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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2017

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 ☒ No ☐

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	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 ☒

375,208,904 shares of our $0.01 par value common stock were outstanding on October 31, 2017.

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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.

"DD&A" Depreciation, depletion, amortization and accretion.

"developed acreage" The number of acres allocated or assignable to productive wells or wells capable of production.

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

"dry hole" Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

"enhanced recovery" The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.

"exploratory well" A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

"field" An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"formation" A layer of rock which has distinct characteristics that differs from nearby rock.

"*gross acres*" or "*gross wells*" Refers to the total acres or wells in which a working interest is owned.

"horizontal drilling" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

"MBbl" One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe" One thousand Boe.

"Mcf" One thousand cubic feet of natural gas.

"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.

"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.

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

"prospect" A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

"proved reserves" The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.

"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," "strategy" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

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

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- future crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- competition;
- marketing of crude oil and natural gas;
- transportation of crude oil, natural gas liquids, and natural gas to markets;
- property exploitation, property acquisitions and dispositions, or joint development opportunities;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position;
- 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, 2016, 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, 2017 (Unaudited)	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 10,765	$ 16,643
Receivables:		
Crude oil and natural gas sales	471,533	404,750
Affiliated parties	56	99
Joint interest and other, net	451,977	364,850
Derivative assets	11,197	4,061
Inventories	105,210	111,987
Prepaid expenses and other	10,237	10,843
Total current assets	1,060,975	913,233
Net property and equipment, based on successful efforts method of accounting	12,919,202	12,881,227
Other noncurrent assets	14,910	17,316
Total assets	$ 13,995,087	$ 13,811,776
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$ 670,966	$ 476,342
Revenues and royalties payable	264,289	217,425
Payables to affiliated parties	146	148
Accrued liabilities and other	190,646	176,770
Derivative liabilities	1,144	59,489
Current portion of long-term debt	2,268	2,219
Total current liabilities	1,129,459	932,393
Long-term debt, net of current portion	6,612,281	6,577,697
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,860,094	1,890,305
Asset retirement obligations, net of current portion	101,673	94,436
Other noncurrent liabilities	14,801	14,949
Total other noncurrent liabilities	1,976,568	1,999,690
Commitments and contingencies (Note 7)		
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; 375,196,507 shares issued and outstanding at September 30, 2017; 374,492,357 shares issued and outstanding at December 31, 2016	3,752	3,745
Additional paid-in capital	1,396,854	1,375,290
Accumulated other comprehensive income (loss)	269	(260)
Retained earnings	2,875,904	2,923,221
Total shareholders' equity	4,276,779	4,301,996
Total liabilities and shareholders' equity	$ 13,995,087	$ 13,811,776

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

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	2017	2016	2017	2016
Revenues:				
Crude oil and natural gas sales	$ 704,818	$ 505,892	$ 1,965,216	$ 1,435,194
Gain (loss) on crude oil and natural gas derivatives, net	8,602	15,668	83,482	(24,477)
Crude oil and natural gas service operations	13,323	4,639	24,959	19,867
Total revenues	726,743	526,199	2,073,657	1,430,584
Operating costs and expenses:				
Production expenses	84,514	67,022	239,842	219,745
Production taxes	51,264	34,583	134,462	104,216
Exploration expenses	1,389	3,987	9,591	8,726
Crude oil and natural gas service operations	3,349	2,605	10,664	9,224
Depreciation, depletion, amortization and accretion	420,243	414,671	1,198,169	1,320,423
Property impairments	35,130	57,689	209,819	202,728
General and administrative expenses	44,006	44,389	130,413	113,043
Net (gain) loss on sale of assets and other	(4,905)	(5,564)	764	(104,690)
Total operating costs and expenses	634,990	619,382	1,933,724	1,873,415
Income (loss) from operations	91,753	(93,183)	139,933	(442,831)
Other income (expense):				
Interest expense	(74,756)	(82,074)	(218,672)	(244,949)
Other	394	360	1,209	1,178
	(74,362)	(81,714)	(217,463)	(243,771)
Income (loss) before income taxes	17,391	(174,897)	(77,530)	(686,602)
(Provision) benefit for income taxes	(6,770)	65,276	25,063	259,254
Net income (loss)	$ 10,621	$ (109,621)	$ (52,467)	$ (427,348)
Basic net income (loss) per share	$ 0.03	$ (0.30)	$ (0.14)	$ (1.15)
Diluted net income (loss) per share	$ 0.03	$ (0.30)	$ (0.14)	$ (1.15)
Comprehensive income (loss):				
Net income (loss)	$ 10,621	$ (109,621)	$ (52,467)	$ (427,348)
Other comprehensive income, net of tax:				
Foreign currency translation adjustments	202	418	529	869
Total other comprehensive income, net of tax	202	418	529	869
Comprehensive income (loss)	$ 10,823	$ (109,203)	$ (51,938)	$ (426,479)

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

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 (loss)	Retained earnings	Total shareholders' equity
Balance at December 31, 2016	374,492,357	$ 3,745	$ 1,375,290	$ (260)	$ 2,923,221	$ 4,301,996
Cumulative effect adjustment from adoption of ASU 2016-09 (unaudited) (see Note 2)	—	—	—	—	5,150	5,150
Net loss (unaudited)	—	—	—	—	(52,467)	(52,467)
Other comprehensive income, net of tax (unaudited)	—	—	—	529	—	529
Stock-based compensation (unaudited)	—	—	32,547	—	—	32,547
Restricted stock:						
Granted (unaudited)	1,518,824	15	—	—	—	15
Repurchased and canceled (unaudited)	(241,060)	(2)	(10,983)	—	—	(10,985)
Forfeited (unaudited)	(573,614)	(6)	—	—	—	(6)
Balance at September 30, 2017 (unaudited)	375,196,507	$ 3,752	$ 1,396,854	$ 269	$ 2,875,904	$ 4,276,779

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

Continental Resources, Inc. and Subsidiaries

Unaudited Condensed Consolidated Statements of Cash Flows

In thousands	Nine months ended September 30, 2017	2016
Cash flows from operating activities		
Net loss	$ (52,467)	$ (427,348)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	1,199,715	1,322,280
Property impairments	209,819	202,728
Non-cash (gain) loss on derivatives, net	(65,481)	105,009
Stock-based compensation	32,490	34,274
Benefit for deferred income taxes	(25,063)	(259,256)
Tax deficiency from stock-based compensation	—	9,460
Dry hole costs	157	233
Gain on sale of assets, net	(703)	(103,174)
Other, net	7,705	7,166
Changes in assets and liabilities:		
Accounts receivable	(154,790)	(2,634)
Inventories	6,736	1,257
Other current assets	729	390
Accounts payable trade	128,337	(43,131)
Revenues and royalties payable	48,447	(11,102)
Accrued liabilities and other	13,050	22,411
Other noncurrent assets and liabilities	(700)	5,325
Net cash provided by operating activities	1,347,981	863,888
Cash flows from investing activities		
Exploration and development	(1,444,991)	(878,928)
Purchase of producing crude oil and natural gas properties	(3,480)	(29)
Purchase of other property and equipment	(10,508)	(5,569)
Proceeds from sale of assets	84,725	334,305
Net cash used in investing activities	(1,374,254)	(550,221)
Cash flows from financing activities		
Credit facility borrowings	985,000	915,000
Repayment of credit facility	(952,000)	(1,203,000)
Repayment of other debt	(1,654)	(1,601)
Debt issuance costs	—	(40)
Repurchase of restricted stock for tax withholdings	(10,985)	(6,540)
Tax deficiency from stock-based compensation	—	(9,460)
Net cash provided by (used in) financing activities	20,361	(305,641)
Effect of exchange rate changes on cash	34	7
Net change in cash and cash equivalents	(5,878)	8,033
Cash and cash equivalents at beginning of period	16,643	11,463
Cash and cash equivalents at end of period	$ 10,765	$ 19,496

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

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 (South Central Oklahoma Oil Province) and STACK (Sooner Trend Anadarko Canadian Kingfisher) 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 approximately 58% of the Company’s crude oil and natural gas production and approximately 67% of its crude oil and natural gas revenues for the nine months ended September 30, 2017. 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 approximately 42% of the Company's crude oil and natural gas production and approximately 33% of its crude oil and natural gas revenues for the nine months ended September 30, 2017.

For the nine months ended September 30, 2017, crude oil accounted for approximately 56% of the Company’s total production and approximately 77% 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 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, 2016 (“2016 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, 2017 and for the three and nine month periods ended September 30, 2017 and 2016 are unaudited. The condensed consolidated balance sheet as of December 31, 2016 was derived from the audited balance sheet included in the 2016 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 and nine months ended September 30, 2017 and 2016.

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2017	2016	2017	2016
Net income (loss) (numerator)	$ 10,621	$ (109,621)	$ (52,467)	$ (427,348)
Weighted average shares (denominator):				
Weighted average shares - basic	371,142	370,483	371,029	370,327
Non-vested restricted stock (1)	1,873	—	—	—
Weighted average shares - diluted	373,015	370,483	371,029	370,327
Net income (loss) per share:				
Basic	$ 0.03	$ (0.30)	$ (0.14)	$ (1.15)
Diluted	$ 0.03	$ (0.30)	$ (0.14)	$ (1.15)

(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. The Company also had net losses for the three and nine months ended September 30, 2016, and therefore approximately 2,176,500 and 2,083,000 weighted average non-vested restricted shares, respectively, were not included in the calculation of diluted net loss per share for those periods.

Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines 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, 2017 and December 31, 2016 consisted of the following:

In thousands	September 30, 2017	December 31, 2016
Tubular goods and equipment	$ 16,709	$ 15,243
Crude oil	88,501	96,744
Total	$ 105,210	$ 111,987

Adoption of new accounting pronouncements

Stock-based compensation – In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*, which changes how companies account for certain aspects of share-based payment awards, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The Company adopted the new standard on January 1, 2017 as required. The impact of adoption is described below.

ASU 2016-09 removes the requirement to delay recognition of an excess tax benefit until it reduces current taxes payable. An excess tax benefit (tax deficiency) arises when stock-based compensation expense recognized in an entity’s tax return exceeds (is less than) the expense recognized in an entity’s financial statements. Under the new standard, effective January 1, 2017 excess tax benefits are recorded when they arise. This change was required to be applied on a modified retrospective basis by recording a cumulative effect adjustment to opening retained earnings upon adoption to account for previously unrecognized excess tax benefits. The Company's cumulative effect adjustment recorded under the new standard resulted in a $5.2 million increase in retained earnings and corresponding decrease in deferred income tax liabilities at January 1, 2017.

Additionally, under ASU 2016-09 companies no longer record excess tax benefits and deficiencies in additional paid-in capital. Instead, excess tax benefits and deficiencies are recognized as income tax benefit or expense in the income statement, effective January 1, 2017 on a prospective basis. This is expected to result in increased volatility in income tax expense/benefit and corresponding variations in the relationship between income tax expense/benefit and pre-tax income/loss from period to period. The Company recognized $0.1 million ($0.00 per share) and $3.9 million ($0.01 per share) of tax deficiencies from stock-based compensation as income tax expense for the three and nine months ended September 30, 2017, respectively, under the new standard, which are reflected in "(Provision) benefit for income taxes" in the unaudited condensed consolidated statements of comprehensive income (loss).

ASU 2016-09 also removed the requirement that entities present excess tax benefits and deficiencies as offsetting cash flows from financing and operating activities in the statement of cash flows. Instead, ASU 2016-09 requires cash flows related to excess tax benefits and deficiencies be classified as operating activities in the same manner as other cash flows related to income taxes. The Company has elected to apply this guidance on a prospective basis. Accordingly, the cash flow presentation of excess tax benefits and deficiencies in periods prior to January 1, 2017 has not been adjusted to conform to current period presentation.

The Company has elected to continue its historical accounting practice of estimating forfeitures in determining the amount of stock-based compensation expense to recognize. Therefore, the adoption of ASU 2016-09 does not have an impact on the amount of stock-based compensation expense to be recognized by the Company on non-vested restricted stock awards.

Business combinations – In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*, which changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business. Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. The new standard may result in more transactions being accounted for as asset acquisitions rather than business combinations. The standard is effective for interim and annual periods beginning after December 15, 2017 and shall be applied prospectively. The Company early adopted ASU 2017-01 as of January 1, 2017, which had no significant impact on the Company's financial statements as of and for the three and nine months ended September 30, 2017.

New accounting pronouncements not yet adopted

Revenue recognition and presentation – 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 in the transaction price, allocate the transaction price 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 various clarifications and interpretive guidance to assist entities with implementation efforts, including guidance pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. Under this guidance, an entity generally shall record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Significant judgment may be required in some circumstances to determine whether gross or net presentation is appropriate.

ASU 2014-09 and related interpretive guidance will be effective for interim and annual periods beginning after December 15, 2017 and allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company plans to adopt the standard on January 1, 2018 using the modified retrospective approach.

The Company is nearing completion of its evaluation of the impact of the new standard and related interpretive guidance on its financial statements, accounting policies, internal controls, and disclosures. Based on assessments performed to date, the standard is not expected to have a material effect on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows, but is expected to have an impact on the Company's revenue-related disclosures and internal controls over financial reporting. Additionally, the standard is expected to impact the presentation of future revenues and expenses under the gross-versus-net presentation guidance. Historically, the Company has generally presented its revenues net of transportation costs. The new guidance is expected to result in future revenues and associated transportation expenses for certain of the Company's operated properties being reported on a gross basis. The Company expects changes from net to gross presentation will result in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company's results of operations, net income, or cash flows. For the three and nine months ended September 30, 2017, the Company had approximately $50.3 million and $148.2 million, respectively, of transportation-related charges on operated properties included in "Crude oil and natural gas sales" on the unaudited condensed consolidated statements of comprehensive income (loss). These amounts are not necessarily indicative of amounts to be expected in future periods. The Company is not currently able to estimate the impact on the presentation of its future revenues and expenses under the new guidance due to uncertainties with respect to future sales volumes, service costs, locations of producing properties, sales destinations, transportation methods utilized, and changes in the nature, timing, and extent of its arrangements from period to period. Ongoing interpretive developments are being monitored which may impact the Company's financial statement presentation and disclosures.

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 and requires adoption by application of a modified retrospective transition approach.

The Company continues to evaluate the impact of ASU 2016-02 on its financial statements, accounting policies and internal controls and is in the process of developing systems and processes to identify, classify, and account for leases within the scope of the new guidance and to comply with the related disclosure requirements. Standard setting guidance and interpretations continue to evolve and are being monitored for applicability and impact to the Company's business and industry. Based on an initial review of the new guidance and the Company’s current commitments, the Company anticipates it may be required to recognize lease assets and liabilities related to drilling rig commitments, certain equipment rentals and leases, certain future surface use agreements, and potentially certain firm transportation agreements, as well as other arrangements, the effect of which cannot be estimated at this time.

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. 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	**2017**	**2016**
Supplemental cash flow information:		
Cash paid for interest	$ 198,405	$ 213,969
Cash paid for income taxes	2	—
Cash received for income tax refunds	148	174
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	5,111	1,645

As of September 30, 2017 and December 31, 2016, the Company had $289.9 million and $223.6 million, respectively, of accrued capital expenditures included in "Net property and equipment" and "Accounts payable trade" in the condensed consolidated balance sheets.

Note 4. Derivative Instruments

Crude oil and natural gas derivatives

The Company may utilize crude oil and natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of crude oil and 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 all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its crude oil and natural gas derivative instruments 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 crude oil and natural gas derivatives, net”.

The estimated fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars and written call options, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars and written call options requires the use of an option-pricing model. See *Note 5. Fair Value Measurements*.

With respect to a crude oil or 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 crude oil or 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.

At September 30, 2017, 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 2017 and 2018 periods. At September 30, 2017 the Company had no outstanding crude oil derivative contracts.

Natural Gas - NYMEX Henry Hub			Collars			
			Floors		Ceilings	
Period and Type of Contract	**MMBtus**	**Swaps Weighted Average Price**	**Range**	**Weighted Average Price**	**Range**	**Weighted Average Price**
October 2017 - December 2017						
Swaps - Henry Hub	33,120,000	$ 3.39				
Collars - Henry Hub	16,560,000		$2.40 - $3.00	$ 2.47	$2.92 - $3.88	$ 3.08
January 2018 - March 2018						
Swaps - Henry Hub	6,300,000	$ 3.28				

Crude oil and 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	**2017**	**2016**	**2017**	**2016**
Cash received (paid) on derivatives:				
Natural gas fixed price swaps	$ 12,893	$ 5,174	$ 25,080	$ 83,141
Natural gas collars	(612)	—	(10,068)	—
Cash received on derivatives, net	12,281	5,174	15,012	83,141
Non-cash gain (loss) on derivatives:				
Crude oil written call options	—	—	—	38
Natural gas fixed price swaps	(8,026)	5,298	27,390	(93,617)
Natural gas collars	4,347	5,196	41,080	(14,039)
Non-cash gain (loss) on derivatives, net	(3,679)	10,494	68,470	(107,618)
Gain (loss) on crude oil and natural gas derivatives, net	$ 8,602	$ 15,668	$ 83,482	$ (24,477)

Diesel fuel derivatives

The Company has entered into diesel fuel swap derivative contracts to economically hedge against the variability in cash flows associated with future purchases of diesel fuel for use in drilling activities. The Company has hedged approximately three million gallons of diesel fuel over the period from October 2017 to December 2017 at a weighted average price of $1.45

per gallon. With respect to these diesel fuel swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is greater 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 less than the swap price. The diesel fuel swap contracts are settled based upon reported NYMEX settlement prices for New York Harbor ultra-low sulfur diesel fuel.

The Company recognizes its diesel fuel derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value is based upon various factors, including commodity exchange prices, over-the-counter quotations, the risk-free interest rate, and time to expiration. The Company has not designated its diesel fuel derivative instruments as hedges for accounting purposes and, as a result, marks the 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 "Operating costs and expenses—Net (gain) loss on sale of assets and other."

Cash receipts in the following table reflect gains on diesel fuel derivatives 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 diesel fuel derivatives 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	2017	2016	2017	2016
Cash received on diesel fuel derivatives	$ 603	$ 100	$ 1,522	$ 100
Non-cash gain (loss) on diesel fuel derivatives	740	(531)	(2,989)	2,609
Gain (loss) on diesel fuel derivatives, net	$ 1,343	$ (431)	$ (1,467)	$ 2,709

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 crude oil, natural gas, and diesel fuel derivative assets and liabilities, 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, 2017	December 31, 2016
Commodity derivative assets:		
Gross amounts of recognized assets	$ 12,229	$ 4,061
Gross amounts offset on balance sheet	(1,032)	—
Net amounts of assets on balance sheet	11,197	4,061
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(2,176)	(59,489)
Gross amounts offset on balance sheet	1,032	—
Net amounts of liabilities on balance sheet	$ (1,144)	$ (59,489)

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, 2017	December 31, 2016
Derivative assets	$ 11,197	$ 4,061
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	11,197	4,061
Derivative liabilities	(1,144)	(59,489)
Noncurrent derivative liabilities	—	—
Net amounts of liabilities on balance sheet	(1,144)	(59,489)
Total derivative assets (liabilities), net	$ 10,053	$ (55,428)

Note 5. Fair Value Measurements

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company's derivative instruments 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, 2017 and December 31, 2016.

	Fair value measurements at September 30, 2017 using:			
In thousands	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets (liabilities):				
Swaps	$ —	$ 12,104	$ —	$ 12,104
Collars	—	(2,051)	—	(2,051)
Total	$ —	$ 10,053	$ —	$ 10,053

	Fair value measurements at December 31, 2016 using:			
In thousands	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative liabilities:				
Swaps	$ —	$ (12,297)	$ —	$ (12,297)
Collars	—	(43,131)	—	(43,131)
Total	$ —	$ (55,428)	$ —	$ (55,428)

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. 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 2021 (adjusted for differentials), escalating 3% per year thereafter
Operating costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 0 to 39 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 nine months ended September 30, 2017 and 2016, 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 amounted to $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 reflect fair value adjustments primarily concentrated in the Arkoma Woodford field ($81.2 million, all in the second quarter) 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.

Impairments of proved properties totaled $2.9 million for year to date 2016, all of which were recognized in the 2016 third quarter primarily for properties in a non-core area of the North region. The impaired properties were written down to their estimated fair value at the time of impairment of approximately $0.7 million.

Certain unproved crude oil and natural gas properties were impaired during the three and nine months ended September 30, 2017 and 2016, 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	2017	2016	2017	2016
Proved property impairments	$ —	$ 2,895	$ 82,340	$ 2,895
Unproved property impairments	35,130	54,794	127,479	199,833
Total	$ 35,130	$ 57,689	$ 209,819	$ 202,728

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.

	September 30, 2017		December 31, 2016	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Revolving credit facility	$ 938,000	$ 938,000	$ 905,000	$ 905,000
Term loan	499,329	500,000	498,865	500,000
Note payable	10,531	10,500	12,176	10,200
5% Senior Notes due 2022	1,997,476	2,030,700	1,997,188	2,020,400
4.5% Senior Notes due 2023	1,486,134	1,508,900	1,484,524	1,474,800
3.8% Senior Notes due 2024	991,764	968,400	990,964	929,400
4.9% Senior Notes due 2044	691,315	635,400	691,199	607,600
Total debt	$ 6,614,549	$ 6,591,900	$ 6,579,916	$ 6,447,400

The fair values of revolving credit facility borrowings and the term loan 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”), 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 6. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $34.0 million and $37.3 million at September 30, 2017 and December 31, 2016, respectively, consists of the following.

In thousands	September 30, 2017	December 31, 2016
Revolving credit facility	$ 938,000	$ 905,000
Term loan	499,329	498,865
Note payable	10,531	12,176
5% Senior Notes due 2022	1,997,476	1,997,188
4.5% Senior Notes due 2023	1,486,134	1,484,524
3.8% Senior Notes due 2024	991,764	990,964
4.9% Senior Notes due 2044	691,315	691,199
Total debt	$ 6,614,549	$ 6,579,916
Less: Current portion of long-term debt	2,268	2,219
Long-term debt, net of current portion	$ 6,612,281	$ 6,577,697

Revolving Credit Facility

The Company has an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.75 billion at September 30, 2017, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

Credit facility borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The weighted-average interest rate on outstanding credit facility borrowings at September 30, 2017 was 2.99%.

The Company had approximately $1.81 billion of borrowing availability on its revolving credit facility at September 30, 2017 and incurs commitment fees based on currently assigned credit ratings of 0.30% per annum on the daily average amount of unused borrowing availability under its revolving credit facility.

The revolving credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the revolving credit facility covenants at September 30, 2017.

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, 2017.

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

(1) The Company has the option to redeem all or a portion of its 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 these 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 these 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, 2017. 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.

Term Loan

In November 2015, the Company borrowed $500 million under a three-year term loan agreement, the proceeds of which were used to repay a portion of the borrowings then outstanding on the Company's revolving credit facility. The term loan matures in full on November 4, 2018 and bears interest at a variable market-based interest rate 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 interest rate on the term loan at September 30, 2017 was 2.76%.

The term loan contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00, consistent with the covenant requirement in the Company's revolving credit facility. The Company was in compliance with the term loan covenants at September 30, 2017.

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, 2017.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of September 30, 2017. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of September 30, 2017, 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, 2017 total approximately $117 million, of which $26 million is expected to be incurred in the remainder of 2017, $61 million in 2018, $29 million in 2019, and $1 million in 2020.

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, 2017 under the arrangements amount to approximately $1.2 billion, of which $57 million is expected to be incurred in the remainder of 2017, $249 million in 2018, $234 million in 2019, $101 million in 2020, $89 million in 2021, and $424 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 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 seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a "hybrid class action" in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate "issues" for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the "hybrid" motion was briefed by plaintiffs and the Company. A hearing on the "hybrid" class certification was held on June 1 and 2, 2015. On June 11, 2015, the trial court certified a "hybrid" class as requested by plaintiffs. 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." The case remains stayed and briefing on the Second Amended motion is not anticipated in the immediate future. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the ultimate resolution of the action will 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. It is reasonably possible one or more events may occur in the near term that could impact the Company's ability to estimate the potential effect this matter could have, if any, on its financial condition, results of operations or cash flows. Plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, which may increase with the passage of time, a majority of which would be comprised of interest. The Company disputes plaintiffs' claims, disputes the case meets the requirements for a class action and continues to vigorously defend the case. An unsuccessful mediation was conducted on December 7, 2015. The parties continue to negotiate a possible resolution to the case. However, it is unclear and unforeseeable whether the parties' efforts will result in settlement and the Company will continue to defend the case on all merits and certification issues and, absent settlement, intends to defend the case to a final judgment.

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. As of September 30, 2017 and December 31, 2016, the Company had recorded a liability in the condensed consolidated balance sheets under the caption "Other noncurrent liabilities" of $6.8 million and $6.5 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 8. Stock-Based Compensation

On January 1, 2017, the Company adopted ASU 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*. See *Note 2. Basis of Presentation and Significant Accounting Policies—Adoption of new accounting pronouncements* for a discussion of the impact of adoption.

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 $11.9 million and $13.2 million for the three months ended September 30, 2017 and 2016, respectively, and $32.5 million and $34.3 million for the nine months ended September 30, 2017 and 2016, 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, 2017, the Company had 14,561,802 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, 2017 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2016	3,913,634	$ 37.12
Granted	1,518,824	44.66
Vested	(816,408)	58.17
Forfeited	(573,614)	37.36
Non-vested restricted shares outstanding at September 30, 2017	4,042,436	$ 35.67

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, 2017 was approximately $37.2 million. As of September 30, 2017, there was approximately $68 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.4 years.

Note 9. 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, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2017	2016	2017	2016
Beginning accumulated other comprehensive income (loss), net of tax	$ 67	$ (2,903)	$ (260)	$ (3,354)
Foreign currency translation adjustments	202	418	529	869
Income taxes (1)	—	—	—	—
Other comprehensive income, net of tax	202	418	529	869
Ending accumulated other comprehensive income (loss), net of tax	$ 269	$ (2,485)	$ 269	$ (2,485)

(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 10. 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) benefit for income taxes totaled ($6.8) million and $25.1 million for the three and nine months ended September 30, 2017, respectively. The Company's benefit for income taxes totaled $65.3 million and $259.3 million for the three and nine months ended September 30, 2016, 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	2017	Tax rate %	2016	Tax rate %	2017	Tax rate %	2016	Tax rate %
Expected income tax (provision) benefit based on US statutory tax rate of 35%	$ (6,087)	35.0%	$ 61,214	35.0%	$ 27,136	35.0%	$ 240,311	35.0%
State income taxes, net of federal benefit	(522)	3.0%	5,247	3.0%	2,326	3.0%	20,598	3.0%
Tax deficiency from stock-based compensation (1)	(134)	0.8%	—	— %	(3,907)	(5.0%)	—	— %
Canadian valuation allowance (2)	(68)	0.4%	(665)	(0.4%)	(325)	(0.4%)	(959)	(0.1%)
Effect of differing statutory tax rate in Canada	(34)	0.1%	(313)	(0.2%)	(156)	(0.3%)	(437)	(0.1%)
Other, net	75	(0.4%)	(207)	(0.1%)	(11)	—%	(259)	— %
(Provision) benefit for income taxes	$ (6,770)	38.9%	$ 65,276	37.3%	$ 25,063	32.3%	$ 259,254	37.8%

(1) The Company recognized $0.1 million and $3.9 million of tax deficiencies from stock-based compensation as income tax expense for the three and nine months ended September 30, 2017, respectively, in accordance with ASU 2016-09 as discussed in *Note 2. Basis of Presentation and Significant Accounting Policies–Adoption of new accounting pronouncements*.

(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 11. Property Dispositions

2017

In September 2017 the Company sold non-strategic properties in the Arkoma Woodford area to a third party for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold in Atoka, Coal, Hughes, and Pittsburg Counties of Oklahoma and producing properties with production totaling approximately 1,700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax loss of $3.8 million. The disposed properties represented an immaterial portion of the Company's proved reserves.

In September 2017 the Company reached an agreement to sell non-core leasehold in the STACK play in Blaine County, Oklahoma to a third party for cash proceeds totaling $63.5 million. A portion of the transaction closed in September 2017, resulting in the receipt of proceeds amounting to $3.6 million and the recognition of a $3.3 million pre-tax gain on sale in the 2017 third quarter. The remainder of the transaction was completed in October 2017 at which time the Company received the remaining $59.9 million of proceeds. In connection with the completion of the transaction in October 2017, the Company expects to recognize an additional pre-tax gain of approximately $52 million, which will be reflected in fourth quarter 2017 results. The disposed properties represented an immaterial portion of the Company's production and proved reserves.

Additionally, in September 2017 the Company sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.5 million pre-tax gain associated with the transaction.

2016

In September 2016 the Company sold non-strategic properties in North Dakota and Montana to a third party for cash proceeds of $214.8 million, with no gain or loss recognized. The sale included approximately 68,000 net acres of leasehold primarily in western Williams County, North Dakota, and approximately 12,000 net acres of leasehold in Roosevelt County, Montana. The sale also included producing properties with production totaling approximately 2,700 barrels of oil equivalent per day. The disposed properties represented an immaterial portion of the Company's proved reserves.

In April 2016 the Company sold approximately 132,000 net acres of undeveloped leasehold acreage located in Wyoming to a third party for cash proceeds of $110.0 million. In connection with the transaction, the Company recognized a pre-tax gain of $96.9 million. The disposed properties had no production or proved reserves.

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, 2016. 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, 2016, 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.

Business Environment and Outlook

Commodity prices remain volatile and unpredictable due to domestic and global supply and demand factors. In light of the challenges facing our industry, our primary business strategies for 2017 focus on: (1) high-grading investments based on rates of return and opportunities to convert undeveloped acreage to acreage held by production, (2) improving cash flows through operating efficiencies, cost reductions, and optimized completions, (3) managing capital spending to minimize the incurrence of new incremental debt and maintain ample liquidity and financial flexibility, and (4) pursuing opportunities to further reduce debt using proceeds from potential sales of non-strategic assets.

2017 Highlights

Production

Crude oil and natural gas production for the third quarter of 2017 averaged 242,788 Boe per day, an increase of 7% from the second quarter of 2017 and 17% higher than the third quarter of 2016. Year to date production averaged 227,692 Boe per day, a 4% increase from the comparable 2016 period.

Average daily crude oil production increased 21% in the third quarter of 2017 compared to the third quarter of 2016, while average daily natural gas production increased 12%. Third quarter 2017 average daily crude oil production increased 12% compared to the second quarter of 2017 reflecting increased well completion activities in North Dakota Bakken, while average daily natural gas production increased 1%.

Crude oil represented 58% of our production for the 2017 third quarter compared to 55% for the 2017 second quarter and 56% for the 2016 third quarter.

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

Boe production per day	3Q 2017	2Q 2017	% Change from 2Q 2017	3Q 2016	% Change from 3Q 2016
Bakken	136,851	119,861	14%	107,929	27%
SCOOP	57,283	61,107	(6%)	67,462	(15%)
STACK	35,619	31,934	12%	17,680	101%
All other	13,035	13,311	(2%)	14,769	(12%)
Total	242,788	226,213	7%	207,840	17%

Revenues

Crude oil and natural gas revenues for the 2017 third quarter increased 39% compared to the 2016 third quarter driven by a 21% increase in realized commodity prices coupled with a 16% increase in total sales volumes.

Year to date crude oil and natural gas revenues increased 37% from the comparable 2016 period driven by a 32% increase in realized commodity prices coupled with a 3% increase in total sales volumes.

Average crude oil sales prices for the third quarter and year to date periods of 2017 increased 15% and 29%, respectively, from the comparable 2016 periods.

Crude oil sales volumes for the third quarter and year to date periods of 2017 increased 19% and decreased 3%, respectively, from the comparable 2016 periods.

Average natural gas sales prices for the third quarter and year to date periods of 2017 increased 36% and 77%, respectively, from the comparable 2016 periods.

Natural gas sales volumes for the third quarter and year to date periods of 2017 increased 12% and 13%, respectively, from the comparable 2016 periods.

Operating cash flows

Cash flows from operating activities totaled $431.4 million for the third quarter of 2017, 3% lower than operating cash flows of $446.4 million for the 2017 second quarter and 18% higher than 2016 third quarter operating cash flows of $366.2 million.

Capital expenditures and drilling activity

Non-acquisition capital expenditures totaled $520.6 million for the third quarter of 2017 bringing year to date 2017 non-acquisition capital expenditures to $1,499.5 million compared to $768.0 million for year to date 2016.

For the third quarter of 2017 we participated in the drilling and completion of 184 gross (80 net) wells, bringing our 2017 year to date total to 425 gross (163 net) wells compared to 256 gross (64 net) wells for year to date 2016.

Property dispositions

In September 2017 we sold non-strategic properties in the Arkoma Woodford area of Oklahoma to a third party for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold and producing properties with production totaling approximately 1,700 barrels of oil equivalent per day. In connection with the transaction, we recognized a pre-tax loss of $3.8 million.

In September 2017 we reached an agreement to sell non-core leasehold in the STACK play in Blaine County, Oklahoma to a third party for cash proceeds totaling $63.5 million. A portion of the transaction closed in September 2017, resulting in the receipt of proceeds amounting to $3.6 million and the recognition of a $3.3 million pre-tax gain on sale in the 2017 third quarter. The remainder of the transaction was completed in October 2017 at which time we received the remaining $59.9 million of proceeds. In connection with the completion of the transaction in October 2017, we expect to recognize an additional pre-tax gain of approximately $52 million, which will be reflected in fourth quarter 2017 results.

In September 2017 we sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.5 million pre-tax gain associated with the transaction.

Credit facility and liquidity

At September 30, 2017, we had $10.8 million of cash and cash equivalents and $1.81 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $938 million of outstanding borrowings on our credit facility at September 30, 2017 compared to $880 million at June 30, 2017 and $905 million at December 31, 2016. At October 31, 2017, outstanding credit facility borrowings totaled $895 million, leaving approximately $1.85 billion of borrowing availability at that date.

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 prices realized; and
- Per unit operating and administrative costs.

The following table contains financial and operating highlights for the periods presented. Average 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,	
	2017	2016	2017	2016
Average daily production:				
Crude oil (Bbl per day)	140,611	116,277	128,476	131,873
Natural gas (Mcf per day)	613,060	549,374	595,294	524,441
Crude oil equivalents (Boe per day)	242,788	207,840	227,692	219,280
Average sales prices:				
Crude oil ($/Bbl)	$ 43.27	$ 37.66	$ 43.26	$ 33.51
Natural gas ($/Mcf)	$ 2.74	$ 2.02	$ 2.78	$ 1.57
Crude oil equivalents ($/Boe)	$ 31.86	$ 26.42	$ 31.67	$ 23.91
Crude oil sales price discount to NYMEX ($/Bbl)	$ (4.98)	$ (7.27)	$ (6.07)	$ (7.44)
Natural gas sales price discount to NYMEX ($/Mcf)	$ (0.26)	$ (0.80)	$ (0.37)	$ (0.73)
Production expenses ($/Boe)	$ 3.82	$ 3.50	$ 3.86	$ 3.66
Production taxes (% of oil and gas revenues)	7.3%	6.8%	6.8%	7.3%
DD&A ($/Boe)	$ 19.00	$ 21.66	$ 19.31	$ 22.00
Total general and administrative expenses ($/Boe) (1)	$ 1.99	$ 2.32	$ 2.10	$ 1.88
Net income (loss) (in thousands)	$ 10,621	$ (109,621)	$ (52,467)	$ (427,348)
Diluted net income (loss) per share	$ 0.03	$ (0.30)	$ (0.14)	$ (1.15)

(1) Represents cash general and administrative expenses per Boe and non-cash equity compensation expenses per Boe. See *Operating Costs and Expenses —General and Administrative Expenses* below for additional discussion of these components.

Three months ended September 30, 2017 compared to the three months ended September 30, 2016

Results of Operations

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

In thousands, except sales price data	Three months ended September 30, 2017	2016
Crude oil and natural gas sales	$ 704,818	$ 505,892
Gain on crude oil and natural gas derivatives, net	8,602	15,668
Crude oil and natural gas service operations	13,323	4,639
Total revenues	726,743	526,199
Operating costs and expenses	(634,990)	(619,382)
Other expenses, net	(74,362)	(81,714)
Income (loss) before income taxes	17,391	(174,897)
(Provision) benefit for income taxes	(6,770)	65,276
Net income (loss)	$ 10,621	$ (109,621)
Production volumes:		
Crude oil (MBbl)	12,936	10,698
Natural gas (MMcf)	56,401	50,542
Crude oil equivalents (MBoe)	22,337	19,121
Sales volumes:		
Crude oil (MBbl)	12,722	10,724
Natural gas (MMcf)	56,401	50,542
Crude oil equivalents (MBoe)	22,123	19,148
Average sales prices:		
Crude oil ($/Bbl)	$ 43.27	$ 37.66
Natural gas ($/Mcf)	2.74	2.02
Crude oil equivalents ($/Boe)	31.86	26.42

Production

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

	Three months ended September 30, 2017		2016		Volume increase	Volume percent increase
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	12,936	58%	10,698	56%	2,238	21%
Natural gas (MMcf)	56,401	42%	50,542	44%	5,859	12%
Total (MBoe)	22,337	100%	19,121	100%	3,216	17%

	Three months ended September 30, 2017		2016		Volume increase	Volume percent increase
	MBoe	Percent	MBoe	Percent		
North Region	13,509	60%	11,003	58%	2,506	23%
South Region	8,828	40%	8,118	42%	710	9%
Total	22,337	100%	19,121	100%	3,216	17%

The 21% increase in crude oil production for the third quarter was driven by increased production from properties in North Dakota Bakken due to an increase in well completion activities and the timing of production commencing from new pad development projects, along with strong initial production results being achieved on new wells resulting from optimized completion technologies. Crude oil production in North Dakota Bakken increased 2,260 MBbls, or 32%, from the prior year third quarter. Additionally, production from our South region properties in the STACK play increased 393 MBbls, or 108%, 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 in that area. These increases were partially offset by decreased production from our North region properties in Montana Bakken and the Red River units due to natural declines in production coupled with reduced drilling activities over the past year in response to low crude oil prices. Montana Bakken production decreased 135 MBbls, or 20%, while crude oil production in the Red River units decreased 82 MBbls, or 9%, from the prior year third quarter. Additionally, crude oil production in SCOOP decreased 198 MBbls, or 12%, due to natural declines in production and reduced drilling activities.

The 12% increase in natural gas production for the third quarter was driven by increased production from our properties in the STACK play due to additional wells being completed and producing subsequent to September 30, 2016. Natural gas production in STACK increased 7,544 MMcf, or 100%, over the prior year third quarter. Additionally, natural gas production in North Dakota Bakken increased 3,180 MMcf, or 26%, in conjunction with the aforementioned increase in crude oil production over the prior year third quarter. These increases were partially offset by reduced production from our SCOOP properties, which decreased 4,431 MMcf, or 16%, along with various other areas in our North and South regions due to natural declines in production and reduced drilling activities over the past year.

In September 2017 we sold substantially all of our producing properties in the Arkoma Woodford area of Oklahoma. The sold properties comprised approximately 940 MMcf of our natural gas production for the three months ended September 30, 2017.

The increase in crude oil production as a percentage of our total production from 56% in the third quarter of 2016 to 58% in the third quarter of 2017 resulted from the significant increase in North Dakota Bakken production in recent months from increased well completion activities, which contributed to a 12% increase in our average daily crude oil production for the 2017 third quarter compared to the 2017 second quarter. Our properties in North Dakota Bakken typically produce a higher concentration of crude oil compared to our Oklahoma properties. Our crude oil production is expected to continue growing in relative significance for the remainder of 2017 based on our planned well completion activities in North Dakota Bakken in the 2017 fourth quarter.

Revenues

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

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the third quarter of 2017 were $704.8 million, a 39% increase from sales of $505.9 million for the 2016 third quarter due to increases in commodity prices and total sales volumes. If commodity prices remain at current levels, we expect our 2017 crude oil and natural gas revenues will continue to be higher than 2016 levels, the extent of which is uncertain due to the unpredictable nature of commodity prices.

Our crude oil sales prices averaged $43.27 per barrel in the 2017 third quarter, an increase of 15% compared to $37.66 per barrel for the 2016 third quarter due to higher crude oil market prices and improved price realizations. The differential between NYMEX West Texas Intermediate ("WTI") calendar month crude oil prices and our realized crude oil prices averaged $4.98 per barrel for the 2017 third quarter compared to $7.27 for the 2016 third quarter. The improved differential was primarily due to improved realizations resulting from new pipeline takeaway capacity and additional markets becoming available in 2017 for Bakken production, along with the growth in our South region 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 sales prices averaged $2.74 per Mcf for the 2017 third quarter, a 36% increase compared to $2.02 per Mcf for the 2016 third quarter due to higher market prices for natural gas and natural gas liquids ("NGLs") and improved price realizations. The discount between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices improved from $0.80 per Mcf for the 2016 third quarter to $0.26 per Mcf for the 2017 third quarter. The majority of our natural gas production is sold at our lease locations to midstream purchasers with price realizations impacted by the volume and value of NGLs that purchasers extract from our sales stream. NGL prices have 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 compared to the prior year third quarter.

Total sales volumes for the third quarter of 2017 increased 2,975 MBoe, or 16%, compared to the 2016 third quarter, reflecting an increase in our pace of drilling and completion activities in 2017. For the third quarter of 2017, our crude oil sales volumes increased 19% from the comparable 2016 period, while our natural gas sales volumes increased 12%.

At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes and caused crude oil sales volumes to be lower than crude oil production by 214 MBbls for the third quarter of 2017.

Derivatives. Changes in natural gas prices during the third quarter of 2017 had a favorable impact on the fair value of our natural gas derivatives, which resulted in positive revenue adjustments of $8.6 million for the period, representing $12.3

million of cash gains partially offset by $3.7 million of non-cash losses. Our revenues for the remainder of 2017 may continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in natural gas prices.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of lower quality reclaimed crude oil. Revenues associated with such activities increased $8.7 million from $4.6 million for the third quarter of 2016 to $13.3 million for the third quarter of 2017 due to an increase in industry production activities and changes in the nature, timing and extent of handling and treatment activities between periods.

Operating Costs and Expenses

Production Expenses. Production expenses increased $17.5 million, or 26%, from $67.0 million for the third quarter of 2016 to $84.5 million for the third quarter of 2017. Production expenses on a per-Boe basis increased to $3.82 for the 2017 third quarter compared to $3.50 for the 2016 third quarter. These increases resulted from an increase in the number of producing wells, an increase in workover-related activities aimed at enhancing production from producing properties, and a higher portion of our production coming from wells in North Dakota Bakken which typically have higher operating costs compared to wells in Oklahoma.

Production Taxes. Production taxes increased $16.7 million, or 48%, to $51.3 million for the third quarter of 2017 compared to $34.6 million for the third quarter of 2016 primarily due to higher crude oil and natural gas revenues resulting from increases in commodity prices and total sales volumes over the prior year period. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of crude oil and natural gas revenues were 7.3% for the third quarter of 2017 compared to 6.8% for the third quarter of 2016, the increase of which primarily resulted from a significant increase in production and revenues being generated in North Dakota in recent months which has higher production tax rates compared to Oklahoma. The production tax rate on new wells in North Dakota is currently 10% of crude oil revenues. The production tax rate on Oklahoma wells that commenced production after July 1, 2015 is currently 2% of crude oil and natural gas revenues for the first 36 months of production and 7% thereafter. Additionally, in May 2017 new legislation was enacted in Oklahoma that increased the production tax rate from 1% to 4% on wells that began producing between July 1, 2011 and July 1, 2015. The new 4% tax rate on these wells went into effect on July 1, 2017 and contributed to the increase in our average production tax rate for the third quarter of 2017.

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.

	Three months ended September 30,	
In thousands	**2017**	**2016**
Geological and geophysical costs	$ 1,389	$ 3,960
Exploratory dry hole costs	—	27
Exploration expenses	$ 1,389	$ 3,987

The decrease in geological and geophysical expenses in 2017 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 ("DD&A"). Total DD&A increased $5.5 million, or 1%, to $420.2 million for the third quarter of 2017 compared to $414.7 million for the third quarter of 2016 due to an increase in total sales volumes which was offset by the impact from an increase in the volume of proved 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.

	Three months ended September 30,	
$/Boe	**2017**	**2016**
Crude oil and natural gas	$ 18.70	$ 21.20
Other equipment	0.23	0.38
Asset retirement obligation accretion	0.07	0.08
Depreciation, depletion, amortization and accretion	$ 19.00	$ 21.66

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 reserves in

2017 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 third quarter of 2017 compared to the third quarter of 2016. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in a significant 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 $22.6 million, or 39%, to $35.1 million for the 2017 third quarter compared to $57.7 million for the 2016 third quarter primarily due to a decrease in non-producing property impairments.

Impairments of non-producing properties decreased $19.7 million, or 36%, to $35.1 million for the 2017 third quarter compared to $54.8 million for the 2016 third quarter. The decrease was due to a lower balance of unamortized leasehold costs in the current year due to property dispositions and reduced land capital expenditures in recent years, along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration.

There were no proved property impairments recognized in the 2017 third quarter compared to $2.9 million of such impairments for the third quarter of 2016.

General and Administrative ("G&A") Expenses. Total G&A expenses decreased $0.4 million, or 1%, from $44.4 million for the third quarter of 2016 to $44.0 million for the third quarter of 2017. Total G&A expenses include non-cash charges for equity compensation of $11.9 million and $13.2 million for the third quarters of 2017 and 2016, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $32.1 million for the 2017 third quarter, an increase of $0.9 million, or 3%, compared to $31.2 million for the 2016 third quarter. This increase resulted from an increase in employee compensation and benefits in 2017 in response to the stabilization and improvement in commodity prices in late 2016, partially offset by higher overhead recoveries from joint interest owners driven by increased completion activities over the prior period.

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	**2017**	**2016**
General and administrative expenses	$ 1.45	$ 1.63
Non-cash equity compensation	0.54	0.69
Total general and administrative expenses	$ 1.99	$ 2.32

The decrease in G&A expenses other than equity compensation on a per-Boe basis was driven by a 16% increase in total sales volumes from new well completions with no comparable increase in G&A expenses.

The decrease in equity compensation expense on a per-Boe basis resulted from changes in the timing and magnitude of forfeitures of unvested restricted stock between periods, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

Interest Expense. Interest expense decreased $7.3 million, or 9%, to $74.8 million for the third quarter of 2017 compared to $82.1 million for the third quarter of 2016 due to a decrease in outstanding debt primarily as a result of the November 2016 redemptions of our $200 million of 2020 Notes and $400 million of 2021 Notes. Our weighted average outstanding long-term debt balance for the 2017 third quarter was approximately $6.7 billion with a weighted average interest rate of 4.1%, compared to averages of $7.1 billion and 4.4% for the 2016 third quarter. The lower interest expense associated with reduced debt was partially offset by higher interest expense being incurred on our variable-rate credit facility and term loan borrowings due to an increase in market interest rates in 2017.

Income Taxes. We recorded income tax expense for the third quarter of 2017 of $6.8 million compared to an income tax benefit of $65.3 million for the third quarter of 2016, resulting in effective tax rates of approximately 39% and 37%, respectively, after taking into account permanent taxable differences, valuation allowances, and other items. For the third quarters of 2017 and 2016, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax income (loss) generated by our operations in the United States and 25% of pre-tax losses generated by our operations in Canada. See *Notes to Unaudited Condensed Consolidated Financial Statements–Note 10. Income Taxes* for a summary of the sources and tax effects of items comprising our effective tax rate for the third quarters of 2017 and 2016.

Nine months ended September 30, 2017 compared to the nine months ended September 30, 2016

Results of Operations

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

In thousands, except sales price data	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Crude oil and natural gas sales	$ 1,965,216	$ 1,435,194
Gain (loss) on crude oil and natural gas derivatives, net	83,482	(24,477)
Crude oil and natural gas service operations	24,959	19,867
Total revenues	2,073,657	1,430,584
Operating costs and expenses (1)	(1,933,724)	(1,873,415)
Other expenses, net	(217,463)	(243,771)
Loss before income taxes	(77,530)	(686,602)
Benefit for income taxes	25,063	259,254
Net loss	$ (52,467)	$ (427,348)
Production volumes:		
Crude oil (MBbl)	35,074	36,133
Natural gas (MMcf)	162,515	143,697
Crude oil equivalents (MBoe)	62,160	60,083
Sales volumes:		
Crude oil (MBbl)	34,975	36,080
Natural gas (MMcf)	162,515	143,697
Crude oil equivalents (MBoe)	62,061	60,029
Average sales prices:		
Crude oil ($/Bbl)	$ 43.26	$ 33.51
Natural gas ($/Mcf)	2.78	1.57
Crude oil equivalents ($/Boe)	31.67	23.91

(1) Net of gain on sale of assets of $103.2 million for the nine months ended September 30, 2016.

Production

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

	Nine months ended September 30,				Volume increase (decrease)	Volume percent increase (decrease)
	2017		2016			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	35,074	56%	36,133	60%	(1,059)	(3%)
Natural gas (MMcf)	162,515	44%	143,697	40%	18,818	13%
Total (MBoe)	62,160	100%	60,083	100%	2,077	3%

	Nine months ended September 30,				Volume increase (decrease)	Volume percent increase (decrease)
	2017		2016			
	MBoe	Percent	MBoe	Percent		
North Region	36,106	58%	37,243	62%	(1,137)	(3%)
South Region	26,054	42%	22,840	38%	3,214	14%
Total	62,160	100%	60,083	100%	2,077	3%

The 3% decrease in crude oil production for year to date 2017 was driven primarily by decreased production from our North region properties in North Dakota Bakken, Montana Bakken and the Red River units due to natural declines in production coupled with delayed completion activities in response to low crude oil prices. North Dakota Bakken crude oil production decreased 324 MBbls, or 1%, and Montana Bakken production decreased 567 MBbls, or 25%, while production in the Red River units decreased 293 MBbls, or 10%, from the prior year period. The decreased crude oil production in North Dakota Bakken was mitigated by new well production generated in recent months from increased well completion activities in

2017, which resulted in a 19% sequential increase in crude oil production in that play for the 2017 third quarter compared to the 2017 second quarter. Additionally, crude oil production in SCOOP decreased 824 MBbls, or 16%, due to natural declines in production and reduced drilling activities. These decreases were partially offset by an increase of 972 MBbls, or 105%, in crude oil production from our STACK properties due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in that area.

The 13% increase in natural gas production for year to date 2017 was primarily driven by increased production from our properties in the STACK play due to additional wells being completed and producing subsequent to September 30, 2016. Natural gas production in STACK increased 23,231 MMcf, or 127%, over the prior year period. Additionally, natural gas production in North Dakota Bakken increased 1,528 MMcf, or 4%, over the prior year period in conjunction with higher crude oil production in recent months arising from increased well completion activities. These increases were partially offset by reduced production from our SCOOP properties, which decreased 4,327 MMcf, or 6%, along with various other areas in our North and South regions due to natural declines in production and reduced drilling activities over the past year.

In September 2017 we sold substantially all of our producing properties in the Arkoma Woodford area of Oklahoma. The sold properties comprised approximately 2,850 MMcf of our natural gas production for the nine months ended September 30, 2017.

In conjunction with our increase in capital spending in 2017 relative to 2016, we expect our production will average between 238,000 and 242,000 Boe per day for the full year of 2017 compared to average daily production of 216,912 Boe per day for 2016.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for year to date 2017 were $1.97 billion, a 37% increase from sales of $1.44 billion for the same period in 2016 due to a 32% increase in realized commodity prices coupled with a 3% increase in total sales volumes.

Our crude oil sales prices averaged $43.26 per barrel for year to date 2017, an increase of 29% compared to $33.51 for year to date 2016 due to higher crude oil market prices and improved price realizations. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for year to date 2017 was $6.07 per barrel compared to $7.44 for year to date 2016. The improved differential was primarily due to improved realizations resulting from new pipeline takeaway capacity and additional markets becoming available in 2017 for Bakken production, along with the growth in our South region 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 sales prices averaged $2.78 per Mcf for year to date 2017, a 77% increase compared to $1.57 for year to date 2016 due to higher market prices for natural gas and NGLs and improved price realizations. The discount between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices improved from $0.73 per Mcf for year to date 2016 to $0.37 per Mcf for year to date 2017. The majority of our natural gas production is sold at our lease locations to midstream purchasers with price realizations impacted by the volume and value of NGLs that purchasers extract from our sales stream. NGL prices have 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 compared to the prior year.

Total sales volumes for year to date 2017 increased 2,032 MBoe, or 3%, compared to year to date 2016. For year to date 2017, our crude oil sales volumes decreased 3% from the comparable 2016 period, while our natural gas sales volumes increased 13%, reflecting an increase over the past year in the proportion of capital spending allocated to areas in Oklahoma which typically have higher concentrations of natural gas compared to oil-weighted properties in North Dakota Bakken.

Derivatives. Changes in natural gas prices during the nine months ended September 30, 2017 had a favorable impact on the fair value of our natural gas derivatives, which resulted in positive revenue adjustments of $83.5 million for the period, representing $68.5 million of non-cash gains and $15.0 million of cash gains.

Operating Costs and Expenses

Production Expenses. Production expenses increased $20.1 million, or 9%, from $219.7 million for year to date 2016 to $239.8 million for year to date 2017. Production expenses on a per-Boe basis increased to $3.86 for year to date 2017 compared to $3.66 for the comparable 2016 period. These increases resulted from an increase in the number of producing wells, higher costs incurred in the 2017 first quarter from severe weather conditions encountered in the North region that created a challenging operating environment, and an increase in workover-related activities aimed at enhancing production from producing properties.

Production Taxes. Production taxes increased $30.3 million, or 29%, to $134.5 million for year to date 2017 compared to $104.2 million for year to date 2016 due to higher crude oil and natural gas revenues resulting primarily from increases in commodity prices over the prior year period.

Production taxes as a percentage of crude oil and natural gas revenues were 6.8% for year to date 2017 compared to 7.3% for year to date 2016, the decrease of which resulted from significant growth over the past year in our STACK operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to North Dakota. The decrease in our year-to-date average production tax rate was partially offset by higher production taxes arising in the 2017 third quarter as a result of increased production and revenues being generated in North Dakota in recent months from increased well completion activities, along with the enactment of new legislation in Oklahoma that increased the production tax rate, effective July 1, 2017, from 1% to 4% on wells that began producing between July 1, 2011 and July 1, 2015. These factors contributed to a sequential increase in our average production tax rate from 6.7% in the 2017 second quarter to 7.3% in the 2017 third quarter.

Exploration Expenses. The following table shows the components of exploration expenses for the periods presented.

	Nine months ended September 30,	
In thousands	**2017**	**2016**
Geological and geophysical costs	$ 9,434	$ 8,493
Exploratory dry hole costs	157	233
Exploration expenses	$ 9,591	$ 8,726

Depreciation, Depletion, Amortization and Accretion. Total DD&A decreased $122.3 million, or 9%, to $1.20 billion for year to date 2017 compared to $1.32 billion for the comparable period in 2016 primarily due to an increase in the volume of proved reserves over which costs are depleted as further discussed below, the impact of which was partially offset by an increase in DD&A resulting from higher total sales volumes in the current year. 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	**2017**	**2016**
Crude oil and natural gas	$ 18.95	$ 21.55
Other equipment	0.29	0.37
Asset retirement obligation accretion	0.07	0.08
Depreciation, depletion, amortization and accretion	$ 19.31	$ 22.00

Upward revisions to proved 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 2017 compared to 2016. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in a significant 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 increased $7.1 million, or 3%, to $209.8 million for year to date 2017 compared to $202.7 million for year to date 2016 primarily due to an increase in proved property impairments partially offset by lower non-producing property impairments as discussed below.

Proved property impairments totaled $82.3 million for year to date 2017 compared to $2.9 million for year to date 2016. The proved property impairments recognized for year to date 2017, nearly all of which were recognized in the second quarter, were primarily concentrated in the Arkoma Woodford field for which we determined the carrying amount of the field was not recoverable from future cash flows, and therefore, was impaired at June 30, 2017. There were no proved property impairments recognized in the 2017 third quarter.

Impairments of non-producing properties decreased $72.3 million, or 36%, to $127.5 million for year to date 2017 compared to $199.8 million for year to date 2016. The decrease was due to a lower balance of unamortized leasehold costs in the current year due to property dispositions and reduced land capital expenditures in recent years, along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration.

General and Administrative Expenses. Total G&A expenses increased $17.4 million, or 15%, from $113.0 million for year to date 2016 to $130.4 million for year to date 2017. Total G&A expenses include non-cash charges for equity compensation of $32.5 million and $34.3 million for year to date 2017 and year to date 2016, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $97.9 million for year to date 2017, an increase of $19.2 million, or 24%, compared to $78.7 million for the comparable 2016 period.

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	2017	2016
General and administrative expenses	$ 1.58	$ 1.31
Non-cash equity compensation	0.52	0.57
Total general and administrative expenses	$ 2.10	$ 1.88

The increase in G&A expenses other than equity compensation was primarily due to an increase in employee compensation and benefits in 2017 in response to the stabilization and improvement in commodity prices in late 2016, partially offset by higher overhead recoveries from joint interest owners driven by increased completion activities over the prior period.

Interest Expense. Year to date interest expense decreased $26.2 million, or 11%, to $218.7 million compared to $244.9 million for the comparable 2016 period due to a decrease in outstanding debt primarily as a result of the November 2016 redemptions of our $200 million of 2020 Notes and $400 million of 2021 Notes. Our weighted average outstanding long-term debt balance for year to date 2017 was approximately $6.7 billion with a weighted average interest rate of 4.2% compared to averages of $7.2 billion and 4.3% for the comparable period in 2016. The lower interest expense associated with reduced debt was partially offset by higher interest expense being incurred on our variable-rate credit facility and term loan borrowings due to an increase in market interest rates in 2017.

Income Taxes. We recorded an income tax benefit for the nine months ended September 30, 2017 of $25.1 million compared to a benefit of $259.3 million for the prior year period, resulting in effective tax rates of approximately 32% and 38%, respectively, after taking into account permanent taxable differences, valuation allowances, and other items. See *Notes to Unaudited Condensed Consolidated Financial Statements–Note 10. Income Taxes* for a summary of the sources and tax effects of items comprising our effective tax rate for the 2017 and 2016 periods.

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 and equity securities. Additionally, non-strategic asset dispositions have provided a significant source of cash flow for use in reducing debt and enhancing liquidity. We intend to continue pursuing opportunities to reduce our long-term debt using 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.

At September 30, 2017, we had $10.8 million of cash and cash equivalents and approximately $1.81 billion of borrowing availability on our revolving credit facility after considering outstanding borrowings of $938 million and letters of credit. At October 31, 2017, outstanding borrowings decreased to $895 million, leaving approximately $1.85 billion of borrowing availability on our credit facility at that date. We expect to maintain a disciplined spending approach and plan to manage the level of our capital spending in order to minimize new incremental borrowings and maintain ample liquidity.

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, three-year term loan, 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, 2017, including those described in *Note 7. 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 from operating activities

Our net cash provided by operating activities totaled $1,348.0 million and $863.9 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in operating cash flows was primarily due to an increase in crude oil and natural gas revenues driven by higher realized commodity prices and total sales volumes in 2017 coupled with lower interest expenses, the effects of which were partially offset by increases in production expenses, production taxes, and general and administrative expenses and a decrease in cash gains on matured natural gas derivatives.

Cash flows used in investing activities

During the nine months ended September 30, 2017 and 2016, we had cash flows used in investing activities of $1,374.3 million and $550.2 million, respectively. These totals include capital spending of $1,459.0 million and $884.5 million, respectively, inclusive of exploration and development drilling, property acquisitions, and dry hole costs. Property acquisitions totaled $28.7 million and $22.6 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in capital spending was driven by an increase in our capital budget and related drilling and completion activities for 2017. We expect our capital spending for the remainder of 2017 will continue to be higher than 2016 levels.

The use of cash for capital expenditures in 2017 and 2016 was partially offset by proceeds received from asset dispositions, which totaled $84.7 million and $334.3 million for the nine months ended September 30, 2017 and 2016, respectively. See *Note 11. Property Dispositions* in *Notes to Unaudited Condensed Consolidated Financial Statements* for further discussion of notable dispositions, including a discussion of sales proceeds totaling $59.9 million received by the Company subsequent to September 30, 2017 in conjunction with the consummation of a property disposition in October 2017, which will be reflected in 2017 fourth quarter cash flows from investing activities.

Cash flows from financing activities

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 revolving credit facility during the period to fund operations.

Net cash used in financing activities for the nine months ended September 30, 2016 totaled $305.6 million primarily resulting from net repayments of $288 million on our revolving credit facility during the period. The net repayments resulted from the reduction of credit facility debt using proceeds totaling $334.3 million from 2016 asset dispositions completed through September 30, 2016, partially offset by borrowings incurred to fund operations.

We plan to manage our level of capital spending for the remainder of 2017 in order to minimize the incurrence of new incremental debt.

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.

Our planned capital spending has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility or proceeds from asset sales.

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.

We currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to fund future capital expenditures primarily through cash flows from operations and through borrowings under our revolving credit facility, but we may also issue debt or equity securities, sell additional assets, or enter into joint development arrangements. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Revolving credit facility

We have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.75 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. The commitments are from a syndicate of 17 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment.

As of October 31, 2017, we had approximately $1.85 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Credit facility borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness.

The commitments under our revolving 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. The weighted-average interest rate on our credit facility borrowings was 2.99% at September 30, 2017 and we incur commitment fees of 0.30% per annum on the daily average amount of unused borrowing availability.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. 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 revolving credit facility covenants at September 30, 2017 and expect to maintain compliance for at least the next 12 months. At September 30, 2017, our consolidated net debt to total capitalization ratio, as defined in our revolving credit facility as amended, was 0.56 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, 2017, our total debt would have needed to independently increase by approximately $2.9 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 $1.6 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at September 30, 2017 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 targeting the Woodford formation in the STACK play until approximately $270 million has been expended by SK on our behalf. As of September 30, 2017, approximately $112 million of the carry had yet to be realized and is expected to be realized through mid-2019.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $5.2 billion at September 30, 2017. We have no near-term senior note maturities, with our earliest scheduled senior note maturity being our $2.0 billion of 2022 Notes due in September 2022. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to *Note 6. Long-Term Debt* in *Notes to Unaudited Condensed Consolidated Financial Statements*.

We were in compliance with our senior note covenants at September 30, 2017 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 as of September 30, 2017.

Term loan

We have a $500 million unsecured term loan that matures in full in November 2018 and bears interest at variable 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. Downgrades or other negative rating actions with respect to our credit rating would not trigger a security requirement or change in covenants for the term loan. The interest rate on the term loan was 2.76% at September 30, 2017.

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 2017 is $1.95 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$ 1,720
Land costs	115
Capital facilities, workovers and other corporate assets	105
Seismic	10
Total 2017 capital budget, excluding acquisitions	$ 1,950

For the nine months ended September 30, 2017, we invested approximately $1,499.5 million in our capital program, excluding $28.7 million of unbudgeted acquisitions, including $66.3 million of capital costs associated with increased accruals for capital expenditures, and including $2.8 million of seismic costs. Our 2017 year to date capital expenditures were allocated as follows by quarter:

In millions	1Q 2017	2Q 2017	3Q 2017	YTD 2017
Exploration and development drilling	$ 329.8	$ 471.0	$ 444.7	$ 1,245.5
Land costs	68.8	49.8	47.7	166.3
Capital facilities, workovers and other corporate assets	27.4	29.3	28.2	84.9
Seismic	1.0	1.8	—	2.8
Capital expenditures, excluding acquisitions	427.0	551.9	520.6	1,499.5
Acquisitions of producing properties	0.1	0.7	2.7	3.5
Acquisitions of non-producing properties	13.3	5.1	6.8	25.2
Total acquisitions	13.4	5.8	9.5	28.7
Total capital expenditures	$ 440.4	$ 557.7	$ 530.1	$ 1,528.2

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 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

Refer to *Note 7. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements* for a discussion of certain future commitments of the Company as of September 30, 2017. We believe our cash flows from operations, our remaining cash balance, and amounts available under our revolving credit facility will be sufficient to satisfy our commitments.

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

There have been no changes in our critical accounting policies from those disclosed in our 2016 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 impact upon adoption of new accounting pronouncements in 2017 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, 2017, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $469 million for each $10.00 per barrel change in crude oil prices at September 30, 2017 and $217 million for each $1.00 per Mcf change in natural gas prices at September 30, 2017.

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 future natural gas production through March 2018. Our future crude oil production, and future natural gas production beyond March 2018, is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

Changes in natural gas prices during the nine months ended September 30, 2017 had an overall favorable impact on the fair value of our derivative instruments. For the nine months ended September 30, 2017, we recognized cash gains on natural gas derivatives of $15.0 million and non-cash mark-to-market gains on natural gas derivatives of $68.5 million.

The fair value of our natural gas derivative instruments at September 30, 2017 was a net asset of $9.0 million. An assumed increase in the forward prices used in the September 30, 2017 valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $29 million at September 30, 2017. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $43 million at September 30, 2017. 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 ($472 million in receivables at September 30, 2017); our joint interest and other receivables ($452 million at September 30, 2017); and counterparty credit risk associated with our derivative instrument receivables ($11 million at September 30, 2017).

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 $55 million at September 30, 2017, 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 any variable-rate borrowings we may have outstanding from time to time under our revolving credit facility and three-year term loan. 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 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.

We had an aggregate of approximately $1.40 billion of variable rate borrowings outstanding on our revolving credit facility and three-year term loan at October 31, 2017. The impact of a 0.25% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.5 million per year and a $2.2 million decrease in net income per year.

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, 2017 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, 2017, 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 7. 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 have 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. We exchanged information and engaged in discussions with NDDH aimed at resolving the allegations in August and October 2017, and anticipate further such discussions and exchanges. Resolution of the allegations may result in monetary sanctions of more than $100,000.

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 2016 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 2016 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 2016 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, 2017:

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, 2017 to July 31, 2017	—	—	—	—
August 1, 2017 to August 31, 2017	8,629	$ 33.14	—	—
September 1, 2017 to September 30, 2017	2,054	$ 38.68	—	—
Total	10,683	$ 34.21	—	—

(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 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
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

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:	November 7, 2017	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer (Duly Authorized Officer and Principal Financial Officer)

Exhibit 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)

I, Harold G. Hamm, certify that:

1. I have reviewed this report on Form 10-Q for the period ended September 30, 2017 of Continental Resources, Inc. ("Registrant");

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

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

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

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

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

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

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

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

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

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

Date: November 7, 2017

/s/ Harold G. Hamm

Harold G. Hamm

Chairman of the Board and
Chief Executive Officer

Exhibit 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)

I, John D. Hart, certify that:

1. I have reviewed this report on Form 10-Q for the period ended September 30, 2017 of Continental Resources, Inc. ("Registrant");

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

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

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

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

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

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

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

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

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

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

Date: November 7, 2017

/s/ John D. Hart

John D. Hart

Sr. Vice President, Chief Financial Officer and Treasurer

Exhibit 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)

Pursuant to 18 U.S.C. Section 1350, the undersigned officers of Continental Resources, Inc. (the "Company") hereby certify that the Company's Report on Form 10-Q for the quarterly period ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Harold G. Hamm	/s/ John D. Hart
Harold G. Hamm	**John D. Hart**
Chairman of the Board and Chief Executive Officer	**Sr. Vice President, Chief Financial Officer and Treasurer**
November 7, 2017	**November 7, 2017**