CONTINENTAL RESOURCES, INC
Form 10-Q
May 04, 2016
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from   to
Commission File Number: 001-32886

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.   Yes x   No ¨
Indicate by check mark whether the registrant has submitted electronically 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 x   No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes ¨   No x
374,571,874 shares of our $0.01 par value common stock were outstanding on April 29, 2016.

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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 we use to describe an area of crude oil and liquids-rich natural gas properties located in the Anadarko basin of Oklahoma in which we operate.
"STACK" Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe properties located in the Anadarko Basin of Oklahoma in which we operate.
“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.
“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
“working interest” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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

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

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

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- 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 or property acquisitions and dispositions;
- 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 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, 2015, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement.

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

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

In thousands, except par values and share data	March 31, 2016 (Unaudited)	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$12,927	$11,463
Receivables:		
Crude oil and natural gas sales	327,083	378,622
Affiliated parties	97	122
Joint interest and other, net	217,435	232,293
Derivative assets	94,720	93,922
Inventories	92,832	94,151
Prepaid taxes	68	94
Prepaid expenses and other	15,019	11,672
Total current assets	760,181	822,339
Net property and equipment, based on successful efforts method of accounting	13,843,132	14,063,328
Noncurrent derivative assets	12,549	14,560
Other noncurrent assets	17,527	19,581
Total assets	$14,633,389	$14,919,808
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$484,901	$553,285
Revenues and royalties payable	169,620	187,000
Payables to affiliated parties	149	69
Accrued liabilities and other	206,769	176,947
Derivative liabilities	1,757	3,583
Current portion of long-term debt	2,162	2,144
Total current liabilities	865,358	923,028
Long-term debt, net of current portion	7,203,440	7,115,644
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,968,876	2,090,228
Asset retirement obligations, net of current portion	103,249	101,251
Noncurrent derivative liabilities	2,456	3,706
Other noncurrent liabilities	14,890	17,051
Total other noncurrent liabilities	2,089,471	2,212,236
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; 374,583,066 shares issued and outstanding at March 31, 2016; 372,959,080 shares issued and outstanding at December 31, 2015	3,746	3,730
Additional paid-in capital	1,349,728	1,345,624
Accumulated other comprehensive loss	(2,928)	(3,354)
Retained earnings	3,124,574	3,322,900

Total shareholders’ equity	4,475,120	4,668,900
Total liabilities and shareholders’ equity	$14,633,389	$14,919,808

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

	Three months ended March 31,	
In thousands, except per share data	2016	2015
Revenues		
Crude oil and natural gas sales	$403,592	$581,192
Crude oil and natural gas sales to affiliates	—	1,400
Gain on crude oil and natural gas derivatives, net	42,112	32,755
Crude oil and natural gas service operations	7,470	10,297
Total revenues	453,174	625,644
Operating costs and expenses		
Production expenses	78,640	91,355
Production expenses to affiliates	—	1,586
Production taxes and other expenses	30,493	48,362
Exploration expenses	3,066	14,340
Crude oil and natural gas service operations	3,043	3,894
Depreciation, depletion, amortization and accretion	463,992	386,512
Property impairments	78,927	147,561
General and administrative expenses	32,407	45,380
Other	1,709	(2,070)
Total operating costs and expenses	692,277	736,920
Loss from operations	(239,103)	(111,276)
Other income (expense):		
Interest expense	(80,953)	(75,063)
Other	384	347
	(80,569)	(74,716)
Loss before income taxes	(319,672)	(185,992)
Benefit for income taxes	(121,346)	(54,021)
Net loss	$(198,326)	$(131,971)
Basic net loss per share	$(0.54)	$(0.36)
Diluted net loss per share	$(0.54)	$(0.36)
Comprehensive loss:		
Net loss	$(198,326)	$(131,971)
Other comprehensive income (loss), net of tax:		
Foreign currency translation adjustments	426	(3,105)
Total other comprehensive income (loss), net of tax	426	(3,105)
Comprehensive loss	$(197,900)	$(135,076)

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 loss	Retained earnings	Total shareholders' equity
Balance at December 31, 2015	372,959,080	$ 3,730	$ 1,345,624	$ (3,354)	$ 3,322,900	$ 4,668,900
Net loss (unaudited)	—	—	—	—	(198,326)	(198,326)
Other comprehensive income, net of tax (unaudited)	—	—	—	426	—	426
Stock-based compensation (unaudited)	—	—	9,189	—	—	9,189
Restricted stock:						
Granted (unaudited)	1,927,889	19	—	—	—	19
Repurchased and canceled (unaudited)	(263,004)	(3)	(5,085)	—	—	(5,088)
Forfeited (unaudited)	(40,899)	—	—	—	—	—
Balance at March 31, 2016 (unaudited)	374,583,066	$ 3,746	$ 1,349,728	$ (2,928)	$ 3,124,574	$ 4,475,120

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

	Three months ended March 31,	
In thousands	2016	2015
Cash flows from operating activities		
Net loss	$(198,326)	$(131,971)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	465,451	391,026
Property impairments	78,927	147,561
Non-cash gain on derivatives, net	(1,863)	(9,320)
Stock-based compensation	9,206	11,263
Benefit for deferred income taxes	(121,352)	(54,026)
Dry hole costs	—	8,401
Gain on sale of assets, net	(109)	(2,070)
Other, net	2,514	2,261
Changes in assets and liabilities:		
Accounts receivable	66,839	173,088
Inventories	1,319	(6,236)
Other current assets	(2,082)	48,967
Accounts payable trade	(31,531)	5,185
Revenues and royalties payable	(17,380)	(45,844)
Accrued liabilities and other	29,806	(17,460)
Other noncurrent assets and liabilities	(2,517)	1,365
Net cash provided by operating activities	278,902	522,190
Cash flows from investing activities		
Exploration and development	(359,090)	(1,267,252)
Purchase of producing crude oil and natural gas properties	—	(132)
Purchase of other property and equipment	(1,927)	(11,923)
Proceeds from sale of assets and other	2,206	903
Net cash used in investing activities	(358,811)	(1,278,404)
Cash flows from financing activities		
Credit facility borrowings	288,000	930,000
Repayment of credit facility	(201,000)	(140,000)
Repayment of other debt	(530)	(515)
Debt issuance costs	(40)	(2,099)
Repurchase of restricted stock for tax withholdings	(5,088)	(3,003)
Net cash provided by financing activities	81,342	784,383
Effect of exchange rate changes on cash	31	(4,905)
Net change in cash and cash equivalents	1,464	23,264
Cash and cash equivalents at beginning of period	11,463	24,381
Cash and cash equivalents at end of period	$12,927	$47,645

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 Kansas and west of the Mississippi River including various plays in the SCOOP (South Central Oklahoma Oil Province), STACK (Sooner Trend Anadarko Canadian Kingfisher), Northwest Cana, and Arkoma Woodford areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.

A substantial portion of the Company’s operations are concentrated in the North region, with that region comprising approximately 66% of the Company’s crude oil and natural gas production and approximately 72% of its crude oil and natural gas revenues for the three months ended March 31, 2016. 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 activity in the South region with its discovery of the SCOOP play and its increased activity in the Northwest Cana and STACK plays. The South region comprised approximately 34% of the Company's crude oil and natural gas production and approximately 28% of its crude oil and natural gas revenues for the three months ended March 31, 2016.

The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the three months ended March 31, 2016, crude oil accounted for approximately 63% of the Company’s total production and approximately 85% 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, 2015 (“2015 Form 10-K”), which includes a summary of the Company’s significant accounting policies and other disclosures.

The condensed consolidated financial statements as of March 31, 2016 and for the three month periods ended March 31, 2016 and 2015 are unaudited. The condensed consolidated balance sheet as of December 31, 2015 was derived from the audited balance sheet included in the 2015 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 of the estimates and assumptions that affect reported results are the 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.

Net loss per share

Basic and diluted net loss per share is computed by dividing net 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 loss per share for the three months ended March 31, 2016 and 2015.

	Three months ended March 31,	
In thousands, except per share data	2016	2015
Loss (numerator):		
Net loss - basic and diluted	$(198,326)	$(131,971)
Weighted average shares (denominator):		
Weighted average shares - basic	370,062	369,385
Non-vested restricted stock (1)	—	—
Weighted average shares - diluted	370,062	369,385
Net loss per share:		
Basic	$(0.54)	$(0.36)
Diluted	$(0.54)	$(0.36)

(1) During the three months ended March 31, 2016 and 2015, the Company had a net loss and therefore the potential dilutive effect of approximately 42,000 and 925,000 weighted average 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 computations.

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 at the lower of cost or market, with cost determined primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of March 31, 2016 and December 31, 2015 consisted of the following:

In thousands	March 31, 2016	December 31, 2015
Tubular goods and equipment	$ 16,062	$ 15,633
Crude oil	76,770	78,518
Total	$ 92,832	$ 94,151

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 recorded valuation allowances of $0.1 million and $11.1 million for the three months ended March 31, 2016 and 2015, respectively, against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary for which the Company does not expect to realize a benefit.

New accounting pronouncements not yet adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 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 is currently evaluating the impact of the new standard on its financial statements and related disclosures.

In March 2016, the FASB issued Accounting Standards Update 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 standard is effective for interim and annual reporting periods beginning after December 15, 2016 and shall be adopted either prospectively, retrospectively or using a modified retrospective transition approach depending on the topic covered in the standard. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

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 has not yet resulted in cash receipts or payments.

	Three months ended March 31,	
In thousands	2016	2015
Supplemental cash flow information:		
Cash paid for interest	$56,825	$51,790
Cash paid for income taxes	—	6
Cash received for income tax refunds	20	50,000
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	481	2,703

As of March 31, 2016 and December 31, 2015, the Company had $246.0 million and $282.8 million, respectively, of accrued capital expenditures included in "Net property and equipment" and "Accounts payable trade" in the condensed consolidated balance sheets. As of March 31, 2015 and December 31, 2014, the Company had $537.3 million and $797.5 million, respectively, of accrued capital expenditures.

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 crude oil and natural gas 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 loss under the caption “Gain on crude oil and natural gas derivatives, net”, which is a component of "Total revenues".

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.

The Company’s crude oil and natural gas derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Inter-Continental Exchange (“ICE”) pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. 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.

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

At March 31, 2016, the Company had outstanding crude oil and natural gas derivative contracts with respect to future production as set forth in the tables below. The hedged volumes reflected below represent an aggregation of multiple derivative contracts that have varying durations and may not be realized on a ratable basis over a calendar year.

Crude Oil - ICE Brent

Period and Type of Contract	Bbls	Ceiling Price
April 2016 - December 2016		
Written call options - ICE Brent (1)	1,100,000	$107.70

(1) Written call options represent the ceiling positions remaining from the Company's previous crude oil collar contracts. The floor positions of the collars were liquidated in the fourth quarter of 2014. For these written call options, the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price.

Natural Gas - NYMEX Henry Hub		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	MMBtus	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
April 2016 - December 2016						
Swaps - Henry Hub	112,780,000	$ 3.03				
January 2017 - December 2017						
Swaps - Henry Hub	25,550,000	$ 3.35				
Collars - Henry Hub	65,700,000		$2.40 - $3.00	$ 2.47	$2.92 - $3.88	$ 3.08

Crude oil and natural gas derivative gains and losses

The following table presents cash settlements on matured crude oil and natural gas derivative instruments and non-cash gains and losses on open crude oil and natural gas derivative instruments for the periods presented. Cash receipts and payments below 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.

In thousands	Three months ended March 31, 2016	2015
Cash received on derivatives:		
Natural gas fixed price swaps	$39,189	$18,391
Natural gas collars	—	5,044
Cash received on derivatives, net	39,189	23,435
Non-cash gain (loss) on derivatives:		
Crude oil written call options	32	3,924
Natural gas fixed price swaps	2,393	6,492
Natural gas collars	498	(1,096)
Non-cash gain on derivatives, net	2,923	9,320
Gain on crude oil and natural gas derivatives, net	$42,112	$32,755

Diesel fuel derivatives

In March 2016, the Company 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 19 million gallons of diesel fuel over the period from July 2016 to December 2017 at a weighted average price of $1.41 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.

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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 loss under the caption "Operating costs and expenses—Other." For the three months ended March 31, 2016, the Company recognized a non-cash loss of $1.1 million associated with its diesel fuel derivatives.

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". 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	March 31, 2016	December 31, 2015
Commodity derivative assets:		
Gross amounts of recognized assets	$109,718	$120,385
Gross amounts offset on balance sheet	(2,449)	(11,903)
Net amounts of assets on balance sheet	107,269	108,482
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(6,662)	(19,192)
Gross amounts offset on balance sheet	2,449	11,903
Net amounts of liabilities on balance sheet	$(4,213)	$(7,289)

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

In thousands	March 31, 2016	December 31, 2015
Derivative assets	$94,720	$ 93,922
Noncurrent derivative assets	12,549	14,560
Net amounts of assets on balance sheet	107,269	108,482
Derivative liabilities	(1,757)	(3,583)
Noncurrent derivative liabilities	(2,456)	(3,706)
Net amounts of liabilities on balance sheet	(4,213)	(7,289)
Total derivative assets, net	$103,056	$ 101,193

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 that are 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.

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- Level 3: Unobservable inputs that are 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 and written call options 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 March 31, 2016 and December 31, 2015.

	Fair value measurements at March 31, 2016 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Swaps	$ —	$ 105,759	$ —	$ 105,759
Collars	—	(2,697)	—	(2,697)
Written call options	—	(6)	—	(6)
Total	$ —	$ 103,056	$ —	$ 103,056

	Fair value measurements at December 31, 2015 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Swaps	$ —	$ 104,426	$ —	$ 104,426
Collars	—	(3,195)	—	(3,195)
Written call options	—	(38)	—	(38)
Total	$ —	$ 101,193	$ —	$ 101,193

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, 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 2020 (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 34 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.

Proved properties were reviewed for impairment at March 31, 2016 and March 31, 2015. For the three months ended March 31, 2016, 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 the three months ended March 31, 2015, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows at that time and, therefore, were impaired. Impairments of proved properties for the first quarter of 2015 totaled $70.0 million, which were primarily concentrated in an emerging area with minimal production and costly reserve additions ($36.1 million), the Medicine Pole Hills units ($14.7 million), various legacy areas in the South region ($11.1 million), and non-Bakken areas of North Dakota and Montana ($8.1 million). The impaired properties were written down to their estimated fair value totaling approximately $38.2 million as of March 31, 2015.

Certain unproved crude oil and natural gas properties were impaired during the three months ended March 31, 2016 and 2015, 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 loss.

	Three months ended March 31,	
In thousands	2016	2015
Proved property impairments	$—	$70,016
Unproved property impairments	78,927	77,545
Total	$78,927	$147,561

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Financial Instruments Not Recorded at Fair Value
The following table sets forth the estimated fair values of financial instruments that are not recorded at fair value in the condensed consolidated financial statements.

	March 31, 2016		December 31, 2015	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Revolving credit facility	$940,000	$940,000	$853,000	$853,000
Term loan	498,401	500,000	498,274	500,000
Note payable	13,781	12,400	14,309	12,500
7.375% Senior Notes due 2020	196,724	197,000	196,574	179,200
7.125% Senior Notes due 2021	395,547	372,000	395,365	388,300
5% Senior Notes due 2022	1,996,917	1,720,000	1,996,831	1,480,400
4.5% Senior Notes due 2023	1,482,958	1,252,800	1,482,451	1,061,000
3.8% Senior Notes due 2024	990,186	803,100	989,932	700,300
4.9% Senior Notes due 2044	691,088	525,000	691,052	430,500
Total debt	$7,205,602	$6,322,300	$7,117,788	$5,605,200

The fair values of revolving credit facility borrowings and the term loan approximate face 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 7.375% Senior Notes due 2020 (“2020 Notes”), the 7.125% Senior Notes due 2021 (“2021 Notes”), 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 $48.2 million and $49.6 million at March 31, 2016 and December 31, 2015, respectively, consists of the following.

In thousands	March 31, 2016	December 31, 2015
Revolving credit facility	$940,000	$ 853,000
Term loan	498,401	498,274
Note payable	13,781	14,309
7.375% Senior Notes due 2020	196,724	196,574
7.125% Senior Notes due 2021	395,547	395,365
5% Senior Notes due 2022	1,996,917	1,996,831
4.5% Senior Notes due 2023	1,482,958	1,482,451
3.8% Senior Notes due 2024	990,186	989,932
4.9% Senior Notes due 2044	691,088	691,052
Total debt	$7,205,602	$ 7,117,788
Less: Current portion of long-term debt	2,162	2,144
Long-term debt, net of current portion	$7,203,440	$ 7,115,644

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Revolving Credit Facility

The Company has an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.75 billion at March 31, 2016, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

The Company had $940 million and $853 million of outstanding borrowings on its revolving credit facility at March 31, 2016 and December 31, 2015, respectively. 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 borrowings at March 31, 2016 was 2.2%.

The Company had approximately $1.81 billion of borrowing availability on its revolving credit facility at March 31, 2016 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 (total debt 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 March 31, 2016.

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 March 31, 2016.

	2020 Notes	2021 Notes	2022 Notes	2023 Notes	2024 Notes	2044 Notes
Face value (in thousands)	$200,000	$400,000	$2,000,000	$1,500,000	$1,000,000	$700,000
Maturity date	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023	June 1, 2024	June 1, 2044
Interest payment dates	April 1, Oct 1	April 1, Oct 1	March 15, Sep 15	April 15, Oct 15	June 1, Dec 1	June 1, Dec 1
Call premium redemption period (1)	Oct 1, 2015	April 1, 2016	March 15, 2017	—	—	—
Make-whole redemption period (2)	—	April 1, 2016	March 15, 2017	Jan 15, 2023	Mar 1, 2024	Dec 1, 2043

(1) On or after these dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the decreasing redemption prices specified in the respective senior note indentures (together, the "Indentures") 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 Indentures 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, and 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 March 31, 2016. Two of the Company's subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, 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 March 31, 2016 was 1.95%.

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 1.0, consistent with the covenant requirement in the Company's revolving credit facility. The Company was in compliance with the term loan covenants at March 31, 2016.

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 $2.2 million is reflected as a current liability under the caption “Current portion of long-term debt” in the condensed consolidated balance sheets as of March 31, 2016.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of March 31, 2016. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of March 31, 2016, the Company had drilling rig contracts with various terms extending to year-end 2019 to ensure rig availability in its key operating areas. Future commitments as of March 31, 2016 total approximately $367 million, of which $145 million is expected to be incurred in the remainder of 2016, $136 million in 2017, $62 million in 2018, and $24 million in 2019.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines. The commitments, which have varying terms extending as far as 2027, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of March 31, 2016 under the operational pipeline transportation arrangements amount to approximately $952 million, of which $161 million is expected to be incurred in the remainder of 2016, $212 million in 2017, $208 million in 2018, $154 million in 2019, $47 million in 2020, and $170 million thereafter.

The Company’s pipeline commitments are for production primarily in the North region. The Company is not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Fuel purchase commitment – The Company has a forward purchase contract with a third party to purchase specified quantities of diesel fuel at specified prices each month through June 2016 for use in drilling operations. Over the remaining contract term, the Company has committed to purchase approximately 5 million gallons of diesel fuel at varying prices depending on the grade of diesel fuel purchased and the timing and location of delivery. The contract satisfies a significant portion of the Company's anticipated diesel fuel needs and provides for physical delivery to desired locations. Future commitments under the arrangement as of March 31, 2016 total approximately $14 million, all of which is expected to be incurred in the second quarter of 2016.

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 1st and 2nd, 2015. On June 11, 2015, the trial court certified a “hybrid” class as requested by plaintiffs. The Company has appealed the trial court’s class certification order, which will be reviewed de novo by the appellate court. The appeal briefing is complete and ready for determination by the court. An unsuccessful mediation was conducted on December 7, 2015. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, 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 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. Although not currently at issue in the “hybrid” certification, 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 that the case meets the requirements for a class action and is vigorously defending the case. The Company will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.

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 March 31, 2016 and December 31, 2015, the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $6.4 million and $6.1 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

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 loss, was $9.2 million and $11.3 million for the three months ended March 31, 2016 and 2015, 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 March 31, 2016, the Company had 15,175,243 shares of restricted stock available to grant to officers, directors and employees 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 or 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 three months ended March 31, 2016 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2015	3,249,611	$ 48.20
Granted	1,927,889	20.75
Vested	(958,965)	38.59
Forfeited	(40,899)	50.27
Non-vested restricted shares outstanding at March 31, 2016	4,177,636	$ 37.72

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 a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. 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 three months ended March 31, 2016 was approximately $18.5 million. As of March 31, 2016, there was approximately $93 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 2.1 years.

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Note 9. Accumulated Other Comprehensive Loss

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive loss" within shareholders' equity on the condensed consolidated balance sheets. The following table summarizes the change in accumulated other comprehensive loss for the three months ended March 31, 2016 and 2015:

In thousands	Three months ended March 31, 2016	Three months ended March 31, 2015
Beginning accumulated other comprehensive loss, net of tax	$(3,354)	$(385)
Foreign currency translation adjustments	426	(3,105)
Income taxes (1)	—	—
Other comprehensive income (loss), net of tax	426	(3,105)
Ending accumulated other comprehensive loss, net of tax	$(2,928)	$(3,490)

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

Note 10. Subsequent Event

On April 27, 2016, the Company sold certain non-core undeveloped leasehold acreage located in Wyoming to a third party for cash proceeds of $110 million. The proceeds were used to pay down a portion of outstanding borrowings on the Company's revolving credit facility. In connection with the transaction, the Company expects to recognize a pre-tax gain of approximately $95 million. The disposed properties represented an immaterial portion of the Company's total acreage and included 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, 2015. 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, 2015, 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, STACK, and Northwest Cana areas of Oklahoma.

Business Environment and Outlook

Crude oil prices experienced significant downward pressure in the first quarter of 2016 due to domestic and global supply and demand factors, with prices dropping below $27 per barrel in February 2016, a level not seen since 2003. Crude oil prices have showed signs of stabilization and recovery in April 2016; however, prices remain volatile and unpredictable.

In light of the challenges facing our industry, our primary business strategies for 2016 continue to focus on: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) high-grading investments based on rates of return and opportunities to convert undeveloped acreage to acreage held by production, and (3) working to balance capital spending with cash flows to minimize new borrowings and maintain ample liquidity.

2016 Highlights

Production

Production for the first quarter of 2016 averaged 230,802 Boe per day, an increase of 3% from the fourth quarter of 2015 and 12% higher than the first quarter of 2015.

North Dakota Bakken production averaged 129,168 Boe per day for the first quarter of 2016, a 3% increase from the fourth quarter of 2015 and 7% higher than the first quarter of 2015.

SCOOP production averaged 64,616 Boe per day for the first quarter of 2016, in line with the fourth quarter of 2015 and 30% higher than the first quarter of 2015.

SCOOP comprised 28% of our total production for the 2016 first quarter compared to 24% for the 2015 first quarter.

Revenues

Crude oil and natural gas revenues for the 2016 first quarter decreased 31% compared to the 2015 first quarter driven by a 39% decrease in realized commodity prices, the effect of which was partially offset by a 14% increase in total sales volumes.

Average crude oil sales prices for the 2016 first quarter decreased 33% compared to the 2015 first quarter.

Crude oil sales volumes for the 2016 first quarter increased 4% compared to the 2015 first quarter.

Average natural gas sales prices for the 2016 first quarter decreased 50% compared to the 2015 first quarter.

Natural gas sales volumes for the 2016 first quarter increased 35% compared to the 2015 first quarter.

Capital expenditures and drilling activity

Non-acquisition capital expenditures totaled approximately $319.9 million for the first quarter of 2016 compared to $394.0 million for the 2015 fourth quarter and $983.8 million for the 2015 first quarter.

For the first quarter of 2016 we participated in the drilling and completion of 90 gross (19 net) wells.
Our inventory of drilled but uncompleted ("DUC") wells in North Dakota increased from 135 gross (107 net) operated wells at December 31, 2015 to 142 gross (114 net) operated wells at March 31, 2016. Our DUC inventory in Oklahoma increased from 35 gross (25 net) operated wells at December 31, 2015 to 42 gross (26 net) operated wells at March 31, 2016. Due to market conditions we have chosen to defer completions on certain wells until commodity prices improve.

Credit facility and liquidity

At March 31, 2016, we had $12.9 million of cash and cash equivalents and approximately $1.81 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $940 million of outstanding borrowings on our credit facility at March 31, 2016 compared to $853 million at December 31, 2015.

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,
- Per unit operating and administrative costs, and
- EBITDAX (a non-GAAP financial measure).

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 March 31, 2016	2015
Average daily production:		
Crude oil (Bbl per day)	146,469	143,511
Natural gas (Mcf per day)	505,998	379,906
Crude oil equivalents (Boe per day)	230,802	206,829
Average sales prices:		
Crude oil ($/Bbl)	$25.72	$38.56
Natural gas ($/Mcf)	$1.36	$2.70
Crude oil equivalents ($/Boe)	$19.27	$31.65
Crude oil sales price discount to NYMEX ($/Bbl)	$(7.78)	$(10.01)
Natural gas sales price discount to NYMEX ($/Mcf)	$(0.73)	$(0.28)
Production expenses ($/Boe)	$3.76	$5.05
Production taxes (% of oil and gas revenues)	7.6%	8.2%
DD&A ($/Boe)	$22.16	$21.00
General and administrative expenses ($/Boe) (1)	$1.11	$1.85
Non-cash equity compensation ($/Boe)	$0.44	$0.61
Net loss (in thousands)	$(198,326)	$(131,971)
Diluted net loss per share	$(0.54)	$(0.36)
EBITDAX (in thousands) (2)	$314,609	$439,427

(1) Excludes non-cash equity compensation expense.

(2) We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income (loss) or operating cash flows as determined by U.S. GAAP. Reconciliations of net loss and operating cash flows to EBITDAX are provided below under the heading Non-GAAP Financial Measures.

Three months ended March 31, 2016 compared to the three months ended March 31, 2015

Results of Operations

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

	Three months ended March 31,	
In thousands, except sales price data	2016	2015
Crude oil and natural gas sales	$403,592	$582,592
Gain on crude oil and natural gas derivatives, net	42,112	32,755
Crude oil and natural gas service operations	7,470	10,297
Total revenues	453,174	625,644
Operating costs and expenses	(692,277)	(736,920)
Other expenses, net	(80,569)	(74,716)
Loss before income taxes	(319,672)	(185,992)
Benefit for income taxes	121,346	54,021
Net loss	$(198,326)	$(131,971)
Production volumes:		
Crude oil (MBbl)	13,329	12,916
Natural gas (MMcf)	46,046	34,192
Crude oil equivalents (MBoe)	21,003	18,615
Sales volumes:		
Crude oil (MBbl)	13,266	12,711
Natural gas (MMcf)	46,046	34,192
Crude oil equivalents (MBoe)	20,940	18,409
Average sales prices:		
Crude oil ($/Bbl)	$25.72	$38.56
Natural gas ($/Mcf)	1.36	2.70
Crude oil equivalents ($/Boe)	19.27	31.65

Production

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

	Three months ended March 31,				Volume increase	Volume percent increase
	2016		2015			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	13,329	63 %	12,916	69 %	413	3 %
Natural gas (MMcf)	46,046	37 %	34,192	31 %	11,854	35 %
Total (MBoe)	21,003	100 %	18,615	100 %	2,388	13 %

	Three months ended March 31,				Volume increase	Volume percent increase
	2016		2015			
	MBoe	Percent	MBoe	Percent		
North Region	13,791	66 %	13,426	72 %	365	3 %
South Region	7,212	34 %	5,189	28 %	2,023	39 %
Total	21,003	100 %	18,615	100 %	2,388	13 %

The 3% increase in crude oil production for the first quarter was driven by increased production from our properties in SCOOP, STACK/Northwest Cana, and North Dakota Bakken. SCOOP crude oil production increased 358 MBbls, or 24%, and STACK/Northwest Cana production increased 222 MBbls, or 740%, while production in North Dakota Bakken increased 376 MBbls, or 4%, over the prior year first quarter. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling programs. These increases were partially offset by a decrease in production from our properties in Montana Bakken and the Red River units totaling 494 MBbls, or 22%, compared to the prior year first quarter due to a combination of natural declines in production and reduced drilling activity.

The 35% increase in natural gas production for the first quarter was driven by increased production from our properties in the SCOOP, STACK/Northwest Cana, and North Dakota Bakken areas due to additional wells being completed and producing subsequent to March 31, 2015. Natural gas production in SCOOP increased 6,194 MMcf, or 34%, over the prior year first quarter, and STACK/Northwest Cana production increased 2,890 MMcf, or 173%, while North Dakota Bakken production increased 2,953 MMcf, or 27%. These increases were partially offset by decreases in production from various areas in our North and South regions primarily due to natural declines in production.

The increase in natural gas production as a percentage of our total production from 31% in the first quarter of 2015 to 37% in the first quarter of 2016 primarily resulted from significant increases in SCOOP, STACK and Northwest Cana production over the past year due in part to a shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma. Our properties in SCOOP, STACK and Northwest Cana typically produce a higher concentration of liquids-rich natural gas compared to oil-weighted properties in the Bakken. For the remainder of 2016, we expect to continue focusing our well completion activities on our Oklahoma properties. Accordingly, we expect our natural gas production may increase to approximately 40% of our total production for the full year of 2016. As crude oil prices recover, we expect to increase our completion activities in the Bakken and shift our production back to a higher proportion of crude oil.

Our reduction in capital spending and deferral of well completion activities throughout 2015, which has continued into 2016, has adversely impacted our production growth and our 13% growth in production realized in the 2016 first quarter compared to the 2015 first quarter is not expected to be sustained for the remainder of 2016. We expect our production may average between 205,000 and 215,000 Boe per day for the full year of 2016 compared to average daily production of 221,715 Boe per day for full year 2015.

Revenues

Our revenues primarily consist of sales of crude oil and natural gas and gains and losses resulting from changes in the fair value of our crude oil and natural gas derivative instruments.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the first quarter of 2016 were $403.6 million, a 31% decrease from sales of $582.6 million for the 2015 first quarter primarily due to a significant decrease in commodity prices, partially offset by an increase in sales volumes.

Our crude oil sales prices averaged $25.72 per barrel in the 2016 first quarter, a decrease of 33% compared to $38.56 for the 2015 first quarter. The downward pressure on crude oil prices arising from domestic and global supply and demand factors intensified in early 2016, with prices dropping below $27 per barrel in February 2016 which resulted in significantly lower realized sales prices compared to the prior year period. The differential between NYMEX West Texas Intermediate calendar month crude oil prices and our realized crude oil prices averaged $7.78 per barrel for the 2016 first quarter compared to $10.01 for the 2015 first quarter. The improved differential was due to increased availability and use of pipeline transportation to move our North region crude oil to market with less dependence on more costly rail transportation, along with significant 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 realized natural gas sales prices averaged $1.36 per Mcf for the 2016 first quarter, a 50% decrease compared to $2.70 per Mcf for the 2015 first quarter due to lower market prices for natural gas and natural gas liquids (“NGLs”). 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. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.73 per Mcf for the 2016 first quarter compared to a discount of $0.28 per Mcf for the 2015 first quarter. NGL prices remained significantly depressed in the 2016 first quarter in conjunction with historically low crude oil prices, which reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing. If NGL prices do not recover from current levels, the prices we receive for the sale of our natural gas stream throughout 2016 may continue to be lower than Henry Hub benchmark prices.

Crude oil, natural gas and NGL prices have experienced significant volatility in recent months and we are unable to predict the impact future price changes may have on our full year 2016 revenues and differentials.

Our crude oil and natural gas sales volumes for the first quarter of 2016 increased 4% and 35%, respectively, over the comparable 2015 period primarily due to an increase in producing wells resulting from our drilling programs in North Dakota Bakken, SCOOP, STACK and Northwest Cana. 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 63 MBbls for the first quarter of 2016.

Derivatives. Changes in natural gas prices during the first quarter of 2016 had a favorable impact on the fair value of our natural gas derivatives, which resulted in positive revenue adjustments of $42.1 million for the period, representing $39.2 million of cash gains and $2.9 million of non-cash gains. Our revenues 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.

Operating Costs and Expenses

Production Expenses. Production expenses decreased 15% from $92.9 million for the first quarter of 2015 to $78.6 million for the first quarter of 2016. Production expenses on a per-Boe basis decreased to $3.76 for the 2016 first quarter compared to $5.05 for the 2015 first quarter. These decreases primarily resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, increased availability and use of water gathering and recycling facilities over the prior year period, and a higher portion of our production coming from natural gas wells in Oklahoma which typically have lower operating costs compared to crude oil wells in the Bakken.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $17.9 million, or 37%, to $30.5 million for the first quarter of 2016 compared to $48.4 million for the first quarter of 2015 primarily due to lower crude oil and natural gas revenues resulting from the significant decrease in commodity prices 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 7.6% for the first quarter of 2016 compared to 8.2% for the first quarter of 2015, the decrease of which resulted from significant growth over the past year in our SCOOP, STACK and Northwest Cana operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to North Dakota. We expect our average production tax rate for the remainder of 2016 will continue to trend lower than 2015 levels as our operations in Oklahoma continue to grow in significance and given the passing of legislation in North Dakota in 2015 that decreased the combined production tax rate in that state from 11.5% to 10.0% of crude oil revenues effective January 1, 2016.

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 March 31,	
In thousands	2016	2015
Geological and geophysical costs	$3,066	$5,939
Exploratory dry hole costs	—	8,401
Exploration expenses	$3,066	$14,340

The decrease in geological and geophysical costs in the first quarter of 2016 is due to changes in the timing and amount of costs incurred by the Company between periods. There were no exploratory dry hole costs incurred in the 2016 first quarter.

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $77.5 million, or 20%, to $464.0 million for the first quarter of 2016 compared to $386.5 million for the first quarter of 2015 primarily due to a 14% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Three months ended March 31,	
$/Boe	2016	2015
Crude oil and natural gas	$21.73	$20.59
Other equipment	0.36	0.35
Asset retirement obligation accretion	0.07	0.06
Depreciation, depletion, amortization and accretion	$22.16	$21.00

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense would increase. Downward revisions of proved reserves at year-end 2015 prompted by depressed commodity prices contributed to an increase in our DD&A rate for crude oil and natural gas properties in the first quarter of 2016 compared to the prior year period. If commodity prices remain at current levels for an extended period or decline further, additional downward revisions of proved reserves may occur in the future, which may be significant and would result in an increase in our DD&A rate. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments decreased $68.6 million, or 47%, to $78.9 million for the first quarter of 2016 compared to $147.5 million for the 2015 first quarter primarily due to a decrease in proved property impairments. There were no proved property impairments recognized in the first quarter of 2016 compared to $70.0 million of such impairments in the first quarter of 2015. This decrease resulted from differences in the timing and severity of commodity price declines and resulting impact on fair value assessments and impairments between periods. The prolonged decrease in commodity prices in 2015 triggered significant impairments of proved properties throughout 2015. As a result of the impairments and DD&A recognized to date, our proved properties are carried at values that did not exceed estimated future net cash flows at March 31, 2016 and required no impairment during the 2016 first quarter.

Estimated reserves are a key component in assessing proved properties for impairment. If commodity prices remain at current levels for an extended period or decline further, downward revisions of reserves may be significant in the future and could result in impairments of proved properties in the remainder of 2016. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on future impairments, if any.

General and Administrative ("G&A") Expenses. Total G&A expenses decreased $13.0 million, or 29%, to $32.4 million for the first quarter of 2016 from $45.4 million for the 2015 first quarter. Total G&A expenses include non-cash charges for equity compensation of $9.2 million and $11.3 million for the first quarters of 2016 and 2015, respectively. G&A expenses other than equity compensation totaled $23.2 million for the 2016 first quarter, a decrease of $10.9 million, or 32%, compared to the 2015 first quarter.

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

	Three months ended March 31,	
$/Boe	2016	2015
General and administrative expenses	$1.11	$1.85
Non-cash equity compensation	0.44	0.61
Total general and administrative expenses	$1.55	$2.46

The decrease in G&A expenses other than equity compensation in 2016 was primarily due to a reduction in employee benefits and other efforts to reduce spending in response to depressed commodity prices. This decrease, coupled with the 14% increase in our sales volumes, resulted in lower G&A expenses on a per-Boe basis compared to the prior year period.

The decrease in equity compensation expense in 2016 was primarily due to an increase in the estimated rate of forfeitures of unvested restricted stock based on historical experience, which resulted in a one-time reduction of compensation expense recognized in the 2016 first quarter of approximately $3.5 million, or $0.17 per Boe. This reduction resulted in lower equity compensation expense on a per-Boe basis compared to the prior year period.

Interest Expense. Interest expense increased $5.9 million, or 8%, to $81.0 million for the first quarter of 2016 compared to $75.1 million for the first quarter of 2015 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the 2016 first quarter was approximately $7.2 billion with a weighted average interest rate of 4.3% compared to averages of $6.4 billion and 4.6% for the 2015 first quarter. The increase in outstanding debt resulted from borrowings incurred subsequent to March 31, 2015 to fund our 2015 and 2016 capital programs.

Income Taxes. We recorded an income tax benefit for the first quarter of 2016 of $121.3 million compared to a benefit of $54.0 million for the first quarter of 2015, resulting in effective tax rates of approximately 38% and 29%, respectively, after taking into account permanent taxable differences and valuation allowances. For the first quarters of 2016 and 2015, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax losses generated by our operations in the United States. Our effective tax rate for the 2015 first quarter was impacted by an $11.1 million valuation allowance recognized against deferred tax assets associated with operating loss carryforwards generated by our Canadian subsidiary for which we do not believe we will realize a benefit.

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. At March 31, 2016, we had $12.9 million of cash and cash equivalents and approximately $1.81 billion of borrowing availability on our revolving credit facility after considering outstanding borrowings and letters of credit. We are focused on balancing our 2016 capital spending with cash flows in order to minimize new borrowings and maintain ample liquidity. At April 29, 2016, outstanding borrowings totaled $870 million with approximately $1.88 billion of borrowing availability on our credit facility after considering outstanding borrowings, letters of credit, and the repayment of credit facility borrowings using the $110 million of proceeds from our April 2016 sale of undeveloped acreage in Wyoming as discussed in Note 10. Subsequent Event in Notes to Unaudited Condensed Consolidated Financial Statements.

Based on our 2016 capital expenditure budget, 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 March 31, 2016, 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.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $278.9 million and $522.2 million for the three months ended March 31, 2016 and 2015, respectively. The decrease in operating cash flows was primarily due to lower crude oil and natural gas revenues driven by lower realized commodity prices, partially offset by lower production expenses, production taxes, and general and administrative expenses and an increase in cash gains on matured natural gas derivatives.

If the depressed commodity price environment existing in the first quarter of 2016 persists or worsens, we expect our 2016 operating cash flows will continue to be lower than 2015 levels, the extent of which is uncertain due to the unpredictable nature of commodity prices.

Cash flows used in investing activities

During the three months ended March 31, 2016 and 2015, we had cash flows used in investing activities (excluding proceeds from asset sales) of $361.0 million and $1.28 billion, respectively, related to our capital program, inclusive of any dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $4.4 million and $36.8 million for the three months ended March 31, 2016 and 2015, respectively. Cash capital expenditures excluding acquisitions totaled $356.6 million and $1.24 billion for the three months ended March 31, 2016 and 2015, respectively, the decrease of which was driven by a decrease in our capital budget and related drilling activity for 2016. Our cash capital expenditures for 2016 include the payment of amounts owed at December 31, 2015 in connection with our 2015 drilling program and associated $36.8 million decrease in accruals for capital expenditures for the three months ended March 31, 2016.

Our capital spending for the remainder of 2016 will continue to be lower than 2015 levels due to the significant decrease in our budgeted capital spending to $920 million for 2016, a reduction of 63% compared to $2.5 billion of capital spending in 2015. Additionally, our 2016 capital budget calls for decreasing levels of drilling activity throughout the year. As a result, the level of capital spending in the first quarter of 2016 is not expected to continue at the same rate for the remainder of the year.

Cash flows from financing activities

Net cash provided by financing activities for the three months ended March 31, 2016 was $81.3 million primarily resulting from net borrowings of $87 million on our revolving credit facility during the period. Our 2016 operating cash flows were adversely impacted by decreased commodity prices, leading to an $87.0 million net increase in credit facility borrowings incurred for the payment of amounts owed in connection with our 2015 drilling program and to fund a portion of our 2016 drilling program.

Net cash provided by financing activities for the three months ended March 31, 2015 was $784.4 million primarily resulting from $790 million of net borrowings on our revolving credit facility during that period.

We are seeking to generally balance our 2016 capital expenditures with cash flows, which may result in reduced credit facility borrowings for full year 2016 compared to full year 2015.

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 2016 capital expenditures budget is reflective of the depressed commodity price environment and 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. If cash flows are materially impacted by further 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 if such financing can be arranged on favorable terms. Additionally, we may choose to sell assets or enter into strategic joint development opportunities in order to obtain funding for our operations and capital program.

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 or sell assets. 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 revolving 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 April 29, 2016, we had approximately $1.88 billion of borrowing availability on our credit facility after considering outstanding borrowings, letters of credit, and the repayment of credit facility borrowings using the $110 million of proceeds from our April 2016 sale of undeveloped acreage in Wyoming as discussed in Note 10. Subsequent Event in Notes to Unaudited Condensed Consolidated Financial Statements. 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, such as the downgrades by Standard & Poor's Ratings Services ("S&P") and Moody's Investor Services, Inc. ("Moody's") that occurred in February 2016 in response to weakened oil and gas industry conditions, do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants. The recent downgrades of our credit rating did, however, trigger a 0.250% increase in our credit facility's interest rate and a 0.075% increase in the rate of commitment fees paid on unused borrowing availability under our credit facility.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our 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 (total debt 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 March 31, 2016 and expect to maintain compliance for at least the next 12 months. At March 31, 2016, our consolidated net debt to total capitalization ratio, as defined in the revolving credit facility as amended, was 0.59 to 1.00. As we are focused on balancing our 2016 capital spending with cash flows to minimize new borrowings, 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 March 31, 2016, our total debt would have needed to independently increase by approximately $2.2 billion, or 31%, above existing levels 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 $1.2 billion (excluding the after-tax impact of any non-cash impairment charges), or 27% below existing levels at March 31, 2016 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 significant portion of the Company's Northwest Cana natural gas properties. Pursuant to the agreement SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest within our Northwest Cana properties until approximately $270 million has been expended by SK on our behalf. As of March 31, 2016, approximately $190 million of the carry had yet to be realized and is expected to be realized over the next four years.

Proceeds from sale of assets

On April 27, 2016, we sold certain non-core undeveloped leasehold acreage located in Wyoming to a third party for cash proceeds of $110 million. The proceeds were used to pay down a portion of outstanding borrowings on our revolving credit facility.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at March 31, 2016. We have no near-term senior note maturities, with our earliest scheduled maturity being our $200 million of 2020 Notes due in October 2020. 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 March 31, 2016 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, such as the downgrades by S&P and Moody's that occurred in February 2016, do not trigger additional senior note covenants.

Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, 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.

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, such as the S&P and Moody's downgrades that occurred in February 2016, do not trigger a security requirement or change in covenants for the term loan. The recent downgrades of our credit rating did, however, trigger a 0.125% increase in our term loan's interest rate.

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 2016 is $920 million excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$ 784
Land costs	78
Capital facilities, workovers and other corporate assets	55
Seismic	3
Total 2016 capital budget, excluding acquisitions	$ 920

During the three months ended March 31, 2016, we invested approximately $319.9 million in our capital program, excluding $4.4 million of unbudgeted acquisitions, excluding $36.8 million of capital costs associated with decreased accruals for capital expenditures, and including $0.1 million of seismic costs. Our 2016 year to date capital expenditures were allocated as follows:

In millions	1Q 2016
Exploration and development drilling	$290.0
Land costs	19.9
Capital facilities, workovers and other corporate assets	9.9
Seismic	0.1
Capital expenditures, excluding acquisitions	319.9
Acquisitions of producing properties	—
Acquisitions of non-producing properties	4.4
Total acquisitions	4.4
Total capital expenditures	$324.3

Our current 2016 capital budget calls for decreasing levels of drilling activity throughout the year. As a result, the level of capital spending in the first quarter of 2016 is not expected to continue at the same rate for the remainder of the year.

Our planned non-acquisition capital spending for 2016 has been set based on an expectation of available cash flows and is designed to target capital expenditures and cash flows being relatively balanced for 2016 at an assumed average West Texas Intermediate benchmark crude oil price of approximately $37 per barrel for the year, with any cash flow deficiencies being funded by borrowings under our revolving credit facility.

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 results, the availability of drilling 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 continue to scale back our spending should commodity prices decrease further. Conversely, an increase in commodity prices 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 March 31, 2016. 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. However, as is customary in the crude oil and natural gas industry, we have various contractual commitments not reflected in the consolidated balance sheets as shown in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations in our 2015 Form 10-K.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our 2015 Form 10-K.

Non-GAAP Financial Measures

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure.

Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income (loss) and operating cash flows in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) or operating cash flows as determined in accordance with U.S. GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of our net loss to EBITDAX for the periods presented.

	Three months ended March 31,	
In thousands	2016	2015
Net loss	$(198,326)	$(131,971)
Interest expense	80,953	75,063
Benefit for income taxes	(121,346)	(54,021)
Depreciation, depletion, amortization and accretion	463,992	386,512
Property impairments	78,927	147,561
Exploration expenses	3,066	14,340
Impact from derivative instruments:		
Total gain on derivatives, net	(41,052)	(32,755)
Cash received on derivatives, net	39,189	23,435
Non-cash gain on derivatives, net	(1,863)	(9,320)
Non-cash equity compensation	9,206	11,263
EBITDAX	$314,609	$439,427

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

	Three months ended March 31,	
In thousands	2016	2015
Net cash provided by operating activities	$278,902	$522,190
Current income tax provision	6	5
Interest expense	80,953	75,063
Exploration expenses, excluding dry hole costs	3,066	5,939
Gain on sale of assets, net	109	2,070
Other, net	(3,973)	(6,775)
Changes in assets and liabilities	(44,454)	(159,065)
EBITDAX	$314,609	$439,427

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 three months ended March 31, 2016, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $535 million for each $10.00 per barrel change in crude oil prices at March 31, 2016 and $185 million for each $1.00 per Mcf change in natural gas prices at March 31, 2016.

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 for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. Our crude oil production and sales for the remainder of 2016 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Changes in natural gas prices during the three months ended March 31, 2016 had an overall favorable impact on the fair value of our derivative instruments. For the three months ended March 31, 2016, we recognized cash gains on natural gas derivatives of $39.2 million and non-cash mark-to-market gains on natural gas derivatives of $2.9 million. The fair value of our natural gas derivative instruments at March 31, 2016 was a net asset of $104.1 million. An assumed increase in the forward prices used in the March 31, 2016 valuation of our natural gas derivatives of $1.00 per MMBtu would change our derivative valuation to a net liability of approximately $79 million at March 31, 2016. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $287 million at March 31, 2016.

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 ($327 million in receivables at March 31, 2016), our joint interest receivables ($218 million at March 31, 2016), and counterparty credit risk associated with our derivative instrument receivables ($107 million at March 31, 2016).

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 $89 million at March 31, 2016, 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 our co-owners 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. In February 2016, our corporate credit rating was downgraded by S&P and Moody's in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. These downgrades caused the interest rates on our revolving credit facility borrowings and three-year term loan to increase by 0.250% and 0.125%, respectively. 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 $1.37 billion of variable rate borrowings outstanding on our revolving credit facility and three-year term loan at April 29, 2016. The impact of a 0.25% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.4 million per year and a $2.1 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 March 31, 2016 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 March 31, 2016, 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.

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 2015 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 2015 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 2015 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 March 31, 2016:

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 (3)
January 1, 2016 to January 31, 2016	—	—	—	—
February 1, 2016 to February 29, 2016	262,613	$ 19.34	—	—
March 1, 2016 to March 31, 2016	391	22.98	—	—
Total	263,004	$ 19.34	—	—

(1) In connection with restricted stock grants under the Company's 2005 Long-Term Incentive Plan and 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.
(3) We are unable to determine at this time the total amount of securities or approximate dollar value of securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the vesting of restrictions on 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 in the Index to Exhibits accompanying this report and are incorporated herein by reference.

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:	May 4, 2016	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer
			(Duly Authorized Officer and Principal Financial Officer)

Index to Exhibits

3.1	Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarter ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 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