the Senior Unsecured Notes and Senior Secured Notes (collectively, the "Senior Notes") contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP's ability and the ability of CRP's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of December 31, 2020 and through the filing of this Annual Report.

For further information on our Senior Notes, refer to *Note 4—Long-Term Debt* under Part II, Item 8 of this Annual Report.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2020, we had no off-balance sheet arrangements.

Contractual Obligations

We routinely enter into or extend operating and transportation agreements, office and equipment leases, drilling rig contracts, among others, in the ordinary course of business. The following table summarizes our obligations and commitments as of December 31, 2020 to make future payments under long-term contracts for the time periods specified below.

(in thousands)	2021	2022	2023	2024	2025	Thereafter	Total
Operating leases[1]	$ 3,260	$ 425	$ —	$ —	$ —	$ —	$ 3,685
Water disposal agreements[2]	1,825	100	—	—	—	—	1,925
Asset retirement obligations[3]	384	—	—	457	—	16,168	17,009
Long term debt obligations[4]	—	—	330,000	—	127,073	645,799	1,102,872
Cash interest expense on long-term debt obligations[5]	62,319	62,319	58,749	50,223	44,290	30,547	308,447
Transportation agreements[6]	9,060	1,770	—	—	—	—	10,830
Total	$ 76,848	$ 64,614	$ 388,749	$ 50,680	$ 171,363	$ 692,514	$ 1,444,768

(1) Operating leases include our office rental agreements and other wellhead equipment. Please refer to *Note 15—Leases* under Part II, Item 8 of this Annual Report for details on our operating lease commitments.

(2) Water disposal agreements consist of contracts for transportation and disposal of produced water from our operated wells. Under the terms of these agreements, we are obligated to deliver a minimum volume of produced water or else pay for any deficiencies at the prices stipulated in the contracts. The obligations reported above represent our remaining minimum financial commitments pursuant to the terms of these contracts as of December 31, 2020. Actual expenditures under these contracts may exceed the minimum commitments presented above.

(3) Asset retirement obligations reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and gas wells and the related land restoration in accordance with applicable laws and regulations.

(4) Long-term debt consists of the principal amounts of the Senior Notes due and borrowings outstanding under the Credit Agreement maturing on May 4, 2023.

(5) Cash interest expense on the Senior Notes is estimated assuming no principal repayment until the maturity of the instruments. Cash interest expense on the Credit Agreement includes unused commitment fees and assumes no additional principal borrowings, repayments or changes to commitments under the agreement through the instrument due date.

(6) Transportation agreements include various firm natural gas transportation contracts whereby we are required to pay fixed pipeline capacity reservation fees over the contractual terms. The obligations reported above represent minimum financial commitments pursuant to the terms of these contracts. However, our expenditures under these contracts are likely to exceed the minimum commitments presented above.

Recently Issued Accounting Standards

There were no significant new accounting standards adopted or new accounting pronouncements that would have a potential effect on us as of December 31, 2020.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these statements requires us to make certain assumptions, judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as, the disclosure of contingent assets, contingent liabilities and commitments as of the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, commodity prices, production performance, drilling results, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies can be found in *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, Item 8. Financial Statements and Supplementary Data in this Annual Report.

We have outlined certain of our accounting policies below which require the application of significant judgment by our management.

Oil and Natural Gas Reserve Quantities

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil, natural gas and NGL reserves. Reserve quantities and the related estimates of future net cash flows are used as inputs to our calculation of depletion, evaluation of proved properties for impairment, assessment of the expected realizability of our deferred income tax assets, and the standardized measure of discounted future net cash flows computations.

The process of estimating quantities of proved reserves is inherently imprecise and relies on the following: i) interpretations and judgment of available geological, geophysical, engineering and production data; ii) certain economic assumptions, some of which are mandated by the SEC, such as commodity prices; and iii) assumptions and estimates of underlying inputs such as operating expenses, capital expenditures, plug and abandonment costs and taxes. All of these assumptions may differ substantially from actual results, which could result in a significant change in our estimated quantities of proved reserves and their future net cash flows. We continually make revisions to reserve estimates throughout the year as additional information becomes available, and we make changes to depletion rates in the same period that changes to reserve estimates are made.

Impairment of Oil and Natural Gas Properties

We assess our proved properties for impairment when events or changes in circumstances indicate that the carrying value of such proved property assets may not be recoverable. For purposes of an impairment evaluation, our proved oil and natural gas properties must be grouped at the lowest level for which independent cash flows can be identified. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to its estimated fair value. Fair value for the purpose of testing impairment is calculated using the present value of expected future cash flows that are estimated to be generated from the asset group. Fair value estimates are based on projected financial information which we believe to be reasonably likely to occur, as of the date that the impairment write-down is being measured. However, such future cash flow estimates are based on numerous assumptions that can materially affect our estimates, and such assumptions are subject to change with variations in commodity prices, production performance, drilling results, operating and development costs, underlying oil and gas reserve quantities, and other internal or external factors.

Unproved properties consist of the costs we incurred to acquire undeveloped leasehold acreage as well as the costs we incurred to acquire unproved reserves. Unproved properties with individually significant acquisition costs are periodically assessed for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or changes in future plans to develop acreage. Unproved properties which are not individually significant are amortized by prospect, based on our historical experience, current drilling plan, existing geological data and average remaining lease terms. Changes in our assumptions as to the estimated nonproductive portion of our undeveloped leases could result in additional impairment charges.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The term "market risk" as it applies to our business refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates, and we are exposed to market risk as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes of mitigating our potential for losses arising from our exposure to market risks and were not entered into for speculative trading purposes.

Commodity Price Risk

Our primary market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue for the foreseeable future. Based on our production for the year ended December 31, 2020, our oil and gas sales for the year ended December 31, 2020 would have moved up or down $47.6 million for each 10% change in oil prices per Bbl, $4.7 million for each 10% change in NGL prices per Bbl, and $5.8 million for each 10% change in natural gas prices per Mcf.

Due to this volatility, we have historically used and will continue to selectively use, commodity derivative instruments (such as collars, swaps and basis swaps) to mitigate price risk associated with a portion of our anticipated production. Our derivative instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in oil and natural gas prices and thereby provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil and natural gas prices, and they also partially limit our gains from potential future increases in price. Our Credit Agreement limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production from proved properties.

Refer to *Note 7—Derivative Instruments* under Part II, Item 8 of this Annual Report for open derivative positions as of December 31, 2020. The following table summarizes the terms of the derivative contracts we had in place as of December 31, 2020 and additional contracts entered into through February 19, 2021:

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Crude Price ($/Bbl)(1)
Crude oil swaps				
NYMEX WTI	January 2021 - March 2021	990,000	11,000	$41.48
	April 2021 - June 2021	1,183,000	13,000	43.18
	July 2021 - September 2021	736,000	8,000	45.87
	October 2021 - December 2021	644,000	7,000	45.59
ICE Brent	January 2021 - March 2021	270,000	3,000	$46.85
	April 2021 - June 2021	409,500	4,500	54.98
	July 2021 - September 2021	184,000	2,000	48.25
	October 2021 - December 2021	184,000	2,000	48.50

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Collar Price Ranges ($/Bbl)(2)
Crude oil collars	January 2021 - March 2021	315,000	3,500	$ 40.00 - $ 48.14
	April 2021 - June 2021	227,500	2,500	42.00 - 51.14
	July 2021 - September 2021	92,000	1,000	42.00 - 50.10
	October 2021 - December 2021	92,000	1,000	42.00 - 50.10

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)(3)
Crude oil basis differential swaps	January 2021 - March 2021	990,000	11,000	$0.01
	April 2021 - June 2021	1,183,000	13,000	0.11
	July 2021 - September 2021	736,000	8,000	0.26
	October 2021 - December 2021	644,000	7,000	0.26

(1) These crude oil swap transactions are settled based on the NYMEX WTI or ICE Brent oil price on each trading day within the specified monthly settlement period versus the contractual swap price for the volumes stipulated.

(2) These crude oil collars are settled based on the NYMEX WTI price on each trading day within the specified monthly settlement period versus the contractual floor and ceiling prices for the volumes stipulated.

(3) These oil basis swap transactions are settled based on the difference between the arithmetic average of the ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices, during each applicable monthly settlement period.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)(1)
Natural gas swaps	January 2021 - March 2021	5,400,000	60,000	$2.91
	April 2021 - June 2021	3,640,000	40,000	2.89
	July 2021 - September 2021	3,680,000	40,000	2.89
	October 2021 - December 2021	3,680,000	40,000	2.95
	January 2022 - March 2022	1,800,000	20,000	3.00

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Collar Price Ranges ($/MMBtu)(2)
Natural gas collars	January 2021 - March 2021	1,800,000	20,000	$ 2.90 - $ 3.64

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Differential ($/MMBtu)(3)
Natural gas basis differential swaps	January 2021 - March 2021	1,800,000	20,000	$(0.30)
	April 2021 - June 2021	3,640,000	40,000	(0.30)
	July 2021 - September 2021	3,680,000	40,000	(0.30)
	October 2021 - December 2021	3,680,000	40,000	(0.28)
	January 2022 - March 2022	1,800,000	20,000	(0.26)

(1) These natural gas swap contracts are settled based on the NYMEX Henry Hub price on each trading day within the specified monthly settlement period versus the contractual swap price for the volumes stipulated.

(2) These natural gas collars are settled based on the NYMEX Henry Hub price on each trading day within the specified monthly settlement period versus the contractual floor and ceiling prices for the volumes stipulated.

(3) These natural gas basis swap contracts are settled based on the difference between the inside FERC's West Texas WAHA price and the NYMEX price of natural gas, during each applicable monthly settlement period.

Changes in the fair value of derivative contracts from December 31, 2019 to December 31, 2020, are presented below:

(in thousands)	**Commodity derivative asset (liability)**
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2019	$ (325)
Commodity hedge contract settlement payments, net of any receipts	46,651
Cash and non-cash mark-to-market losses on commodity hedge contracts(1)	(64,535)
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2020	$ (18,209)

(1) At inception, new derivative contracts entered into by us have no intrinsic value.

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2020 would cause a $23.4 million increase or $24.1 million decrease in this fair value position, and a hypothetical upward or downward shift of 10% per Mcf in the NYMEX forward curve for natural gas as of December 31, 2020 would cause a $4.5 million increase or $4.4 million decrease in this same fair value position.

Interest Rate Risk

Our ability to borrow and the rates offered by lenders can be adversely affected by deteriorations in the credit markets and/or downgrades in our credit rating. The uncertainties regarding the impact of COVID-19 as well as the significant decline in March and April of 2020 in global oil and gas prices and their continued volatility throughout 2020 has impacted the credit markets, resulting in increases in market interest rates for new debt issuances in our industry. CRP's Credit Agreement interest rate is based on a LIBOR spread (subject to a 1% floor), which exposes us to interest rate risk to the extent LIBOR increases above the floor and we have borrowings outstanding. Further, LIBOR rates are expected to no longer be published beginning June 30, 2023, however, due to the structure of the Credit Agreement, we do not expect the termination of LIBOR rates to have a material impact to us.

At December 31, 2020, we had $330.0 million of debt outstanding under our Credit Agreement, with a weighted average interest rate of 3.25%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the weighted average interest rate would be approximately $3.3 million per year. We do not currently have or intend to enter into any derivative hedge contracts to protect against fluctuations in interest rates that are applicable to our outstanding indebtedness.

The remaining long-term debt balance of $738.6 million consists of our Senior Notes, which have fixed interest rates; therefore, this balance is not affected by interest rate movements. For additional information regarding our debt instruments, see *Note 4—Long-Term Debt*, in Item 8. Financial Statements and Supplementary Data in this Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CENTENNIAL RESOURCE DEVELOPMENT, INC.
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Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Centennial Resource Development, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Centennial Resource Development, Inc. and subsidiaries (the Company) as of December 31, 2020 and 2019, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 15 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Update 2016-02 Leases (ASC Topic 842).

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Estimation of oil and gas reserves on depletion expense related to proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, capitalized proved property acquisition and development costs are depleted on a units-of-production method, which is based on the estimated oil and gas reserves remaining. For the year ended December 31, 2020, the Company recorded depletion expense of proved oil and gas properties included in total depreciation, depletion and amortization expense of $358.6 million. The estimation of economically recoverable proved oil and gas reserves requires the expertise of professional petroleum reserve engineers who take into consideration forecasted production, operating and development cost assumptions and forecasted oil and gas prices inclusive of market differentials. The Company annually engages independent reserve engineers to estimate the proved oil and gas reserves and the Company's internal reserve engineers update the estimates of proved oil and gas reserves on a quarterly basis.

We identified the estimation of oil and gas reserves on depletion expense related to proved oil and gas properties as a critical audit matter. There was a high degree of subjectivity in evaluating the estimate of proved oil and gas reserves, which is a significant input into the calculation of depletion. Subjective auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production, operating and development costs, and forecasted oil and gas prices inclusive of market differentials.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's process to estimate depletion expense related to proved oil and gas properties. This included controls related to the assumptions used in the proved oil and gas reserves estimate, and to calculate depletion expense. We evaluated (1) the professional qualifications of the Company's internal reserve engineers as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm to the Company. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We assessed the data used in the average of the first-day-of-the-month pricing assumptions used in the internal reserve engineers' and the independent reserve engineers' estimates of the proved reserves by comparing them to publicly available oil and gas benchmark pricing data, calculations of historical differentials and existing contractual arrangements. We evaluated assumptions used in the internal reserve engineers' and independent reserve engineers' estimates regarding future operating and development costs by comparing them to historical information including assessing the nature and timing of future development costs compared to development plan. Additionally, we compared the forecasted production volumes to historical production, and we compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast. We read the report of the Company's independent reserve engineers in order to understand the methods and assumptions used by the independent reserve engineers in connection with our evaluation of the Company's reserve estimates. We compared reserve quantity information to the corresponding information used for depletion expense and recalculated the depletion expense for compliance with regulatory standards.

Impairment of proved oil and natural gas properties

As discussed in Note 1 to the consolidated financial statements, the Company assesses its proved oil and natural gas properties for impairment whenever events and circumstances indicate that the fair value of these assets may be below their carrying value. If an impairment indicator is identified in relation to one or more proved oil and natural gas properties, the estimated undiscounted future net cash flows are compared to the carrying amount of the proved oil and natural gas property to determine if the carrying amount is recoverable. When the carrying amount of a proved oil and natural gas property exceeds its estimated undiscounted future net cash flows, the carrying amount is written down to its estimated fair value. Estimated discounted cash flows used to estimate fair value are based on the Company's forecasted production of proved oil and natural gas reserves, commodity prices based on published forward price curves as of the date of the estimate, operating and development costs, and a market participant-based weighted average cost of capital rate. The Company recorded an impairment expense of $591.8 million for the year ended December 31, 2020 related to proved oil and natural gas properties.

We identified the assessment of the impairment of proved oil and natural gas properties as a critical audit matter. There was a high degree of subjective auditor judgment in evaluating the key assumptions used to estimate the undiscounted and discounted cash flows of proved oil and natural gas properties. The key assumptions were the estimated future commodity prices, including relevant price differentials, forecasted production of oil and natural gas reserves, risk adjustment factors associated with oil and natural gas reserves, estimated future operating and development costs, and the discount rate.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's process to assess its proved oil and natural gas properties for impairment. This included controls related to the development of the key assumptions including the estimated future commodity prices, including relevant price differentials, forecasted production of oil and natural gas reserves, risk adjustment factors associated with oil and natural gas reserves, estimated future operating and development costs, and the discount rate. We evaluated the professional qualifications, knowledge, skills and ability of the Company's internal reserve engineers. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We evaluated assumptions used in the internal reserve engineers' estimates regarding future operating and development costs based by comparing them to historical information including assessing the nature and timing of future development costs compared to development plan. Additionally, we compared the forecasted production volumes to historical production, and we compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's discount rate, by comparing it to a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the reserve category risk adjustment factors used by the Company by comparing them to third party publications of risk adjustment factors utilized by market participants
- evaluating benchmark commodity prices used by the Company in estimating future commodity prices by comparing the benchmark prices utilized to publicly disclosed commodity pricing curves

/s/ KPMG LLP

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

Denver, Colorado
February 24, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Centennial Resource Development, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Centennial Resource Development, Inc. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2021 expressed an unqualified opinion on those consolidated 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 Annual 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ KPMG LLP

Denver, Colorado

February 24, 2021

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,800	$ 10,223
Accounts receivable, net	54,557	101,912
Prepaid and other current assets	5,229	7,994
Total current assets	65,586	120,129
Property and equipment		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,209,205	1,470,903
Proved properties	4,395,473	3,962,175
Accumulated depreciation, depletion and amortization	(1,877,832)	(931,737)
Total oil and natural gas properties, net	3,726,846	4,501,341
Other property and equipment, net	12,650	14,612
Total property and equipment, net	3,739,496	4,515,953
Noncurrent assets		
Operating lease right-of-use assets	3,176	11,841
Other noncurrent assets	19,167	40,365
TOTAL ASSETS	$ 3,827,425	$ 4,688,288
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 110,439	$ 244,309
Operating lease liabilities	3,155	9,232
Other current liabilities	18,274	925
Total current liabilities	131,868	254,466
Noncurrent liabilities		
Long-term debt, net	1,068,624	1,057,389
Asset retirement obligations	17,009	16,874
Deferred income taxes	2,589	85,504
Operating lease liabilities	422	3,354
Other noncurrent liabilities	2,952	—
Total liabilities	1,223,464	1,417,587
Commitments and contingencies (Note 13)		
Shareholders' equity		
Preferred stock, $.0001 par value, 1,000,000 shares authorized:		
Series A: No shares issued and outstanding at December 31, 2020 and 1 share issued and outstanding at December 31, 2019	—	—
Common stock, $0.0001 par value, 620,000,000 shares authorized:		
Class A: 290,645,623 shares issued and 278,551,901 shares outstanding at December 31, 2020 and 280,650,341 shares issued and 275,811,346 shares outstanding at December 31, 2019	29	28
Class C (Convertible): No shares issued and outstanding at December 31, 2020 and 1,034,119 shares issued and outstanding at December 31, 2019	—	—
Additional paid-in capital	3,004,433	2,975,756
Retained earnings (accumulated deficit)	(400,501)	282,336
Total shareholders' equity	2,603,961	3,258,120
Noncontrolling interest	—	12,581
Total equity	2,603,961	3,270,701
TOTAL LIABILITIES AND EQUITY	$ 3,827,425	$ 4,688,288

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2020	2019	2018
Operating revenues			
Oil and gas sales	$ 580,456	$ 944,330	$ 891,045
Operating expenses			
Lease operating expenses	109,282	145,976	83,313
Severance and ad valorem taxes	39,417	63,200	56,523
Gathering, processing and transportation expenses	71,309	72,834	57,624
Depreciation, depletion and amortization	358,554	444,243	326,462
Impairment and abandonment expense	691,190	47,245	11,136
Exploration and other expenses	18,355	11,390	9,968
General and administrative expenses	72,867	79,156	63,304
Total operating expenses	1,360,974	864,044	608,330
Net gain (loss) on sale of long-lived assets	398	(857)	475
Income (loss) from operations	(780,120)	79,429	283,190
Other income (expense)			
Interest expense	(69,192)	(55,991)	(26,358)
Gain on exchange of debt	143,443	—	—
Net gain (loss) on derivative instruments	(64,535)	(1,561)	15,336
Other income (expense)	81	334	8
Total other income (expense)	9,797	(57,218)	(11,014)
Income (loss) before income taxes	(770,323)	22,211	272,176
Income tax (expense) benefit	85,124	(5,797)	(59,440)
Net income (loss)	(685,199)	16,414	212,736
Less: Net (income) loss attributable to noncontrolling interest	2,362	(616)	(12,837)
Net income (loss) attributable to Class A Common Stock	$ (682,837)	$ 15,798	$ 199,899
Income (loss) per share of Class A Common Stock:			
Basic	$ (2.46)	$ 0.06	$ 0.76
Diluted	$ (2.46)	$ 0.06	$ 0.75

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2020	2019	2018
Cash flows from operating activities:			
Net income (loss)	$ (685,199)	$ 16,414	$ 212,736
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	358,554	444,243	326,462
Stock-based compensation expense - equity awards	20,966	28,997	20,670
Impairment and abandonment expense	691,190	47,245	11,136
Exploratory dry hole costs	6,615	—	528
Deferred tax expense (benefit)	(85,124)	5,797	59,440
Net (gain) loss on sale of long-lived assets	(398)	857	(475)
Non-cash portion of derivative (gain) loss	17,884	(4,094)	5,274
Amortization of debt issuance costs and discount	5,923	2,861	1,749
Gain on exchange of debt	(143,443)	—	—
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	44,572	(10,098)	(33,001)
(Increase) decrease in prepaid and other assets	(3,804)	(1,882)	(1,168)
Increase (decrease) in accounts payable and other liabilities	(56,360)	33,833	66,660
Net cash provided by operating activities	171,376	564,173	670,011
Cash flows from investing activities:			
Acquisition of oil and natural gas properties	(8,464)	(103,709)	(212,513)
Drilling and development capital expenditures	(318,465)	(855,153)	(998,242)
Purchases of other property and equipment	(1,083)	(8,857)	(6,058)
Proceeds from sales of oil and natural gas properties	1,689	34,730	148,149
Net cash used in investing activities	(326,323)	(932,989)	(1,068,664)
Cash flows from financing activities:			
Proceeds from borrowings under revolving credit facility	570,000	595,000	475,000
Repayment of borrowings under revolving credit facility	(415,000)	(720,000)	(175,000)
Proceeds from issuance of Senior Notes	—	496,175	—
Debt exchange and debt issuance costs	(6,650)	(7,200)	(5,157)
Proceeds from exercise of stock options	—	—	982
Restricted stock used for tax withholdings	(607)	(1,038)	(1,665)
Net cash provided by financing activities	147,743	362,937	294,160
Net increase (decrease) in cash, cash equivalents and restricted cash	(7,204)	(5,879)	(104,493)
Cash, cash equivalents and restricted cash, beginning of period	15,543	21,422	125,915
Cash, cash equivalents and restricted cash, end of period	$ 8,339	$ 15,543	$ 21,422

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
(in thousands)

	Year Ended December 31,		
	2020	2019	2018
Supplemental cash flow information			
Cash paid for interest	$ 69,675	$ 48,905	$ 18,284
Supplemental non-cash activity			
Accrued capital expenditures included in accounts payable and accrued expenses	$ 23,409	$ 97,090	$ 119,492
Asset retirement obligations incurred, including revisions to estimates	(563)	2,262	1,451
Change in Senior Notes from debt exchange:			
Senior Secured Notes issued in the debt exchange, net of debt discount	106,030	—	—
2026 Senior Notes extinguished in the debt exchange, net of unamortized debt issue costs	(108,632)	—	—
2027 Senior Notes extinguished in the debt exchange, net of unamortized discount and debt issue costs	(140,840)	—	—

Reconciliation of cash, cash equivalents and restricted cash presented in the consolidated statements of cash flows:

	Year Ended December 31,		
	2020	2019	2018
Cash and cash equivalents	$ 5,800	$ 10,223	$ 18,157
Restricted cash[1]	2,539	5,320	3,265
Total cash, cash equivalents and restricted cash	$ 8,339	$ 15,543	$ 21,422

(1) Included in *Prepaid and other current assets* and *Other noncurrent assets* line items in the consolidated balance sheets.

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Stock								
	Class A		Class C						
	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total Shareholder's Equity	Non-controlling Interest	Total Equity
Balance at December 31, 2017	261,338	$ 26	15,661	$ 2	$ 2,767,558	$ 66,639	$ 2,834,225	$ 169,747	$ 3,003,972
Restricted stock issued	1,030	—	—	—	—	—	—	—	—
Restricted stock forfeited	(136)	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(91)	—	—	—	(1,665)	—	(1,665)	—	(1,665)
Option exercises	60	—	—	—	982	—	982	—	982
Stock-based compensation	—	—	—	—	20,670	—	20,670	—	20,670
Conversion of common shares from Class C to Class A, net of tax	3,658	1	(3,658)	(1)	46,066	—	46,066	(38,892)	7,174
Net income (loss)	—	—	—	—	—	199,899	199,899	12,837	212,736
Balance at December 31, 2018	265,859	27	12,003	1	2,833,611	266,538	3,100,177	143,692	3,243,869
Restricted stock issued	4,109	—	—	—	—	—	—	—	—
Restricted stock forfeited	(116)	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(171)	—	—	—	(1,038)	—	(1,038)	—	(1,038)
Stock-based compensation	—	—	—	—	28,997	—	28,997	—	28,997
Conversion of common shares from Class C to Class A, net of tax	10,969	1	(10,969)	(1)	114,186	—	114,186	(131,727)	(17,541)
Net income (loss)	—	—	—	—	—	15,798	15,798	616	16,414
Balance at December 31, 2019	280,650	28	1,034	—	2,975,756	282,336	3,258,120	12,581	3,270,701
Restricted stock issued	10,246	1	—	—	(1)	—	—	—	—
Restricted stock forfeited	(897)	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(550)	—	—	—	(607)	—	(607)	—	(607)
Issuance of Class A common stock under Employee Stock Purchase Plan	163	—	—	—	308	—	308	—	308
Stock-based compensation	—	—	—	—	20,966	—	20,966	—	20,966
Conversion of common stock from Class C to Class A, net of tax	1,034	—	(1,034)	—	8,011	—	8,011	(10,219)	(2,208)
Net income (loss)	—	—	—	—	—	(682,837)	(682,837)	(2,362)	(685,199)
Balance at December 31, 2020	290,646	$ 29	—	$ —	$ 3,004,433	$ (400,501)	$ 2,603,961	$ —	$ 2,603,961

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

Note 1—Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

Centennial Resource Development, Inc. is an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The Company's assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, and its properties consist of large, contiguous acreage blocks located in West Texas and New Mexico. Unless otherwise specified or the context otherwise requires, all references in these notes to "Centennial" or the "Company" are to Centennial Resource Development, Inc. and its consolidated subsidiary, Centennial Resource Production, LLC ("CRP").

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiary CRP, and CRP's wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and the rules and regulations of the United States Securities and Exchange Commission ("SEC"). All intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interests represent third-party ownership in CRP and is presented as a component of equity. See *Note 9—Shareholders' Equity and Noncontrolling Interest* for discussion on noncontrolling interest.

Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Use of Estimates

The preparation of the Company's consolidated financial statements requires the Company's management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events, and accordingly, actual results could differ from amounts previously established. Additionally, the prices received for oil, natural gas and NGL production can heavily influence the Company's assumptions, judgments and estimates and continued volatility of oil and gas prices could have a significant impact on the Company's estimates.

The more significant areas requiring the use of assumptions, judgments and estimates include: (i) oil and natural gas reserves; (ii) cash flow estimates used in impairment tests of long-lived assets; (iii) impairment expense of unproved properties; (iv) depreciation, depletion and amortization; (v) asset retirement obligations; (vi) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (vii) accrued revenues and related receivables; (viii) accrued liabilities; (ix) derivative valuations; and (x) deferred income taxes.

Cash and Cash Equivalents and Restricted Cash

The Company considers all highly liquid instruments with an original maturity of three months or less at the time of issuance to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short-term maturity of these investments. From time to time, the Company is required to maintain cash in separate accounts, the use of which is restricted by the terms of contracted arrangements. Such amounts are included in *Prepaid and other current assets* and *Other noncurrent assets* as of December 31, 2020 and December 31, 2019 in the consolidated balance sheets.

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Accordingly, the Company's oil and natural gas receivables are generally collected, and the Company has minimal bad debts.

Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized, and the Company therefore establishes an allowance for doubtful accounts equal to the portions of its accounts receivable for which collectability is not reasonably assured. The Company had $0.1 million in allowance for doubtful accounts as of December 31, 2020 and December 31, 2019.

Credit Risk and Other Concentrations

Centennial is exposed to credit risk in the event of nonpayment by counterparties. The Company normally sells production to a relatively small number of customers, as is customary in its business. The table below summarizes the purchasers that accounted for 10% or more of the Company's total net revenues for the periods presented:

	Year Ended December 31,		
	2020	2019	2018
BP America	47 %	37 %	18 %
Shell Trading (US) Company	20 %	11 %	19 %
Eagleclaw Midstream Ventures, LLC	8 %	8 %	12 %
ExxonMobil Oil Corporation	4 %	26 %	— %

During these periods, no other purchaser accounted for 10% or more of the Company's net revenues. The loss of any of the Company's major purchasers could materially and adversely affect its revenues in the short-term. However, based on the demand for oil and natural gas and the availability of other purchasers, the Company believes that the loss of any major purchaser would not have a material adverse effect on its financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company also exposes itself to credit risk. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; and (ii) only entering into hedging arrangements with counterparties that are also participants in CRP's credit agreement, all of which have investment-grade credit ratings.

Oil and Natural Gas Properties

The Company's oil and natural gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete development wells are capitalized to proved properties. Exploration costs, including personnel and other internal costs, geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Costs of drilling exploratory wells, on the other hand, are initially capitalized but are charged to expense if the well is determined to be unsuccessful. Costs to operate, repair and maintain wells and field equipment are expensed as incurred.

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in process to bring the projects to their intended use. Capitalized interest cannot exceed interest expense for the period capitalized. The Company capitalized interest of $2.1 million, $4.1 million and $2.9 million during the years ended December 31, 2020, 2019 and 2018, respectively.

Proved Properties. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, natural gas and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, extension wells and service wells, are capitalized. Capitalized proved property acquisition and development costs are depleted using a units-of production method based on the remaining life of proved and proved developed reserves, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized. Gains or losses from the disposal of complete units of depreciable property are recognized to the consolidated statements of operations.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that there could be a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital and operating expenditures and discount rates, which are based on a weighted average cost of capital. For the year ended December 31, 2020, a non-cash impairment of $591.8 million for proved oil and natural gas properties was recorded as a result of depressed oil and natural gas commodity prices. There were no impairments of proved oil and natural gas properties for the years ended December 31, 2019 and 2018. Refer to *Note 8—Fair Value Measurements* for additional information on the 2020 impairment charge.

Unproved Properties. Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves, and they are both capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or a right in a property such as a lease, in addition to broker fees, recording fees and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered on or otherwise attributed to the property, at which time the related unproved property costs are transferred to proved oil and natural gas properties.

The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or changes in future plans to develop acreage. Unproved properties that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on the Company's historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of unproved properties are included in *Impairment and abandonment expense* in the consolidated statements of operations.

Other Property and Equipment

Other property and equipment includes office furniture and equipment, buildings, vehicles, computer hardware and software and is recorded at cost. These assets are depreciated using the straight-line method over their estimated useful lives which range from three to twenty years. Equipment upgrades and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts and a gain or loss is recorded in the consolidated statements of operations as needed.

Debt Issuance Costs and Discount

Debt issuance costs related to the Company's revolving credit facility are included in the line item *Other Noncurrent Assets* in the consolidated balance sheets. These costs are amortized to interest expense on a straight-line basis over the borrowing term. Issuance costs incurred in connection with the Company's Senior Notes offerings and any related issuance discount are deferred and charged to interest expense over the term of the agreement; however, these amounts are reflected as a reduction of the related obligation in the line item *Long-term debt* on the consolidated balance sheets.

Derivative Financial Instruments

In order to mitigate its exposure to oil and natural gas price volatility, the Company may periodically use derivative instruments, such as swaps, costless collars, basis swaps, and other similar agreements. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis.

The Company records derivative instruments in its consolidated balance sheets as either an asset or liability measured at fair value. The commodity derivative instruments are accounted for using mark-to-market accounting where all gains and losses are recognized in earnings during the period in which they are incurred. The Company's derivatives have not been designated as hedges for accounting purposes.

Asset Retirement Obligations

The Company recognizes a liability for the estimated future costs associated with abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired. The fair value of the liability recognized is based on the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The Company depletes the amount added to proved oil and natural gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when a performance obligation is satisfied by transferring control of the produced oil, natural gas or NGLs to the customer. For all commodity products, the Company records revenue in the month production is delivered to the purchaser based on estimates of the amount of production delivered to the purchaser and the price the Company will receive. Payments are generally received between 30 and 90 days after the date of production. Variances between estimated sales and actual amounts received are insignificant and are recorded in the month payment is received. Refer to *Note 14—Revenues* for additional information.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes and provisions recorded for deferred income taxes. Deferred income tax assets and liabilities are recognized based on temporary differences resulting from: (i) net operating loss carryforwards for income tax purposes, and (ii) differences between the amounts recorded to the consolidated financial statements and the tax basis of assets and liabilities, as measured using enacted statutory tax rates in effect at the end of a period. The effect of a change in tax rates or tax laws is recognized in income during the period such changes are enacted. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized.

Stock-Based Compensation

The Company's stock-based compensation consists of equity grants of restricted stock, stock options, and performance stock units to employees and directors, an employee stock purchase plan which is available to eligible employees, and grants of restricted stock units and performance stock units that are settled in cash. The Company determines compensation expense related to all equity-based awards based on their estimated grant-date fair value, and such expense is recognized on a straight-line basis over the applicable service period of the award. For cash settled awards, compensation expense is estimated based on the fair value of the awards as of the balance sheet date, and such expense is recognized ratably over the period in which the award is expected to be paid. See *Note 6—Stock-Based Compensation* for additional information regarding the Company's stock-based compensation.

Earnings (Loss) Per Share

Basic earnings per share ("EPS") is calculated by dividing net income available to Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Dilutive EPS is calculated by dividing adjusted net income available to Class A Common Stock by the weighted average number of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. See *Note 10—Earnings Per Share* for additional information regarding the Company's computation of EPS.

Segment Reporting

The Company operates in only one industry segment which is the exploration and production of oil and natural gas. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Note 2—Property Acquisitions and Divestitures

2020 Dispositions

On February 24, 2020, the Company entered into a purchase and sale agreement (the "Agreement") to sell certain of its water disposal assets. On May 15, 2020, the Agreement was terminated after the purchaser failed to close the transaction as set forth in the Agreement.

The purchaser deposited $10.0 million of cash in an escrow account (the "Deposit") which, in the event of termination of the Agreement, was to be distributed to the Company or the purchaser in accordance with the remedy provisions of the Agreement. Centennial believes it has a right to receive the Deposit pursuant to the terms of the Agreement. However, the purchaser advised the Company that it disputes this position, and as a result, the distribution of the Deposit is under ongoing litigation between the Company and the purchaser.

2018 Acquisitions

On February 8, 2018, the Company completed the acquisition of approximately 4,000 undeveloped net acres, as well as certain minor producing properties, in Lea County, New Mexico for an unadjusted purchase price of $94.7 million. The operated acreage position contains an approximate 92% average working interest and is largely contiguous to Centennial's existing positions in the northern Delaware Basin.

During the fourth quarter of 2018, the Company completed several acquisitions totaling approximately 2,900 net acres, which are located adjacent to the Company's existing acreage in Lea County, New Mexico and Reeves County, Texas, for an aggregate unadjusted purchase price of $87.9 million. This purchase price encompasses certain minor producing properties that were also included in the acquisitions.

All acquisitions during 2018 were recorded as asset acquisitions under Accounting Standards Update ("ASU") 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*. Accordingly, the purchase consideration for these assets has been allocated to the proved and unproved oil and gas properties based on their relative fair values measured as of the acquisition dates. After settlement statement adjustments of $0.3 million, the Company paid an aggregate purchase price of $182.3 million. On a relative fair value basis, $142.5 million was allocated to unproved properties and $39.8 million to proved properties. Transaction costs incurred and capitalized amounted to $0.2 million and mainly consisted of advisory and legal fees.

2018 Disposition

On March 2, 2018, the Company completed the sale of approximately 8,600 undeveloped net acres and 12 gross producing wells located in Reeves County, Texas for a total unadjusted sales price of $140.7 million. The divested acreage represents a largely non-operated position (32% average working interest) on the western portion of Centennial's position in Reeves County. There was no gain or loss recognized as a result of this divestiture, which constituted a partial sale of oil and gas properties in accordance with Accounting Standard Codification ("ASC") 932*, Extractive Activities - Oil and Gas*. The Company used the net proceeds from the sale to fund the 2018 acquisitions discussed above.

Note 3—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	December 31, 2020	December 31, 2019
Accrued oil and gas sales receivable, net	$ 41,670	$ 76,578
Joint interest billings, net	12,770	25,136
Other	117	198
Accounts receivable, net	$ 54,557	$ 101,912

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	December 31, 2020	December 31, 2019
Accounts payable	$ 5,052	$ 21,484
Accrued capital expenditures	21,471	83,002
Revenues payable	42,115	82,539
Accrued employee compensation and benefits	11,516	12,979
Accrued interest	15,138	19,405
Accrued derivative settlements payable	3,488	—
Accrued expenses and other	11,659	24,900
Accounts payable and accrued expenses	$ 110,439	$ 244,309

Note 4—Long-Term Debt

The following table provides information about the Company's long-term debt as of the dates indicated:

(in thousands)	December 31, 2020	December 31, 2019
Credit Facility due 2023	$ 330,000	$ 175,000
8.00% Senior Secured Notes due 2025	127,073	—
5.375% Senior Notes due 2026	289,448	400,000
6.875% Senior Notes due 2027	356,351	500,000
Unamortized debt issuance costs on Senior Notes	(12,790)	(14,061)
Unamortized debt discount	(21,458)	(3,550)
Senior Notes, net	738,624	882,389
Total long-term debt, net	$ 1,068,624	$ 1,057,389

Credit Agreement

CRP, the Company's consolidated subsidiary, has a credit agreement with a syndicate of banks that provides for a five-year secured revolving credit facility, maturing on May 4, 2023 (the "Credit Agreement"). On May 1, 2020, CRP, as borrower, and the Company, as parent guarantor, entered into the second and third amendments to the Credit Agreement (the "Q2 2020 Amendments"), which, among other things, established a new borrowing base and level of elected commitments of $700.0 million. The Q2 2020 Amendments that the lenders approved also permitted the issuance of the Senior Secured Notes in connection with the Debt Exchange (defined below), and they implemented an availability blocker equal to 25% of the newly issued amount of Senior Secured Notes. As of December 31, 2020, the Company had $330.0 million in borrowings outstanding and $333.9 million in available borrowing capacity, which was net of $4.3 million in letters of credit outstanding and the availability blocker of $31.8 million.

The amount available to be borrowed under the Credit Agreement is equal to the lesser of (i) the borrowing base less the availability blocker, (ii) aggregate elected commitments, which was set at $700.0 million pursuant to the Q2 2020 Amendments, or (iii) $1.5 billion. The borrowing base is redetermined semi-annually in the spring and fall by the lenders in their sole discretion. It also allows for two optional borrowing base redeterminations on January 1 and July 1. The borrowing base depends on, among other things, the quantities of CRP's proved oil and natural gas reserves, estimated cash flows from these reserves, and the Company's commodity hedge positions. Upon a redetermination of the borrowing base, if actual borrowings exceed the revised borrowing capacity, CRP could be required to immediately repay a portion of its debt outstanding. Borrowings under the Credit Agreement are guaranteed by certain of CRP's subsidiaries and the Company. In connection with the Credit Agreement's fall 2020 semi-annual borrowing base redetermination, the borrowing base and amount of elected commitments was reaffirmed at $700.0 million.

Borrowings under the Credit Agreement may be base rate loans or LIBOR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for LIBOR loans. LIBOR loans bear interest at LIBOR (adjusted for statutory reserve requirements and subject to 1% floor) plus an applicable margin, which ranged from 200 to 300 basis points as of December 31, 2020, depending on the percentage of the borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; or (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin, which ranged 100 to 200 basis points as of December 31, 2020, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee of 37.5 to 50 basis points on unused amounts under its facility.

CRP's Credit Agreement contains restrictive covenants that limit its ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make or declare dividends; (v) enter into commodity hedges exceeding a specified percentage of the Company's expected production; (vi) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (vii) incur liens; (viii) sell assets; and (ix) engage in transactions with affiliates.

CRP's Credit Agreement also requires it to maintain compliance with the following financial ratios:

(i) a current ratio, which is the ratio of CRP's consolidated current assets (including an add back of unused commitments under the revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding any current portion of long-term debt due under the Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0;

(ii) a first lien leverage ratio, as defined within the Credit Agreement as the ratio of first lien debt to EBITDAX for the rolling four fiscal quarter period, which may not exceed 2.75 to 1.00 beginning with the quarter ending June 30, 2020 and extending through the quarter ending December 31, 2021, after which the maximum ratio shall decrease to 2.50 to 1.00 for each of the quarters ending in 2022; and

(iii) a leverage ratio, as also defined in the Credit Agreement as the ratio of total funded debt to consolidated EBITDAX for the rolling four fiscal quarter period. Pursuant to the Q2 2020 Amendments, the leverage ratio is suspended until March 31, 2022, at which time, the ratio may not exceed 5.0 to 1.0, with such maximum ratio declining at a rate of 0.25 for each succeeding quarter until March 31, 2023 when the ratio is set at not greater than 4.0 to 1.0.

CRP was in compliance with the covenants and applicable financial ratios described above as of December 31, 2020 and through the filing of this Annual Report.

Senior Unsecured Notes Debt Exchange

On May 22, 2020, CRP completed its private exchange of debt pursuant to which a $254.2 million aggregate principal amount of Senior Unsecured Notes (defined below) was validly tendered and exchanged by certain eligible bondholders for consideration consisting of $127.1 million aggregate principal amount (the "Debt Exchange") of newly issued 8.00% second lien senior secured notes due 2025 (the "Senior Secured Notes").

Whether a debt exchange should be accounted for pursuant to Financial Accounting Standards Board's Accounting Standard Codification ("ASC") Topic 470-60*, Troubled Debt Restructurings by Debtors*, or pursuant to ASC Topic 470-50, *Modifications and Extinguishments* ("ASC 470-50"), requires judgments to be made with respect to whether or not an entity is experiencing financial difficulty. As it was determined that Centennial was not experiencing financial difficulty and could obtain funds at market rates it could afford (i.e. non-investment grade but nontroubled debtor rates), the Company's Debt Exchange was accounted for as an extinguishment of debt in accordance with ASC 470-50. As a result, a gain on the exchange of debt of $143.4 million was recognized in the consolidated statement of operations, which consisted of the carrying values of the Senior Unsecured Notes exchanged less the aggregate principal amount of the new Senior Secured Notes issued, net of their associated debt discount of $21.0 million (which was based on the Senior Secured Notes' estimated fair value on the exchange date).

Senior Secured Notes

In connection with the Debt Exchange, on May 22, 2020, the Company issued $127.1 million aggregate principal amount of Senior Secured Notes. The Senior Secured Notes were recorded at their fair value on the date of issuance equal to 83.44% of par (a debt discount of $21.0 million) and net of their associated debt issuance costs of $4.2 million. The Senior Secured Notes bear interest at an annual rate of 8.00% and are due on June 1, 2025. Interest is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2020.

The Senior Secured Notes are guaranteed, subject to certain exceptions, by the Company and each of CRP's subsidiaries and are secured on a second priority basis (subject in priority only to certain exceptions) by substantially all of the assets of CRP and the Company, including deposit accounts and substantially all proved reserves and undeveloped acreage.

The Company has the option to redeem all (but not less than all) of the Senior Secured Notes, at any time prior to May 22, 2021 on a single occasion, at a redemption price equal to 100% of the principal amount, plus accrued and unpaid interest to the date of redemption, if such redemption is made entirely with proceeds from equity offerings or the issuance of unsecured indebtedness.

At any time prior to June 1, 2022, the Company has the option to redeem the Senior Secured Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the Senior Secured Notes redeemed plus accrued and unpaid interest and a "make-whole" premium. The Senior Secured Notes are redeemable at the Company's option, in whole or in part, at any time on or after June 1, 2022, at specified redemption prices, together with accrued and unpaid interest. In addition, at any time prior to June 1, 2022, the Company may redeem up to 35% of the aggregate principal amount of each of the Senior Secured Notes, including any permitted additional Senior Secured Notes, with an amount of cash not greater than the net proceeds of certain equity offerings at a redemption price equal to 108% of the principal amount of such Senior Secured Notes, plus any accrued and unpaid interest to, but excluding, the redemption date.

Senior Unsecured Notes

On March 15, 2019, CRP issued $500.0 million of 6.875% senior unsecured notes due 2027 (the "2027 Senior Notes") in a 144A private placement at a price equal to 99.235% of par that resulted in net proceeds to CRP of $489.0 million, after deducting the original issuance discount of $3.8 million and debt issuance costs of $7.2 million. Interest is payable on the 2027 Senior Notes semi-annually in arrears on each April 1 and October 1, which commenced on October 1, 2019. In May 2020 in connection with the Debt Exchange, $143.7 million aggregate principal amount of the 2027 Senior Notes was exchanged for Senior Secured Notes. As of December 31, 2020, the remaining aggregate principal amount of 2027 Senior Notes outstanding was $356.4 million.

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior unsecured notes due 2026 (the "2026 Senior Notes" and collectively with the 2027 Senior Notes, the "Senior Unsecured Notes") in an 144A private placement that resulted in net proceeds to CRP of $391.0 million, after deducting $9.0 million in debt issuance costs. Interest is payable on the 2026 Senior Notes semi-annually in arrears on each January 15 and July 15, which commenced on July 15, 2018. In May 2020 in connection with the Debt Exchange, $110.6 million aggregate principal amount of the 2026 Senior Notes was exchanged for Senior Secured Notes. As of December 31, 2020, the remaining aggregate principal amount of 2026 Senior Notes outstanding was $289.4 million.

The Senior Unsecured Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Company and each of CRP's current subsidiaries that guarantee CRP's revolving credit facility.

At any time prior to January 15, 2021 (for the 2026 Senior Notes) and April 1, 2022 (for the 2027 Senior Notes), the "Optional Redemption Dates," CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of either series of Senior Unsecured Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.375% (for the 2026 Senior Notes) and 106.875% (for the 2027 Senior Notes) of the principal amount of the Senior Unsecured Notes of the applicable series redeemed, plus accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount of each such series of Senior Unsecured Notes remains outstanding immediately after such redemption, and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to Optional Redemption Dates, CRP may, on any one or more occasions, redeem all or a part of the Senior Unsecured Notes at a redemption price equal to 100% of the principal amount of the Senior Unsecured Notes redeemed, plus a "make-whole" premium, and any accrued and unpaid interest as of the date of redemption. On and after the Optional Redemption Dates, CRP may redeem the Senior Unsecured Notes, in whole or in part, at redemption prices expressed as percentages of principal amount plus accrued and unpaid interest to the redemption date.

Senior Notes

The following section discusses the general terms of the indentures applicable to the Company's Senior Unsecured Notes and the Senior Secured Notes (collectively, the "Senior Notes").

The indentures governing the Senior Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP's ability and the ability of CRP's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of December 31, 2020 and through the filing of this Annual Report.

Upon an Event of Default (as defined in the indentures governing the Senior Notes), the trustee or the holders of at least 25% of the aggregate principal amount of then outstanding Senior Notes may declare the Senior Notes immediately due and payable. In addition, a default resulting from certain events of bankruptcy or insolvency with respect to CRP, any restricted subsidiary of CRP that is a significant subsidiary, or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary, will automatically cause all outstanding Senior Notes to become due and payable.

If CRP experiences certain defined changes of control (and in certain cases followed by a ratings decline), each holder of the Senior Notes may require CRP to repurchase all or a portion of its Senior Notes for cash at a price equal to 101% of the aggregate principal amount of such Senior Notes, plus any accrued and unpaid interest to the date of repurchase.

Note 5—Asset Retirement Obligations

The following table summarizes the period-to-period changes in the Company's asset retirement obligations ("ARO") that are associated with its oil and gas properties for the periods presented:

(in thousands)	December 31, 2020	December 31, 2019
Asset retirement obligations, beginning of period	$ 16,874	$ 13,895
Liabilities incurred	589	1,393
Liabilities on acquired properties	147	1,167
Liabilities divested and settled	(578)	(1,361)
Accretion expense	1,128	912
Revision to estimated cash flows	(1,151)	868
Asset retirement obligations, end of period	$ 17,009	$ 16,874

ARO reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. Inherent in the present value calculation of ARO are numerous estimates and assumptions, including plug and abandonment settlement amounts, inflation factors, credit adjusted discount rates and the timing of ultimate ARO settlement. To the extent future revisions to these assumptions impact the value of the existing ARO liabilities, a corresponding offsetting adjustment is made to the oil and gas property balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability with an offsetting charge to accretion expense, which is included within depreciation, depletion and amortization.

Note 6—Stock-Based Compensation

On October 7, 2016, the stockholders of the Company approved the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the "LTIP"), which authorized an aggregate of 16,500,000 shares of Common Stock for issuance to employees and directors. In April 29, 2020, the stockholders of the Company approved the amended and restated LTIP which, among other things, increased the number of shares of Common Stock authorized for issuance by 8,250,000 shares. As of December 31, 2020, the Company had 6,579,226 shares of Common Stock available for future grants. The LTIP provides for grants of restricted stock, stock options (including incentive stock options and nonqualified stock options), restricted stock units, stock appreciation rights and other stock or cash-based awards.

As a result of the decline in crude oil and natural gas prices, ongoing uncertainty regarding the oil supply-demand macro environment and the related temporary suspension of the Company's drilling and completion activities during 2020, the Company implemented a reduction to its workforce in the second quarter of 2020. In connection with this workforce reduction, the Compensation Committee of the Company's Board of Directors approved an accelerated partial vesting of certain unvested stock options and restricted stock awards held by 37 of the terminated employees. The acceleration changed the terms of the vesting conditions and are therefore treated as modifications in accordance with ASC Topic 718, *Compensation-Stock Compensation* ("ASC 718"). The modification resulted in a decrease to total stock-based compensation expense of $2.7 million associated with the decrease in the fair value of the modified awards compared to the original awards' fair value. The shares and options that were accelerated are included within the vested line item in the below tables.

Stock-based compensation expense is recognized within both *General and administrative expenses* and *Exploration and other expenses* in the consolidated statements of operations. The Company accounts for forfeitures of its stock-based compensation awards as they occur, when determining compensation expense.

The following table summarizes stock-based compensation expense recognized for the periods presented:

(in thousands)	Year Ended December 31, 2020	2019	2018
Equity Awards			
Restricted stock awards	$ 15,355	$ 15,929	$ 9,185
Stock option awards	1,980	9,562	9,433
Performance stock units	3,312	3,374	2,052
Other stock-based compensation expense(1)	319	132	—
Total stock-based compensation expense - equity awards	20,966	28,997	20,670
Liability Awards			
Restricted stock units	1,788	—	—
Performance stock units	1,814	—	—
Total stock-based compensation - liability awards	3,602	—	—
Total stock-based compensation expense	$ 24,568	$ 28,997	$ 20,670

(1) Includes expenses related to the Company's Employees Stock Purchase Plan (the "ESPP"). In May 2019, an aggregate of 2,000,000 shares were authorized by stockholders for issuance under the ESPP, which became effective on July 1, 2019. As of December 31, 2020, the Company had 1,837,381 shares of Common Stock available for future issuance.

Equity Awards

The Company has restricted stock awards, stock options and performance stock units ("PSUs") outstanding that were granted under the LTIP as discussed below. Each award has service-based and, in the case of the PSUs, market-based vesting requirements and are expected to be settled in shares of the Company's Common Stock upon vesting. As a result, these awards are classified as equity-based awards in accordance with ASC 718.

Restricted Stock

The following table provides a summary of the restricted stock activity during the year ended December 31, 2020:

	Awards	Wtd. Avg. Grant-Date Fair Value
Unvested balance as of December 31, 2019	4,838,996	$ 8.51
Granted	10,245,500	1.12
Vested	(2,093,937)	8.31
Forfeited	(896,836)	5.85
Unvested balance as of December 31, 2020	12,093,723	2.33

The Company grants service-based restricted stock awards to executive officers and employees, which vest ratably over a three-year service period, and to directors, which vest over a one-year service period. Compensation cost for these service-based restricted stock awards is based on the closing market price of the Company's Common Stock on the grant date, and such costs are recognized ratably over the applicable vesting period. The weighted average grant-date fair value for restricted stock awards granted was $1.12, $6.59 and $18.11 per share for the years ended December 31, 2020, 2019 and 2018, respectively. The total fair value of restricted stock awards that vested for the years ended December 31, 2020, 2019 and 2018 was $17.4 million, $12.0 million and $6.6 million, respectively. Unrecognized compensation cost related to restricted shares that were unvested as of December 31, 2020 was $21.0 million, which the Company expects to recognize over a weighted average period of 1.9 years.

Stock Options

Stock options that have been granted under the LTIP expire ten years from the grant date and vest ratably over a three-year service period. The exercise price for an option granted under the LTIP is the closing price of the Company's Common Stock on the grant date.

Compensation cost for stock options is based on the grant-date fair value of the award, which is then recognized ratably over the vesting period of three years. The Company estimates the grant-date fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the weighted average historical volatilities of the Company and an identified set of comparable companies. Expected term is based on the simplified method and is estimated as the mid-point between the weighted average vesting term and the time to expiration as of the grant date. The Company uses U.S. Treasury bond rates in effect at the grant date for its risk-free interest rates.

The following table summarizes the assumptions and related information used to determine the grant-date fair value of stock options awarded for the periods presented:

	Years Ended December 31,		
	2020	2019	2018
Weighted average grant-date fair value per share	$ 1.16	$ 4.32	$ 8.58
Expected term (in years)	6	6	6
Expected stock volatility	86 %	47 %	42 %
Dividend yield	—	—	—
Risk-free interest rate	1.0 %	2.2 %	2.7 %

The following table provides information about stock option awards outstanding during the year ended December 31, 2020:

	Options	Wtd. Avg. Exercise Price	Wtd. Avg. Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of December 31, 2019	4,764,167	$ 15.99		
Granted	124,000	2.13		
Exercised	(366)	0.25		$ —
Forfeited	(130,424)	13.12		
Expired	(2,394,043)	16.34		
Outstanding as of December 31, 2020	2,363,334	15.07	6.5	$ 78
Exercisable as of December 31, 2020	2,011,809	15.98	6.2	$ —

The total fair value of stock options that vested during the years ended December 31, 2020, 2019 and 2018 was $5.7 million, $10.2 million and $8.8 million, respectively. The intrinsic value of the stock options exercised during the year ended December 31, 2020 was minimal, there were no stock options exercised during the year ended December 31, 2019, and the intrinsic value of stock options exercised during the year ended December 31, 2018 was approximately $0.2 million. As of December 31, 2020, there was $0.9 million of unrecognized compensation cost related to unvested stock options, which the Company expects to recognize on a pro-rata basis over a weighted-average period of 1.1 years.

Performance Stock Units

The Company grants performance stock units to certain executive officers that are subject to market-based vesting criteria as well as a three-year service period. Vesting at the end of the three-year service period is subject to the condition that the Company's stock price increases by a greater percentage, or decreases by a lesser percentage, than the average percentage increase or decrease, respectively, of the stock prices of a peer group of companies. The market-based conditions must be met in order for these stock awards to vest, and it is therefore possible that no shares could ultimately vest. However, the Company recognizes compensation expense for these performance stock units subject to market conditions regardless of whether such conditions are met or not, and compensation expense is not reversed if vesting does not actually occur.

The grant-date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock as well as the peer companies that are specified in the award agreement, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

The following table summarizes the key assumptions and related information used to determine the grant-date fair value of performance stock units awarded during the periods presented:

	2019	2018
Weighted average grant-date fair value per unit	$ 6.68	$ 22.35
Number of simulations	1,000,000	1,000,000
Expected stock volatility	52.3 %	40.2 %
Dividend yield	— %	— %
Risk-free interest rate	1.8 %	2.8 %

The following table provides information about performance stock units outstanding during the year ended December 31, 2020:

	Awards	Wtd. Avg. Grant Date Fair Value
Unvested balance as of December 31, 2019	872,672	$ 13.44
Granted	—	—
Vested	—	—
Cancelled	(193,391)	21.53
Forfeited	—	—
Unvested balance as of December 31, 2020	679,281	11.13

As of December 31, 2020, there was $2.4 million of unrecognized compensation cost related to unvested performance stock units, which the Company expects to recognize on a pro rata basis over a weighted average period of 1.2 years

Liability Awards

The Company has restricted stock units and performance stock units that were granted under the LTIP, which will be settled in cash by the Company and are therefore classified as liability awards in accordance with ASC 718. Compensation cost for the liability awards is based on the fair value of the units as of each balance sheet date as further discussed below, and such costs are recognized ratably over the service periods of the awards. As the fair value of liability awards is required to be re-measured at each period end, stock compensation expense amounts recognized in future periods for these awards will vary. The estimated future cash payments of these awards are presented as liabilities within *Other current liabilities* and *Other long-term liabilities* in the consolidated balances sheets.

Restricted Stock Units

During the year ended December 31, 2020, the Company granted 5.5 million restricted stock units to certain officers and employees that will be settled in cash. The restricted stock units vest annually in one-third increments over a three-year service period, with the first portion vesting on September 1, 2021. After one year from the grant date, however, the restricted stock units can vest immediately on an accelerated basis if they meet certain market-based vesting criteria (equal to the maximum return percentage discussed below for at least 20 out of any 30 consecutive trading days). Additionally, the restricted stock units include maximum and minimum return amounts equal to 400% and 25%, respectively, of the closing market price of the Company's common stock on the grant date. As of December 31, 2020, there was $5.5 million of unrecognized compensation cost, which represents the unvested portion of the fair value of the restricted stock units at December 31, 2020 and which will be recognized over a weighted average period of 1.8 years.

Performance Stock Units

During the year ended December 31, 2020, the Company granted 5.5 million performance stock units to certain executive officers that will be settled in cash that are subject to market-based vesting criteria as well as a three-year service condition. Vesting at the end of the three-year service period is subject to the condition that the Company's stock price increases by a greater percentage, or decreases by a lessor percentage, than the average percentage increase or decrease, respectively, of the stock price of a peer group of companies. The market-based conditions must be met in order for the awards to vest, and it is therefore possible that no units could ultimately vest and cumulative stock compensation expense recognized for these awards would then be reduced to zero. As of December 31, 2020, there was $10.6 million of unrecognized compensation cost, which represents the unvested portion of the fair value of the performance stock units at December 31, 2020, and which will be recognized over a weighted average period of 2.5 years.

Liability Awards Fair Value

The fair value of the restricted stock units and performance stock units was estimated using a Monte Carlo valuation model as of the balance sheet date. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock as well as the historical volatility of certain peer companies that are named in the award agreement for the performance stock units. The risk-free rate is based on U.S. Treasury yield curve rates with maturities consistent with the remaining vesting or performance period.

The following table summarizes the key assumptions and related information used to determine the fair value of the liability awards as of December 31, 2020:

	Restricted stock units	Performance stock units
Number of simulations	10,000,000	10,000,000
Expected stock volatility	123.2 %	126.9 %
Dividend yield	— %	— %
Risk-free interest rate	0.2 %	0.1 %
Shares outstanding	5,442,681	5,464,433

Note 7—Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations and may use derivative instruments to manage its exposure to commodity price risk from time to time.

Commodity Derivative Contracts

Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. The Company may periodically use derivative instruments, such as swaps, costless collars and basis swaps, to mitigate its exposure to declines in commodity prices and to the corresponding negative impacts such declines can have on its cash flow from operations, returns on capital and other financial results. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not enter into derivative contracts for speculative or trading purposes.

Commodity Swap and Collar Contracts. The Company may use commodity derivative instruments known as fixed price swaps to realize a known price for a specific volume of production, basis swaps to hedge the difference between the index price and a local index price, or costless collars to establish fixed price floors and ceilings. All transactions are settled in cash with one party paying the other for the resulting difference in price multiplied by the contract volume.

The following table summarizes the approximate volumes and average contract prices of derivative contracts the Company had in place as of December 31, 2020:

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Crude Price ($/Bbl)(1)
Crude oil swaps				
NYMEX WTI	January 2021 - March 2021	990,000	11,000	$41.48
	April 2021 - June 2021	1,183,000	13,000	43.18
	July 2021 - September 2021	736,000	8,000	45.87
	October 2021 - December 2021	644,000	7,000	45.59
ICE Brent	January 2021 - March 2021	270,000	3,000	$46.85
	April 2021 - June 2021	182,000	2,000	48.01
	July 2021 - September 2021	184,000	2,000	48.25
	October 2021 - December 2021	184,000	2,000	48.50

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Collar Price Ranges ($/Bbl)(2)
Crude oil collars	January 2021 - March 2021	315,000	3,500	$ 40.00 - $ 48.14
	April 2021 - June 2021	136,500	1,500	40.00 - 48.57
	July 2021 - September 2021	92,000	1,000	42.00 - 50.10
	October 2021 - December 2021	92,000	1,000	42.00 - 50.10

	Period	Volume (Bbls)	Volume (Bbls/d)	Wtd. Avg. Differential ($/Bbl)(3)
Crude oil basis differential swaps	January 2021 - March 2021	990,000	11,000	$0.01
	April 2021 - June 2021	1,183,000	13,000	0.11
	July 2021 - September 2021	736,000	8,000	0.26
	October 2021 - December 2021	644,000	7,000	0.26

(1) These crude oil swap transactions are settled based on the NYMEX WTI or ICE Brent oil price on each trading day within the specified monthly settlement period versus the contractual swap price for the volumes stipulated.

(2) These crude oil collars are settled based on the NYMEX WTI price on each trading day within the specified monthly settlement period versus the contractual floor and ceiling prices for the volumes stipulated.

(3) These oil basis swap transactions are settled based on the difference between the arithmetic average of ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices, during each applicable monthly settlement period.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Gas Price ($/MMBtu)[1]
Natural gas swaps	January 2021 - March 2021	5,400,000	60,000	$2.91
	April 2021 - June 2021	3,640,000	40,000	2.89
	July 2021 - September 2021	3,680,000	40,000	2.89
	October 2021 - December 2021	3,680,000	40,000	2.95
	January 2022 - March 2022	1,800,000	20,000	3.00

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Collar Price Ranges ($/MMBtu)[2]
Natural gas collars	January 2021 - March 2021	1,800,000	20,000	$ 2.90 - $ 3.64

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Wtd. Avg. Differential ($/MMBtu)[3]
Natural gas basis differential swaps	January 2021 - March 2021	1,800,000	20,000	$(0.30)
	April 2021 - June 2021	3,640,000	40,000	(0.30)
	July 2021 - September 2021	3,680,000	40,000	(0.30)
	October 2021 - December 2021	3,680,000	40,000	(0.28)
	January 2022 - March 2022	1,800,000	20,000	(0.26)

(1) These natural gas swap contracts are settled based on the NYMEX Henry Hub price on each trading day within the specified monthly settlement period versus the contractual swap price for the volumes stipulated.

(2) These natural gas collars are settled based on the NYMEX Henry Hub price on each trading day within the specified monthly settlement period versus the contractual floor and ceiling prices for the volumes stipulated.

(3) These natural gas basis swap contracts are settled based on the difference between the Inside FERC's West Texas WAHA price and the NYMEX price of natural gas, during each applicable monthly settlement period.

Derivative Instrument Reporting. The Company's oil and natural gas derivative instruments have not been designated as hedges for accounting purposes. Therefore, all gains and losses are recognized in the Company's consolidated statements of operations. All derivative instruments are recorded at fair value in the consolidated balance sheets, other than derivative instruments that meet the "normal purchase normal sale" exclusion, and any fair value gains and losses are recognized in current period earnings.

The following table presents the impact of the Company's derivative instruments on its consolidated statements of operations for the periods presented:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Net gain (loss) on derivative instruments	$ (64,535)	$ (1,561)	$ 15,336

Offsetting of Derivative Assets and Liabilities. The Company's commodity derivatives are included in the accompanying consolidated balance sheets as derivative assets and liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master netting agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The tables below summarize the fair value amounts and classification in the consolidated balance sheets of the Company's derivative contracts outstanding at the respective balance dates, as well as the gross recognized derivative assets, liabilities and offset amounts:

(in thousands)	Balance Sheet Classification	Gross Fair Value Asset/ Liability Amounts	Gross Amounts Offset[(1)]	Net Recognized Fair Value Assets/ Liabilities
		December 31, 2020		
Derivative Assets				
Commodity contracts	Prepaid and other current assets	$ 6,131	$ (6,131)	$ —
	Other noncurrent assets	152	(100)	52
Derivative Liabilities				
Commodity contracts	Other current liabilities	$ 24,392	$ (6,131)	$ 18,261
	Other noncurrent liabilities	100	(100)	—
		December 31, 2019		
Derivative Liabilities				
Commodity contracts	Other current liabilities	$ 325	$ —	$ 325

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets against derivative liabilities at settlement or in the event of a default under the agreements or contract termination.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under CRP's Credit Agreement. The Company uses only Credit Agreement participants to hedge with, since these institutions are secured equally with the holders of any CRP bank debt, which eliminates the potential need to post collateral when Centennial is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

In addition, the Company is exposed to credit risk associated with its derivative contracts from non-performance by its counterparties. The Company mitigates its exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a member of CRP's credit facility as referenced above.

Note 8—Fair Value Measurements

Recurring Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurement and Disclosure,* which establishes 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: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The following table presents, for each applicable level within the fair value hierarchy, the Company's net derivative assets and liabilities, including both current and noncurrent portions, measured at fair value on a recurring basis:

(in thousands)	Level 1	Level 2	Level 3
December 31, 2020			
Total assets	$ —	$ 52	$ —
Total liabilities	—	18,261	—
December 31, 2019			
Total assets	$ —	$ —	$ —
Total liabilities	—	325	—

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgement and considers factors specific to the asset or liability. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. There were no transfers between any of the fair value levels during any period presented.

Derivatives

The Company uses Level 2 inputs to measure the fair value of its oil and natural gas commodity derivatives. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations. Refer to *Note 7—Derivative Instruments* for details of the gross and net derivative assets, liabilities and offset amounts as presented in the consolidated balance sheets.

Nonrecurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a nonrecurring basis to its non-financial assets and liabilities, including proved oil and gas properties. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances.

Impairment of Oil and Natural Gas Properties. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that the fair value of these assets may be below their carrying value. The significant decrease in the forward price curves for crude oil and natural gas in March of 2020 resulted in a triggering event which required the Company to reassess its proved oil and natural gas properties for impairment as of March 31, 2020. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows from oil and gas properties is less than the carrying amount of the assets. In this circumstance, the Company then recognizes impairment expense for the amount by which the carrying amount of proved properties exceeds their estimated fair value. The Company reviews its oil and natural gas properties on a field-by-field basis.

The Company calculates the estimated fair values of its oil and natural gas properties using an income approach that is based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the expected future net cash flows used for the impairment review and the related fair value measurement of oil and natural gas proved properties include estimates of: (i) reserves; (ii) future production decline rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; and (v) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management.

The impairment test performed by the Company indicated that a proved property impairment had occurred with respect to certain of its oil and gas fields, and therefore a non-cash impairment charge to reduce the carrying value of the impaired property to its fair value was recorded. Proved oil and natural gas properties with a previous carrying value of $771.4 million were partially written down to their fair value of $179.6 million, resulting in a noncash impairment charge of $591.8 million being recorded in the first quarter of 2020. All of the Company's proved oil and gas properties were included in the impairment assessment performed as of March 31, 2020. Two of the Company's fields were subject to an impairment write-down as quantified above, but the remaining five fields were not impaired due to their undiscounted cash flows exceeding their carrying values by 30% to over 100%. The Company did not recognize any additional impairment write-downs with respect to its proved property during the remainder of the year ending December 31, 2020. Impairment expense for proved properties is presented as part of *Impairment and Abandonment Expense* in the consolidated statements of operations.

*Asset Retirement Obligation*s. The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include the estimated future costs to plug and abandon oil and gas properties and reserve lives. Refer to *Note 5—Asset Retirement Obligations* for additional information on the Company's ARO.

Senior Secured Notes. The Company's Senior Secured Notes were measured and recorded at their fair value on the date of issuance equal to 83.44% of par. The fair value was determined utilizing the Black-Derman-Toy binomial lattice model, which is a one-factor binomial lattice model that determines the future evolution of the relevant yields. For each node on the lattice, it is determined whether it is preferable to redeem, or not, based on the yields. The model utilizes both a yield curve and a yield volatility as of the valuation date, both of which are estimated based on yields of comparable debt instruments and are inputs that are not observable for the Senior Secured Notes for the term of the debt instrument (a Level 3 classification in the fair value hierarchy). The fair value was measured by the model using the following inputs: (i) the treasury yield curve as of the valuation date, (ii) 12% credit spread, (iii) 45% yield volatility, and (iv) a corporate credit rating of B. The Company has not elected the fair value option, which would require remeasurement at fair value each period, to account for this debt instrument.

Other Financial Instruments

The carrying amounts of the Company's cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate their fair values because of the short-term maturities and/or liquid nature of these assets and liabilities.

The Company's Senior Notes and borrowings under its Credit Agreement are accounted for at cost, and the cost basis of the Company's Senior Secured Notes issued in the Debt Exchange was measured based on their fair value on the date of the exchange, as discussed above. The following table summarizes the fair values and carrying values of these instruments as of the periods indicated:

	December 31, 2020			December 31, 2019		
	Carrying Value	Principal Amount	Fair Value	Carrying Value	Principal Amount	Fair value
Credit facility due 2023[(1)]	$ 330,000	$ 330,000	$ 330,000	$ 175,000	$ 175,000	$ 175,000
8.00% Senior Secured Notes due 2025[(2)]	103,902	127,073	114,366	—	—	—
5.375% Senior Notes due 2026[(2)]	284,867	289,448	206,955	392,623	400,000	394,480
6.875% Senior Notes due 2027[(2)]	349,856	356,351	254,791	489,766	500,000	520,000

(1) The carrying values of the amounts outstanding under CRP's Credit Agreement approximate fair value because its variable interest rates are tied to current market rates and the applicable credit spreads represent current market rates for the credit risk profile of the Company.

(2) The carrying values include associated unamortized debt issuance costs and any debt discounts as reflected in the consolidated balance sheets. The fair values are determined using quoted market prices for these debt securities, a Level 1 classification in the fair value hierarchy, and are based on the aggregate principal amount of the Senior Notes outstanding.

Note 9—Shareholders' Equity and Noncontrolling Interest

On April 2, 2020, the legacy owners of CRP (the "Centennial Contributors") converted all of their remaining 1,034,119 CRP Common Units (and corresponding shares of Class C Common Stock) into Class A Common Stock (the "Conversion"), which eliminated the noncontrolling interest ownership in CRP. No cash proceeds were received by the Company in connection with the Conversion, and deferred tax expense of $2.2 million was recorded in equity.

During 2019, the Centennial Contributors converted 10,969,064 of their CRP Common Units (and corresponding shares of Class C Common Stock) into Class A Common Stock. No cash proceeds were received by the Company and deferred tax expense of $17.5 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

On March 7, 2018, Silver Run Sponsor, LLC ("Silver Run Sponsor"), affiliates of Riverstone Investment Group LLC ("Riverstone") and the Centennial Contributors completed an underwritten public offering of 25,000,000 shares of Class A Common Stock. No cash proceeds were received by the Company in connection with this offering and 3,347,647 shares of CRP Common Units (and corresponding shares of Class C Common Units) were converted to shares of Class A Common Stock on a one-to-one basis. A tax benefit of $7.2 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

Class A Common Stock

Holders of the Company's Class A Common Stock are entitled to one vote for each share held on all matters submitted to a vote by the Company's stockholders, except as required by law. Unless specified in the Company’s second amended and restated certificate of incorporation (the “Charter”) (including any certificate of designation of preferred stock) or the Company’s second amended and restated bylaws, or as required by applicable provisions of the Delaware General Corporation Law or applicable stock exchange rules, the affirmative vote of a majority of the Company’s shares of common stock that are voted is required to approve any such matter voted on by the Company’s stockholders. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors. Subject to the rights of the holders of any outstanding series of preferred stock, the holders of the Class A Common Stock are entitled to receive ratable dividends when, as and if declared by the board of directors out of funds legally available therefor.

In the event of a liquidation, dissolution or winding up of the Company, the holders of the Class A Common Stock are entitled to share ratably in all assets remaining available for distribution to them after payment of liabilities and after provision is made for each class of stock, if any, having preference over the Class A Common Stock. The holders of the Class A Common Stock have no preemptive or other subscription rights. There are no sinking fund provisions applicable to the Class A Common Stock.

Class C Common Stock

The Company had no shares of Class C Common Stock outstanding as of December 31, 2020 as the remaining shares were converted on April 2, 2020 as part of the Conversion discussed above. The shares converted represented the remaining portion of the 20,000,000 shares of Class C Common Stock issued to the Centennial Contributors in connection with the acquisition of approximately 89% of the outstanding membership interests in CRP, consummated on October 11, 2016 (the “Business Combination”).

Prior to the Conversion, holders of Class C Common Stock, together with holders of the Class A Common Stock voting as a single class, had the right to vote on all matters properly submitted to a vote of the stockholders. In addition, the holders of Class C Common Stock, voting as a separate class, were entitled to approve any amendment, alteration or repeal of any provision of the Charter that would alter or change the powers, preferences or relative, participating, optional, other or special rights of the Class C Common Stock. Holders of Class C Common Stock were not entitled to any dividends from the Company and were not entitled to receive any of its assets in the event of any voluntary or involuntary liquidation, dissolution or winding up of its affairs.

Shares of Class C Common Stock were only allowed to be issued to the Centennial Contributors, their respective successors and assigns, as well as any permitted transferees of the Centennial Contributors. Holders of Class C Common Stock had the right to cause CRP to redeem all or a portion of their CRP Common Units in exchange for shares of the Company’s Class A Common Stock or, at CRP’s option, an equivalent amount of cash.

Preferred Stock

In connection with the Business Combination, the Company issued one share of Series A Preferred Stock at par value, $0.0001 per share (the “Series A Preferred Stock”) to one of the Centennial Contributors. The Series A Preferred Stock provided the holder thereof with the right to nominate and elect one director to the Company’s Board of Directors, but it did not provide any other voting rights or rights with respect to dividends except distributions in liquidation in the amount of $0.0001 per share. In July 2020, the Company redeemed the one share of Series A Preferred Stock after NGP X US Holdings, L.P., the current holder of the share of Series A Preferred Stock and a former indirect equity owner of CRP, ceased to own, in the aggregate, at least 5,000,000 CRP Common Units and/or shares of Class A Common Stock.

Warrants

Simultaneously with the closing of the Company’s initial public offering, 8,000,000 warrants were purchased by Silver Run Sponsor in a private placement (the “Private Placement Warrants”). The Private Placement Warrants are non-redeemable so long as they are held by Riverstone or its permitted transferees. Each whole Private Placement Warrant is exercisable for one whole share of Class A Common Stock at a price of $11.50 per share. The Private Placement Warrants became exercisable on March 1, 2017 and will expire on October 11, 2021 (five years after the completion of the Business Combination) or earlier upon redemption or liquidation. As of December 31, 2020, 8,000,000 Private Placement Warrants remained outstanding.

Noncontrolling Interest

The noncontrolling interest relates to CRP Common Units that were issued to the Centennial Contributors in connection with the Business Combination. At the date of the Business Combination, the noncontrolling interest held 10.9% of the ownership in CRP. The noncontrolling interest percentage is affected by various equity transactions such as CRP Common Unit and Class C Common Stock exchanges and Class A Common Stock activities.

As of December 31, 2019 and 2018, the noncontrolling interest ownership of CRP decreased to 0.37% and 4.34%, respectively. The decreases were the result of the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock. As of December 31, 2020, the noncontrolling interest ownership of CRP was reduced to zero due to the Conversion discussed above and CRP has since been a wholly-owned subsidiary of Centennial.

The Company consolidated the results of operations and cash flows of CRP and reflected the portion retained by other holders of CRP Common Units as a noncontrolling interest through the date of the Conversion. Refer to the consolidated statements of shareholders' equity for a summary of the activity attributable to the noncontrolling interest during the periods.

Note 10—Earnings Per Share

Basic EPS is calculated by dividing net income available to Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Dilutive EPS is calculated by dividing adjusted net income available to Class A Common Stock by the weighted average shares of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted EPS calculation consists of (i) unvested equity based restricted stock and performance stock units, outstanding stock options, withholding amounts from employee stock purchase plan and warrants using the treasury stock method, and (ii) the Company's Class C Common Stock outstanding prior to the Conversion using the "if-converted" method, which is net of tax. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and therefore excluded from the computation of diluted earnings per share.

The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

	Year Ended December 31,		
(in thousands, except per share data)	**2020**	**2019**	**2018**
Net income attributable to Class A Common Stock	$ (682,837)	$ 15,798	$ 199,899
Add: Income from conversion of Class C Common Stock	—	328	—
Adjusted net income attributable to Class A Common Stock	$ (682,837)	$ 16,126	$ 199,899
Basic net earnings per share of Class A Common Stock	$ (2.46)	$ 0.06	$ 0.76
Diluted net earnings per share of Class A Common Stock	$ (2.46)	$ 0.06	$ 0.75
Basic weighted average shares of Class A Common Stock outstanding	277,368	267,700	263,341
Add: Dilutive effects of conversion of Class C Common Stock	—	8,869	—
Add: Dilutive effects of potential common stock	—	63	3,514
Diluted weighted average shares of Class A Common Stock outstanding	277,368	276,632	266,855

The following table presents shares excluded from the diluted earnings per share calculation as their impacts were anti-dilutive for the periods presented:

	Year Ended December 31,		
(in thousands)	**2020[1]**	**2019**	**2018**
Out-of-the-money stock options	3,571	4,706	818
Restricted stock	6,299	2,895	—
Performance stock units	13	—	39
Employee Stock Purchase Plan	76	22	—
Weighted average shares of Class C Common Stock	261	—	12,791
Warrants	8,000	8,000	—

(1) The Company recognized a net loss during the year ended December 31, 2020, and therefore all potential common shares were anti-dilutive and excluded from the calculation of diluted net earnings per share.

Note 11—Income Taxes

Historically, CRP has been treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, CRP was not subject to U.S. federal and certain state and local income taxes, and any taxable income or loss generated by CRP was passed through to and included in the taxable income or loss of its members, including Centennial, on a pro rata basis. Following the Conversion, CRP is no longer a partnership for tax purposes and the Company is now subject to U.S. federal and applicable state and local income taxes for its entire consolidated taxable income or loss.

Income tax expenses and benefits included in the consolidated statements of operations are detailed below:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Current taxes			
Federal	$ —	$ —	$ —
State	—	—	—
	—	—	—
Deferred taxes			
Federal	80,091	(5,396)	(56,365)
State	5,033	(401)	(3,075)
	85,124	(5,797)	(59,440)
Income tax (expense) benefit	$ 85,124	$ (5,797)	$ (59,440)

A reconciliation of the statutory federal income tax expense, which is calculated at the federal statutory rate of 21%, to the income tax expense from continuing operations provided for the periods presented, is as follows:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Income tax (expense) benefit at the federal statutory rate	$ 161,768	$ (4,664)	$ (57,157)
State income tax (expense) benefit - net of federal benefit	9,046	(383)	(3,075)
Noncontrolling interest in partnership	(496)	129	2,696
Stock-based compensation	(8,047)	(780)	(1,825)
Nondeductible expenses	(151)	(99)	(79)
Change in valuation allowance	(76,996)	—	—
Income tax (expense) benefit	$ 85,124	$ (5,797)	$ (59,440)

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities are presented below:

(in thousands)	December 31, 2020	December 31, 2019
Deferred tax assets:		
Net operating loss carryforwards	$ 107,897	$ 88,043
Capitalized intangible drilling cost	110,590	100,307
Stock-based compensation	4,871	8,284
Derivative assets	3,985	—
Asset retirement obligations	3,722	—
Interest expense	—	18,722
Other assets	637	295
Total deferred tax assets	231,702	215,651
Deferred tax liabilities:		
Investment in CRP	—	(301,155)
Oil and gas properties	(155,748)	—
Other liabilities	(1,547)	—
Total deferred tax liabilities	(157,295)	(301,155)
Valuation Allowance	(76,996)	—
Net deferred tax asset (liability)	$ (2,589)	$ (85,504)

In connection with the conversions of shares from a noncontrolling interest owner, a tax loss was recorded in equity of $2.2 million and $17.5 million in 2020 and 2019, respectively, and a tax benefit was recorded in equity of $7.2 million in 2018. The Conversion that occurred during 2020 eliminated the noncontrolling interest and CRP is no longer treated as a partnership for tax purposes. As a result, the deferred tax assets and liabilities previously recorded within the partnership, and previously reported by the Company as a net deferred tax liability related to its investment in CRP, are now directly included within the Company's deferred tax asset and liability categories above. Additionally, the Company's deferred tax asset related to its interest expense limitation carryover at the partnership level was allocated proportionally to the Company's oil and gas properties. All interest expense after the Conversion was deductible in the current year.

As of December 31, 2020, the Company had approximately $496.3 million and $93.2 million of U.S. federal and state net operating loss carryovers, respectively. Approximately $417.4 million and $78.2 million of these U.S. federal and state net operating loss carryovers expire in 2037, respectively.

The Company periodically assesses whether it is more-likely-than-not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating loss carry forwards. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. Based on when the Company expects existing taxable differences to be realized, management determined that sufficient negative evidence exists as of December 31, 2020 to conclude that it is more-likely-than-not that a portion of its deferred tax assets will not be realized. Accordingly, a valuation allowance against its deferred tax assets in the amount of $77.0 million was recorded as of December 31, 2020.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon the examination by the Internal Revenue Service or other governmental agency. As of December 31, 2020 and 2019, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. Interest and penalties related to uncertain tax positions are reported in income tax expense.

The Company is subject to the following material taxing jurisdictions: U.S., Colorado, New Mexico, and Texas. As of December 31, 2020, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2017 through 2020.

Note 12—Transactions with Related Parties

Riverstone and its affiliates beneficially own more than 10% equity interest in the Company and are therefore considered related parties. The Company has a marketing agreement with Lucid Energy Delaware, LLC ("Lucid"), an affiliate of Riverstone. The Company believes that the term of the marketing agreement with Lucid are no less favorable to either party than those held with unaffiliated parties.

The following table summarizes the revenues recognized and the associated processing fees incurred from this marketing agreement as presented in the consolidated statements of operations for the periods indicated as well as the related net receivables outstanding as of the balance sheet dates:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Lucid Energy Delaware, LLC ("Lucid")			
Oil and gas sales	$ 5,089	$ 3,559	$ 3,946
Gathering, processing and transportation expenses	4,818	2,642	792

(in thousands)	**December 31, 2020**	**December 31, 2019**
Accounts receivable, net(1)	$ 994	$ 91

(1) Represents amounts due from Lucid and are presented net of unpaid processing fees as of the indicated period end date.

Senior Secured Notes

During 2020, Riverstone acquired an aggregate of $100.7 million and $111.9 million of the Company's 2026 Senior Notes and 2027 Senior Notes, respectively, in open market purchases. Subsequently, on May 22, 2020, Riverstone participated in the Company's Debt Exchange, discussed in *Note 4—Long-Term Debt*, and exchanged all of its Senior Unsecured Notes for $106.3 million of the Company's Senior Secured Notes. Riverstone's participation in the Debt Exchange represented $120.0 million of the total extinguishment gain recognized in the consolidated statements of operations. The Company paid Riverstone $4.5 million in interest associated with the Senior Secured Notes during the year ended December 31, 2020.

Note 13—Commitments and Contingencies

Contractual Obligations

The following table is a schedule of the Company's future minimum payments required under contractual commitments that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2020**:**

(in thousands)	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**	**Total**
Water disposal agreements	$ 1,825	$ 100	$ —	$ —	$ —	$ —	$ 1,925
Transportation agreements	9,060	1,770	—	—	—	—	10,830
Total	$ 10,885	$ 1,870	$ —	$ —	$ —	$ —	$ 12,755

Water Disposal Agreement

The Company has entered into agreements for the transportation and disposal of produced water from a portion of its operated wells. Under the terms of these agreements, Centennial is obligated to deliver a minimum volume of produced water or else pay for any deficiencies at the prices stipulated in the contracts. The obligations reported above represent the remaining minimum financial commitment pursuant to the terms of the contracts as of December 31, 2020. Actual expenditures under these contracts may exceed the minimum commitments presented above. The Company recognized water disposal costs of $2.4 million, $2.6 million and $2.2 million for the years ended December 31, 2020, 2019 and 2018, respectively, related to these water disposal agreements.

Transportation Agreements

The Company has various natural gas transportation agreements whereby it is required to pay fixed reservation fees for pipeline capacity over the contractual terms. The obligations reported above represent the gross minimum financial commitments pursuant to these agreements as of December 31, 2020. The Company has an additional gas transport agreement with a volumetric obligation, but this agreement has variable pricing components that cannot reliably be determined and therefore is not included above. Actual expenditures under these contracts are likely to exceed the minimum commitment amounts presented above. The Company paid transportation and gathering costs of $19.5 million, $12.8 million and $3.7 million for the years ended December 31, 2020, 2019 and 2018, respectively, related to these agreements.

Purchase Obligations

The Company has purchase agreements to buy frac' sand used in its well fracture stimulation process. Historically, under the terms of these agreements, Centennial was obligated to purchase a minimum volume of frac sand at a fixed sales price. However, these agreements were renegotiated in 2020 and all future minimum volume commitments were eliminated. No penalties were paid under these agreements during the year ended December 31, 2020 related to the failure to purchase the minimum volumes of frac sand or as a result of the modifications to the agreements.

Delivery Commitments

In August 2018, the Company entered into a firm crude oil sales agreement with a large integrated oil company that was subsequently amended during the year ended December 31, 2020. Utilizing this company's transport capacity out of the Permian Basin, the agreement, as amended, provides for firm gross sales of 30,000 Bbls/d over the next 4.5 years and is based upon prevailing market prices of ICE Brent and contractual differentials. Under-delivery of volumes would result in a financial obligation to the Company.

The Company has firm gas sales agreements that provide for firm gross sales ranging from approximately 41,000 to 91,000 MMBtu/d in aggregate over the next two years. These sales agreements do not require the Company to physically deliver the aforementioned volumes over the terms of the agreements, but if the volumetric commitments are not met and the purchaser incurs financial damages, the Company is required to pay for any differences between the contracted prices and current market prices for replacement volumes bought by the purchaser.

The amounts discussed above represent the total gross volumes the Company is required to deliver per these agreements, which gross volumes are not comparable to the Company's net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation,* as amounts therein are reflected net of all royalties, overriding royalties and production due to others. The Company believes its current production and reserves are sufficient to fulfill the physical delivery commitments, and the Company is not required to deliver oil or gas specifically produced from any of the Company's properties under these agreements. Further, if the Company's production is not sufficient to satisfy the firm delivery commitments, the Company believes it can purchase sufficient volumes in the market at index-related prices to satisfy its commitments. The aggregate amount of any such potential financial obligation under these contracts is not determinable since the amount and timing of any volumetric shortfalls, as well as the difference between the prevailing market price and contract price at such time, cannot be predicted with accuracy.

Lease Commitments

Refer to *Note 15—Leases* for details on the Company's operating lease agreements.

Contingencies

The Company may at times be subject to various commercial or regulatory claims, prior period adjustments from service providers, litigation or other legal proceedings that arise in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, management believes it is remote that the impact of such matters that are reasonably possible to occur will have a material adverse effect on the Company's financial position, results of operations or cash flows. Management is unaware of any pending claims or litigation brought against the Company requiring the reserve of a contingent liability as of the date of these consolidated financial statements.

Note 14—Revenues

Revenue from Contracts with Customers

Crude oil, natural gas and NGL sales are recognized at the point control of the product is transferred to the customer and collectability is reasonably assured. Virtually all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, transportation costs to an active spot market and quality differentials. As a result, the Company's realized price of oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies both globally (in the case of crude oil) and locally.

Oil and gas revenues presented within the consolidated statements of operations relate to the sale of oil, natural gas and NGLs as shown below:

	Year Ended December 31,		
	2020	2019	2018
Operating revenues (in thousands):			
Oil sales	$ 475,694	$ 810,655	$ 709,813
Natural gas sales	46,776	44,556	62,325
NGL sales	57,986	89,119	118,907
Oil and gas sales	$ 580,456	$ 944,330	$ 891,045

Oil sales

The Company's crude oil sales contracts are generally structured whereby oil is delivered to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes title of the product. This delivery point is usually at the wellhead or at the inlet of a transportation pipeline. Revenue is recognized when control transfers to the purchaser at the delivery point based on the net price received from the purchaser. Any downstream transportation costs incurred by crude purchasers are reflected as a net reduction to oil sales revenues.

Natural gas and NGL sales

Under the Company's natural gas processing contracts, liquids rich natural gas is delivered to a midstream gathering and processing entity at the inlet of the gas gathering system. The midstream processing entity gathers and processes the raw gas and then remits proceeds to Centennial for the resulting sales of NGLs, while the Company generally elects to take its residue gas product "in-kind" at the plant tailgate. For these contracts, the Company evaluates when control is transferred and revenue should be recognized. Where the Company has concluded that control transfers at the tailgate of the processing facility, fees incurred prior to transfer of control are presented as gathering, processing and transportation expenses ("GP&T") within the consolidated statements of operations. Any transportation and fractionation costs incurred subsequent to the point of transfer of control are reflected as a net reduction to natural gas and NGL sales revenues presented in the table above.

Performance obligations

For all commodity products, the Company records revenue in the month production is delivered to the purchaser. Settlement statements for natural gas and NGL sales may not be received for 30 to 90 days after the date production volumes are delivered and for crude oil, generally within 30 days after delivery has occurred. However, payment is unconditional once the performance obligations have been satisfied. At this time, the volume and price can be reasonably estimated and amounts due from customers are accrued in *Accounts receivable, net i*n the consolidated balance sheets. As of December 31, 2020 and December 31, 2019, such receivable balances were $41.7 million and $76.6 million, respectively.

The Company records any differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Historically, any identified differences between revenue estimates and actual revenue received have not been significant. For the years ended December 31, 2020 and 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods were not material.

Transaction price allocated to remaining performance obligations

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606 which states the Company is not required to disclose the transaction price allocated to the remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, monthly sales of a product generally represent a separate performance obligation; therefore, future commodity volumes to be delivered and sold are wholly unsatisfied and disclosure of the transaction price allocated to such unsatisfied performance obligations is not required.

Note 15—Leases

At contract inception, the Company determines whether or not an arrangement contains a lease. However, in connection with the implementation of ASC 842, *Leases* ("ASC 842"), this assessment was made as of the adoption date of ASC 842, January 1, 2019. Upon determination of a lease, a lease right-of-use ("ROU") asset and related liability are recorded based on the present value of the future lease payments over the lease term. ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make future lease payments arising from the lease.

The Company has operating leases for drilling rig contracts, office rental agreements, and other wellhead equipment. As of December 31, 2020, these leases have remaining lease terms ranging from two months to one year, some of which include options to extend the lease term for up to five years, and some of which include options to early terminate. These options are considered in determining the lease term and are included in the present value of future payments that are recorded for leases when the Company is reasonably certain to exercise the option. Leases with an initial term of one year or less are not recorded in the consolidated balance sheets. Additionally, none of the Company's lease agreements contain any material residual value guarantees or material restrictive covenants.

The present value of future lease payments is determined at the lease commencement date based upon the Company's incremental borrowing rate. The incremental borrowing rate is calculated using a risk-free interest rate adjusted for the Company's specific risk and the specific lease term. The table below summarizes the Company's discount rate and weighted-average remaining lease term as of the periods presented.

	December 31, 2020	December 31, 2019
Weighted-average discount rate	5.1 %	4.56 %
Weighted-average remaining lease term (years)	1.07	1.29

The Company's drilling rig contracts, office rental agreements, and wellhead equipment agreements contain both lease and non-lease components, which are combined and accounted for as a single lease component.

Variable lease payments are recognized in the period in which they are incurred and include operating expenses related to the office rental agreements and cost incurred on the drilling rig contracts in excess of the contractual rate. Cost related to short-term leases are recognized on a straight-line basis over the lease term as either expenses to the consolidated statements of operations or capitalized to the consolidated balance sheets. The following table presents the components of the Company's lease cost for the period presented.

	Year Ended December 31,	
(in thousands)	**2020**	**2019**
Lease costs		
Operating lease cost	$ 8,117	$ 33,881
Variable lease cost	4,773	3,104
Short-term lease cost	41,533	60,798
Total Lease Cost	$ 54,423	$ 97,783

The following table presents supplemental cash flow information related to the Company's leases for the periods presented.

	Year Ended December 31,	
(in thousands)	**2020**	**2019**
Operating lease liability payments:		
Cash used in operating activities	$ 6,285	$ 15,897
Cash used in investing activities	$ 1,832	$ 17,984
Right-of-use assets recognized (derecognized) with offsetting operating lease liabilities	$ (3,843)	$ 34,833

Maturities of the Company's long-term operating lease liabilities by fiscal year as of December 31, 2020 are as follows:

(in thousands)	**Total**[(2)]
2021	3,260
2022	425
Total lease payments	3,685
Less: imputed interest	(108)
Present value of lease liabilities[(1)]	$ 3,577

(1) Of the total present value of lease liabilities, $3.2 million was recorded to current *Operating lease liabilities* and $0.4 million was recorded in noncurrent *Operating lease liabilities* in the consolidated balance sheets as of December 31, 2020.

(2) Total lease payments exclude variable lease payments which can be charged under the terms of the lease agreements.

Supplemental Information About Oil & Natural Gas Producing Activities (Unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

(in thousands)	December 31, 2020	December 31, 2019
Proved properties	$ 4,395,473	$ 3,962,175
Unproved properties	1,209,205	1,470,903
Total proved and unproved properties	5,604,678	5,433,078
Accumulated depreciation, depletion and amortization	(1,877,832)	(931,737)
Net capitalized costs	$ 3,726,846	$ 4,501,341

Costs Incurred for Oil and Natural Gas Producing Activities

The costs incurred in the Company's oil and gas production, exploration, and development activities are displayed in the table below and include costs whether capitalized or expensed as well as revisions and additions to the estimated future asset retirement obligations.

	Year Ended December 31,		
(in thousands)	2020	2019	2018
Acquisition costs:			
Proved properties	$ 1,384	$ 3,437	$ 39,731
Unproved properties	4,768	81,602	173,519
Advances for unproved properties(1)	2,312	18,345	—
Development costs(2)	284,006	875,911	933,639
Exploration costs	18,355	11,390	9,968
Total	$ 310,825	$ 990,685	$ 1,156,857

(1) Advances for unproved properties represent amounts paid to a third-party broker to acquire approximately 24,000 net leasehold acres on the Company's behalf in the Permian Basin. This prepaid amount was included in the *Other noncurrent assets* line item on the consolidated balance sheet; however, it was impaired during the year ended December 31, 2020. Refer to the *Management Discussion and Analysis of Financial Condition and Results of Operations* under Part II, Item 7 of this Annual Report for further discussion.

(2) Includes the cost of drilling development wells and associated facilities for which construction was completed during the period. Costs associated with wells and facilities that are in progress or awaiting completion at year-end are not included and were $45.3 million, $86.8 million and $115.0 million as of the years ended December 31, 2020, 2019 and 2018, respectively.

Estimated Quantities of Proved Oil and Gas Reserves

The reserve estimates presented below and included herein conform to the definitions prescribed by the SEC. The Company retained Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, to prepare the estimates of all of its proved reserves as of December 31, 2020, 2019 and 2018 and their related pre-tax future net cash flows. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC.

As of December 31, 2020, all of the Company's oil and gas reserves are attributable to properties within the United States. The table below presents a summary of changes in quantities of proved oil and gas reserves in the Company's estimated proved reserves:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBoe)[(1)]
Total proved reserves:				
Balance - December 31, 2017	100,933	327,212	30,986	186,454
Extensions and discoveries	64,159	179,052	23,937	117,938
Revisions to previous estimates	(12,429)	(74,781)	770	(24,123)
Purchases of reserves in place	3,573	7,455	1,012	5,827
Divestitures of reserves in place	(791)	(4,379)	(455)	(1,975)
Production	(12,679)	(31,707)	(4,332)	(22,295)
Balance - December 31, 2018	142,766	402,852	51,918	261,826
Extensions and discoveries	33,093	76,820	10,527	56,424
Revisions to previous estimates	(9,845)	64,558	10,047	10,959
Purchases of reserves in place	9	209	30	74
Divestitures of reserves in place	(282)	(306)	(46)	(378)
Production	(15,582)	(41,703)	(5,234)	(27,766)
Balance - December 31, 2019	150,159	502,430	67,242	301,139
Extensions and discoveries	33,220	73,669	9,877	55,375
Revisions to previous estimates	(19,680)	(7,010)	(12,184)	(33,031)
Production	(13,207)	(41,302)	(4,490)	(24,581)
Balance - December 31, 2020	150,492	527,787	60,445	298,902
Proved developed reserves:				
December 31, 2018	63,317	180,542	23,093	116,500
December 31, 2019	74,842	237,791	32,743	147,216
December 31, 2020	70,716	279,556	31,672	148,981
Proved undeveloped reserves:				
December 31, 2018	79,449	222,310	28,825	145,326
December 31, 2019	75,317	264,639	34,499	153,923
December 31, 2020	79,776	248,231	28,773	149,921

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Notable changes in proved reserves for the year ended December 31, 2020 included the following:

- *Extensions and discoveries.* In 2020, 55.4 MMBoe of proved reserves were added through extensions and discoveries and include: i) 52.1 MMBoe for new proved undeveloped ("PUD") locations; and ii) 3.3 MMBoe for unproved locations that were successfully converted to new proved developed ("PDP") wells during the period. These additions resulted from the Company's 2020 drilling program, which added locations primarily in the 2nd and 3rd Bone Spring formations on the Company's New Mexico acreage and also on the Company's Texas position in the Wolfcamp C and 3rd Bone Spring formations.
- *Revisions to previous estimates.* In 2020, total revisions to previous estimates reduced proved reserves by a net amount of 33.0 MMBoe. Aggregate downward revisions of 133.4 MMBoe for 2020 consisted of (i) 103.7 MMBoe of downward pricing adjustments and (ii) 29.4 MMBoe of negative revisions associated with PUD locations that were either reclassified to unproved reserves or removed due to changes in the Company's active development program. These downward revisions were partially offset by aggregate upward revisions of 100.4 MMBoe that were primarily related to reductions in the Company's operating costs, which extended the lives and increased total reserves for PDP and PUD locations, as well as reductions in per-well capital expenditures that elevated economics for certain PUD locations.

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- *Extensions and discoveries.* In 2019, 56.4 MMBoe of proved reserves were added through extensions and discoveries and include: i) 30.5 MMBoe for new PUD locations; and ii) 25.9 MMBoe for unproved locations that were successfully converted to new PDP wells during the period. These additions resulted from the Company's effective drilling program throughout the year, which added locations primarily in the Upper Wolfcamp A formation in the Company's Texas position and also in the 2nd Bone Spring formations in the Company's New Mexico acreage.
- *Revisions to previous estimates.* In 2019, revisions to previous estimates of 11.0 MMBoe consisted of 27.5 MMBoe of upward revisions primarily related to well performance revisions to reflect higher gas and NGL yields on older wells, which in turn increased total EURs for most proved developed and PUD locations. These positive revisions were partially offset by 16.5 MMBoe of negative revisions, of which 10.1 MMBoe related to downward pricing adjustments due to lower average commodity prices for oil, gas and NGLs for the year ended December 31, 2019. The remainder of the downward revisions related to PUD locations that were reclassified to unproven reserves due to them no longer being a part of the Company's active development program.

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* In 2018, total extensions and discoveries of 117.9 MMBoe were primarily attributable to increased drilling activity as a result of the Company's seven-rig drilling program effective throughout the year. These additions include 90.0 MMBoe related to new PUD locations, primarily in the Upper Wolfcamp A, and 27.9 MMBoe for the conversion of unproved locations to PDP wells.
- *Revisions to previous estimates.* In 2018, revisions to previous estimates were 24.1 MMBoe and mainly consist of negative revisions to PUD locations of 20.3 MMBoe. Of these PUD revisions, the majority related to locations that were reclassified to unproved reserves due to them no longer being a part of the Company's active development program. In addition, 1.4 MMBoe of reserves were removed for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules.
- *Purchases of reserves in place.* In 2018, purchases of reserves of 5.8 MMBoe was primarily attributable to asset acquisitions discussed in *Note 2—Property Acquisitions and Divestitures*.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows (the "Standardized Measure") relating to proved oil and gas reserves has been prepared in accordance with FASB ASC Topic 932, *Extractive Activities - Oil and Gas* ("ASC 932"). Future cash inflows as of December 31, 2020, 2019 and 2018 have been computed by applying average fiscal year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month periods ended December 31, 2020, 2019 and 2018, respectively) to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves, based on year-end costs and assuming the continuation of existing economic conditions. The Standardized Measure also includes costs for future dismantlement, abandonment and rehabilitation obligations.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves.

Future net cash flows are discounted at a rate of 10% annually to derive the Standardized Measure. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

The following table presents the Company's Standardized Measure of discounted future net cash flows:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Future cash inflows	$ 6,700,654	$ 9,616,702	$ 10,989,064
Future development costs	(974,163)	(1,410,494)	(1,548,551)
Future production costs	(3,135,089)	(3,943,766)	(3,313,981)
Future income tax expenses	(25,487)	(391,168)	(1,027,976)
Future net cash flows	2,565,915	3,871,274	5,098,556
10% discount to reflect timing of cash flows	(1,381,240)	(1,808,902)	(2,618,705)
Standardized measure of discounted future net cash flows	$ 1,184,675	$ 2,062,372	$ 2,479,851

The following summarizes the principal sources of change in the Standardized Measure of discounted future net cash flows and such changes have been computed in accordance with ASC 932:

	Year Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Standardized measure of discounted future net cash flows, beginning of period	$ 2,062,372	$ 2,479,851	$ 1,503,326
Sales of oil, natural gas and NGLs, net of production costs	(360,448)	(662,319)	(693,585)
Purchase of minerals in place	—	154	61,137
Divestiture of minerals in place	—	(5,593)	(17,516)
Extensions and discoveries, net of future development costs	177,325	526,083	1,213,206
Previously estimated development costs incurred during the period	167,135	380,376	380,452
Net change in prices and production costs	(1,428,068)	(1,395,537)	532,702
Change in estimated future development costs	463,286	15,056	(145,048)
Revisions of previous quantity estimates	(236,917)	47,226	(155,943)
Accretion of discount	219,789	297,946	174,806
Net change in income taxes	131,054	364,089	(254,873)
Net change in timing of production and other	(10,853)	15,040	(118,813)
Standardized measure of discounted future net cash flows, end of period	$ 1,184,675	$ 2,062,372	$ 2,479,851

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate weighted average sales prices (inclusive of adjustments for transportation, quality and basis differentials) for each of the periods indicated below as follows:

	Year Ended December 31,		
	2020	**2019**	**2018**
Oil (per Bbl)	$ 35.89	$ 52.62	$ 58.71
Gas (per Mcf)	0.97	0.87	2.45
NGLs (per Bbl)	13.00	18.99	31.20

Selected Quarterly Financial Data (Unaudited)

	Quarter Ended			
(in thousands)	**March 31**	**June 30**	**September 30**	**December 31**
2020				
Operating revenues	$ 192,769	$ 90,509	$ 149,101	$ 148,077
Operating expenses	801,588	183,309	181,112	194,965
Income (loss) from operations	(608,574)	(92,802)	(31,866)	(46,878)
Other income (expense)	(24,979)	96,216	(19,663)	(41,777)
Income tax (expense) benefit	83,208	1,916	—	—
Net income (loss) attributable to Class A Common Stock	(547,983)	5,330	(51,529)	(88,655)
Income (loss) per share of Class A Common Stock:				
Basic	$ (1.99)	$ 0.02	$ (0.19)	$ (0.32)
Diluted	(1.99)	0.02	(0.19)	(0.32)

	Quarter Ended			
(in thousands)	**March 31**	**June 30**	**September 30**	**December 31**
2019				
Operating revenues	$ 214,569	$ 244,239	$ 229,130	$ 256,392
Operating expenses	209,462	207,142	217,766	229,674
Income (loss) from operations[(1)]	5,105	37,106	11,342	25,876
Other income (expense)[(1)]	(15,905)	(12,176)	(13,662)	(15,475)
Income tax (expense) benefit	2,263	(5,928)	(1,393)	(739)
Net income (loss) attributable to Class A Common Stock	(8,112)	17,877	(3,585)	9,618
Income (loss) per share of Class A Common Stock:				
Basic	$ (0.03)	$ 0.07	$ (0.01)	$ 0.03
Diluted	(0.03)	0.07	(0.01)	0.03

(1) Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, the Company has evaluated, under the supervision and with the participation of management, including the principal executive officer and principal financial officer, the effectiveness of the design and operation of disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2020. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports that the Company files under the Exchange Act is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, the principal executive officer and principal financial officer concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2020 at the reasonable assurance level.

Management’s Annual Report on Internal Control Over Financial Reporting

Management, including the principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. The Company’s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP.

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.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2020, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that the Company’s internal control over financial reporting was effective as of December 31, 2020.

This Annual Report includes an attestation report of KPMG LLP, the Company’s independent registered public accounting firm, on the Company’s internal control over financial reporting as of December 31, 2020, which is included in this Annual Report.

Changes in Internal Control over Financial Reporting

There were no changes in the system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2021 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2021 annual meeting of stockholders and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required in response to this item will be set forth in our definitive proxy statement for the 2021 annual meeting of stockholders and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2021 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2021 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES

		Page
(a)(1)	The following financial statements are included in Item 8. Financial Statements and Supplementary Data in this Annual Report:	
	Consolidated Balance Sheets as of December 31, 2020 and 2019	64
	Consolidated Statements of Operations for the years ended December 31, 2020, 2019 and 2018	65
	Consolidated Statements of Cash Flows for the years ended December 31, 2020, 2019 and 2018	66
	Consolidated Statements of Shareholders' Equity for the years ended December 31, 2020, 2019 and 2018	68
	Notes to Consolidated Financial Statements for the years ended December 31, 2020, 2019 and 2018	69
(2)	Financial statement schedules—None	
(3)	Exhibits:	

Exhibit Number	Description of Exhibits
2.1	Contribution Agreement, dated as of July 6, 2016, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, among Centennial Resource Development, LLC, NGP Centennial Follow-On LLC, Celero Energy Company, LP, Centennial Resource Production, LLC and New Centennial, LLC (incorporated by reference to Annex A of the Registrant's definitive proxy statement filed with the SEC on September 23, 2016).
2.2	Purchase and Sale Agreement, dated as of November 21, 2016, by and among SB RS Holdings, LLC, Silverback Exploration, LLC and Silverback Operating, LLC (incorporated by reference to Exhibit 2.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-215621) filed with the SEC on January 19, 2017).
2.3	Purchase and Sale Agreement, dated as of April 28, 2017, by and between GMT Exploration Company LLC and Centennial Resource Production, LLC (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 1, 2017).
3.1	Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019).
3.2	Second Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 1, 2019).
3.3	Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of October 11, 2016 (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.4	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of December 28, 2016 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on December 29, 2016).
3.5	Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of March 20, 2017 (incorporated by reference to Exhibit 3.5 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 23, 2017).
3.6	Amendment No. 3 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of June 15, 2018 (incorporated by reference to Exhibit 3.6 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018).
4.1	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
4.2	Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
4.3	Warrant Agreement between Continental Stock Transfer & Trust Company and the Registrant (incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed with the SEC on February 29, 2016).
4.4	Certificate of Designation of Series A Preferred Stock (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
4.5	Description of Registrant's Common Stock (incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 24, 2020).
4.6	Indenture, dated as of November 30, 2017, by and among Centennial Resource Production, LLC, the subsidiary guarantors named therein and UMB Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed with the SEC on December 5, 2017).
4.7	First Supplemental Indenture (2026 Senior Notes), dated as of May 22, 2020, between Centennial Resource Development, Inc., as parent guarantor, and UMB Bank, N.A., as trustee (incorporated by reference to Exhibit 4.2 on the Registrant's Current Report on Form 8-K filed with the SEC on May 22, 2020).

4.8	Indenture, dated as of March 15, 2019, by and among Centennial Resource Production, LLC, the subsidiary guarantors named therein and UMB Bank, N.A. as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed with SEC on March 18, 2019).
4.9	First Supplemental Indenture (2027 Senior Notes), dated as of May 22, 2020, between Centennial Resource Development, Inc., as parent guarantor, and UMB Bank, N.A., as trustee (incorporated by reference to Exhibit 4.3 on the Registrant's Current Report on Form 8-K filed with the SEC on May 22, 2020).
4.10	Indenture, dated as of May 22, 2020, by and among CRP, the guarantors party thereto and UMB Bank, N.A., as trustee and collateral agent (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed with SEC on March 22,2020).
10.1	Amended and Restated Registration Rights Agreement among the Registrant and certain stockholders (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.2	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.7 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016).
10.3	Second Amended and Restated Credit Agreement, dated as of May 4, 2018, among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on May 8, 2018).
10.4	Second Amendment to Second Amended and Restated Credit Agreement, dated as of May 1, 2020, among Centennial Resource Production, LLC, as borrower, Centennial Resource Development, Inc., as parent guarantor, the other guarantors party thereto, JP Morgan Chase Bank, N.A., as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 4, 2020).
10.5	Third Amendment to Second Amended and Restated Credit Agreement and First Amendment to Second Amended and Restated Pledge and Security Agreement, dated May 1, 2020, among Centennial Resource Production, LLC, as borrower, Centennial Resource Development, Inc., as parent guarantor, the other guarantors party thereto, JP Morgan Chase Bank, N.A., as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 4, 2020).
10.6	Fourth Amendment to Second Amended and Restated Credit Agreement, dated October 8, 2020, among Centennial Resource Production, LLC, as borrower, Centennial Resource Development, Inc., as parent guarantor, the other guarantors party thereto, JP Morgan Chase Bank, N.A., as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 13, 2020).
10.7	Second Lien Pledge and Security Agreement by and among CRP, the grantors party thereto and the Collateral Agent (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 22, 2020).
10.8	Purchase and Sale Agreement, dated as of August 2, 2018, by and between Centennial Resource Production, LLC and BP Products North America Inc. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on August 6, 2018).
10.9	Amendment no. 1 to Purchase and Sale Agreement, dated as of August 2, 2018, by and between Centennial Resource Production, LLC and BP Products North America Inc. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on April 1, 2020).
10.10	Crude Oil Purchase and Sale Agreement, dated as of August 31, 2018, by and between Centennial Resource Production, LLC and ExxonMobil Oil Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on September 4, 2018).
10.11#	Centennial Resource Development, Inc. Amended and Restated Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report filed with the SEC on May 4, 2020).
10.12#	Form of Stock Option Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.13#	Form of Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.14#	Form of Restricted Stock Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016).
10.15#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.16 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 26, 2018).
10.16#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018).
10.17#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 5, 2019).
10.18#	Form of Cash-Settled Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 3, 2020.

10.19#	Form of Cash-Settled Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 3, 2020.
10.20#	Centennial Resource Development, Inc. Second Amended and Restated Severance Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed with the SEC on February 17, 2021).
10.21#	Centennial Resource Development, Inc. Third Amended and Restated Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report filed with the SEC on May 4, 2020).
10.22#	Centennial Resource Development, Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019).
21.1	Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-214355) filed with the SEC on October 31, 2016).
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a).
31.2*	Certification of the Chief Financial Officer required by Rule 13a-14(a) or Rule 15d-14(a).
32.1*	Certification of the Chief Executive Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
32.2*	Certification of the Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350.
99.1	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2018 (incorporated by reference to Exhibit 99.3 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 25, 2019).
99.2	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2019 (incorporated by reference to Exhibit 99.3 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 24, 2020).
99.3*	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2020.
101.INS*	Inline XBRL Instance Document - The 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.

* Filed herewith.

Management contract or compensatory plan or agreement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis

Vice President, Chief Financial Officer and Assistant Secretary

Pursuant to the requirements of the Securities Act of 1934, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ SEAN R. SMITH Sean R. Smith	Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2021
/s/ GEORGE S. GLYPHIS George S. Glyphis	Vice President, Chief Financial Officer and Assistant Secretary (Principal Financial Officer)	February 24, 2021
/s/ BRENT P. JENSEN Brent P. Jensen	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2021
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Chairman	February 24, 2021
/s/ MAIRE A. BALDWIN Maire A. Baldwin	Director	February 24, 2021
/s/ KARL E. BANDTEL Karl E. Bandtel	Director	February 24, 2021
/s/ MATTHEW G. HYDE Matthew G. Hyde	Director	February 24, 2021
/s/ PIERRE F. LAPEYRE, JR. Pierre F. Lapeyre, Jr.	Director	February 24, 2021
/s/ DAVID M. LEUSCHEN David M. Leuschen	Director	February 24, 2021
/s/ JEFFREY H. TEPPER Jeffrey H. Tepper	Director	February 24, 2021
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	February 24, 2021

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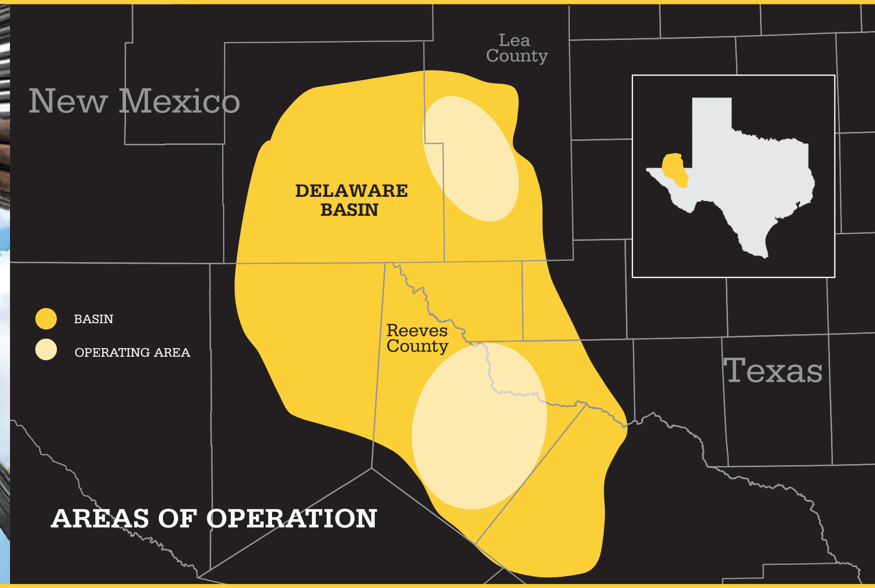

DIRECTORS AND OFFICERS

Directors

Steven J. Shapiro +*
Chairman of the Board

Maire A. Baldwin #+*
Compensation Committee Chairperson

Karl E. Bandtel #*
Nominating, Environmental, Social and Governance Committee Chairperson

Matthew G. Hyde +*

Pierre F. Lapeyre, Jr.

David M. Leuschen

Sean R. Smith

Jeffrey H. Tepper #+
Audit Committee Chairperson

Robert M. Tichio

Audit Committee Member
+ Compensation Committee Member
* Nominating, Environmental, Social and Governance Committee Member

Executive Officers

Sean R. Smith
Chief Executive Officer

Matt R. Garrison
Vice President and Chief Operating Officer

George S. Glyphis
Vice President and Chief Financial Officer

Brent P. Jensen
Vice President and Chief Accounting Officer

Davis O. O'Connor
Vice President and General Counsel

Other Officers

Sean W. Marshall
Vice President of Land

Kathleen M. Phillips
Vice President of Human Resources

Colleen C. Proctor
Vice President of Information Technology

Clayton T. Smith
Vice President of Operations

Jeff B. Thompson
Vice President of Strategic Planning and Corporate Reserves

William A. Weidig
Vice President of Finance and Treasurer

Company Information

Independent Registered Public Accounting Firm
KPMG LLP

Registrar and Stock Transfer Agent
Continental Stock Transfer & Trust Company

Investor Relations
Hays Mabry
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ir@cdevinc.com

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Denver, CO 80202
(720) 499-1400
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www.cdevinc.com

Ticker
CDEV

Stock Exchange Listing
NASDAQ

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