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

FORM 10-Q

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

For the quarterly period ended September 30, 2018

OR

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

For the transition period from to

Commission file number 001-37697

CENTENNIAL RESOURCE DEVELOPMENT, INC.
(Exact Name of Registrant as Specified in its Charter)

Delaware	**47-5381253**
(State of Incorporation)	(I.R.S. Employer Identification Number)
1001 Seventeenth Street, Suite 1800, Denver, Colorado	**80202**
(Address of Principal Executive Offices)	(Zip Code)

(720) 499-1400

(Registrant's Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

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

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

As of October 31, 2018, there were 264,257,387 shares of Class A Common Stock, par value $0.0001 per share and 12,003,183 shares of Class C Common Stock, par value $0.0001 per share, outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this Quarterly Report on Form 10-Q, 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.

Bbls/d. Barrels 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 optimize production.

Development project. The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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/or location of oil or natural gas.

Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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.

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.

Flush production. First yield from a flowing oil well during its most productive period after it is first completed and put on line.

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.

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 or recompletion.

Realized price. The cash market price less differentials.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

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, transportation and demand adjustments.

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.

GLOSSARY OF CERTAIN OTHER TERMS

The following are definitions of certain other terms that are used in this Quarterly Report on Form 10-Q:

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.

Celero. Celero Energy Company, LP, a Delaware limited partnership.

Centennial Contributors. CRD, NGP Follow-On and Celero, collectively.

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.

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.

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.

CRD. Centennial Resource Development, LLC, a Delaware limited liability company, which was dissolved on June 15, 2018.

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.

NGP Follow-On. NGP Centennial Follow-On LLC, a Delaware limited liability company.

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.

Riverstone Purchasers. Riverstone VI Centennial QB Holdings, L.P., Riverstone Non-ECI USRPI AIV, L.P. and REL US Centennial Holdings, LLC, which are affiliates of Riverstone.

Series B Preferred Stock. Our Series B Preferred Stock, par value $0.0001 per share, all outstanding shares of which were converted into 26,100,000 shares of Class A Common Stock on May 25, 2017.

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

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Quarterly 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 Quarterly 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 Quarterly Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" 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 under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 Annual Report") and the risk factors and other cautionary statements contained in our other filings with the United States Securities and Exchange Commission ("SEC").

Forward-looking statements may include statements about:

- 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;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical.

All forward-looking statements, expressed or implied, are made only as of the date of this Quarterly Report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including but not limited to those risks described under "Item 1A. Risk Factors" in our 2017 Annual Report. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

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.

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements.

All forward-looking statements, expressed or implied, included in this Quarterly 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 to reflect events or circumstances after the date of this Quarterly Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 58,922	$ 117,315
Accounts receivable, net	88,817	78,786
Derivative instruments	3,871	433
Prepaid and other current assets	14,277	6,051
Total current assets	165,887	202,585
Property and Equipment		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,801,965	1,952,680
Proved properties	2,402,331	1,602,002
Accumulated depreciation, depletion and amortization	(395,675)	(173,906)
Total oil and natural gas properties, net	3,808,621	3,380,776
Other property and equipment, net	7,828	5,465
Total property and equipment, net	3,816,449	3,386,241
Noncurrent assets		
Derivative instruments	—	662
Other noncurrent assets	35,036	27,081
TOTAL ASSETS	$ 4,017,372	$ 3,616,569
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 210,608	$ 199,533
Derivative instruments	—	240
Other current liabilities	655	—
Total current liabilities	211,263	199,773
Noncurrent liabilities		
Long-term debt, net	531,390	390,764
Asset retirement obligations	13,156	12,161
Deferred tax liability	53,380	9,899
Derivative instruments	2,437	—
Other long-term liabilities	540	—
Total liabilities	812,166	612,597
Commitments and contingencies (Note 12)		
Shareholders' equity		
Preferred stock, $0.0001 par value, 1,000,000 shares authorized:		
Series A: 1 share issued and outstanding	—	—
Common stock, $0.0001 par value, 620,000,000 shares authorized:		
Class A: 265,771,082 shares issued and 264,214,812 shares outstanding at September 30, 2018 and 261,337,636 shares issued and 260,327,920 shares outstanding at December 31, 2017	27	26
Class C (Convertible): 12,003,183 and 15,661,338 shares issued and outstanding at September 30, 2018 and December 31, 2017, respectively	1	2
Additional paid-in capital	2,827,756	2,767,558
Retained earnings	235,558	66,639
Total shareholders' equity	3,063,342	2,834,225
Noncontrolling interest	141,864	169,747
Total equity	3,205,206	3,003,972
TOTAL LIABILITIES AND EQUITY	$ 4,017,372	$ 3,616,569

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Operating revenues				
Oil and gas sales	$ 234,880	$ 111,611	$ 668,541	$ 263,772
Operating expenses				
Lease operating expenses	23,706	11,373	59,164	26,924
Severance and ad valorem taxes	14,410	6,448	42,791	14,358
Gathering, processing and transportation expenses	16,090	9,925	45,214	22,572
Depreciation, depletion and amortization	83,423	42,387	224,379	102,847
Impairment and abandonment expenses	8,612	—	10,396	(29)
Exploration expense	2,712	1,622	8,026	4,092
General and administrative expenses	16,561	13,311	44,667	36,017
Total operating expenses	165,514	85,066	434,637	206,781
Income from operations	69,366	26,545	233,904	56,991
Other income (expense)				
Gain (loss) on sale of oil and natural gas properties	52	(141)	(74)	7,216
Interest expense	(6,534)	(1,015)	(18,138)	(2,132)
Net gain (loss) on derivative instruments	(9,571)	(896)	14,969	5,392
Other income (expense)	13	—	(4)	—
Other income (expense)	(16,040)	(2,052)	(3,247)	10,476
Income before income taxes	53,326	24,493	230,657	67,467
Income tax expense	(11,652)	(8,233)	(50,729)	(17,302)
Net income	41,674	16,260	179,928	50,165
Less: Net income attributable to noncontrolling interest	2,386	1,813	11,009	5,133
Net income attributable to Class A Common Stock	$ 39,288	$ 14,447	$ 168,919	$ 45,032
Income per share of Class A Common Stock:				
Basic	$ 0.15	$ 0.06	$ 0.64	$ 0.20
Diluted	$ 0.15	$ 0.06	$ 0.63	$ 0.19

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

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

	For the Nine Months Ended September 30,	
	2018	2017
Cash flows from operating activities:		
Net income	$ 179,928	$ 50,165
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	224,379	102,847
Stock-based compensation expense	14,329	9,420
Undeveloped leasehold abandonment expense	10,396	(29)
Exploratory dry hole cost	395	—
Deferred tax expense	50,729	17,302
(Gain) loss on sale of oil and natural gas properties	74	(7,216)
Non-cash mark-to-market derivative gain	(579)	(5,126)
Amortization of debt issuance costs	1,258	348
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(18,327)	(28,172)
(Increase) decrease in prepaid and other assets	(52)	(12,890)
Increase (decrease) in accounts payable and other liabilities	32,165	10,501
Net cash provided by operating activities	494,695	137,150
Cash flows from investing activities:		
Acquisitions of oil and natural gas properties	(114,870)	(419,471)
Drilling and development capital expenditures	(723,100)	(354,515)
Purchases of other property and equipment	(4,409)	(3,482)
Proceeds from sales of oil and natural gas properties	147,413	10,714
Net cash used in investing activities	(694,966)	(766,754)
Cash flows from financing activities:		
Issuance of Class A common shares	—	340,750
Underwriters discount and offering costs	—	(7,233)
Proceeds from revolving credit facility	295,000	190,000
Repayment of revolving credit facility	(155,000)	(25,000)
Proceeds from stock options exercised	847	—
Restricted stock used for tax withholdings	(1,119)	—
Debt issuance costs	(4,217)	(415)
Net cash provided by financing activities	135,511	498,102
Net decrease in cash and cash equivalents and restricted cash	(64,760)	(131,502)
Cash and cash equivalents and restricted cash, beginning of period	125,915	134,083
Cash, cash equivalents and restricted cash, end of period	$ 61,155	$ 2,581

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

Supplemental cash flow information and non-cash activity (in thousands):

	For the Nine Months Ended September 30,	
	2018	2017
Supplemental cash flow information		
Cash paid for interest	$ 15,587	$ 1,915
Supplemental non-cash activity		
Accrued capital expenditures included in accounts payable and accrued expenses	$ 97,844	$ 102,152
Asset retirement obligations incurred, including revisions to estimates	1,040	1,016

Reconciliation of cash, cash equivalents and restricted cash presented on the Consolidated Statements of Cash Flows:

	For the Nine Months Ended September 30,	
	2018	2017
Cash and cash equivalents	$ 58,922	$ 2,581
Restricted cash(1)	2,233	—
Total cash, cash equivalents and restricted cash	$ 61,155	$ 2,581

(1) Included in *Prepaid and other current assets* line item on the Consolidated Balance Sheets

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

	Common Stock				Preferred Stock								
	Class A		Class C		Series A		Series B						
	Shares	Amount	Shares	Amount	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, 2016	201,092	$ 20	19,156	$ 2	—	$ —	104	$ —	$ 2,364,049	$ (8,929)	$ 2,355,142	$ 197,793	$ 2,552,935
Warrants exercised	6,236	1	—	—	—	—	—	—	(1)	—	—	—	—
Restricted stock issued	841	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(9)	—	—	—	—	—	—	—	—	—	—	—	—
Conversion of Series B preferred shares to Class A common shares	26,100	3	—	—	—	—	(104)	—	(3)	—	—	—	—
Sale of unregistered Class A common shares	23,500	2	—	—	—	—	—	—	340,748	—	340,750	—	340,750
Underwriters' discount and offering expense	—	—	—	—	—	—	—	—	(7,233)	—	(7,233)	—	(7,233)
Stock-based compensation	—	—	—	—	—	—	—	—	9,420	—	9,420	—	9,420
Change in equity due to issuance of shares by Centennial Resource Production, LLC	—	—	—	—	—	—	—	—	(2,682)	—	(2,682)	2,682	—
Net income	—	—	—	—	—	—	—	—	—	45,032	45,032	5,133	50,165
Balance at September 30, 2017	257,760	$ 26	19,156	$ 2	—	$ —	—	$ —	$ 2,704,298	$ 36,103	$ 2,740,429	$ 205,608	$ 2,946,037
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	919	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(136)	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(60)	—	—	—	—	—	—	—	(1,119)	—	(1,119)	—	(1,119)
Option Exercises	52	—	—	—	—	—	—	—	847	—	847	—	847
Stock-based compensation	—	—	—	—	—	—	—	—	14,329	—	14,329	—	14,329
Conversion of common shares from Class C to Class A, net of tax	3,658	1	(3,658)	(1)	—		—	—	46,141	—	46,141	(38,892)	7,249
Net income	—	—	—	—	—	—	—	—	—	168,919	168,919	11,009	179,928
Balance at September 30, 2018	265,771	$ 27	12,003	$ 1	—	$ —	—	$ —	$ 2,827,756	$ 235,558	$ 3,063,342	$ 141,864	$ 3,205,206

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1—Basis of Presentation

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 primarily of large, contiguous acreage blocks primarily in Reeves County in West Texas and Lea County in 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 accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") and the rules and regulations of the United States Securities and Exchange Commission ("SEC") for interim financial reporting. Accordingly, certain disclosures normally included in an Annual Report on Form 10-K have been omitted. The consolidated financial statements and related notes included in this Quarterly Report should be read in conjunction with the Company's consolidated financial statements and related notes included in the Company's Annual Report on Form 10-K for the period ended December 31, 2017 (the "2017 Annual Report"). Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in the Company's 2017 Annual Report.

In the opinion of management, all normal, recurring adjustments and accruals considered necessary to present fairly, in all material respects, the Company's interim financial results have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year.

The consolidated financial statements include the accounts of the Company and its majority owned subsidiary CRP, and CRP's wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interest represents third-party ownership in the Company's consolidated subsidiary, and it is presented as a component of equity. See *Note 9—Shareholders' Equity and Noncontrolling Interest* for further discussion of noncontrolling interest.

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.

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) depreciation, depletion and amortization; (iv) asset retirement obligations; (v) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (vi) accrued revenues and related receivables; (vii) accrued liabilities; (viii) valuation of derivative instruments; and (ix) deferred income taxes.

Income Taxes

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to the Company's year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent and temporary differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

Recently Issued Accounting Standards

In August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which updates the disclosure requirements for fair value measurements in Accounting Standard Codification ("ASC") Topic 820, *Fair Value Measurement* ("ASC Topic 820"). Certain disclosure requirements under ASC Topic 820 were removed, modified or added in order to improve the effectiveness of the fair value note to the financial statement. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2019, including interim periods within those fiscal years. An entity is permitted to early adopt any removed or modified disclosures and delay adoption of the additional disclosures until the effective date. The Company is currently assessing the impact of this update on the Company's consolidated financial statements.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*. This update applies to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years with early adoption permitted. This update should be applied using the retrospective transition method. The Company adopted ASU 2016-15 in the first quarter of 2018. As a result of adoption, there were no changes to the presentation of cash flow activities in the statement of cash flows for the nine months ended September 30, 2018.

In February 2016, the FASB issued ASU 2016-02, *Leases*, which created ASC Topic 842, *Leases* ("ASC Topic 842"), superseding current lease requirements under ASC Topic 840, *Leases*. Subsequently in 2018, the FASB issued various ASUs which provide a practical expedient for the evaluation of existing land easement agreements, optionality in the adoption transition method, and additional implementation guidance. ASC Topic 842 and its related amendments apply to any entity that enters into a lease, with some specified scope exemptions. Under ASC Topic 842, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. ASC Topic 842 will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. The standard permits retrospective application using either of the following methodologies: (i) application of the new standard at the earliest presented period or (ii) application of the new standard at the adoption date with a cumulative-effect adjustment recognized to retained earnings. The Company will adopt this guidance as of January 1, 2019, the effective date, and plans to recognize a cumulative-effect adjustment at the time of adoption. Although the Company is still in the process of evaluating the effect of adopting ASC Topic 842 and its related amendments, the adoption is expected to result in the recognition of assets and liabilities on its Consolidated Balance Sheet for current operating leases such as drilling rig contracts and office rental agreements. The Company is continuing to evaluate existing arrangements to determine if they qualify for lease accounting under ASC Topic 842.

In May 2014, the FASB issued ASU 2014-09, which created ASC Topic 606, *Revenue from Contracts with Customers* ("ASC Topic 606"), superseding revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, and most industry-specific guidance. The FASB subsequently issued various ASUs which deferred the effective date of ASC Topic 606 and provided additional implementation guidance. ASC Topic 606 provides companies with a single model for use in accounting for revenue arising from contracts with customers. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. In addition, new qualitative and quantitative disclosure requirements aim to enable financial statement users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. ASC Topic 606 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented or (ii) recognition of a cumulative-effect adjustment as of the date of initial application. The Company has selected the modified retrospective method and has adopted this guidance as of January 1, 2018, the effective date. The Company has completed its review of the impact of the new standard on its significant contracts and concluded that there was not a material impact to the presentation of revenues or expenses as a result of the adoption of this standard. Refer to *Note 13—Revenues* for additional disclosures required by the new standard.

Note 2—Property Acquisitions and Divestiture

Acquisition

On February 8, 2018, the Company completed the acquisition of approximately 4,000 undeveloped net acres, as well as certain 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. Upon signing the purchase and sale agreement, the Company placed $8.6 million of cash in escrow accounts on December 21, 2017, and such deposits were applied as a payment against the purchase price upon closing of the transactions. The Company presented the cash in escrow as restricted cash within the line item *Other Noncurrent Assets* in the Consolidated Balance Sheet as of December 31, 2017.

The acquisition was recorded as an asset acquisition under ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*. Accordingly, the purchase consideration has been allocated to the oil and natural gas properties based on their relative fair values measured as of the acquisition date. After settlement statement adjustments of $0.2 million, the Company paid a net purchase price of $94.5 million. On a relative fair value basis, $80.7 million was allocated to unproved properties and $13.8 million to proved properties. Transaction costs incurred and capitalized as of September 30, 2018, amounted to $0.2 million and mainly consisted of advisory and legal fees.

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 ASC 932*, Extractive Activities - Oil and Gas*. The Company used the net proceeds from the sale to fund the 2018 acquisition discussed above and for general corporate purposes.

Note 3—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	**September 30, 2018**	**December 31, 2017**
Accrued oil and gas sales receivable, net	$ 68,128	$ 52,891
Joint interest billings	20,093	25,256
Receivables for divestitures	416	—
Other	180	639
Accounts receivable, net	$ 88,817	$ 78,786

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	**September 30, 2018**	**December 31, 2017**
Accounts payable	$ 27,252	$ 64,004
Accrued capital expenditures	107,786	90,511
Revenues payable	47,995	23,390
Accrued interest	5,310	1,936
Accrued employee compensation and benefits	7,338	8,350
Accrued expenses and other	14,927	11,342
Accounts payable and accrued expenses	$ 210,608	$ 199,533

Note 4—Long-Term Debt

Credit Agreement

On May 4, 2018, CRP, the Company's consolidated subsidiary, entered into an amended and restated credit agreement with a syndicate of banks that as of September 30, 2018, had a borrowing base of $800.0 million and elected commitments of $600.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of September 30, 2018, the Company had $140.0 million borrowings outstanding and $459.1 million in available borrowing capacity, which was net of $0.9 million in letters of credit outstanding.

The amount available to be borrowed under the Company's credit agreement is equal to the lesser of (i) the borrowing base, (ii) aggregate elected commitments, or (iii) $1.5 billion. The borrowing base is redetermined semi-annually each April 1 and October 1 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 under the credit agreement. In connection with the October 2018 semi-annual credit facility redetermination, the borrowing base under the revolving credit facility was increased from $800.0 million to $1.0 billion and the lenders increased their aggregate elected commitments from $600.0 million to $800.0 million.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the credit agreement and are discussed in "*Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources*" later in this Quarterly Report. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount and are included in interest expense in the Consolidated Statements of Operations. The credit facility provides for interest only payments until May 4, 2023, when the credit agreement expires and all outstanding borrowings are due.

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 unused commitments under its 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; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with the covenants and the financial ratios described above as of September 30, 2018 and through the filing of this Quarterly Report.

5.375% Senior Unsecured Notes due 2026

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (the "Senior Notes") in a 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 Senior Notes semi-annually in arrears on each January 15 and July 15, commencing July 15, 2018. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of CRP's current subsidiaries that guarantee CRP's revolving credit facility. The Senior Notes are not guaranteed by the Company, nor is the Company subject to the terms of the indenture governing the Senior Notes.

At any time prior to January 15, 2021, CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the Senior 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% of the principal amount of the Senior Notes redeemed, plus any accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount issued under the indenture governing the Senior 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 January 15, 2021, CRP may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100% of the principal amount of the Senior Notes redeemed, plus a "make-whole" premium, and any accrued and unpaid interest as of the date of redemption. On and after January 15, 2021, CRP may redeem the Senior Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.688% for the 12-month period beginning on January 15, 2021, 101.344% for the 12-month period beginning January 15, 2022, and 100% beginning on January 15, 2023, plus accrued and unpaid interest to the redemption date.

If CRP experiences certain defined changes of control (and, in some 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 but unpaid interest to the date of repurchase.

The indenture governing the Senior Notes contains 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 September 30, 2018 and through the filing of this Quarterly Report.

Upon an Event of Default (as defined in the indenture 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.

Debt issuance costs netted against the principal balance of the Senior Notes amounted to $8.6 million as of September 30, 2018 and $9.2 million as of December 31, 2017.

Note 5—Asset Retirement Obligations

The following table summarizes the changes in the Company's asset retirement obligations ("ARO") for the nine months ended September 30, 2018 (in thousands):

Asset retirement obligations at January 1, 2018	$	12,161
Liabilities acquired		42
Liabilities incurred		1,051
Liabilities divested and settled		(672)
Accretion expense		585
Revisions to estimated cash flows		(11)
Asset retirement obligations at September 30, 2018	$	13,156

ARO reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and natural 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 fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates and timing of settlement. To the extent future revisions to these assumptions impact the value of the existing ARO liability, a corresponding offsetting adjustment is made to the oil and gas property balance.

Note 6—Stock-Based Compensation

Long Term Incentive Plan

On October 7, 2016, the stockholders of the Company approved the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the "LTIP"). An aggregate of 16,500,000 shares of Class A Common Stock were authorized for issuance under the LTIP, and as of September 30, 2018, the Company had 9,795,116 shares of Class A Common Stock available for future grants. The LTIP provides for grants of stock options (including incentive stock options and nonqualified stock options), stock appreciation rights, restricted stock, dividend equivalents, restricted stock units and other stock or cash-based awards.

Stock-based compensation expense is recognized within both *General and administrative expenses* and *Exploration expense* in the Consolidated Statements of Operations. The expense amounts in the table below may not be representative of future expense amounts to be recognized as the value of future awards may vary from historical award amounts. Upon adoption of ASU 2016-09 in October 2016, the Company elected to account for forfeitures of awards granted under the LTIP as they occur in determining compensation expense.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Restricted stock awards	$ 2,393	$ 1,490	$ 6,157	$ 3,364
Stock option awards	2,337	2,104	6,853	5,825
Performance stock units	611	231	1,319	231
Total stock-based compensation expense	$ 5,341	$ 3,825	$ 14,329	$ 9,420

Restricted Stock

The following table provides information about restricted stock awards outstanding during the nine months ended September 30, 2018:

	Awards	Weighted Average Grant Date Fair Value
Unvested balance as of December 31, 2017	1,009,716	$ 17.64
Granted	919,306	18.38
Vested	(236,701)	16.92
Forfeited	(136,051)	17.70
Unvested balance as of September 30, 2018	1,556,270	18.18

The Company grants service-based restricted stock awards to executive officers and employees, which generally vest ratably over a three-year service period, and to directors, which generally vest over a one-year service period. Compensation cost for the service-based restricted stock awards is based upon the grant-date fair value of the award, and such costs are recognized ratably over the applicable vesting period. The weighted average grant-date fair value for restricted stock awards granted was $18.38 per share and $17.21 per share for the nine months ended September 30, 2018 and 2017, respectively. The total fair value of restricted stock awards that vested during the nine months ended September 30, 2018 was $4.4 million, and no awards vested during the nine months ended September 30, 2017. Unrecognized compensation cost related to restricted shares that were unvested as of September 30, 2018 was $23.5 million, which the Company expects to recognize over a weighted average period of 2.3 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 Class A Common Stock as reported on the NASDAQ on the date of grant.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. The Company estimates the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the weighted average asset volatility of the Company and 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 during the nine months ended September 30, 2018 and 2017:

	For the Nine Months Ended September 30,	
	2018	2017
Weighted average grant-date fair value per share	$ 7.74	$ 7.15
Expected term (in years)	6	6
Expected stock volatility	41.4%	38.1%
Dividend yield	—%	—%
Risk-free interest rate	2.6%	2.0%

The following table provides information about stock option awards outstanding during the nine months ended September 30, 2018:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of December 31, 2017	4,290,001	$ 16.15		
Granted	358,500	17.78		
Exercised	(52,331)	16.18		$ 192
Forfeited	(225,337)	15.80		
Expired	(4,166)	16.60		
Outstanding as of September 30, 2018	4,366,667	16.30	8.4	24,218
Exercisable as of September 30, 2018	1,223,811	15.98	8.2	7,179

The total fair value of stock options that vested during the nine months ended September 30, 2018 was $3.7 million, and no awards vested during the nine months ended September 30, 2017. As of September 30, 2018, there was $13.5 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 1.6 years.

Performance Stock Units

The Company grants to certain executive officers performance stock units 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 the stock awards to vest, and it is, therefore, possible that no shares could vest. However, the Company recognizes compensation expense for the performance stock units subject to market conditions regardless of whether it becomes probable that these conditions will be achieved 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 our common stock, 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 nine months ended September 30, 2018 and 2017:

	For the Nine Months Ended September 30,	
	2018	2017
Weighted average grant-date fair value per share	$ 22.35	$ 21.53
Number of simulations	1,000,000	1,000,000
Expected stock volatility	40.2%	41.6%
Dividend yield	—%	—%
Risk-free interest rate	2.8%	1.5%

The following table provides information about performance stock units outstanding during the nine months ended September 30, 2018:

	Awards	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2017	193,391	$ 21.53
Vested	—	—
Granted	193,068	22.35
Forfeited	—	—
Outstanding as of September 30, 2018	386,459	21.94

As of September 30, 2018, there was $6.6 million of unrecognized compensation cost related to performance stock units that were unvested, which the Company expects to recognize on a pro-rata basis over a weighted average period of 2.4 years.

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 periodically uses derivative instruments, such as swaps, 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 Contracts. The Company opportunistically uses commodity derivative instruments known as fixed price swaps to realize a known price for a specific volume of production as well as basis swaps to hedge the difference between the index price and a local index price. 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 swap contracts the Company had in place as of September 30, 2018:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl) [(1)]
Crude oil basis swaps	October 2018 - December 2018	828,000	9,000	$ (2.38)
	January 2019 - March 2019	540,000	6,000	(5.34)
	April 2019 - June 2019	91,000	1,000	(10.00)
	July 2019 - September 2019	1,380,000	15,000	(9.03)
	October 2019 - December 2019	920,000	10,000	(4.24)

(1) The oil basis swap transactions are settled based on the difference between the arithmetic average of ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices, during the relevant calculation period.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu) [(1)]
Natural Gas Swaps - Henry Hub	January 2019 - December 2019	10,950,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	January 2019 - December 2019	5,475,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu) [(2)]
Natural gas basis swaps	October 2018 - December 2018	460,000	5,000	$ (0.43)
	January 2019 - December 2019	12,775,000	35,000	(1.31)

(1) The natural gas swap contracts are settled based on either i) the NYMEX Henry Hub price or ii) the Inside FERC West Texas WAHA price of natural gas as of the specified settlement date, as applicable.

(2) The 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 the relevant calculation period.

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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 gains and losses for derivative instruments not designated as hedges for accounting purposes for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Net gain (loss) on derivative instruments	$ (9,571)	$ (896)	$ 14,969	$ 5,392

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 table below summarizes the fair value amounts and the classification in the Consolidated Balance Sheets of the Company's derivative contracts outstanding at the respective balance sheet dates. Refer to *Note 8—Fair Value Measurements* for details of the gross and net derivative assets, liabilities and offset amounts as presented in the Consolidated Balance Sheets.

		Gross Asset/Liability Amounts	
(in thousands)	**Balance Sheet Classification**	**September 30, 2018**	**December 31, 2017**
Derivative Assets			
Derivative instruments	Current assets	$ 10,184	$ 720
Derivative instruments	Noncurrent assets	418	662
Total derivative assets		$ 10,602	$ 1,382
Derivative Liabilities			
Derivative instruments	Current liabilities	$ 6,313	$ 527
Derivative instruments	Noncurrent liabilities	2,855	—
Total derivative liabilities		$ 9,168	$ 527

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 the Company 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 lender under CRP's credit facility as referenced above.

Note 8—Fair Value Measurements

Recurring Fair Value Measurements

The Company follows FASB 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 the Company's netted asset or liability positions that have been measured at fair value and where they have been classified within the fair value hierarchy as of September 30, 2018 and December 31, 2017:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities			Netting Adjustments[(1)]	Net Amounts Presented on the Balance Sheets
	Level 1	Level 2	Level 3		
(in thousands)	September 30, 2018				
Financial assets					
Commodity derivative asset - current	$ —	$ 10,184	$ —	$ (6,313)	$ 3,871
Commodity derivative asset - noncurrent	—	418	—	(418)	—
Total financial assets	$ —	$ 10,602	$ —	$ (6,731)	$ 3,871
Financial liabilities					
Commodity derivative liability - current	$ —	$ 6,313	$ —	$ (6,313)	$ —
Commodity derivative liability - noncurrent	—	2,855	—	(418)	2,437
Total financial liabilities	$ —	$ 9,168	$ —	$ (6,731)	$ 2,437
	December 31, 2017				
Financial Assets					
Commodity derivative asset - current	$ —	$ 720	$ —	$ (287)	$ 433
Commodity derivative asset - noncurrent	—	662	—	—	662
Total financial assets	$ —	$ 1,382	$ —	$ (287)	$ 1,095
Financial liabilities					
Commodity derivative liability - current	$ —	$ 527	$ —	$ (287)	$ 240

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

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 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.

Nonrecurring Fair Value Measurements

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and natural gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation. Refer to *Note 2—Property Acquisitions and Divestiture* for additional information on the fair value of assets acquired.

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 plugging costs and reserve lives. Refer to *Note 5—Asset Retirement Obligations* for additional information on the Company's ARO.

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 carrying values of the amounts outstanding under CRP's credit agreement, if any, 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. As of September 30, 2018 and December 31, 2017, the fair value of the Senior Notes was $399.0 million and $407.5 million, respectively, which were determined using quoted market prices for this same debt security, a Level 1 classification in the fair value hierarchy.

Note 9—Shareholders' Equity and Noncontrolling Interest

Shareholders' Equity

On March 7, 2018, Silver Run Sponsor, LLC ("Silver Run Sponsor"), the Riverstone Purchasers 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 Stock) were converted to shares of Class A Common Stock on a one-to-one basis. A tax benefit of $6.7 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

Noncontrolling Interest

The noncontrolling interest relates to CRP Common Units that were originally issued to the Centennial Contributors in connection with the Business Combination and continue to be held by holders other than the Company. At the date of the Business Combination, the noncontrolling interest represented 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 September 30, 2018, the noncontrolling interest ownership of CRP decreased to 4.3% from 5.7% as of December 31, 2017. The decrease was mainly the result of the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock.

The Company consolidates the financial position, results of operations and cash flows of CRP and reflects that portion retained by other holders of CRP Common Units as a noncontrolling interest. Refer to the Consolidated Statements of Shareholders' Equity for a summary of the activity attributable to the noncontrolling interest during the period.

Note 10—Earnings 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. Diluted 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 restricted stock and performance stock units, outstanding stock options and warrants using the treasury stock method, and (ii) the Company's Class C Common Stock using the "if-converted" method, which is net of tax.

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings.

Shares of the Company's unvested restricted stock and performance stock units are eligible to receive dividends; however, dividend rights will be forfeited if the award does not vest. Accordingly, these shares are not considered participating securities. Shares of the Company's Class C Common Stock and warrants do not share in earnings or losses and are therefore not participating securities. The Company's shares of Series B Preferred Stock had a non-forfeitable right to participate in distributions with common stockholders on a pro-rata, as-converted basis. All of Company's shares of Series B Preferred Stock were converted into shares of Class A Common Stock on May 25, 2017 in accordance with their terms. As such, the Company no longer has any participating securities as of September 30, 2018 and 2017.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands, except per share data)	**2018**	**2017**	**2018**	**2017**
Net income attributable to Class A Common Stock	$ 39,288	$ 14,447	$ 168,919	$ 45,032
Add: Income from conversion of Class C Common Stock	1,717	1,193	—	3,196
Adjusted net income attributable to Class A Common Stock	41,005	15,640	168,919	48,228
Basic net earnings per share of Class A Common Stock	$ 0.15	$ 0.06	$ 0.64	$ 0.20
Diluted net earnings per share of Class A Common Stock	$ 0.15	$ 0.06	$ 0.63	$ 0.19
Basic weighted average shares of Class A Common Stock outstanding	263,959	223,622	263,029	227,557
Add: Dilutive effects of equity awards	3,766	2,598	3,625	4,481
Add: Dilutive effects of conversion	12,189	19,156	—	19,156
Diluted weighted average shares of Class A Common Stock outstanding	279,914	245,376	266,654	251,194

For the three and nine months ended September 30, 2018 and 2017, the following shares were excluded from the diluted earnings per share calculation as their impacts were anti-dilutive:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Out-of-the-money stock options	142	1,501	318	1,046
Weighted average shares of Class C Common Stock	—	—	13,056	—
Performance stock units	—	—	52	—

Note 11—Transactions with Related Parties

The Company obtains services related to its drilling and completion activities from related parties from time to time. The Company believes that the terms of the arrangements with these related parties are no less favorable to either party than those held with unaffiliated parties. The following table summarizes the costs incurred for such services which were either included as part of oil and natural gas properties in the Consolidated Balance Sheet or as lease operating expense in the Consolidated Statements of Operations, as well as the related payables outstanding as of the balance sheet dates:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Costs of goods/services provided				
Liberty Oilfield Services, LLC[1]	$ —	$ 30,434	$ —	$ 70,616
Schlumberger Limited and affiliates[2]	2,872	—	2,872	—
Oil States International, Inc.[3]	647	2,443	5,047	6,375

(in thousands)	**September 30, 2018**	**December 31, 2017**
Accounts payable and accrued expenses		
Schlumberger Limited and affiliates[2]	$ 1,290	$ —
Oil States International, Inc.[3]	—	1,518

(1) This entity is a Riverstone affiliate. Riverstone and its affiliates, beneficially own more than 10% equity interest in the Company and are therefore considered related parties.

(2) On August 8, 2018, Mark G. Papa, the Company's Chief Executive Officer and Chairman of the Board, was elected as a director of the Board of Schlumberger Limited ("Schlumberger"), an oilfield services company. As a result, Schlumberger and its affiliates are considered related parties of the Company. Any goods/services acquired from Schlumberger and its affiliates on or after August 8, 2018, are classified as related party transactions.

(3) Mark G. Papa served as a director and Chairman of the Board of Oil States International, Inc. ("Oil States"), an energy services company. Effective August 7, 2018, Mr. Papa resigned from Oil States' Board and they were no longer a related party of the Company. Any goods/services acquired on or after August 7, 2018 from Oil States are no longer classified as related party transactions.

Note 12—Commitments and Contingencies

Commitments

In 2018, the Company entered into various natural gas transportation agreements whereby it is required to deliver approximately 491 million MMBtu, in aggregate, over a term ranging from one to four years or else pay for any volume deficiencies. These delivery commitments are tied to the Company's natural gas production, and the aggregate financial obligation under these contracts is $38.4 million, representing the minimum commitments pursuant to the terms of these agreements as of September 30, 2018. Actual expenditures under these contracts may exceed this minimum commitment amount. The following table summarizes the natural gas volumes the Company is required to deliver by period under these agreements as well as its existing natural gas transportation agreements:

Period	**Total Volume Commitments (MMBtu) [1]**	**Volume (MMBtu/d) [1]**
October 2018 - December 2018	16,200,000	176,000
January 2019 - December 2019	116,800,000	320,000
January 2020 - December 2020	194,800,000	533,600
January 2021 - December 2021	158,100,000	433,200
January 2022 - October 2022	19,700,000	64,800
Total	505,600,000	

(1) The amounts reflected within this table are the total gross volumes the Company is required to deliver per the agreements. These volumetric quantities are therefore not comparable to the Company's net production presented in *Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operation* as the amounts therein are reflected net of all royalties, overriding royalties and production due to others.

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In May 2018, the Company entered into a three-year supply agreement to purchase frac sand from an in-basin sand mine in West Texas. Under the terms of the agreement, the Company is obligated to purchase a minimum volume of sand at a fixed sales price. The aggregate financial obligation under this contract is $23.8 million, which represents the minimum commitments pursuant to the terms of the agreement as of September 30, 2018. Actual expenditures under this contract may exceed this minimum commitment amount.

Delivery Commitments

In August 2018, the Company entered into two firm crude oil sales agreements with large integrated oil companies. Utilizing these companies' existing transport capacity out of the Permian Basin, the agreements provide for firm gross sales ranging from approximately 40,000 to 105,000 Bbls/d in aggregate over the next six years. These amounts represent the total gross volumes the Company is required to deliver per the agreements, which are not comparable to the Company's net production presented in *Item 2. 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. These sales agreements require the Company to physically deliver the aforementioned volumes of crude oil over the contractual terms of the agreements. The Company believes its current production and reserves are sufficient to fulfill these delivery commitments, but if the physical delivery commitments are not met, a financial obligation may arise. However, 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.

The Company routinely enters into or extends operating agreements, office and equipment leases, drilling and completion rig contracts, among others, in the ordinary course of business. Other than those discussed above, there have been no material, non-routine changes in commitments during the nine months ended September 30, 2018. Please refer to *Note 13—Commitments and Contingencies* included in Part II, Item 8 in the Company's 2017 Annual Report.

Contingencies

The Company may at times be subject to various commercial or regulatory claims, 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 litigation brought against the Company requiring a contingent liability to be recognized as of the date of these consolidated financial statements.

Note 13—Revenues

Revenue from Contracts with Customers

Sales of crude oil and natural gas 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 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:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Operating revenues (in thousands):				
Oil sales	$ 184,510	$ 87,286	$ 533,507	$ 204,702
Natural gas sales	14,311	12,852	46,612	33,226
NGL sales	36,059	11,473	88,422	25,844
Oil and gas sales	$ 234,880	$ 111,611	$ 668,541	$ 263,772

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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 custody, title and risk of loss 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 certain natural gas processing contracts, liquids rich natural gas is delivered to a midstream processing entity at the inlet of the gas plant processing system. The midstream processing entity gathers and processes the natural gas and remits proceeds to Centennial for the resulting sales of NGLs and residue gas. 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, rather than as a net reduction to natural gas and NGL sales.

In the Company's other natural gas processing agreements, it has the election to take its residue gas 'in-kind' at the tailgate of the midstream processing plant and then subsequently market the product. For these contracts, the Company recognizes revenue when control transfers to purchasers at delivery points downstream of the processing plant. The gathering, processing and compression fees are presented as GP&T, and 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 certain 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 in the Consolidated Balance Sheets. As of September 30, 2018 and December 31, 2017, such receivable balances were $68.1 million and $52.9 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 nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was 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 14—Subsequent Events

Credit Facility Amendment

In connection with the October 2018 semi-annual credit facility redetermination, the borrowing base under the revolving credit facility was increased from $800.0 million to $1.0 billion and the lenders increased their aggregate elected commitments from $600.0 million to $800.0 million.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operation

The following discussion and analysis of our financial condition and results of operation should be read in conjunction with the accompanying consolidated financial statements and related notes. 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, market prices for oil, natural gas and NGLs, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed above in "Cautionary Statement Regarding Forward-Looking Statements" and in our 2017 Annual Report under the heading "Item 1A. Risk Factors," 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

Centennial Resource Development, Inc. (the "Company," "Centennial," "we," "us," or "our") 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. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. Our capital programs are specifically focused on projects that we believe provide the greatest potential for repeatable success and return on capital.

Market Conditions

The oil and natural gas industry is cyclical, and commodity prices can be volatile. During 2015 and 2016, global and domestic oil supply continued to outpace demand resulting in ongoing low realized oil and gas prices. In 2017 and thus far into 2018, commodity prices have improved yet remain volatile, and it is likely that commodity prices will continue to fluctuate due to global supply and demand, inventory supply levels, weather conditions, geopolitical and other factors.

The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2016:

	2016				2017				2018		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Crude oil (per Bbl)	$ 33.49	$ 45.70	$ 45.00	$ 49.27	$ 51.82	$ 48.32	$ 48.17	$ 55.31	$ 62.91	$ 68.07	$ 69.50
Natural gas (per MMBtu)	$ 1.98	$ 2.25	$ 2.80	$ 3.17	$ 3.06	$ 3.14	$ 2.95	$ 2.91	$ 3.08	$ 2.85	$ 2.93

Although oil and natural gas prices have begun to recover from the lows experienced during the first quarter of 2016, forecast prices for both oil and natural gas have not rebounded to pre-2015 levels. A sustained drop in oil, natural gas and NGL prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil, natural gas and NGLs that we can produce economically and therefore potentially lower our oil, natural gas and NGL reserve quantities.

Lower commodity prices (including realized differentials) in the future could result in impairments of our proved oil and natural gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower realized prices may also reduce the borrowing base under CRP's credit agreement, 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.

2018 Highlights and Future Considerations

Operational Highlights

We operated, on average, a seven-rig drilling program during the first nine months of 2018 which enabled us to complete and bring online 22 gross operated wells in the third quarter and 58 gross operated wells year to date. The total number of completed wells during the year had an average effective lateral length of approximately 7,500 feet.

Acquisition and Divestiture Highlights

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

On March 2, 2018, we 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 acreage in Reeves County. The properties divested consisted of 1,987 MBoe of proved reserves as of December 31, 2017, representing approximately 1% of our proved reserves as of that date, and generated 769 Boe/d (608 Bbls/d) in the first quarter of 2018.

Financing Highlights

On May 4, 2018, the Company entered into an amended and restated credit agreement (the "Amended Agreement") with a syndicate of banks, the majority of which were lenders to the Company's existing credit agreement. Under the Amended Agreement, the borrowing base increased from $575.0 million to $800.0 million and aggregate elected commitments increased from $475.0 million to $600.0 million. The Amended Agreement also provided for lower rates and fees compared to the existing credit agreement, with varying rates depending on the percentage of the borrowing base utilized, as follows: the LIBOR margin decreased from the range of 225 to 325 basis points to 150 to 250 basis points; the alternate base rate margin decreased from the range of 125 to 225 basis points to 50 to 150 basis points; and the commitment fees, which are paid on unused amounts of the revolving credit facility, were reduced from 50 basis points to a range of 37.5 to 50 basis points. The credit facility under the Amended Agreement has a term of five years.

In connection with the October 2018 credit facility semi-annual redetermination, the borrowing base under the revolving credit facility was increased from $800.0 million to $1.0 billion and the lenders increased their aggregate elected commitments from $600.0 million to $800.0 million.

Results of Operations

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

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:

	For the Three Months Ended September 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating revenues (in thousands):				
Oil sales	$ 184,510	$ 87,286	$ 97,224	111 %
Natural gas sales	14,311	12,852	1,459	11 %
NGL sales	36,059	11,473	24,586	214 %
Oil and gas sales	$ 234,880	$ 111,611	$ 123,269	110 %
Average sales prices:				
Oil (per Bbl)	$ 55.68	$ 44.95	$ 10.73	24 %
Effect of derivative settlements on average price (per Bbl)	2.56	0.21	2.35	1,119 %
Oil net of hedging (per Bbl)	$ 58.24	$ 45.16	$ 13.08	29 %
Average NYMEX price for oil (per Bbl)	$ 69.50	$ 48.17	$ 21.33	44 %
Oil differential from NYMEX	(13.82)	(3.22)	(10.60)	(329)%
Natural gas (per Mcf)	$ 1.83	$ 2.72	$ (0.89)	(33)%
Effect of derivative settlements on average price (per Mcf)	0.05	—	0.05	100 %
Natural gas net of hedging (per Mcf)	$ 1.88	$ 2.72	$ (0.84)	(31)%
Average NYMEX price for natural gas (per Mcf)	$ 2.93	$ 2.95	$ (0.02)	(1)%
Natural gas differential from NYMEX	(1.10)	(0.23)	(0.87)	(378)%
NGL (per Bbl)	$ 30.85	$ 24.83	$ 6.02	24 %
Net production:				
Oil (MBbls)	3,314	1,942	1,372	71 %
Natural gas (MMcf)	7,837	4,733	3,104	66 %
NGL (MBbls)	1,169	462	707	153 %
Total (MBoe)[1]	5,790	3,192	2,598	81 %
Average daily net production volume:				
Oil (Bbls/d)	36,027	21,108	14,919	71 %
Natural gas (Mcf/d)	85,180	51,444	33,736	66 %
NGL (Bbls/d)	12,706	5,018	7,688	153 %
Total (Boe/d)[1]	62,930	34,700	28,230	81 %

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

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the three months ended September 30, 2018 were $123.3 million (or 110%) higher than total net revenues for the three months ended September 30, 2017. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Net production volumes for oil, natural gas and NGLs increased 71%, 66% and 153%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin. Since the third quarter 2017, 84 gross operated wells were placed on production in the Delaware Basin, which added 2,263 MBbls of net oil production during the third quarter of 2018. The increase in the Company's operated well count is attributable to the continued ramp up of development drilling activities and our seven-rig drilling program during 2018. These oil volume increases were partially offset by normal field production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. During the third quarter of 2018, our production was made up of 43% natural gas and NGL volumes compared to 39% in the third quarter of 2017. This change in our commodity mix was due to the significant increase in NGL volumes (up 153%) between periods, which was primarily a result of the main processor of our wet gas switching from ethane-rejection to ethane-recovery. This switch enabled us to recover an increased amount of ethane from our wet gas. The change to recover a higher portion of ethane started in the second quarter of 2018 and was made due to lower natural gas prices in the Permian Basin and higher ethane prices, which in turn led to stronger ethane processing economics.

In addition to production-related increases in net revenue between periods, there were also significant increases in our average realized sales prices for oil and NGLs in the third quarter of 2018 compared to the same 2017 period. The average price for oil before the effects of hedging increased 24%, and the average price for NGLs also increased 24% between periods. The 24% increase in average realized oil price was a result of higher NYMEX crude prices between periods (average NYMEX prices increased 44%), which were partially offset by lower realizations due to wider oil differentials (an increase of $10.60 per Bbl) in the third quarter of 2018. The 24% increase in average realized NGL prices between periods was primarily attributable to higher Mont Belvieu spot prices for plant products in the third quarter 2018 as compared to the third quarter of 2017. Conversely, the average realized sales price of natural gas decreased by 33% from third quarter 2017 to third quarter 2018. This decrease was due to significantly wider gas differentials (an increase of $0.87 per Mcf) and average NYMEX prices that were 1% lower between periods. Both our oil and gas differentials widened during the third quarter 2018 due to anticipated pipeline takeaway capacity constraints impacting the Permian Basin.

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

	For the Three Months Ended September 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 23,706	$ 11,373	$ 12,333	108 %
Severance and ad valorem taxes	14,410	6,448	7,962	123 %
Gathering, processing and transportation expenses	16,090	9,925	6,165	62 %
Operating costs per Boe:				
Lease operating expenses	$ 4.09	$ 3.56	$ 0.53	15 %
Severance and ad valorem taxes	2.49	2.02	0.47	23 %
Gathering, processing and transportation expenses	2.78	3.11	(0.33)	(11)%

Lease Operating Expenses. Lease operating expenses ("LOE") for the three months ended September 30, 2018 increased $12.3 million compared to the three months ended September 30, 2017. Higher LOE for the third quarter of 2018 was primarily related to an $11.4 million increase in expense associated with our higher well count. We had 240 gross operated horizontal wells as of September 30, 2018 as compared to 171 gross operated horizontal wells as of September 30, 2017. The net increase in well count was mainly the result of our successful drilling activity adding 84 gross operated wells since the third quarter of 2017, which was partially offset by divestiture activity. In addition, workover activity increased $0.9 million between periods and impacted LOE by this same amount, as a result of our higher well count.

LOE on a per Boe basis increased when comparing the third quarter of 2018 to the same 2017 period. LOE per Boe was $4.09 for the third quarter of 2018, which represents an increase of $0.53 per Boe from the third quarter of 2017. This increase in rate was mainly due to higher costs associated with water handling and equipment rentals for our existing and newly completed wells.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of production at the wellhead, and ad valorem taxes are generally based on the valuation of our proved developed oil and natural gas reserves and vary across the different counties in which we operate. Severance taxes for the three months ended September 30, 2018 increased $7.1 million compared to the three months ended September 30, 2017 primarily due to higher oil, natural gas and NGL revenues between periods. Ad valorem taxes increased $0.9 million between periods as a result of our higher well count and higher oil and gas property values. Severance and ad valorem taxes as a percentage of total net revenues was consistent at 6% for both the three months ended September 30, 2018 and 2017.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses ("GP&T") for the three months ended September 30, 2018 increased $6.2 million compared to the three months ended September 30, 2017 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing fees and transportation and gathering costs being incurred.

On a per Boe basis, GP&T decreased 11% from $3.11 for the third quarter of 2017 to $2.78 per Boe for the third quarter of 2018. On a natural gas and NGL volumes basis (i.e. excluding crude oil barrels) the Boe rate decreased 18% between periods from $7.93 to $6.50 for the third quarters of 2017 and 2018, respectively. This decrease was attributable to lower natural gas prices between periods, due to residue gas being a primary cost component of gas processing fees.

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

	For the Three Months Ended September 30,	
(in thousands, except per Boe data)	**2018**	**2017**
Depreciation, depletion and amortization	$ 83,423	$ 42,387
Depreciation, depletion and amortization per Boe	14.41	13.28

DD&A rate can fluctuate as a result of finding and development costs, acquisitions, impairments, as well as changes in proved reserves or proved developed reserves. For the three months ended September 30, 2018, DD&A expense amounted to $83.4 million, an increase of $41.0 million over the same 2017 period. The primary factor contributing to higher DD&A in 2018 was the increase in our overall production volumes between periods, which added $34.4 million of incremental DD&A expense to the third quarter of 2018, while higher DD&A rates between periods contributed an additional $6.6 million of DD&A expense to the third quarter of 2018.

DD&A per Boe was $14.41 for the third quarter of 2018 compared to $13.28 for the same period in 2017. The primary factor contributing to this higher DD&A rate was increased drilling and completion costs incurred for new wells completed and placed on production over the past 12 months.

Impairment and Abandonment Expenses. During the three months ended September 30, 2018, $8.6 million of abandonment expense was incurred related to undeveloped leasehold acreage that expired during the period.

Exploration Expense. The following table summarizes our exploration expense for the periods indicated:

	For the Three Months Ended September 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 453	$ 465
Exploratory dry hole costs	—	—
Geological and geophysical costs	2,259	1,157
Exploration expense	$ 2,712	$ 1,622

Exploration expense was $2.7 million for the three months ended September 30, 2018 compared to $1.6 million for the same prior year period. Exploration expense mainly consists of topographical studies, geographical and geophysical ("G&G") projects, and salaries and expenses of G&G personnel. The period over period increase in exploration expense was primarily due to increased costs incurred on G&G projects and seismic studies of $1.1 million.

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

	For the Three Months Ended September 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 4,888	$ 3,360
Cash general and administrative expenses	11,673	9,951
General and administrative expenses	$ 16,561	$ 13,311

G&A expenses for the three months ended September 30, 2018 were $16.6 million compared to $13.3 million for the three months ended September 30, 2017. The higher G&A expenses incurred in 2018 were primarily due to $2.4 million in increased employee salaries and payroll burdens and $1.5 million in higher stock-based compensation compared to the prior year period. G&A personnel costs were higher during the third quarter of 2018 due to the number of administrative employees increasing from

94 as of September 30, 2017 to 122 as of September 30, 2018. These increases were partially offset by lower professional fees incurred during the third quarter of 2018 as compared to third quarter of 2017.

Other Income and Expenses.

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

	For the Three Months Ended September 30,	
(in thousands)	**2018**	**2017**
Credit facility	$ 1,364	$ 1,347
Senior Notes	5,375	—
Amortization of debt issuance costs	452	133
Interest capitalized	(657)	(465)
Total	$ 6,534	$ 1,015

Interest expense was $5.5 million higher for the three months ended September 30, 2018 compared to the three months ended September 30, 2017 primarily due to interest we incurred in 2018 on our issuance of Senior Notes that we issued in November 2017.

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 corresponding changes in underlying commodity prices and (ii) monthly cash settlements of our hedged derivative positions.

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

	For the Three Months Ended September 30,	
(in thousands)	**2018**	**2017**
Cash derivative settlement gain	$ 8,866	$ 390
Non-cash mark-to-market derivative gain (loss)	(18,437)	(1,286)
Net gain (loss) on derivative instruments	$ (9,571)	$ (896)

Income Tax Expense. During the three months ended September 30, 2018 and 2017, the Company recognized income tax expense amounting to $11.7 million and $8.2 million, respectively. The increase in income tax expense for the three months ended September 30, 2018 was primarily due to an increase in income before taxes of $28.8 million from the third quarter of 2017 to the third quarter of 2018, which was partially offset by a lower effective income tax rate between periods. The enactment of the Jobs Act in December 2017 reduced the corporate tax rate to 21%, which had the effect of lowering our overall effective income tax rate from 33.6% for the third quarter of 2017 to 21.9% for the same 2018 period.

The Company's provision for income taxes for the third quarter of 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax income because of state income taxes and permanent differences.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

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:

	For the Nine Months Ended September 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating revenues (in thousands):				
Oil sales	$ 533,507	$ 204,702	$ 328,805	161 %
Natural gas sales	46,612	33,226	13,386	40 %
NGL sales	88,422	25,844	62,578	242 %
Oil and gas sales	$ 668,541	$ 263,772	$ 404,769	153 %
Average sales prices:				
Oil (per Bbl)	$ 59.27	$ 45.76	$ 13.51	30 %
Effect of derivative settlements on average price (per Bbl)	1.50	0.12	1.38	1,150 %
Oil net of hedging (per Bbl)	$ 60.77	$ 45.88	$ 14.89	32 %
Average NYMEX price for oil (per Bbl)	$ 66.75	$ 49.44	$ 17.31	35 %
Oil differential from NYMEX	(7.48)	(3.68)	(3.80)	(103)%
Natural gas (per Mcf)	$ 2.02	$ 2.78	$ (0.76)	(27)%
Effect of derivative settlements on average price (per Mcf)	0.04	(0.02)	0.06	300 %
Natural gas net of hedging (per Mcf)	$ 2.06	$ 2.76	$ (0.70)	(25)%
Average NYMEX price for natural gas (per Mcf)	$ 2.95	$ 3.05	$ (0.10)	(3)%
Natural gas differential from NYMEX	(0.93)	(0.27)	(0.66)	(244)%
NGL (per Bbl)	$ 29.08	$ 23.67	$ 5.41	23 %
Net production:				
Oil (MBbls)	9,002	4,473	4,529	101 %
Natural gas (MMcf)	23,092	11,938	11,154	93 %
NGLs (MBbls)	3,040	1,092	1,948	178 %
Total (MBoe)[1]	15,891	7,554	8,337	110 %
Average daily net production volume:				
Oil (Bbls/d)	32,973	16,384	16,589	101 %
Natural gas (Mcf/d)	84,585	43,729	40,856	93 %
NGLs (Bbls/d)	11,137	3,999	7,138	178 %
Total (Boe/d)[1]	58,208	27,670	30,538	110 %

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

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the nine months ended September 30, 2018 were $404.8 million, or 153%, higher than total net revenues for the nine months ended September 30, 2017. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Net production volumes for oil, natural gas and NGLs increased 101%, 93% and 178%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin, as well as the producing properties acquired in the GMT Acquisition, which added 229 MBbls of net oil production to our nine months ended September 30, 2018 results. Since the third quarter 2017, 84 gross wells were placed on production in the Delaware Basin, which added 5,270 MBbls of net oil production during the first nine months of 2018. The increase in the Company's operated well count is attributable to the continued ramp up of development drilling activities and our seven-rig drilling program during 2018. These oil volume increases were partially offset by normal field production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. During the nine months ended September 30, 2018, our production was made up of 43% natural gas and NGL volumes compared to 41% in the same 2017 period. This change in our commodity mix was due to the significant increase in NGL volumes (up 178%) between periods, which was primarily a result of the main processor of our wet gas switching from ethane-rejection to ethane-recovery. This switch enabled us to recover an increased amount of ethane from our wet gas. The change to recover a higher portion of ethane started in the second quarter of 2018 and was made due to lower gas prices in the Permian Basin and higher ethane prices, which in turn led to stronger ethane processing economics.

In addition to production-related increases in net revenue between periods, there were also significant increases in our average realized sales prices for oil and NGLs when comparing the nine months ended September 30, 2018 to the same 2017 period. The average price for oil before the effects of hedging increased 30%, and the average price for NGLs increased 23% between periods. The 30% increase in the average realized oil price was primarily the result of higher NYMEX crude prices between periods (average NYMEX oil prices increased 35%), which were partially offset by lower realizations due to wider oil differentials (an increase of $3.80 per Bbl) in the first nine months of 2018. The overall 23% increase in average realized NGL prices between periods was primarily attributable to higher Mont Belvieu spot prices for plant products. Conversely, the average realized sales price of natural gas decreased by 27% between periods. This decrease was mainly due to significantly wider gas differentials (an increase of $0.66 per Mcf) and average NYMEX prices that were 3% lower between periods. Both our oil and gas differentials widened during the nine months ended September 30, 2018 due to anticipated pipeline takeaway capacity constraints impacting the Permian Basin.

Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	For the Nine Months Ended September 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 59,164	$ 26,924	$ 32,240	120 %
Severance and ad valorem taxes	42,791	14,358	28,433	198 %
Gathering, processing and transportation expenses	45,214	22,572	22,642	100 %
Operating costs per Boe:				
Lease operating expenses	$ 3.72	$ 3.56	$ 0.16	4 %
Severance and ad valorem taxes	2.69	1.90	0.79	42 %
Gathering, processing and transportation expenses	2.85	2.99	(0.14)	(5)%

Lease Operating Expenses. LOE for the nine months ended September 30, 2018 increased $32.2 million as compared to the nine months ended September 30, 2017. Higher LOE for the first nine months of 2018 was primarily related to a $30.6 million increase in expense associated with our higher well count. We had 240 gross operated horizontal wells as of September 30, 2018 compared to 171 gross operated horizontal wells as of September 30, 2017. The net increase in well count was mainly the result of our successful drilling activity adding 84 gross operated wells since the third quarter of 2017, which was partially offset by divestiture activity. In addition, workover activity increased $1.6 million between periods as a result of our higher well count.

LOE on a per Boe basis increased when comparing the first nine months of 2018 to the same 2017 period. LOE per Boe was $3.72 for the nine months ended September 30, 2018, which represents an increase of $0.16 per Boe from the comparable 2017 period. This increase in rate was mainly due to higher costs associated with water handling and equipment rentals for our existing and newly completed wells.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of our production at the wellhead and ad valorem taxes are generally based on the valuation of our proved developed oil and natural gas properties and vary across the different counties in which we operate. Severance taxes for the nine months ended September 30, 2018 increased $21.9 million compared to the same 2017 period primarily due to higher oil, natural gas and NGL revenues between periods. Severance and ad valorem taxes as a percentage of total net revenues increased to 6.4% for the nine months ended September 30, 2018 as compared to 5.4% in 2017 due to increased ad valorem taxes of $6.5 million between periods, associated with our higher well count and higher oil and gas property values.

Gathering, Processing and Transportation Expenses. GP&T for the nine months ended September 30, 2018 increased $22.6 million compared to the nine months ended September 30, 2017 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing fees and transportation and gathering costs being incurred.

On a per Boe basis, GP&T decreased 5% from $2.99 for the nine months ended September 30, 2017 to $2.85 per Boe for the compared 2018 period. On a natural gas and NGL volume basis (i.e. excluding crude oil barrels) the Boe rate decreased 10% between periods to $6.56 from $7.32 for the nine months ended September 30, 2018 and 2017, respectively. This decrease was attributable to lower natural gas prices between periods, due to residue gas being a primary component of gas processing fees, as well as lower rates on our primary gas contract from processing rebates we received for new wells connected to the plant.

Depreciation, Depletion and Amortization. The following table summarizes our DD&A for the periods indicated:

	For the Nine Months Ended September 30,	
(in thousands, except per Boe data)	**2018**	**2017**
Depreciation, depletion and amortization	$ 224,379	$ 102,847
Depreciation, depletion and amortization per Boe	14.12	13.61

DD&A rate can fluctuate as a result of finding and development costs, acquisitions, impairments, as well as changes in proved reserve or proved developed reserves. For the nine months ended September 30, 2018, DD&A expense amounted to $224.4 million, an increase of $121.5 million over the same 2017 period. The primary factor contributing to higher DD&A in 2018 was the increase in our overall production volumes between periods, which added $113.1 million of incremental DD&A expense during the first nine months of 2018, while higher DD&A rates between periods contributed an additional $8.4 million of DD&A expense to the first nine months of 2018.

DD&A per Boe was $14.12 for the nine months ended September 30, 2018 compared to $13.61 for the same period in 2017. The primary factor contributing to this higher DD&A rate was increased drilling and completion costs incurred for new wells completed and placed on production over the past 12 months.

Impairment and Abandonment Expenses. During the nine months ended September 30, 2018, $10.4 million of abandonment expense was incurred related to undeveloped leasehold acreage that expired during the period.

Exploration Expense. The following table summarizes our exploration expense for the periods indicated:

	For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 1,323	$ 1,132
Exploratory dry hole costs	395	—
Geological and geophysical costs	6,308	2,960
Exploration expense	$ 8,026	$ 4,092

Exploration was $8.0 million for the nine months ended September 30, 2018 compared to $4.1 million for the same prior year period. Exploration expense mainly consists of topographical studies, G&G projects, and salaries and expenses of G&G personnel. The period over period increase in exploration expense was primarily due to increased costs incurred on G&G projects and seismic studies of $3.3 million.

General and Administrative Expenses. The following table summarizes our G&A expenses for the periods indicated:

	For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 13,006	$ 8,288
Cash general and administrative expenses	31,661	27,729
General and administrative expenses	$ 44,667	$ 36,017

G&A expenses for the nine months ended September 30, 2018 were $44.7 million compared to $36.0 million for the nine months ended September 30, 2017. The higher G&A expenses incurred in 2018 were primarily due to $5.9 million in increased employee salaries and payroll burdens and $4.7 million in higher stock-based compensation compared to the prior year period. G&A personnel costs were substantially higher during the first nine months of 2018 due to the number of administrative employees increasing from 94 as of September 30, 2017 to 122 as of September 30, 2018. These increases were partially offset by lower professional fees and transaction costs incurred during the nine months ended September 30, 2018 as compared to the same prior year period.

Other Income and Expenses.

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

	For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Credit facility	$ 2,835	$ 2,285
Senior Notes	16,125	—
Amortization of debt issuance costs	1,258	348
Interest capitalized	(2,080)	(501)
Total	$ 18,138	$ 2,132

Interest expense was $16.0 million higher for the nine months ended September 30, 2018 compared to the same 2017 period primarily due to the interest we incurred in 2018 on our Senior Notes that we issued in November 2017, which was partially offset by an increase in the amount of interest we capitalized on capital projects under construction.

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 corresponding changes in underlying commodity prices and (ii) monthly cash settlements of our hedged derivative positions.

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

	For the Nine Months Ended September 30,	
(in thousands)	**2018**	**2017**
Cash derivative settlement gain	$ 14,390	$ 266
Non-cash mark-to-market derivative gain	579	5,126
Net gain (loss) on derivative instruments	$ 14,969	$ 5,392

Income Tax Expense. During the nine months ended September 30, 2018 and 2017, the Company recognized income tax expense amounting to $50.7 million and $17.3 million, respectively. The increase in income tax expense for the nine months ended September 30, 2018 as compared to the same period in 2017 was primarily due to an increase in income before taxes of $163.2 million between periods and the release of $5.1 million of the Company’s deferred tax asset valuation allowance in the first half of 2017, which was partially offset by a lower effective income tax rate in 2018. The enactment of the Jobs Act in December 2017 reduced the corporate tax rate to 21%, which had the effect of lowering our overall effective income tax rate to 22.0% for the nine months ended September 30, 2018.

The Company's provision for income taxes for the nine months ended September 30, 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax income because of state income taxes and permanent differences.

Liquidity and Capital Resources

Overview

Our drilling and completion and land acquisition activities require us to make significant operating and capital expenditures. Historically, our primary sources of liquidity have been borrowings under CRP's revolving credit facility, cash flows from operations, and offerings of debt and equity securities. To date, our primary use of capital has been for the development and acquisition of oil and natural gas properties.

The following table summarizes our capital expenditures incurred for the nine months ended September 30, 2018:

(in millions)	For the Nine Months Ended September 30, 2018
Drilling and completion capital expenditures	$ 566.9
Facilities, infrastructure and other [(1)]	128.0
Land	20.2
Total capital expenditures	$ 715.1

(1) Facilities, infrastructure and other includes $97.9 million of well-level facility costs. In previous years, these costs were presented within drilling and completion capital expenditures. This presentation change was made to conform our drilling and completion capital expenditures to that of our peer group and to also present our costs incurred consistently with our 2018 capital expenditure guidance.

We continually evaluate our capital needs and compare them to our capital resources. Our estimated capital expenditure budget for 2018 is $885 million to $1,050 million, of which $710 million to $820 million is allocated to drilling and completion ("D&C") activity. We expect to fund our capital expenditure budget with cash flows from operations and borrowings under our credit facility. The D&C portion of our 2018 capital budget represents an increase over the $624.1 million of D&C expenditures we incurred during 2017. This increased 2018 capital budget is driven by an increase in rig activity from six to seven rigs, the associated increase in wells to be drilled in 2018 versus 2017, and the increase in the number of extended lateral wells to be drilled which require more capital than shorter laterals.

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

Based upon current oil and natural gas price expectations for the remainder of 2018, we believe that our cash flow from operations and borrowings under our credit facility or otherwise will provide us with sufficient liquidity to execute our current capital program. However, our future cash flows are subject to a number of variables, including the future level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot ensure that operations and other needed capital will be available on acceptable terms or at all. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional sources for funding capital investments. As we pursue our future development program, we are actively assessing the correct mix of reserve-based borrowings and debt offerings. If we require additional capital to fund acquisitions, we may also seek such capital through traditional reserve-based borrowings, offerings of debt and equity securities, asset sales, or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Analysis of Cash Flow Changes

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

(in thousands)	For the Nine Months Ended September 30, 2018	2017
Net cash provided by operating activities	$ 494,695	$ 137,150
Net cash used in investing activities	(694,966)	(766,754)
Net cash provided by financing activities	135,511	498,102

During the nine months ended September 30, 2018, we generated $494.7 million of cash from operating activities, an increase of $357.5 million from the same period in 2017. Cash provided by operating activities increased primarily due to higher net income between periods as a result of increased crude oil, natural gas and NGL production volumes, higher realized sales prices for crude oil and NGLs, higher cash derivative settlements and timing of our receivable collections and supplier payments. These positive factors were partially offset by higher operating expenses and interest expense during the nine months ended September 30, 2018 as compared to the same period in 2017. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on fluctuations in our operating expenses between periods.

During the nine months ended September 30, 2018, cash flows from operating activities, cash on hand, proceeds from sales of oil and natural gas properties, and $140.0 million in net borrowings under our credit facility were used to finance $723.1 million of drilling and development expenditures and $114.9 million in oil and gas property acquisitions.

During the nine months ended September 30, 2017, cash flows from operating activities, and cash on hand and $130.0 million of net borrowings from our credit facility were used to finance $354.5 million of drilling and development expenditures, while $333.5 million in net proceeds from the issuance of Class A common shares together with cash on hand, $35.0 million in net borrowings under our credit facility, and proceeds from the sale of oil and gas properties were used to finance $419.5 million in oil and gas property acquisitions.

Credit Agreement

On May 4, 2018, CRP, the Company's consolidated subsidiary, entered into an amended and restated credit agreement with a syndicate of banks that as of September 30, 2018, had a borrowing base of $800.0 million and elected commitments of $600.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. The Company had $140.0 million borrowings outstanding and $459.1 million in available borrowing capacity, which was net of $0.9 million in letters of credit outstanding.

The amount available to be borrowed under the Company's credit agreement is equal to the lesser of (i) the borrowing base, (ii) aggregate elected commitments, or (iii) $1.5 billion. The borrowing base is redetermined semi-annually each April 1 and October 1 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 under the credit agreement.

Borrowings under CRP's revolving credit facility 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) plus an applicable margin ranging from 150 to 250 basis points, 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; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee on unused amounts under its facility of a range of 37.5 to 50 basis points. CRP may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

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 CRP'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 unused commitments under its 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; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with these covenants and the financial ratios described above as of September 30, 2018 and through the filing of this Quarterly Report.

In connection with the October 2018 credit facility semi-annual redetermination, the borrowing base under the revolving credit facility was increased from $800.0 million to $1.0 billion and the lenders increased their aggregate elected commitments from $600.0 million to $800.0 million.

5.375% Senior Unsecured Notes due 2026

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (the "Senior Notes") in a 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 Senior Notes semi-annually in arrears on each January 15 and July 15, commencing July 15, 2018. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of CRP's current subsidiaries that guarantee CRP's revolving credit facility. The Senior Notes are not guaranteed by the Company, nor is the Company subject to the terms of the indenture governing the Senior Notes.

At any time prior to January 15, 2021, CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the Senior 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% of the principal amount of the Senior Notes redeemed, plus any accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount issued under the indenture governing the Senior 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 January 15, 2021, CRP may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100% of the principal amount of the Senior Notes redeemed, plus a "make-whole" premium and any accrued and unpaid interest as of the date of redemption. On and after January 15, 2021, CRP may redeem the Senior Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.688% for the 12-month period beginning on January 15, 2021, 101.344% for the 12-month period beginning January 15, 2022, and 100% beginning on January 15, 2023, plus accrued and unpaid interest to the redemption date.

If CRP experiences certain defined changes of control (and, in some 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 but unpaid interest to the date of repurchase.

The indenture governing the Senior Notes contains 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 September 30, 2018 and through the filing of this Quarterly Report.

Upon an Event of Default (as defined in the indenture 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.

Contractual Obligations

The Company's contractual obligations include drilling rig commitments, office leases, water disposal agreements, purchase obligations, asset retirement obligations, long-term debt obligations, cash interest expense on long-term debt obligations and transportation and gathering agreements. Since December 31, 2017, there have not been any significant, non-routine changes in our contractual obligations, other than additional agreements as discussed in *Note 12—Commitments and Contingencies* under Part I, Item 1. of this Quarterly Report.

Critical Accounting Policies and Estimates

There have been no material changes during the nine months ended September 30, 2018 to the methodology applied by management for critical accounting policies previously disclosed in our 2017 Annual Report. Please refer to Part II, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates* in our 2017 Annual Report for a discussion of our critical accounting policies and estimates.

New Accounting Pronouncements

Please refer to *Note 1—Basis of Presentation* under Part I, Item 1. of this Quarterly Report for a discussion of the effects of recently adopted accounting standards and the potential effects of new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk in the form of adverse changes in commodity prices and interest rates 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 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. 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 other than speculative trading.

Commodity Price Risk

Our major 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 in the future. Based on our production for the nine months of 2018, our income before income taxes for the nine months ended September 30, 2018 would have moved up or down $53.4 million for each 10% change in oil prices per Bbl, $8.8 million for each 10% change in NGL prices per Bbl, and $4.7 million for each 10% change in natural gas prices per Mcf.

Due to this volatility, we have historically used, and we may elect to 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 flows from operations due to fluctuations in oil and natural gas prices and 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 may partially limit our potential gains from future increases in prices. Our credit agreement limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production from proved properties.

The following table summarizes the terms of the swap contracts the Company had in place as of September 30, 2018:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl) (1)
Crude oil basis swaps	October 2018 - December 2018	828,000	9,000	$ (2.38)
	January 2019 - March 2019	540,000	6,000	(5.34)
	April 2019 - June 2019	91,000	1,000	(10.00)
	July 2019 - September 2019	1,380,000	15,000	(9.03)
	October 2019 - December 2019	920,000	10,000	(4.24)

(1) The 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 the relevant calculation period.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu) (1)
Natural Gas Swaps - Henry Hub	January 2019 - December 2019	10,950,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	January 2019 - December 2019	5,475,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu) (2)
Natural gas basis swaps	October 2018 - December 2018	460,000	5,000	$ (0.43)
	January 2019 - December 2019	12,775,000	35,000	(1.31)

(1) The natural gas swap contracts are settled based on either i) the NYMEX Henry Hub price or ii) the Inside FERC West Texas WAHA price of natural gas as of the specified settlement date, as applicable.

(2) The 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 the relevant calculation period.

Changes in the fair value of derivative contracts from December 31, 2017 to September 30, 2018, are presented below:

(in thousands)	Commodity derivative contracts	
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2017	$	855
Contracts settled		(164)
Change in the futures curve of forecasted commodity prices		(4,611)
Contracts added		5,354
Net fair value of oil and gas derivative contracts outstanding as of September 30, 2018	$	1,434

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2018 would cause a $1.9 million increase or decrease, respectively, in this fair value asset, and a hypothetical upward or downward shift of 10% per Mcf in the NYMEX forward curve for natural gas as of September 30, 2018 would cause a $2.2 million decrease or increase, respectively, in this fair value asset.

Interest Rate Risk

The Company's ability to borrow and the rates offered by lenders can be adversely affected by deteriorations in the credit markets and/or downgrades in the Company's credit rating. CRP's credit facility interest rate is based on a LIBOR spread, which exposes the Company to interest rate risk if we have borrowings outstanding.

At September 30, 2018, the Company had $140.0 million of debt outstanding under its credit agreement, with a weighted average interest rate of 3.66%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would be approximately $1.4 million per year. We do not currently have or intend to enter into any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

The Company's remaining long-term debt balance of $391.4 million consists of our Senior Notes, which has a fixed interest rate; therefore, this balance is not affected by interest rate movements. For additional information regarding the Company's debt instruments, see *Note 4—Long-Term Debt*, in Item 1 of Part I of this Quarterly Report.

Item 4. Controls and Procedures

Evaluation of Disclosure Control and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our 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, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the three months ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, we are 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 1A. Risk Factors.

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading “Item 1A. Risk Factors” included in our 2017 Annual Report and the risk factors and other cautionary statements contained in our other SEC filings, which could materially affect our businesses, financial condition, or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or future results. There have been no material changes in our risk factors from those described in our 2017 Annual Report or our other SEC filings.

Item 6. Exhibits.

Exhibit Number	Description of Exhibit
3.1	Second Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on October 7, 2016).
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).
10.1	Purchase and Sale Agreement, dated as of August 2, 2018, between Centennial Resource Production, LLC and BP North America Inc. (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 6, 2018).
10.2	Crude Oil Purchase and Sale Agreement, dated as of August 31, 2018, between Centennial Resource Production, LLC and ExxonMobil Oil Corporation (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 4, 2018).
10.3#	Amended and Restated Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018)
10.4#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 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).
31.1*	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

\# Management contract or compensatory plan or agreement.

* Filed herewith.

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
Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)

Date: November 5, 2018

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULES 13a-14(a) AND 15d-14(a)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Mark G. Papa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q (this “report”) of Centennial Resource Development, Inc. (the “registrant”);

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

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

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

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

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 5, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

Mark G. Papa
Chief Executive Officer (Principal Executive Officer)

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULES 13a-14(a) AND 15d-14(a)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, George S. Glyphis, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q (this "report") of Centennial Resource Development, Inc. (the "registrant");

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

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

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

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

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: November 5, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis
Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)

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

In connection with the Quarterly Report on Form 10-Q for the quarter ended September 30, 2018 of Centennial Resource Development, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark G. Papa, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

Date: November 5, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

Mark G. Papa
Chief Executive Officer (Principal Executive Officer)

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

In connection with the Quarterly Report on Form 10-Q for the quarter ended September 30, 2018 of Centennial Resource Development, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, George S. Glyphis, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

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

Date: November 5, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis
Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)