CONTINENTAL RESOURCES, INC
Form 10-Q
October 29, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x 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: 001-32886

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

Oklahoma	73-0767549
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
20 N. Broadway, Oklahoma City, Oklahoma	73102
(Address of principal executive offices)	(Zip Code)

(405) 234-9000
(Registrant's telephone number, including area code)
Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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 x 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 x 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	x	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 x
376,016,349 shares of our $0.01 par value common stock were outstanding on October 19, 2018.

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When we refer to "us," "we," "our," "Company," or "Continental" we are describing Continental Resources, Inc. and our subsidiaries.

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:
“Bbl” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.
“Boe” Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.
“Btu” British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.
“completion” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.
“developed acreage” The number of acres allocated or assignable to productive wells or wells capable of production.
“development well” A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
“dry hole” Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.
“exploratory well” A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.
“field” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
“formation” A layer of rock which has distinct characteristics that differs from nearby rock.
"gross acres" or "gross wells" Refers to the total acres or wells in which a working interest is owned.
“MBbl” One thousand barrels of crude oil, condensate or natural gas liquids.
“MBoe” One thousand Boe.
“Mcf” One thousand cubic feet of natural gas.
“MMBoe” One million Boe.
“MMBtu” One million British thermal units.
“MMcf” One million cubic feet of natural gas.
“net acres” or "net wells" Refers to the sum of the fractional working interests owned in gross acres or gross wells.
"Net crude oil and natural gas sales" Represents total crude oil and natural gas sales less total transportation expenses.
"Net sales price" Represents the average net wellhead sales price received by the Company for its crude oil or natural gas sales after deducting transportation expenses. Amount is calculated by taking revenues less transportation expenses divided by sales volumes for a period, whether for crude oil or natural gas, as applicable.
“NYMEX” The New York Mercantile Exchange.
“play” A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.
“proved reserves” The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under

existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.
“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
“royalty interest” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.
“SCOOP” Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.
"STACK" Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma.
“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.
“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
“working interest” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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

This report and information incorporated by reference in this report include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, included in this report are forward-looking statements. The words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

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

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

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate or will not change over time. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under Part II, Item 1A. Risk Factors and elsewhere in this report, if any, our Annual Report on Form 10-K for the year ended December 31, 2017, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this report or our Annual

Report on Form 10-K occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement.

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

PART I. Financial Information
ITEM 1. Financial Statements
Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets

In thousands, except par values and share data	September 30, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$12,896	$43,902
Receivables:		
Crude oil and natural gas sales	794,447	671,665
Affiliated parties	126	63
Joint interest and other, net	442,779	426,585
Derivative assets	—	2,603
Inventories	104,230	97,406
Prepaid expenses and other	14,659	9,501
Total current assets	1,369,137	1,251,725
Net property and equipment, based on successful efforts method of accounting	13,644,538	12,933,789
Other noncurrent assets	17,385	14,137
Total assets	$15,031,060	$14,199,651
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$771,425	$692,908
Revenues and royalties payable	462,082	374,831
Payables to affiliated parties	316	143
Accrued liabilities and other	245,229	260,074
Derivative liabilities	9,056	—
Current portion of long-term debt	2,341	2,286
Total current liabilities	1,490,449	1,330,242
Long-term debt, net of current portion	5,955,326	6,351,405
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,511,569	1,259,558
Asset retirement obligations, net of current portion	122,532	111,794
Noncurrent derivative liabilities	354	—
Other noncurrent liabilities	12,020	15,449
Total other noncurrent liabilities	1,646,475	1,386,801
Commitments and contingencies (Note 8)		
Shareholders' equity:		
Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding	—	—
Common stock, $0.01 par value; 1,000,000,000 shares authorized; 375,995,294 shares issued and outstanding at September 30, 2018; 375,219,769 shares issued and outstanding at December 31, 2017	3,760	3,752
Additional paid-in capital	1,426,222	1,409,326
Accumulated other comprehensive income	430	307
Retained earnings	4,508,398	3,717,818
Total shareholders' equity	5,938,810	5,131,203
Total liabilities and shareholders' equity	$15,031,060	$14,199,651

The accompanying notes are an integral part of these condensed consolidated financial statements.
1

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

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2018	2017	2018	2017
Revenues:				
Crude oil and natural gas sales	$1,273,238	$704,818	$3,524,618	$1,965,216
Gain (loss) on natural gas derivatives, net	(2,025)	8,602	(4,536)	83,482
Crude oil and natural gas service operations	10,938	13,323	40,210	24,959
Total revenues	1,282,151	726,743	3,560,292	2,073,657
Operating costs and expenses:				
Production expenses	103,032	84,514	286,165	239,842
Production taxes	98,572	51,264	262,747	134,462
Transportation expenses	46,008	—	142,559	—
Exploration expenses	2,324	1,389	4,347	9,591
Crude oil and natural gas service operations	5,163	3,349	17,434	10,664
Depreciation, depletion, amortization and accretion	469,333	420,243	1,370,912	1,198,169
Property impairments	23,770	35,130	86,715	209,819
General and administrative expenses	44,151	44,006	134,368	130,413
Net (gain) loss on sale of assets and other	(1,510)	(4,905)	(8,261)	764
Total operating costs and expenses	790,843	634,990	2,296,986	1,933,724
Income from operations	491,308	91,753	1,263,306	139,933
Other income (expense):				
Interest expense	(73,409)	(74,756)	(223,590)	(218,672)
Loss on extinguishment of debt	(7,133)	—	(7,133)	—
Other	869	394	2,231	1,209
	(79,673)	(74,362)	(228,492)	(217,463)
Income (loss) before income taxes	411,635	17,391	1,034,814	(77,530)
(Provision) benefit for income taxes	(97,466)	(6,770)	(244,234)	25,063
Net income (loss)	$314,169	$10,621	$790,580	$(52,467)
Basic net income (loss) per share	$0.84	$0.03	$2.13	$(0.14)
Diluted net income (loss) per share	$0.84	$0.03	$2.11	$(0.14)
Comprehensive income (loss):				
Net income (loss)	$314,169	$10,621	$790,580	$(52,467)
Other comprehensive income, net of tax:				
Foreign currency translation adjustments	105	202	123	529
Total other comprehensive income, net of tax	105	202	123	529
Comprehensive income (loss)	$314,274	$10,823	$790,703	$(51,938)

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statement of Shareholders' Equity

In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income	Retained earnings	Total shareholders' equity
Balance at December 31, 2017	375,219,769	$ 3,752	$ 1,409,326	$ 307	$ 3,717,818	$ 5,131,203
Net income (unaudited)	—	—	—	—	790,580	790,580
Other comprehensive income, net of tax (unaudited)	—	—	—	123	—	123
Stock-based compensation (unaudited)	—	—	33,196	—	—	33,196
Restricted stock:						
Granted (unaudited)	1,332,705	13	—	—	—	13
Repurchased and canceled (unaudited)	(298,648)	(3)	(16,300)	—	—	(16,303)
Forfeited (unaudited)	(258,532)	(2)	—	—	—	(2)
Balance at September 30, 2018 (unaudited)	375,995,294	$ 3,760	$ 1,426,222	$ 430	$ 4,508,398	$ 5,938,810

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

	Nine months ended September 30,	
In thousands	2018	2017
Cash flows from operating activities		
Net income (loss)	$790,580	$(52,467)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	1,370,676	1,199,715
Property impairments	86,715	209,819
Non-cash (gain) loss on derivatives, net	12,013	(65,481)
Stock-based compensation	33,209	32,490
Provision (benefit) for deferred income taxes	252,012	(25,063)
Dry hole costs	1	157
Gain on sale of assets, net	(8,261)	(703)
Loss on extinguishment of debt	7,133	—
Other, net	11,068	7,705
Changes in assets and liabilities:		
Accounts receivable	(139,219)	(154,790)
Inventories	(7,852)	6,736
Other current assets	(4,766)	729
Accounts payable trade	32,708	128,337
Revenues and royalties payable	86,814	48,447
Accrued liabilities and other	(19,677)	13,050
Other noncurrent assets and liabilities	(2,413)	(700)
Net cash provided by operating activities	2,500,741	1,347,981
Cash flows from investing activities		
Exploration and development	(2,093,010)	(1,444,991)
Purchase of producing crude oil and natural gas properties	(25,476)	(3,480)
Purchase of other property and equipment	(15,724)	(10,508)
Proceeds from sale of assets	30,727	84,725
Net cash used in investing activities	(2,103,483)	(1,374,254)
Cash flows from financing activities		
Credit facility borrowings	1,706,000	985,000
Repayment of credit facility	(1,704,000)	(952,000)
Redemption of Senior Notes	(400,000)	—
Premium and costs on redemption of Senior Notes	(6,700)	—
Repayment of other debt	(1,707)	(1,654)
Debt issuance costs	(5,543)	—
Repurchase of restricted stock for tax withholdings	(16,303)	(10,985)
Net cash (used in) provided by financing activities	(428,253)	20,361
Effect of exchange rate changes on cash	(11)	34
Net change in cash and cash equivalents	(31,006)	(5,878)
Cash and cash equivalents at beginning of period	43,902	16,643
Cash and cash equivalents at end of period	$12,896	$10,765

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

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Continental Resources, Inc. (the “Company”) was originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company's principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

A substantial portion of the Company’s operations are located in the North region, with that region comprising 59% of the Company’s crude oil and natural gas production and 74% of its crude oil and natural gas revenues for the nine months ended September 30, 2018. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. In recent years, the Company has significantly expanded its operations in the South region with its increased activity in the SCOOP and STACK plays. The South region comprised 41% of the Company's crude oil and natural gas production and 26% of its crude oil and natural gas revenues for the nine months ended September 30, 2018.

For the nine months ended September 30, 2018, crude oil accounted for 56% of the Company’s total production and 82% of its crude oil and natural gas revenues.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The condensed consolidated financial statements as of September 30, 2018 include the accounts of the Company and its subsidiaries, all of which are 100% owned, after all significant intercompany accounts and transactions have been eliminated upon consolidation.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the “SEC”) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States (“U.S. GAAP”), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Quarterly Report on Form 10-Q (“Form 10-Q”) together with the Company’s Annual Report on Form 10-K for the year ended December 31, 2017 (“2017 Form 10-K”), which includes a summary of the Company’s significant accounting policies and other disclosures.

The condensed consolidated financial statements as of September 30, 2018 and for the three and nine month periods ended September 30, 2018 and 2017 are unaudited. The condensed consolidated balance sheet as of December 31, 2017 was derived from the audited balance sheet included in the 2017 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these condensed consolidated financial statements.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates. The most significant estimates and assumptions impacting reported results are estimates of the Company’s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these unaudited interim condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations that may be expected for any other interim period or for an entire year.

Earnings per share

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

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

and nine months ended September 30, 2018 and 2017.

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2018	2017	2018	2017
Net income (loss) (numerator)	$314,169	$10,621	$790,580	$(52,467)
Weighted average shares (denominator):				
Weighted average shares - basic	371,960	371,142	371,810	371,029
Non-vested restricted stock (1)	2,663	1,873	2,952	—
Weighted average shares - diluted	374,623	373,015	374,762	371,029
Net income (loss) per share:				
Basic	$0.84	$0.03	$2.13	$(0.14)
Diluted	$0.84	$0.03	$2.11	$(0.14)

(1) For the nine months ended September 30, 2017, the Company had a net loss and therefore the potential dilutive effect of approximately 2,558,900 weighted average non-vested restricted shares were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computation.

Inventories

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

The components of inventory as of September 30, 2018 and December 31, 2017 consisted of the following:

In thousands	September 30, 2018	December 31, 2017
Tubular goods and equipment	$ 15,829	$ 14,946
Crude oil	88,401	82,460
Total	$ 104,230	$ 97,406

Adoption of new accounting pronouncements

Revenue recognition and presentation – In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes nearly all previously existing revenue recognition guidance under U.S. GAAP. Subsequently, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This new guidance became effective for reporting periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on January 1, 2018 as required. See Note 4. Revenues for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New accounting pronouncements not yet adopted

Leases – In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for interim and annual reporting periods beginning after December 15, 2018. The Company plans to adopt the new standard using the simplified transition method prescribed by ASU 2018-11, Leases (Topic 842): Targeted Improvements, whereby the Company will initially apply the new standard as of the January 1, 2019 adoption date and will recognize a cumulative-effect adjustment to the opening balance of retained earnings, if any, upon adoption in lieu of retrospectively applying the new standard to pre-adoption periods.

The Company is nearing completion of its evaluation of the impact of ASU 2016-02 on its financial statements, accounting policies, and internal controls and is working to finalize its implementation of systems and processes to capture, classify, and account for leases within the scope of the new guidance and to comply with the related disclosure requirements.

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

Based on its current commitments, the Company anticipates it will be required to recognize lease assets and liabilities related to drilling rig commitments, certain equipment rentals and leases, certain surface use agreements, and potentially other arrangements. The Company does not believe any of its current firm transportation agreements will qualify as leases.

If the Company was to adopt ASU 2016-02 as of September 30, 2018 based on long-term lease commitments in place as of that date, the Company estimates its lease assets and liabilities would total approximately $25 million, primarily representing minimum future payments associated with drilling rig commitments and surface use agreements with contractual durations in excess of one year. This estimate will change with the passage of time and from changes in the nature, timing, and extent of the Company's contractual arrangements from period to period and may not be indicative of the actual value of lease assets and liabilities to be recognized upon formal adoption of the new guidance on January 1, 2019.

Credit losses – In June 2016, the FASB issued ASU 2016-13, Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost. The standard is effective for interim and annual periods beginning after December 15, 2019 and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. The Company continues to evaluate the new standard and is unable to estimate its financial statement impact at this time; however, the impact is not expected to be material. Historically, the Company's credit losses on crude oil and natural gas sales receivables and joint interest receivables have been immaterial.

Note 3. Supplemental Cash Flow Information

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

	Nine months ended September 30,	
In thousands	2018	2017
Supplemental cash flow information:		
Cash paid for interest	$199,960	$198,405
Cash paid for income taxes	—	2
Cash received for income tax refunds	7,786	148
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	6,591	5,111

As of September 30, 2018 and December 31, 2017, the Company had $348.1 million and $302.8 million, respectively, of accrued capital expenditures included in “Net property and equipment” and “Accounts payable trade” in the condensed consolidated balance sheets.

Note 4. Revenues

Adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received, allocate the consideration to each separate performance obligation, and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition.

Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity records revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Applying the guidance in ASU 2016-08 requires significant judgment in determining the point in time when control of products transfers to customers.

The Company adopted the new revenue recognition and presentation guidance on January 1, 2018 using a modified retrospective transition approach to all applicable contracts at the date of initial application, whereby the standard has been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation. Adoption of the new guidance had no cumulative effect impact on the Company's retained earnings at January 1, 2018.

The new guidance does not have a material impact on the timing of the Company’s revenue recognition or its financial position, results of operations, net income, or cash flows, but does impact the Company's presentation of revenues and expenses under the gross-versus-net presentation guidance in ASU 2016-08. In years prior to 2018, the Company generally presented its revenues net of costs incurred to transport its production to market. Under the new guidance, revenues and transportation expenses associated with production originating from the Company’s operated properties are now reported on a gross basis as further discussed below. The changes from net to gross presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company’s results of operations, net income, or cash flows for the three and nine months ended September 30, 2018.

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

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
In thousands	New Standard	Prior Presentation	Change	New Standard	Prior Presentation	Change
Revenues:						
Crude oil and natural gas sales	$1,273,238	$1,227,230	$46,008	$3,524,618	$3,382,059	$142,559
Loss on natural gas derivatives, net	(2,025)	(2,025)	—	(4,536)	(4,536)	—
Crude oil and natural gas service operations	10,938	10,938	—	40,210	40,210	—
Total revenues	$1,282,151	$1,236,143	$46,008	$3,560,292	$3,417,733	$142,559
Operating costs and expenses:						
Transportation expenses	$46,008	$—	$46,008	$142,559	$—	$142,559
Net income	$314,169	$314,169	$—	$790,580	$790,580	$—

Revenue from contracts with customers

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

Operated crude oil revenues – The Company pays third parties to transport the majority of its operated crude oil production from lease locations to downstream market centers, at which time the Company's customers take title and custody of the product in exchange for prices based on the particular market where the product was delivered. Operated crude oil revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. Crude oil sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred. Operated crude oil revenues and transportation expenses are reported on a gross basis, as the Company controls the operated production prior to its transfer to customers. Transportation expenses associated with the Company's operated crude oil production totaled $39.3 million and $119.9 million for the three and nine months ended September 30, 2018, respectively.

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

Under certain arrangements, the Company may elect to take a volume of processed residue gas and/or NGLs in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement based on the customer's proceeds for sale of those processed products. When the Company elects to do so, it pays third parties to transport the processed products which it took in-kind to downstream delivery points, where it then sells the products to customers at prices applicable to those downstream markets. In such situations, operated revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Operated sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, the Company's revenues include the pricing adjustments applied by the midstream processing entity according to the applicable contractual pricing formula, but exclude the transportation expenses the Company incurs to transport the processed products to downstream customers. Transportation expenses associated with these arrangements totaled $6.7 million and $22.6 million for the three and nine months ended September 30, 2018, respectively, comprised entirely of costs to transport processed residue gas.

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

Natural gas derivative revenues – See Note 5. Derivative Instruments for discussion of the Company's accounting for its derivative instruments.

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

Disaggregation of crude oil and natural gas revenues

The following table presents the disaggregation of the Company's crude oil and natural gas revenues for the three and nine months ended September 30, 2018.

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
In thousands	North Region	South Region	Total	North Region	South Region	Total
Crude oil revenues:						
Operated properties	$634,251	$159,506	$793,757	$1,791,045	$443,562	$2,234,607
Non-operated properties	225,513	19,288	244,801	604,700	52,415	657,115
Total crude oil revenues	859,764	178,794	1,038,558	2,395,745	495,977	2,891,722
Natural gas revenues:						
Operated properties	60,381	140,168	200,549	153,627	388,610	542,237
Non-operated properties	16,397	17,734	34,131	44,058	46,601	90,659
Total natural gas revenues	76,778	157,902	234,680	197,685	435,211	632,896
Crude oil and natural gas sales	$936,542	$336,696	$1,273,238	$2,593,430	$931,188	$3,524,618
Timing of revenue recognition						
Goods transferred at a point in time	$936,542	$336,696	$1,273,238	$2,593,430	$931,188	$3,524,618
Goods transferred over time	—	—	—	—	—	—
	$936,542	$336,696	$1,273,238	$2,593,430	$931,188	$3,524,618

Performance obligations

The Company satisfies the performance obligations under its crude oil and natural gas sales contracts upon delivery of its production and related transfer of control to customers. Upon delivery of production, the Company has a right to

receive consideration from its customers in amounts determined by the sales contracts.
All of the Company's outstanding crude oil sales contracts at September 30, 2018 are short-term in nature with contract terms of less than one year. For such contracts, the Company has utilized the practical expedient in Accounting

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Standards Codification ("ASC") 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

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

Contract balances

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

Revenues from previously satisfied performance obligations

To record revenues for commodity sales, at the end of each month the Company estimates the amount of production delivered and sold to customers and the prices to be received for such sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer and are reflected in the financial statements within the caption "Crude oil and natural gas sales". Revenues recognized during the three and nine months ended September 30, 2018 related to performance obligations satisfied in prior reporting periods were not material.

Note 5. Derivative Instruments

Natural gas derivatives

From time to time the Company has entered into natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.

The Company recognizes its natural gas derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its natural gas derivatives as hedges for accounting purposes and, as a result, marks such derivative instruments to fair value and recognizes the changes in fair value in the unaudited condensed consolidated statements of comprehensive income (loss) under the caption “Gain (loss) on natural gas derivatives, net”.

The Company's natural gas derivative contracts are settled based upon reported NYMEX Henry Hub settlement prices. The estimated fair value of derivatives is based upon various factors, including commodity exchange prices, over-the-counter quotations and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See Note 6. Fair Value Measurements.

With respect to a natural gas fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a natural gas collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.

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At September 30, 2018 the Company had outstanding natural gas derivative contracts as set forth in the table below. The volumes reflected below represent an aggregation of multiple derivative contracts having similar remaining durations expected to be realized ratably over the respective 2018 and 2019 periods. At September 30, 2018 the Company had no outstanding crude oil derivative contracts.

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
October 2018 - December 2018		
Swaps - Henry Hub	57,960,000	$ 2.88
April 2019 - December 2019		
Swaps - Henry Hub	14,850,000	$ 2.68

Natural gas derivative gains and losses

Cash receipts and payments in the following table reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2018	2017	2018	2017
Cash received (paid) on derivatives:				
Natural gas fixed price swaps	$(1,477)	$12,893	$7,477	$25,080
Natural gas collars	—	(612)	—	(10,068)
Cash received (paid) on derivatives, net	(1,477)	12,281	7,477	15,012
Non-cash gain (loss) on derivatives:				
Natural gas fixed price swaps	(548)	(8,026)	(12,013)	27,390
Natural gas collars	—	4,347	—	41,080
Non-cash gain (loss) on derivatives, net	(548)	(3,679)	(12,013)	68,470
Gain (loss) on natural gas derivatives, net	$(2,025)	$8,602	$(4,536)	$83,482

Diesel fuel derivatives

The Company previously entered into diesel fuel swap derivative contracts, all of which matured on or before December 31, 2017, to economically hedge against the variability in cash flows associated with purchases of diesel fuel for use in drilling activities. With respect to the diesel fuel swap contracts, the counterparty was required to make a payment to the Company if the settlement price for any settlement period was greater than the swap price, and the Company was required to make a payment to the counterparty if the settlement price for any settlement period was less than the swap price. The diesel fuel swap contracts were settled based upon reported NYMEX settlement prices for New York Harbor ultra-low sulfur diesel fuel.

The Company recognized its diesel fuel derivatives on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value was based upon various factors, including commodity exchange prices, over-the-counter quotations, the risk-free interest rate, and time to expiration. The Company did not designate its diesel fuel derivatives as hedges for accounting purposes and, as a result, marked the derivative instruments to fair value and recognized the changes in fair value in the unaudited condensed consolidated statements of comprehensive income (loss) under the caption “Operating costs and expenses—Net (gain) loss on sale of assets and other.”

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Cash receipts in the following table reflect gains on diesel fuel derivatives which matured during the 2017 period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of diesel fuel derivatives held at September 30, 2017 and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the three and nine months ended September 30, 2017.

In thousands	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Cash received on diesel fuel derivatives	$ —	$ 603	$ —	$ 1,522
Non-cash gain (loss) on diesel fuel derivatives	—	740	—	(2,989)
Gain (loss) on diesel fuel derivatives, net	$ —	$ 1,343	$ —	$ (1,467)

Balance sheet offsetting of derivative assets and liabilities

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

The following table presents the gross amounts of recognized natural gas and diesel fuel derivative assets and liabilities, as applicable, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value.

In thousands	September 30, 2018	December 31, 2017
Commodity derivative assets:		
Gross amounts of recognized assets	$ 276	$ 2,603
Gross amounts offset on balance sheet	(276)	—
Net amounts of assets on balance sheet	—	2,603
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(9,686)	—
Gross amounts offset on balance sheet	276	—
Net amounts of liabilities on balance sheet	$ (9,410)	$ —

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

In thousands	September 30, 2018	December 31, 2017
Derivative assets	$ —	$ 2,603
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	—	2,603
Derivative liabilities	(9,056)	—
Noncurrent derivative liabilities	(354)	—
Net amounts of liabilities on balance sheet	(9,410)	—
Total derivative assets (liabilities), net	$ (9,410)	$ 2,603

Note 6. Fair Value Measurements

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

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

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

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available. The Company's policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of September 30, 2018 and December 31, 2017.

	Fair value measurements at September 30, 2018 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative liabilities:				
Swaps	$ —	$ (9,410)	$ —	$ (9,410)
Total	$ —	$ (9,410)	$ —	$ (9,410)

	Fair value measurements at December 31, 2017 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$ 2,603	$ —	$ 2,603
Total	$ —	$ 2,603	$ —	$ 2,603

Assets Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips adjusted for differentials, operating costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

Unobservable Input	Assumption
Future production	Future production estimates for each property
Forward commodity prices	Forward NYMEX strip prices through 2022 (adjusted for differentials), escalating 3% per year thereafter
Operating costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of properties	Up to 50 years
Discount rate	10%

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

For the three and nine months ended September 30, 2018, estimated future net cash flows were determined to be in excess of cost basis, therefore no impairment was recorded for the Company's proved crude oil and natural gas properties for those periods.

For the nine months ended September 30, 2017, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Impairments of proved properties totaled $82.3 million for the nine months ended September 30, 2017, all of which were recognized prior to the 2017 third quarter. For the three months ended September 30, 2017, estimated future net cash flows were determined to be in excess of cost basis, therefore no impairment was recorded for the Company's proved crude oil and natural gas properties for that period. The 2017 year to date impairments reflected fair value adjustments primarily concentrated in the Arkoma Woodford field ($81.2 million, all in the second quarter of 2017) and various non-core areas in the North and South regions ($1.1 million). The impaired properties were written down to their estimated fair value at the time of impairment of approximately $72 million.

Certain unproved crude oil and natural gas properties were impaired during the three and nine months ended September 30, 2018 and 2017, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

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

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2018	2017	2018	2017
Proved property impairments	$—	$—	$—	$82,340
Unproved property impairments	23,770	35,130	86,715	127,479
Total	$23,770	$35,130	$86,715	$209,819

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Financial Instruments Not Recorded at Fair Value

The following table sets forth the estimated fair values of financial instruments that are not recorded at fair value in the condensed consolidated financial statements.

In thousands	September 30, 2018 Carrying Amount	September 30, 2018 Estimated Fair Value	December 31, 2017 Carrying Amount	December 31, 2017 Estimated Fair Value
Debt:				
Revolving credit facility	$190,000	$190,000	$188,000	$188,000
Note payable	8,275	8,200	9,974	9,900
5% Senior Notes due 2022	1,598,313	1,623,400	1,997,576	2,040,000
4.5% Senior Notes due 2023	1,488,378	1,526,100	1,486,690	1,526,800
3.8% Senior Notes due 2024	992,868	983,300	992,036	988,800
4.375% Senior Notes due 2028	988,358	992,900	988,061	987,200
4.9% Senior Notes due 2044	691,475	693,400	691,354	679,900
Total debt	$5,957,667	$6,017,300	$6,353,691	$6,420,600

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

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

The fair values of the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 (“2023 Notes”), the 3.8% Senior Notes due 2024 (“2024 Notes”), the 4.375% Senior Notes due 2028 (“2028 Notes”), and the 4.9% Senior Notes due 2044 (“2044 Notes”) are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

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

Note 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $40.6 million and $44.3 million at September 30, 2018 and December 31, 2017, respectively, consists of the following.

In thousands	September 30, 2018	December 31, 2017
Revolving credit facility	$ 190,000	$ 188,000
Note payable	8,275	9,974
5% Senior Notes due 2022	1,598,313	1,997,576
4.5% Senior Notes due 2023	1,488,378	1,486,690
3.8% Senior Notes due 2024	992,868	992,036
4.375% Senior Notes due 2028	988,358	988,061
4.9% Senior Notes due 2044	691,475	691,354
Total debt	$ 5,957,667	$ 6,353,691
Less: Current portion of long-term debt	2,341	2,286
Long-term debt, net of current portion	$ 5,955,326	$ 6,351,405

Revolving Credit Facility

On April 9, 2018, the Company entered into a new unsecured revolving credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. In connection with the execution of the new credit facility, the Company terminated its then-existing $2.75 billion credit facility that was due to mature in May 2019.

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Borrowings under the credit facility bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The weighted-average interest rate on the $190.0 million of outstanding credit facility borrowings at September 30, 2018 was 3.69%. Such borrowings were repaid in October 2018.

The Company had approximately $1.31 billion of borrowing availability on its credit facility at September 30, 2018 and incurs commitment fees based on currently assigned credit ratings of 0.20% per annum on the daily average amount of unused borrowing availability.

The Company's new credit facility retains substantially the same restrictive covenants as the previous credit facility, including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the credit facility covenants at September 30, 2018.

Senior Notes

The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company's outstanding senior note obligations at September 30, 2018.

	2022 Notes (1)	2023 Notes	2024 Notes	2028 Notes	2044 Notes
Face value (in thousands)	$1,600,000	$1,500,000	$1,000,000	$1,000,000	$700,000
Maturity date	Sep 15, 2022	April 15, 2023	June 1, 2024	January 15, 2028	June 1, 2044
Interest payment dates	March 15, Sep 15	April 15, Oct 15	June 1, Dec 1	Jan 15, July 15	June 1, Dec 1
Make-whole redemption period (2)	—	Jan 15, 2023	Mar 1, 2024	Oct 15, 2027	Dec 1, 2043

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

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

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

The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, or consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at September 30, 2018. Three of the Company's subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company's other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Partial redemption of senior notes

On August 16, 2018, the Company redeemed $400 million, or 20%, of its previously outstanding $2.0 billion of 5% Senior Notes due 2022. The redemption price was equal to 101.667% of the principal amount called for redemption plus accrued and unpaid interest to the redemption date in accordance with the terms of the 2022 Notes and the related indenture under which the 2022 Notes were issued.

The aggregate of the principal amount, redemption premium, and accrued interest paid upon redemption of the 2022 Notes was approximately $415.1 million. The Company recorded a pre-tax loss on extinguishment of debt related to the redemption of approximately $7.1 million, which included the redemption premium and pro-rata write-off of deferred financing costs and unamortized debt premium associated with the notes. The loss is reflected under the caption “Loss on extinguishment of debt” in the unaudited condensed consolidated statements of comprehensive income (loss).

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

Note Payable

In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.3 million is reflected as a current liability under the caption "Current portion of long-term debt" in the condensed consolidated balance sheets as of September 30, 2018.

Note 8. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of September 30, 2018. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of September 30, 2018, the Company has drilling rig contracts with various terms extending to February 2020 to ensure rig availability in its key operating areas. Future commitments as of September 30, 2018 total approximately $113 million, of which $35 million is expected to be incurred in the remainder of 2018, $77 million in 2019, and $1 million in 2020. Such amounts include short-term commitments as well as commitments with durations in excess of one year that will be recognized on the balance sheet upon adoption of ASU 2016-02 on January 1, 2019 as discussed in Note 2. Basis of Presentation and Significant Accounting Policies–New accounting pronouncements not yet adopted–Leases.

Transportation and processing commitments – The Company has entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. The commitments, which have varying terms extending as far as 2028, require the Company to pay per-unit transportation or processing charges regardless of the amount of capacity used. Future commitments remaining as of September 30, 2018 under the arrangements amount to approximately $1.3 billion, of which $59 million is expected to be incurred in the remainder of 2018, $223 million in 2019, $191 million in 2020, $173 million in 2021, $165 million in 2022, and $477 million thereafter. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition, as amended, alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and sought recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. The Company denied all allegations and denied that the case was properly brought as a class action. On June 11, 2015, the trial court certified a "hybrid" class requested by plaintiffs over the objections of the Company. The Company appealed the trial court's class certification order. On February 8, 2017, the Oklahoma Court of Civil Appeals reversed the trial court's ruling on certification and remanded the case for further proceedings. The plaintiffs filed a Petition for Rehearing which was denied by the Oklahoma Court of Civil Appeals. Plaintiffs then filed a Petition for Writ of Certiorari on May 23, 2017 to the Oklahoma Supreme Court, which was denied on October 2, 2017. On October 10, 2017, Plaintiffs filed with the trial court a "Second Amended and Renewed Motion for Class Action Certification and Request that the Court to Set a Briefing Schedule Related to Class Certification." During the litigation the Company was not able to estimate a reasonably possible loss or range of loss or what impact, if any, the ultimate resolution of the action would have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the existence and the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. The Company further disclosed that it was reasonably possible one or more events could occur in the near term that could impact the Company's ability to estimate the potential effect of this matter if any, on its financial condition, results of operations or cash flows. During the litigation the Company also disclosed plaintiffs alleged underpayments in excess of $200 million as damages, which may increase with the passage of time, a majority of which would be comprised of interest. After certification of the case as a class action was reversed the parties continued settlement negotiations. Due to the uncertainty of and burdens of litigation, on February 16, 2018, the Company reached a settlement in connection with this matter. Under the settlement, the Company initially expected to make payments and incur costs associated with the settlement of approximately $59.6 million. The Company accrued a loss for such amount at December 31, 2017, which was increased to $61.7 million at June 30, 2018 to reflect additional settlement obligations resulting from the passage of time. The accrued loss was subsequently reduced due to settlement payments made by the Company in the 2018 third quarter as described below. On April 3, 2018, the District Court of Garfield County, Oklahoma preliminarily approved the settlement and set certain dates applicable to the settlement including the timing and content of Notice, Opt-out, and Objections to Class

Members. The Fairness Hearing was held on June 11, 2018. On June 12, 2018, the court entered an order formally approving the settlement. The order approving the settlement is not subject to appeal. In the third quarter of 2018, the Company made payments totaling $45.8 million to satisfy the majority of its obligations under the settlement. The Company's remaining loss accrual for this matter totals $17.3 million at September 30, 2018, representing additional settlement obligations expected to be satisfied in 2019. The accrual for this matter is included in “Accrued liabilities and other” on the condensed consolidated balance sheets.

The Company is involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. In addition to the accrued loss on the matter described above, as of September 30, 2018 and December 31, 2017 the Company recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $4.5 million and $7.6 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 9. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2013 Long-Term Incentive Plan ("2013 Plan") as discussed below. The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the unaudited condensed consolidated statements of comprehensive income (loss), was $11.7 million and $11.9 million for the three months ended September 30, 2018 and 2017, respectively, and $33.2 million and $32.5 million for the nine months ended September 30, 2018 and 2017, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved 19,680,072 shares of common stock that may be issued pursuant to the plan. As of September 30, 2018, the Company had 13,763,015 shares of common stock available for long-term incentive awards to employees and directors under the 2013 Plan.

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

A summary of changes in non-vested restricted shares outstanding for the nine months ended September 30, 2018 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2017	4,026,110	$ 35.63
Granted	1,332,705	52.82
Vested	(1,077,356)	46.67
Forfeited	(258,532)	37.66
Non-vested restricted shares outstanding at September 30, 2018	4,022,927	$ 38.24

The grant date fair value of restricted stock represents the closing market price of the Company’s common stock on the date of grant. Compensation expense for a restricted stock grant is determined at the grant date fair value and is recognized over the vesting period as services are rendered by employees and directors. The Company estimates the number of forfeitures expected to occur in determining the amount of stock-based compensation expense to recognize. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value at the vesting date of restricted stock that vested during the nine months ended September 30, 2018 was approximately $59.1 million. As of September 30, 2018, there was approximately $82 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.3 years.

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

Note 10. Accumulated Other Comprehensive Income (Loss)

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in “Accumulated other comprehensive income (loss)” within shareholders’ equity in the condensed consolidated balance sheets and “Other comprehensive income, net of tax” in the unaudited condensed consolidated statements of comprehensive income (loss). The following table summarizes the change in accumulated other comprehensive income (loss) for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2018	2017	2018	2017
Beginning accumulated other comprehensive income (loss), net of tax	$325	$67	$307	$(260)
Foreign currency translation adjustments	105	202	123	529
Income taxes (1)	—	—	—	—
Other comprehensive income, net of tax	105	202	123	529
Ending accumulated other comprehensive income, net of tax	$430	$269	$430	$269

(1) A valuation allowance has been recognized against all deferred tax assets associated with losses generated by the Company's Canadian operations, thereby resulting in no income taxes on other comprehensive income.

Note 11. Income Taxes

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

The Company's (provision) for income taxes totaled ($97.5) million and ($6.8) million for the three months ended September 30, 2018 and 2017, respectively. The Company's (provision) benefit for income taxes totaled ($244.2) million and $25.1 million for the nine months ended September 30, 2018 and 2017, respectively. These amounts differ from the amounts computed by applying the United States statutory federal income tax rate to net income/loss before income taxes. The sources and tax effects of the differences are reflected in the table below:

	Three months ended September 30,				Nine months ended September 30,			
$ in thousands	2018	Tax rate %	2017	Tax rate %	2018	Tax rate %	2017	Tax rate %
Expected income tax (provision) benefit based on US statutory tax rate (1)	$(86,443)	21%	$(6,087)	35%	$(217,311)	21%	$27,136	35%
State income taxes, net of federal benefit	(12,349)	3 %	(522)	3 %	(31,044)	3 %	2,326	3 %
Tax benefit (deficiency) from stock-based compensation	235	—%	(134)	1 %	2,103	—%	(3,907)	(5 %)
Canadian valuation allowance (2)	(51)	—%	(68)	—%	(198)	—%	(325)	(1 %)
Other, net	1,142	—%	41	—%	2,216	—%	(167)	— %
(Provision) benefit for income taxes	$(97,466)	24%	$(6,770)	39%	$(244,234)	24%	$25,063	32%

(1) In December 2017 the Tax Cuts and Jobs Act was signed into law, which among other things reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

(2) Represents valuation allowances recognized against all deferred tax assets associated with operating loss carryforwards generated by the Company's Canadian operations during the respective periods for which the Company does not expect to realize a benefit.

Note 12. Subsequent Event

On August 6, 2018, the Company entered into a strategic relationship with Franco-Nevada Corporation, subject to certain closing conditions and final execution of transaction documents, to acquire oil and gas mineral interests in the SCOOP and STACK plays through a newly-formed subsidiary named The Mineral Resources Company II, LLC ("TMRC II"). Final transaction documents were subsequently executed and the transaction closed on October 23, 2018. At closing, the Company contributed most of its previously acquired mineral interests to TMRC II in exchange for a controlling interest in the entity. Additionally, Franco-Nevada paid approximately $215 million to the Company for a noncontrolling interest in TMRC II and for funding of its share of certain mineral acquisition costs.

In accordance with the transaction terms, the parties have committed, subject to satisfaction of agreed upon development thresholds, to spend up to a combined $125 million per year in 2019, 2020, and 2021 to acquire additional oil and gas mineral interests through TMRC II. Continental is to fund 20% of future mineral acquisitions and will be entitled to receive between 25% and 50% of total revenues generated by TMRC II based upon performance relative to certain predetermined targets.

Beginning in the fourth quarter of 2018, Continental expects to consolidate the financial results of TMRC II and present the portion of TMRC II's results attributable to Franco-Nevada as a noncontrolling interest. The Company does not expect to recognize a gain or loss on this transaction and the operating results of TMRC II are not expected to have a material impact on Continental's consolidated net income in the 2018 fourth quarter.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2017. Our operating results for the periods discussed below may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described in Part II, Item 1A. Risk Factors included in this report, if any, and in our Annual Report on Form 10-K for the year ended December 31, 2017, along with Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995 at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

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

Change in presentation of revenues

As discussed in Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues, we adopted new revenue recognition and presentation rules on January 1, 2018. The new rules did not have a material impact on the timing of our revenue recognition or our financial position, results of operations, net income, or cash flows for the three and nine months ended September 30, 2018, but did impact the presentation of our crude oil and natural gas revenues. We adopted the new rules using a modified retrospective transition approach whereby changes have been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation.

Under the new rules, revenues and transportation expenses associated with production from our operated properties are now reported on a gross basis compared to net presentation in the prior year. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice. As a result, beginning January 1, 2018 the gross presentation of revenues from our operated properties differs from the net presentation of revenues from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

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

The following table presents a reconciliation of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the three and nine months ended September 30, 2018. Information is also presented for the three and nine months ended September 30, 2017 for comparative purposes.

	Three months ended September 30, 2018			Three months ended September 30, 2017		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total

Crude oil and natural gas sales (GAAP)	$1,038,558	$234,680	$1,273,238	$550,451	$154,367	$704,818
Less: Transportation expenses	(39,336)	(6,672)	(46,008)	—	—	—
Net crude oil and natural gas sales (non-GAAP for 2018)	$999,222	$228,008	$1,227,230	$550,451	$154,367	$704,818
Sales volumes (MBbl/MMcf/MBoe)	15,190	73,029	27,361	12,722	56,401	22,123
Net sales price (non-GAAP for 2018)	$65.78	$3.12	$44.85	$43.27	$2.74	$31.86

In thousands	Nine months ended September 30, 2018 Crude oil	Natural gas	Total	Nine months ended September 30, 2017 Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$2,891,722	$632,896	$3,524,618	$1,512,990	$452,226	$1,965,216
Less: Transportation expenses	(119,939)	(22,620)	(142,559)	—	—	—
Net crude oil and natural gas sales (non-GAAP for 2018)	$2,771,783	$610,276	$3,382,059	$1,512,990	$452,226	$1,965,216
Sales volumes (MBbl/MMcf/MBoe)	44,183	209,069	79,028	34,975	162,515	62,061
Net sales price (non-GAAP for 2018)	$62.73	$2.92	$42.80	$43.26	$2.78	$31.67

Third Quarter 2018 Highlights

Production

Total production for the third quarter of 2018 averaged 296,904 Boe per day, up 5% compared to the second quarter of 2018 and 22% higher than the third quarter of 2017.

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

Boe production per day	3Q 2018	3Q 2017	% Change from 3Q 2017	2Q 2018	% Change from 2Q 2018
Bakken	167,643	136,851	23 %	158,119	6 %
SCOOP	63,270	57,283	10 %	64,786	(2 %)
STACK	56,129	35,619	58 %	51,722	9 %
All other	9,862	13,035	(24 %)	9,432	5 %
Total	296,904	242,788	22 %	284,059	5 %

Revenues

Net crude oil and natural gas sales totaled $1.2 billion for the 2018 third quarter, a 74% increase compared to the 2017 third quarter driven by a 52% increase in crude oil net sales prices, a 14% increase in natural gas net sales prices, and a 24% increase in total sales volumes.

Cash flows

Net cash inflows from operating activities totaled $861 million for the third quarter of 2018, exceeding third quarter net cash outflows from investing activities by $101 million.

Debt and liquidity

In August 2018, we redeemed $400 million, or 20%, of our previously outstanding $2.0 billion of 5% Senior Notes due 2022. The redemption price was equal to 101.667% of the principal amount called for redemption plus accrued and unpaid interest to the redemption date. The aggregate of the principal amount, redemption premium, and accrued interest paid upon redemption was $415.1 million. We recognized a $7.1 million pre-tax loss on extinguishment of debt in the 2018 third quarter related to the redemption.

We had $190 million of outstanding borrowings and $1.31 billion of borrowing availability on our credit facility at September 30, 2018. The outstanding borrowings were repaid in October 2018.

Capital expenditures and drilling activity

Non-acquisition capital expenditures totaled $790.8 million for the third quarter of 2018, bringing year to date 2018 non-acquisition capital expenditures to $2.10 billion compared to $1.50 billion for year to date 2017.

In the 2018 third quarter, production was initiated on 203 gross (55 net) operated and non-operated completed wells, bringing the 2018 year to date total to 520 gross (163 net) completed wells with first production compared to 395 gross (139 net) wells for the comparable 2017 period.

Financial and operating highlights

We use a variety of financial and operating measures to assess our performance. Among these measures are:

- Volumes of crude oil and natural gas produced;
- Crude oil and natural gas net sales price differentials relative to NYMEX benchmark prices; and
- Per unit operating and administrative costs.

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Average daily production:				
Crude oil (Bbl per day)	164,605	140,611	161,856	128,476
Natural gas (Mcf per day)	793,793	613,060	765,821	595,294
Crude oil equivalents (Boe per day)	296,904	242,788	289,492	227,692
Average net sales prices (1):				
Crude oil ($/Bbl)	$65.78	$43.27	$62.73	$43.26
Natural gas ($/Mcf)	$3.12	$2.74	$2.92	$2.78
Crude oil equivalents ($/Boe)	$44.85	$31.86	$42.80	$31.67
Crude oil net sales price discount to NYMEX ($/Bbl)	$(3.72)	$(4.98)	$(4.05)	$(6.07)
Natural gas net sales price premium (discount) to NYMEX ($/Mcf)	$0.22	$(0.26)	$0.03	$(0.37)
Production expenses ($/Boe)	$3.77	$3.82	$3.62	$3.86
Production taxes (% of net crude oil and natural gas sales)	8.0 %	7.3 %	7.8 %	6.8 %
Depreciation, depletion, amortization and accretion ($/Boe)	$17.15	$19.00	$17.35	$19.31
Total general and administrative expenses ($/Boe)	$1.61	$1.99	$1.70	$2.10

(1) See the previous section titled Change in presentation of revenues for a discussion and calculation of net sales prices, which are non-GAAP measures for the three and nine months ended September 30, 2018.

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Three months ended September 30, 2018 compared to the three months ended September 30, 2017

Results of Operations

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

In thousands	Three months ended September 30, 2018	2017
Crude oil and natural gas sales	$1,273,238	$704,818
Gain (loss) on natural gas derivatives, net	(2,025)	8,602
Crude oil and natural gas service operations	10,938	13,323
Total revenues	1,282,151	726,743
Operating costs and expenses	(790,843)	(634,990)
Other expenses, net	(79,673)	(74,362)
Income before income taxes	411,635	17,391
Provision for income taxes	(97,466)	(6,770)
Net income	$314,169	$10,621
Production volumes:		
Crude oil (MBbl)	15,144	12,936
Natural gas (MMcf)	73,029	56,401
Crude oil equivalents (MBoe)	27,315	22,337
Sales volumes:		
Crude oil (MBbl)	15,190	12,722
Natural gas (MMcf)	73,029	56,401
Crude oil equivalents (MBoe)	27,361	22,123

Production

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

	Three months ended September 30, 2018		2017		Volume increase	Volume percent increase
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	15,144	55 %	12,936	58 %	2,208	17 %
Natural gas (MMcf)	73,029	45 %	56,401	42 %	16,628	29 %
Total (MBoe)	27,315	100 %	22,337	100 %	4,978	22 %

	Three months ended September 30, 2018		2017		Volume increase	Volume percent increase
	MBoe	Percent	MBoe	Percent		
North Region	16,252	59 %	13,509	60 %	2,743	20 %
South Region	11,063	41 %	8,828	40 %	2,235	25 %
Total	27,315	100 %	22,337	100 %	4,978	22 %

The 17% increase in crude oil production for the 2018 third quarter was primarily driven by a 1,960 MBbls, or 21%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities and improved initial production results being achieved on new wells resulting from optimized completion technologies. Additionally, crude oil production from the SCOOP play increased 462 MBbls (up 33%) from the prior year third quarter due to additional wells being completed and producing as a result of an increase in our drilling and completion activities. These increases were partially offset by decreased crude oil production from our North region properties in Montana Bakken and the Red River units due to natural declines in production. Montana Bakken crude oil production decreased 54 MBbls, or 10%, while crude oil production in the Red River units decreased 46 MBbls, or 6%, from the prior year third quarter.

The 29% increase in natural gas production for the 2018 third quarter was driven by increased production from our properties in the STACK play due to additional wells being completed. Natural gas production in STACK increased 11,925 MMcf, or 79%, over the prior year third quarter. Additionally, natural gas production in North Dakota Bakken increased 5,585 MMcf, or 37%, in conjunction with the aforementioned increase in crude oil production over the prior year third quarter.

Increased drilling and completion activities in the SCOOP play contributed to a 532 MMcf, or 2%, increase in natural gas production. These increases were partially offset by reduced production from various other areas due to property dispositions and natural declines in production.

Revenues

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

Net crude oil and natural gas sales and related net sales prices presented below are non-GAAP measures for the three and nine months ended September 30, 2018. See the previous section titled Change in presentation of revenues for discussion and calculation of these measures.

Net crude oil and natural gas sales. Net crude oil and natural gas sales were $1,227.2 million for the third quarter of 2018, a 74% increase from sales of $704.8 million for the 2017 third quarter due to increases in net sales prices and sales volumes as described below.

Our crude oil net sales prices averaged $65.78 per barrel in the 2018 third quarter, an increase of 52% compared to $43.27 per barrel for the 2017 third quarter due to higher crude oil market prices and improved price realizations. The differential between NYMEX West Texas Intermediate ("WTI") calendar month prices and our realized crude oil net sales prices averaged $3.72 per barrel for the 2018 third quarter compared to $4.98 per barrel for the 2017 third quarter. The improved differential was due in part to the amendment of an existing third party transportation arrangement for North region production that resulted in lower per-barrel fees charged to the Company, effective January 1, 2018, along with growth in our South region crude oil production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma. Our crude oil differential to WTI is expected to widen in the 2018 fourth quarter relative to the 2018 third quarter during heavy seasonal refinery maintenance.

Our natural gas net sales prices averaged $3.12 per Mcf for the 2018 third quarter, an increase of 14% compared to $2.74 per Mcf for the 2017 third quarter. The difference between our realized natural gas net sales prices and NYMEX Henry Hub calendar month prices was a premium of $0.22 per Mcf for the 2018 third quarter compared to a discount of $0.26 per Mcf for the 2017 third quarter. We sell the majority of our operated natural gas production to midstream customers at lease locations under multi-year term contracts based on market prices in the field where the sales occur. The field markets are impacted by residue gas and natural gas liquids ("NGLs") prices at secondary, downstream markets. NGL prices have generally increased over prior year levels in conjunction with increased crude oil prices and other factors, resulting in significantly improved price realizations for our natural gas sales stream relative to benchmark prices compared to the prior year third quarter.

Total sales volumes for the third quarter of 2018 increased 5,238 MBoe, or 24%, compared to the 2017 third quarter, reflecting an increase in our pace of drilling and completion activities over the past year. For the third quarter of 2018, our crude oil sales volumes increased 19% from the comparable 2017 period, while our natural gas sales volumes increased 29%.

Derivatives. Changes in natural gas prices during the third quarter of 2018 had an unfavorable impact on the fair value of our natural gas derivatives, which resulted in negative revenue adjustments of $2.0 million for the period, representing $0.5 million of non-cash losses coupled with $1.5 million of cash losses.

Operating Costs and Expenses

Production Expenses. Production expenses increased $18.5 million, or 22%, from $84.5 million for the third quarter of 2017 to $103.0 million for the third quarter of 2018 primarily due to an increase in the number of producing wells and related 24% increase in sales volumes. Production expenses on a per-Boe basis decreased to $3.77 for the 2018 third quarter compared to $3.82 for the 2017 third quarter due to improved operating efficiencies and a decrease in workover-related activities.

Production Taxes. Production taxes increased $47.3 million, or 92%, to $98.6 million for the third quarter of 2018 compared to $51.3 million for the third quarter of 2017 primarily due to higher crude oil and natural gas sales. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of net crude oil and natural gas sales were 8.0% for the third quarter of 2018 compared to 7.3% for the third quarter of 2017. This increase was due in part to a significant increase in production and revenues generated in

North Dakota from increased well completion activities over the past year, which has higher production tax rates compared to Oklahoma. Additionally, in 2017 legislation was enacted in Oklahoma that increased the production tax rate from 4% to 7% (effective December 1, 2017) on wells that began producing between July 1, 2011 and July 1, 2015, which contributed to the increase in our average production tax rate for the third quarter of 2018. In March 2018, new legislation was enacted again in Oklahoma that increased the state's production tax rate, effective July 1, 2018, from 2% to 5% for the first 36 months of production for wells commencing production after July 1, 2015, which also contributed to the increase in our average production tax rate.

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods presented.

In thousands	Three months ended September 30, 2018	2017
Geological and geophysical costs	$2,324	$1,389
Exploratory dry hole costs	—	—
Exploration expenses	$2,324	$1,389

Depreciation, Depletion, Amortization and Accretion ("DD&A"). Total DD&A increased $49.1 million, or 12%, to $469.3 million for the third quarter of 2018 compared to $420.2 million for the third quarter of 2017 due to an increase in total sales volumes which was partially offset by the impact from an increase in the volume of proved developed reserves over which costs are depleted as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

$/Boe	Three months ended September 30, 2018	2017
Crude oil and natural gas	$16.91	$18.70
Other equipment	0.18	0.23
Asset retirement obligation accretion	0.06	0.07
Depreciation, depletion, amortization and accretion	$17.15	$19.00

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense increases. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense decreases. Upward revisions to proved developed reserves over the past year due in part to an improvement in commodity prices contributed to a decrease in our DD&A rate for crude oil and natural gas properties in the current period. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in an improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in the current period.

Property Impairments. There were no proved property impairments recognized in the third quarter periods of 2018 and 2017. Impairments of unproved properties decreased $11.3 million, or 32%, to $23.8 million for the 2018 third quarter compared to $35.1 million for the 2017 third quarter. This decrease was due to a lower balance of unamortized leasehold costs in the current period and a reduction over the past year in the Company's estimates of undeveloped properties not expected to be developed prior to lease expiration due to an increase in the allocation of capital to development drilling activities in 2017 and 2018.

General and Administrative ("G&A") Expenses. G&A expenses totaled $44.2 million for the third quarter of 2018, consistent with $44.0 million for the third quarter of 2017. Total G&A expenses include non-cash charges for equity compensation of $11.7 million and $11.9 million for the third quarters of 2018 and 2017, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $32.5 million for the 2018 third quarter, consistent with $32.1 million for the 2017 third quarter. We have incurred higher personnel-related costs in 2018 associated with the growth in our operations over the past year in response to improved crude oil prices; however, the increased costs have been mitigated by higher overhead recoveries from joint interest owners driven by increased drilling and completion activities.

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

Three months ended

	September 30,	
$/Boe	2018	2017
General and administrative expenses	$1.18	$1.45
Non-cash equity compensation	0.43	0.54
Total general and administrative expenses	$1.61	$1.99

The decrease in G&A expenses on a per-Boe basis was driven by a 24% increase in total sales volumes from new well completions with no comparable increase in G&A expenses.

Interest Expense. Interest expenses totaled $73.4 million for the third quarter of 2018, a decrease of 2% compared to $74.8 million for the third quarter of 2017. We incurred lower interest expenses in the 2018 period resulting from a decrease in total outstanding debt, the impact of which was nearly offset by higher expenses incurred due to increases in market interest rates on variable-rate credit facility borrowings over the past year. Our weighted average outstanding long-term debt balance for the 2018 third quarter was approximately $6.2 billion with a weighted average interest rate of 4.5% compared to averages of $6.7 billion and 4.1% for the 2017 third quarter. The 2018 third quarter included approximately $3 million of interest expense associated with the $400 million portion of our 2022 Notes that was redeemed on August 16, 2018.

Income Taxes. For the third quarters of 2018 and 2017 we provided for income taxes at a combined federal and state tax rate of 24% and 38%, respectively, of pre-tax income generated by our operations in the United States. We recorded an income tax provision for the third quarter of 2018 of $97.5 million compared to an income tax provision of $6.8 million for the third quarter of 2017, which resulted in effective tax rates of 24% and 39%, respectively, after taking into account statutory tax rates, permanent taxable differences, tax effects from stock-based compensation, valuation allowances, and other items. Our tax provision for the 2018 period reflects our application of the Tax Cuts and Jobs Act that was signed into law in December 2017, which among other things reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. See Notes to Unaudited Condensed Consolidated Financial Statements–Note 11. Income Taxes for a summary of the sources and tax effects of items comprising our effective tax rates for the third quarters of 2018 and 2017.

Nine months ended September 30, 2018 compared to the nine months ended September 30, 2017

Results of Operations

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

	Nine months ended September 30,	
In thousands	2018	2017
Crude oil and natural gas sales	$3,524,618	$1,965,216
Gain (loss) on crude oil and natural gas derivatives, net	(4,536)	83,482
Crude oil and natural gas service operations	40,210	24,959
Total revenues	3,560,292	2,073,657
Operating costs and expenses	(2,296,986)	(1,933,724)
Other expenses, net	(228,492)	(217,463)
Income (loss) before income taxes	1,034,814	(77,530)
(Provision) benefit for income taxes	(244,234)	25,063
Net income (loss)	$790,580	$(52,467)
Production volumes:		
Crude oil (MBbl)	44,187	35,074
Natural gas (MMcf)	209,069	162,515
Crude oil equivalents (MBoe)	79,031	62,160
Sales volumes:		
Crude oil (MBbl)	44,183	34,975
Natural gas (MMcf)	209,069	162,515
Crude oil equivalents (MBoe)	79,028	62,061

Production

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

	Nine months ended September 30,				Volume increase	Volume percent increase
	2018		2017			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	44,187	56 %	35,074	56 %	9,113	26 %
Natural gas (MMcf)	209,069	44 %	162,515	44 %	46,554	29 %
Total (MBoe)	79,031	100 %	62,160	100 %	16,871	27 %

	Nine months ended September 30,				Volume increase	Volume percent increase
	2018		2017			
	MBoe	Percent	MBoe	Percent		
North Region	46,829	59 %	36,106	58 %	10,723	30 %
South Region	32,202	41 %	26,054	42 %	6,148	24 %
Total	79,031	100 %	62,160	100 %	16,871	27 %

The 26% increase in crude oil production for year to date 2018 was primarily driven by a 8,475 MBbls, or 35%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities and improved initial production results being achieved on new wells resulting from optimized completion technologies. Additionally, crude oil production from the STACK and SCOOP plays increased 544 MBbls (up 29%) and 568 MBbls (up 13%), respectively, from the prior year period due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in those areas. These increases were partially offset by decreased crude oil production from our North region properties in Montana Bakken and the Red River units due to natural declines in production. Montana Bakken crude oil production decreased 235 MBbls, or 14%, while crude oil production in the Red River units decreased 218 MBbls, or 9%, from the prior year period.

The 29% increase in natural gas production for year to date 2018 was primarily driven by increased production from our properties in the STACK play due to additional wells being completed. Natural gas production in STACK increased 31,879 MMcf, or 77%, over the prior year period. Additionally, natural gas production in North Dakota Bakken increased 16,901 MMcf, or 42%, in conjunction with the aforementioned increase in crude oil production over the prior year. Increased drilling and completion activities in the SCOOP play contributed to a 1,816 MMcf, or 3%, increase in natural gas production compared to the prior year period. These increases were partially offset by reduced production from various other areas due to property dispositions and natural declines in production.

Revenues

Net crude oil and natural gas sales. Net crude oil and natural gas sales for year to date 2018 were $3.38 billion, a 72% increase from sales of $1.97 billion for the comparable 2017 period due to increases in net sales prices and sales volumes as described below.

Our crude oil net sales prices averaged $62.73 per barrel for year to date 2018, an increase of 45% compared to $43.26 per barrel for year to date 2017 due to higher crude oil market prices and improved price realizations. The differential between NYMEX WTI calendar month prices and our realized crude oil net sales prices averaged $4.05 per barrel for year to date 2018 compared to $6.07 per barrel for year to date 2017. The improved differential was due in part to the amendment of an existing third party transportation arrangement for North region production that resulted in lower per-barrel fees charged to the Company, effective January 1, 2018, along with growth in our South region crude oil production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma.

Our natural gas net sales prices averaged $2.92 per Mcf for year to date 2018, an increase of 5% compared to $2.78 per Mcf for year to date 2017. The difference between our realized natural gas net sales prices and NYMEX Henry Hub calendar month prices was a premium of $0.03 per Mcf for year to date 2018 compared to a discount of $0.37 per Mcf for year to date 2017. NGL prices have generally increased over prior year levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream relative to benchmark prices compared to the prior year.

Total sales volumes for year to date 2018 increased 16,967 MBoe, or 27%, compared to year to date 2017, reflecting an increase in our pace of drilling and completion activities over the past year. For year to date 2018, our crude oil sales volumes increased 26% from the comparable 2017 period, while our natural gas sales volumes increased 29%.
Derivatives. Changes in natural gas prices during the nine months ended September 30, 2018 had an unfavorable impact on the fair value of our natural gas derivatives, which resulted in negative revenue adjustments of $4.5 million for the period, representing $12.0 million of non-cash losses partially offset by $7.5 million of cash gains.
Crude oil and natural gas service operations. Revenues associated with our crude oil and natural gas service operations increased $15.2 million from $25.0 million for year to date 2017 to $40.2 million for year to date 2018 due to an increase in the magnitude of water handling and recycling activities compared to the prior period. The increased activities also resulted in higher service-related expenses compared to the prior period.
Operating Costs and Expenses
Production Expenses. Production expenses increased $46.4 million, or 19%, from $239.8 million for year to date 2017 to $286.2 million for year to date 2018 primarily due to an increase in the number of producing wells and related 27% increase in sales volumes. Production expenses on a per-Boe basis decreased to $3.62 for year to date 2018 compared to $3.86 for the comparable 2017 period due to improved operating efficiencies and a decrease in workover-related activities.
Production Taxes. Production taxes increased $128.2 million, or 95%, to $262.7 million for year to date 2018 compared to $134.5 million for year to date 2017 primarily due to higher crude oil and natural gas sales. Production taxes as a percentage of net crude oil and natural gas sales were 7.8% for year to date 2018 compared to 6.8% for year to date 2017. This increase resulted from a significant increase in production and revenues generated in North Dakota over the past year, which has higher production tax rates compared to Oklahoma, along with the aforementioned legislation enacted in Oklahoma in 2017 and 2018 that increased the production tax rate on certain producing wells.
Exploration Expenses. The following table shows the components of exploration expenses for the periods presented.

	Nine months ended September 30,	
In thousands	2018	2017
Geological and geophysical costs	$4,346	$9,434
Exploratory dry hole costs	1	157
Exploration expenses	$4,347	$9,591

The decrease in geological and geophysical expenses in the 2018 period was due to changes in the timing and amount of costs incurred by the Company and billed to joint interest owners between periods.
Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $172.7 million, or 14%, to $1.37 billion for year to date 2018 compared to $1.20 billion for the comparable period in 2017 due to an increase in total sales volumes which was partially offset by the impact from an increase in the volume of proved developed reserves over which costs are depleted. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Nine months ended September 30,	
$/Boe	2018	2017
Crude oil and natural gas	$17.10	$18.95
Other equipment	0.19	0.29
Asset retirement obligation accretion	0.06	0.07
Depreciation, depletion, amortization and accretion	$17.35	$19.31

Upward revisions to proved developed reserves over the past year due in part to an improvement in commodity prices contributed to a decrease in our DD&A rate for crude oil and natural gas properties in 2018 compared to 2017. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in an improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in the current period.

Property Impairments. Total property impairments decreased $123.1 million, or 59%, to $86.7 million for year to date 2018 compared to $209.8 million for year to date 2017. There were no proved property impairments recognized for year to date 2018 compared to $82.3 million for year to date 2017.

Impairments of unproved properties decreased $40.8 million, or 32%, to $86.7 million for year to date 2018 compared to $127.5 million for year to date 2017. This decrease was due to a lower balance of unamortized leasehold costs in the current period and a reduction over the past year in the Company's estimates of undeveloped properties not expected to be developed prior to lease expiration due to an increase in the allocation of capital to development drilling activities in 2017 and 2018.

General and Administrative Expenses. Total G&A expenses increased $4.0 million, or 3%, from $130.4 million for year to date 2017 to $134.4 million for year to date 2018. Total G&A expenses include non-cash charges for equity compensation of $33.2 million and $32.5 million for year to date 2018 and year to date 2017, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $101.2 million for year to date 2018, an increase of $3.3 million, or 3%, compared to $97.9 million for the comparable 2017 period. This increase resulted from growth in our operations and associated increase in personnel-related costs in response to the improvement in crude oil prices over the past year, nearly offset by higher overhead recoveries from joint interest owners driven by increased drilling and completion activities.

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

	Nine months ended September 30,	
$/Boe	2018	2017
General and administrative expenses	$1.28	$1.58
Non-cash equity compensation	0.42	0.52
Total general and administrative expenses	$1.70	$2.10

The decrease in G&A expenses on a per-Boe basis was driven by a 27% increase in total sales volumes from new well completions with no comparable increase in G&A expenses.

Interest Expense. Year to date interest expenses increased $4.9 million, or 2%, to $223.6 million compared to $218.7 million for the comparable 2017 period. We incurred higher interest expenses in the 2018 period primarily resulting from increases in market interest rates on variable-rate credit facility borrowings over the past year, the impact of which was partially offset by lower interest expenses resulting from a decrease in total outstanding debt in the current period. Our weighted average outstanding long-term debt balance for year to date 2018 was approximately $6.3 billion with a weighted average interest rate of 4.5% compared to averages of $6.7 billion and 4.2% for the comparable period in 2017. The year to date 2018 period includes approximately $13 million of interest expense associated with the $400 million portion of our 2022 Notes that were redeemed on August 16, 2018.

Income Taxes. For the nine months ended September 30, 2018 and 2017 we provided for income taxes at a combined federal and state tax rate of 24% and 38%, respectively, of pre-tax income (loss) generated by our operations in the United States. We recorded an income tax provision for the nine months ended September 30, 2018 of $244.2 million compared to an income tax benefit of $25.1 million for the nine months ended September 30, 2017, which resulted in effective tax rates of 24% and 32%, respectively, after taking into account statutory tax rates, permanent taxable differences, tax effects from stock-based compensation, valuation allowances, and other items. See Notes to Unaudited Condensed Consolidated Financial Statements–Note 11. Income Taxes for a summary of the sources and tax effects of items comprising our effective tax rates for the nine months ended September 30, 2018 and 2017.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt securities. Additionally, in recent years asset dispositions and joint development arrangements have provided a source of cash flow for use in reducing debt and enhancing liquidity. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from additional potential sales of non-strategic assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

Based on our planned capital spending, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our revolving credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of September 30, 2018, including those described in Note 8. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements, recognizing we may be required to meet such commitments even if our business plan assumptions were to change. We monitor our capital spending closely based on actual and projected cash flows and have the ability to reduce spending or dispose of assets to preserve liquidity and financial flexibility if needed to fund our operations.

Cash Flows

Cash flows provided by operating activities

Our net cash provided by operating activities totaled $2.50 billion and $1.35 billion for the nine months ended September 30, 2018 and 2017, respectively. The increase in operating cash flows was primarily due to an increase in crude oil and natural gas revenues driven by higher realized net sales prices and sales volumes in 2018, the effects of which were partially offset primarily by increases in production expenses and production taxes and the third quarter litigation settlement payment described in Notes to Unaudited Condensed Consolidated Financial Statements–Note 8. Commitments and Contingencies–Litigation.

Cash flows used in investing activities

During the nine months ended September 30, 2018 and 2017, we had cash flows used in investing activities of $2.10 billion and $1.37 billion, respectively. These totals include cash capital expenditures of $2.13 billion and $1.46 billion, respectively, inclusive of exploration and development drilling, property acquisitions, and dry hole costs. Property acquisitions totaled $77.1 million and $28.7 million for the nine months ended September 30, 2018 and 2017, respectively. The increase in capital spending was driven by an increase in our capital budget and related drilling and completion activities in 2018.

Cash flows from financing activities

Net cash used in financing activities for the nine months ended September 30, 2018 totaled $428.3 million, primarily resulting from cash used to fund our $400 million partial redemption of 2022 Notes in August 2018.

Net cash provided by financing activities for the nine months ended September 30, 2017 totaled $20.4 million, primarily resulting from $33 million of net borrowings on our credit facility during that period to fund operations.

Future Sources of Financing

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

Under the current commodity price environment, our planned capital expenditures for the next 12 months are expected to be funded entirely from operating cash flows. Additionally, we expect to generate significant cash flows in excess of operating and capital needs, which we plan to apply toward further reduction of debt in the future.

We currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our revolving credit facility if needed to fund our operations. We may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise. Further, we may sell additional assets or enter into strategic joint development opportunities in order to obtain funding for our operations and capital program if such transactions can be executed on satisfactory terms.

Revolving credit facility

On April 9, 2018, we entered into a new unsecured revolving credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. In connection with the execution of the new credit facility, we terminated our then-existing $2.75 billion credit facility that was due to mature in May 2019.

As of October 29, 2018 we had no outstanding borrowings and approximately $1.5 billion of borrowing availability on our credit facility.

The commitments under our credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating would not trigger a reduction in our current credit facility commitments, nor would such actions trigger a security requirement or change in covenants.

Our new credit facility retains substantially the same restrictive covenants as our previous credit facility, including covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets, and a financial covenant that requires us to maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014.

We were in compliance with our credit facility covenants at September 30, 2018 and expect to maintain compliance for at least the next 12 months. At September 30, 2018, our consolidated net debt to total capitalization ratio was 0.46 to 1.00. We do not believe the revolving credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing to a material extent if needed to support our business. At September 30, 2018, our total debt would have needed to independently increase by approximately $7.2 billion above the existing level at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $3.9 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at September 30, 2018 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Joint development agreement funding

In September 2014, we entered into an agreement with a U.S. subsidiary of SK E&S Co. Ltd ("SK") of South Korea to jointly develop a portion of the Company's STACK properties. Pursuant to the agreement, SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest in the STACK play until approximately $270 million has been expended by SK on our behalf. As of September 30, 2018, approximately $35 million of the carry had yet to be realized and is expected to be realized through mid-2019.

Strategic mineral relationship

See Note 12. Subsequent Event in Notes to Unaudited Condensed Consolidated Financial Statements for discussion of the capital requirements and future sources of financing associated with our newly formed strategic relationship with Franco-Nevada to acquire oil and gas mineral interests in the SCOOP and STACK plays.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $5.8 billion at September 30, 2018. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Note 7. Long-Term Debt in Notes to Unaudited Condensed Consolidated Financial Statements.

In August 2018, we redeemed $400 million of our $2.0 billion of 5% Senior Notes due 2022. Under the current commodity price environment we expect to generate significant cash flows in excess of operating and capital needs, which we plan to apply toward further redemptions of our 2022 Notes in 2019.

We were in compliance with our senior note covenants at September 30, 2018 and expect to maintain compliance for at least the next 12 months. We do not believe the senior note covenants will materially limit our ability to undertake additional debt financing. Downgrades or other negative rating actions with respect to the credit ratings assigned to our senior unsecured debt would not trigger additional senior note covenants.

Three of our subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Capital expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas. Acquisition expenditures are not budgeted.

Our capital expenditures budget for 2018 is $2.7 billion excluding acquisitions. For the nine months ended September 30, 2018, we invested $2.1 billion in our capital program excluding $77.1 million of unbudgeted acquisitions and including $45.3 million of capital costs associated with increased accruals for capital expenditures. Our 2018 year to date capital expenditures were allocated as follows.

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In millions	1Q 2018	2Q 2018	3Q 2018	YTD 2018
Exploration and development drilling	$496.3	$627.9	$633.5	$1,757.7
Land costs (1)	67.0	44.9	105.5	217.4
Capital facilities, workovers and other corporate assets	33.0	41.4	51.8	126.2
Seismic	—	—	—	—
Capital expenditures, excluding acquisitions	596.3	714.2	790.8	2,101.3
Acquisitions of producing properties	2.6	21.5	1.4	25.5
Acquisitions of non-producing properties (1)	28.0	21.6	2.0	51.6
Total acquisitions	30.6	43.1	3.4	77.1
Total capital expenditures	$626.9	$757.3	$794.2	$2,178.4

(1) These captions include costs incurred during the nine months ended September 30, 2018 to acquire minerals, most of which, along with minerals acquired prior to 2018, were contributed to our newly-formed minerals subsidiary in October 2018 as part of the transaction described in Note 12. Subsequent Event in Notes to Unaudited Condensed Consolidated Financial Statements.

Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, access to capital, available cash flows, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our capital spending plans should commodity prices decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at competitive terms.

Commitments and contingencies

Refer to Note 8. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements for discussion of certain future commitments and contingencies of the Company as of September 30, 2018. We believe our cash flows from operations, our remaining cash balance, and amounts available under our revolving credit facility will be sufficient to satisfy such commitments and contingencies.

Derivative Instruments

Between October 1, 2018 and October 29, 2018 we entered into additional natural gas derivative instruments as summarized below. The hedged volumes reflected below represent an aggregation of multiple contracts that are expected to be realized ratably over the indicated period. These derivative instruments will be settled based upon reported NYMEX Henry Hub settlement prices.

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
April 2019 - December 2019		
Swaps - Henry Hub	29,700,000	$ 2.76

Off-balance sheet arrangements

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

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates.

Revenues
On January 1, 2018 we adopted Accounting Standards Update 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), which impacted the presentation of our crude oil and natural gas revenues. For the sale of crude oil and natural gas, we evaluate whether we are the principal, and report revenues on a gross basis, or an agent, and report revenues on a net basis. In this assessment, we consider if we obtain control of the products before they are transferred to the customer as well as other indicators. Applying the control principle to transactions with customers requires significant judgment.
See Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues for discussion of the impact from adoption of ASU 2016-08. There have been no other changes in our application of critical accounting policies from those disclosed in our 2017 Form 10-K.
New Accounting Pronouncements
See Notes to Unaudited Condensed Consolidated Financial Statements–Note 2. Basis of Presentation and Significant Accounting Policies for a discussion of the new revenue recognition and presentation pronouncements adopted on January 1, 2018 along with a discussion of accounting pronouncements not yet adopted.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk
General. We are exposed to a variety of market risks including commodity price risk, credit risk, and interest rate risk. We seek to address these risks through a program of risk management which may include the use of derivative instruments.
Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the nine months ended September 30, 2018, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $591 million for each $10.00 per barrel change in crude oil prices at September 30, 2018 and $280 million for each $1.00 per Mcf change in natural gas prices at September 30, 2018.
To reduce price risk caused by market fluctuations in crude oil and natural gas prices, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds to be used for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. We have hedged a portion of our forecasted natural gas production through December 2019. Our future crude oil production is currently unhedged and directly exposed to volatility in market prices, whether favorable or unfavorable.
Changes in natural gas prices during the nine months ended September 30, 2018 had an overall unfavorable impact on the fair value of our derivative instruments. For the nine months ended September 30, 2018, we recognized cash gains on natural gas derivatives of $7.5 million while non-cash mark-to-market losses on natural gas derivatives totaled $12.0 million.
The fair value of our natural gas derivative instruments at September 30, 2018 was a net liability of $9.4 million. An assumed increase in the forward prices used in the September 30, 2018 valuation of our natural gas derivatives of $1.00 per MMBtu would increase our natural gas derivative liability to approximately $62 million at September 30, 2018. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would change our natural gas derivative valuation to a net asset of approximately $43 million at September 30, 2018. Changes in the fair value of

our natural gas derivatives from the above price sensitivities would produce a corresponding change in our total revenues.
Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($794 million in receivables at September 30, 2018); our joint interest and other receivables ($443 million at September 30, 2018); and counterparty credit risk associated with our derivative instrument receivables, if any.

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

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $44 million at September 30, 2018, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on a co-owner's interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty.

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

We had no outstanding borrowings on our revolving credit facility at October 29, 2018.

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

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded the Company's disclosure controls and procedures were effective as of September 30, 2018 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2018, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even an effective system of internal control will provide only reasonable assurance that the objectives of the internal control system are met.

PART II. Other Information

ITEM 1. Legal Proceedings

See Note 8. Commitments and Contingencies–Litigation in Part I, Item I. Financial Statements–Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of the legal matter involving the Company, Billy J. Strack and Daniela A. Renner, which is incorporated herein by reference.

We previously received Notices of Violation from the North Dakota Department of Health ("NDDH") alleging violations of the state's air quality and water pollution control laws and rules, which were identified in prior disclosures as potentially resulting in monetary penalties exceeding $100,000. After exchanging information and engaging in discussions with the NDDH, we resolved all such alleged violations by paying monetary penalties totaling $171,500 in the third quarter of 2018.

ITEM 1A. Risk Factors

In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our 2017 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q, if any, and in our 2017 Form 10-K are not the only risks facing our Company. 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 disclosed in our 2017 Form 10-K.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Recent Sales of Unregistered Securities – Not applicable.
(b) Use of Proceeds – Not applicable.
(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers – The following table provides information about purchases of shares of our common stock during the three months ended September 30, 2018:

Period	Total number of shares purchased (1)	Average price paid per share (2)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
July 1, 2018 to July 31, 2018	—	—	—	—
August 1, 2018 to August 31, 2018	11,142	$ 61.40	—	—
September 1, 2018 to September 30, 2018	—	—	—	—
Total	11,142	$ 61.40	—	—

(1) In connection with restricted stock grants under the Company's 2013 Long-Term Incentive Plan, we adopted a policy that enables employees to surrender shares to cover their tax liability. Shares indicated as having been purchased in the table above represent shares surrendered by employees to cover tax liabilities. We paid the associated taxes to the applicable taxing authorities.

(2) The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

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

3.1	Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company's Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
10.1*†	Description of cash bonus plan updated as of August 3, 2018.
10.2***†	Continental Resources, Inc. Deferred Compensation Plan.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
32**	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
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

*Filed herewith

**Furnished herewith

***Re-filed herewith pursuant to Item 10(d) of Regulation S-K.

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

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SIGNATURE

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 thereunto duly authorized.

CONTINENTAL RESOURCES, INC.

Date:	October 29, 2018	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer
			(Duly Authorized Officer and Principal Financial Officer)