CONTINENTAL RESOURCES, INC
Form 10-Q
August 05, 2015
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 June 30, 2015

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

373,104,530 shares of our $0.01 par value common stock were outstanding on July 31, 2015.

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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 a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.
“field” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
“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.
"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 south central Oklahoma.
"undeveloped acreage" Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.
"unit" The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
"working interest" The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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

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

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

- our business and financial strategy;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- our 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 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 considers these expectations to be reasonable and based on reasonable assumptions, 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 our control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. 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, 2014, registration statements filed 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, our 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 otherwise required by applicable law, we do not intend, and disclaim any duty, to 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	June 30, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$25,458	$24,381
Receivables:		
Crude oil and natural gas sales	545,860	552,476
Affiliated parties	96	13,360
Joint interest and other, net	450,534	567,476
Derivative assets	50,214	52,423
Inventories	100,173	102,179
Deferred and prepaid taxes	13,283	63,266
Prepaid expenses and other	14,695	14,040
Total current assets	1,200,313	1,389,601
Net property and equipment, based on successful efforts method of accounting	14,169,202	13,635,852
Noncurrent derivative assets	22,015	31,992
Other noncurrent assets	18,321	18,588
Total assets	$15,409,851	$15,076,033
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$776,966	$1,263,724
Revenues and royalties payable	255,166	272,755
Payables to affiliated parties	757	7,305
Accrued liabilities and other	280,231	404,506
Derivative liabilities	339	1,645
Current portion of long-term debt	2,110	2,078
Total current liabilities	1,315,569	1,952,013
Long-term debt, net of current portion	6,988,046	5,926,800
Other noncurrent liabilities:		
Deferred income tax liabilities	2,156,268	2,141,447
Asset retirement obligations, net of current portion	82,069	75,462
Noncurrent derivative liabilities	828	3,109
Other noncurrent liabilities	11,044	9,358
Total other noncurrent liabilities	2,250,209	2,229,376
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; 373,074,092 shares issued and outstanding at June 30, 2015; 372,005,502 shares issued and outstanding at December 31, 2014	3,731	3,720
Additional paid-in capital	1,310,161	1,287,941
Accumulated other comprehensive loss	(2,865)	(385)

Retained earnings	3,545,000	3,676,568
Total shareholders’ equity	4,856,027	4,967,844
Total liabilities and shareholders’ equity	$15,409,851	$15,076,033

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 Income (Loss)

	Three months ended June 30,		Six months ended June 30,	
In thousands, except per share data	2015	2014	2015	2014
Revenues				
Crude oil and natural gas sales	$790,102	$1,112,998	$1,371,294	$2,085,145
Crude oil and natural gas sales to affiliates	—	25,087	1,400	55,273
Gain (loss) on derivative instruments, net	(4,737)	(262,524)	28,018	(302,198)
Crude oil and natural gas service operations	11,009	10,534	21,306	20,370
Total revenues	796,374	886,095	1,422,018	1,858,590
Operating costs and expenses				
Production expenses	91,667	84,236	183,021	160,211
Production expenses to affiliates	68	285	1,654	1,196
Production taxes and other expenses	61,545	97,025	109,908	175,327
Exploration expenses	109	11,205	14,449	16,018
Crude oil and natural gas service operations	7,092	5,979	10,986	14,053
Depreciation, depletion, amortization and accretion	452,957	326,871	839,469	599,732
Property impairments	76,872	79,316	224,432	137,524
General and administrative expenses	44,190	46,919	89,571	90,455
(Gain) loss on sale of assets, net	(20,573)	(2,135)	(22,643)	6,363
Total operating costs and expenses	713,927	649,701	1,450,847	1,200,879
Income (loss) from operations	82,447	236,394	(28,829)	657,711
Other income (expense):				
Interest expense	(78,442)	(72,841)	(153,505)	(135,816)
Other	540	793	886	1,552
	(77,902)	(72,048)	(152,619)	(134,264)
Income (loss) before income taxes	4,545	164,346	(181,448)	523,447
Provision (benefit) for income taxes	4,142	60,808	(49,880)	193,675
Net income (loss)	$403	$103,538	$(131,568)	$329,772
Basic net income (loss) per share	$—	$0.28	$(0.36)	$0.89
Diluted net income (loss) per share	$—	$0.28	$(0.36)	$0.89
Comprehensive income (loss):				
Net income (loss)	$403	$103,538	$(131,568)	$329,772
Other comprehensive income (loss), net of tax:				
Foreign currency translation adjustments	625	—	(2,480)	—
Total other comprehensive income (loss), net of tax	625	—	(2,480)	—
Comprehensive income (loss)	$1,028	$103,538	$(134,048)	$329,772

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, 2014	372,005,502	$3,720	$1,287,941	$ (385)	$3,676,568	$4,967,844
Net loss (unaudited)	—	—	—	—	(131,568)	(131,568)
Other comprehensive loss, net of tax (unaudited)	—	—	—	(2,480)	—	(2,480)
Stock-based compensation (unaudited)	—	—	27,411	—	—	27,411
Restricted stock:						
Granted (unaudited)	1,338,699	13	—	—	—	13
Repurchased and canceled (unaudited)	(109,462)	(1)	(5,191)	—	—	(5,192)
Forfeited (unaudited)	(160,647)	(1)	—	—	—	(1)
Balance at June 30, 2015 (unaudited)	373,074,092	$3,731	$1,310,161	$ (2,865)	$3,545,000	$4,856,027

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

	Six months ended June 30,	
In thousands	2015	2014
Cash flows from operating activities		
Net income (loss)	$(131,568)	$329,772
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	838,216	606,638
Property impairments	224,432	137,524
Non-cash (gain) loss on derivatives, net	8,599	204,791
Stock-based compensation	27,429	26,017
Provision (benefit) for deferred income taxes	(49,890)	190,571
Dry hole costs	8,003	4,383
(Gain) loss on sale of assets, net	(22,643)	6,363
Other, net	5,388	4,411
Changes in assets and liabilities:		
Accounts receivable	138,882	(144,821)
Inventories	1,938	(23,519)
Other current assets	50,561	(7,938)
Accounts payable trade	(106,174)	44,505
Revenues and royalties payable	(17,589)	42,051
Accrued liabilities and other	(60,162)	9,186
Other noncurrent assets and liabilities	1,390	2,519
Net cash provided by operating activities	916,812	1,432,453
Cash flows from investing activities		
Exploration and development	(1,972,887)	(2,052,870)
Purchase of producing crude oil and natural gas properties	(557)	(33,606)
Purchase of other property and equipment	(22,449)	(29,829)
Proceeds from sale of assets	32,590	39,018
Net cash used in investing activities	(1,963,303)	(2,077,287)
Cash flows from financing activities		
Credit facility borrowings	1,375,000	1,105,000
Repayment of credit facility	(315,000)	(1,380,000)
Proceeds from issuance of Senior Notes	—	1,681,834
Repayment of other debt	(1,032)	(999)
Debt issuance costs	(2,110)	(7,874)
Repurchase of restricted stock for tax withholdings	(5,192)	(4,646)
Net cash provided by financing activities	1,051,666	1,393,315
Effect of exchange rate changes on cash	(4,098)	—
Net change in cash and cash equivalents	1,077	748,481
Cash and cash equivalents at beginning of period	24,381	28,482
Cash and cash equivalents at end of period	$25,458	$776,963

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

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Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements
Note 1. Organization and Nature of Business
Continental Resources, Inc. (the “Company”) was originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company's principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including various plays in the South Central Oklahoma Oil Province (“SCOOP”), Northwest Cana, and Arkoma areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.
The Company’s operations are geographically concentrated in the North region, with that region comprising 70% of the Company’s crude oil and natural gas production and 79% of its crude oil and natural gas revenues for the six months ended June 30, 2015. 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 and announcement of the SCOOP play in Oklahoma. The South region now comprises 30% of the Company's crude oil and natural gas production and 21% of its crude oil and natural gas revenues for the six months ended June 30, 2015.
The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the six months ended June 30, 2015, crude oil accounted for 68% of the Company’s total production and 86% 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. All significant intercompany accounts and transactions have been eliminated upon consolidation.
On August 18, 2014, the Company's Board of Directors declared a 2-for-1 stock split of the Company's common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. Previously reported common stock and earnings per share amounts for the three and six months ended June 30, 2014 have been retroactively adjusted in the accompanying financial statements and related notes to reflect the stock split.
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, 2014 (“2014 Form 10-K”), which includes a summary of the Company’s significant accounting policies and other disclosures.
The condensed consolidated financial statements as of June 30, 2015 and for the three and six month periods ended June 30, 2015 and 2014 are unaudited. The condensed consolidated balance sheet as of December 31, 2014 was derived from the audited balance sheet included in the 2014 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.

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

Earnings per share

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. Diluted net income (loss) per share reflects the potential dilution of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share for the three and six months ended June 30, 2015 and 2014.

	Three months ended June 30,		Six months ended June 30,	
In thousands, except per share data	2015	2014	2015	2014
Income (loss) (numerator):				
Net income (loss) - basic and diluted	$403	$103,538	$(131,568)	$329,772
Weighted average shares (denominator):				
Weighted average shares - basic	369,510	368,746	369,448	368,702
Non-vested restricted stock (1)	1,363	1,588	—	1,686
Weighted average shares - diluted	370,873	370,334	369,448	370,388
Net income (loss) per share:				
Basic	$—	$0.28	$(0.36)	$0.89
Diluted	$—	$0.28	$(0.36)	$0.89

(1) The potential dilutive effect of 1,472,300 weighted average restricted shares were not included in the calculation of diluted net loss per share for the six months ended June 30, 2015 because to do so would have been anti-dilutive.

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 June 30, 2015 and December 31, 2014 consisted of the following:

In thousands	June 30, 2015	December 31, 2014
Tubular goods and equipment	$16,690	$15,659
Crude oil	83,483	86,520
Total	$100,173	$102,179

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. 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 $1.3 million and $12.4 million for the three and six months ended June 30, 2015, respectively, against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary in 2015 for which the Company does not expect to realize a benefit.

Affiliate transactions

The affiliate transactions reflected in the accompanying unaudited condensed consolidated statements of comprehensive income (loss) include transactions between the Company and Hiland Partners, LP and its subsidiaries ("Hiland"). Hiland was controlled by the Company's principal shareholder through February 13, 2015, at which time it was sold to an unaffiliated third party. As a result of the sale, the related party relationship that existed previously between the Company and Hiland terminated as of February 13, 2015, which resulted in a reduction in affiliate transactions recognized in the Company's financial statements at June 30, 2015 and for the three and six months then ended.

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

Adoption of new accounting pronouncement

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). The new standard requires debt issuance costs related to a recognized term debt liability, such as the Company's senior notes and note payable, be presented in the balance sheet as a direct deduction from the carrying amount of that term debt liability, consistent with the presentation of a debt discount. Under previous guidance, debt issuance costs were required to be presented in the balance sheet as an asset. The new standard does not affect the existing recognition and measurement guidance for debt issuance costs. The new standard is effective for annual and interim periods beginning after December 15, 2015, with early adoption permitted.

The Company early adopted ASU 2015-03 as of June 30, 2015 on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified unamortized debt issuance costs associated with its senior notes and note payable, which totaled $65.7 million and $69.0 million as of June 30, 2015 and December 31, 2014, respectively, from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion" on the condensed consolidated balance sheets. Adoption of ASU 2015-03 had no impact on the Company's current and previously reported shareholders' equity, results of operations, or cash flows. The December 31, 2014 carrying amounts for the Company's senior notes and note payable presented throughout this report on Form 10-Q have been adjusted to reflect the retroactive adoption of ASU 2015-03. Unamortized debt issuance costs associated with the Company's credit facility, which amounted to $8.1 million and $7.0 million as of June 30, 2015 and December 31, 2014, respectively, were not reclassified and remain reflected in "Other noncurrent assets" on the condensed consolidated balance sheets.

Note 3. Supplemental Cash Flow Information

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

	Six months ended June 30,	
In thousands	2015	2014
Supplemental cash flow information:		
Cash paid for interest	$148,454	$122,879
Cash paid for income taxes	27	2,012
Cash received for income tax refunds	50,000	5
Non-cash investing activities:		
Increase (decrease) in accrued capital expenditures	(387,113)	115,956
Asset retirement obligation additions and revisions, net	4,945	3,710

Note 4. Derivative Instruments

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

The Company may utilize swap and collar derivative contracts to economically hedge against the variability in cash flows associated with the sale of future 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.

With respect to a 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 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, the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price, and 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.

Continental Resources, Inc. and Subsidiaries
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The Company’s derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate (“WTI”) pricing or 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.

At June 30, 2015, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
July 2015 - December 2015			
Written call options - WTI (1)	2,208,000	$95.85 - $103.75	$98.36

Crude Oil - ICE Brent		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
July 2015 - December 2015			
Written call options - ICE Brent (1)	368,000	$107.40	$107.40
January 2016 - December 2016			
Written call options - ICE Brent (1)	1,464,000	$107.70	$107.70

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
July 2015 - December 2015						
Swaps - Henry Hub	7,360,000	$4.16				
Collars - Henry Hub	14,720,000		$3.50 - $3.75	$3.69	$4.89 - $5.48	$5.04
January 2016 - December 2016						
Swaps - Henry Hub	75,930,000	$3.85				
January 2017 - December 2017						
Swaps - Henry Hub	25,550,000	$3.35				

(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.

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Derivative gains and losses

The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open 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.

	Three months ended June 30,		Six months ended June 30,	
In thousands	2015	2014	2015	2014
Cash received (paid) on derivatives:				
Crude oil fixed price swaps	$—	$(50,499)	$—	$(73,022)
Crude oil collars	—	(1,453)	—	(2,037)
Natural gas fixed price swaps	5,551	(12,191)	23,942	(22,348)
Natural gas collars	7,631	—	12,675	—
Cash received (paid) on derivatives, net	13,182	(64,143)	36,617	(97,407)
Non-cash gain (loss) on derivatives:				
Crude oil fixed price swaps	—	(201,482)	—	(187,792)
Crude oil collars	—	(4,369)	—	914
Crude oil written call options	3	—	3,927	—
Natural gas fixed price swaps	(9,296)	7,494	(2,804)	(17,907)
Natural gas collars	(8,626)	(24)	(9,722)	(6)
Non-cash gain (loss) on derivatives, net	(17,919)	(198,381)	(8,599)	(204,791)
Gain (loss) on derivative instruments, net	$(4,737)	$(262,524)	$28,018	$(302,198)

Balance sheet offsetting of derivative assets and liabilities

All of 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 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	June 30, 2015	December 31, 2014
Commodity derivative assets:		
Gross amounts of recognized assets	$72,275	$84,415
Gross amounts offset on balance sheet	(46)	—
Net amounts of assets on balance sheet	72,229	84,415
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(1,167)	(4,770)
Gross amounts offset on balance sheet	—	16
Net amounts of liabilities on balance sheet	$(1,167)	$(4,754)

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

In thousands	June 30, 2015	December 31, 2014
Derivative assets	$50,214	$52,423
Noncurrent derivative assets	22,015	31,992
Net amounts of assets on balance sheet	72,229	84,415
Derivative liabilities	(339)	(1,645)
Noncurrent derivative liabilities	(828)	(3,109)
Net amounts of liabilities on balance sheet	(1,167)	(4,754)
Total derivative assets, net	$71,062	$79,661

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.
- 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 fixed price swaps, 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 fixed price swaps 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 commodity prices, 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.

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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 June 30, 2015 and December 31, 2014.

	Fair value measurements at June 30, 2015 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$59,795	$—	$59,795
Collars	—	12,094	—	12,094
Written call options	—	(827)	—	(827)
Total	$—	$71,062	$—	$71,062

	Fair value measurements at December 31, 2014 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$62,599	$—	$62,599
Collars	—	21,816	—	21,816
Written call options	—	(4,754)	—	(4,754)
Total	$—	$79,661	$—	$79,661

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 management's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development 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 2019 (adjusted for differentials), escalating 3% per year thereafter
Operating and development costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 0 to 50 years
Discount rate	10%

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

During the periods ended June 30, 2015 and June 30, 2014, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows and, therefore, were impaired. Impairments of proved properties amounted to $5.0 million and $75.0 million for the three and six months ended June 30, 2015, respectively, resulting from depressed commodity prices that indicated the carrying amounts for certain fields were not recoverable. The 2015 year to date impairments reflect fair value adjustments primarily concentrated in an emerging area with limited production history and costly reserve additions ($41.2 million, including $5.0 million in the second quarter), the Medicine Pole Hills units ($14.7 million), various non-core areas in the South region ($11.0 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.

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Impairments of proved properties totaled $27.5 million and $31.3 million for the three and six months ended June 30, 2014, respectively, which primarily reflect fair value adjustments made for certain properties in non-core areas of the South region. The impaired properties were written down to their estimated fair value totaling approximately $10.2 million as of June 30, 2014.

Certain unproved crude oil and natural gas properties were impaired during the three and six months ended June 30, 2015 and 2014, reflecting recurring amortization of undeveloped leasehold costs on properties that management expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

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

	Three months ended June 30,		Six months ended June 30,	
In thousands	2015	2014	2015	2014
Proved property impairments	$5,028	$27,529	$75,043	$31,291
Unproved property impairments	71,844	51,787	149,389	106,233
Total	$76,872	$79,316	$224,432	$137,524

Financial Instruments Not Recorded at Fair Value

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

	June 30, 2015		December 31, 2014	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$1,225,000	$1,225,000	$165,000	$165,000
Note payable	15,349	13,600	16,375	14,900
7.375% Senior Notes due 2020	196,278	211,200	195,997	213,000
7.125% Senior Notes due 2021	395,007	426,000	394,668	421,000
5% Senior Notes due 2022	1,996,664	1,970,000	1,996,507	1,857,900
4.5% Senior Notes due 2023	1,481,446	1,439,800	1,480,479	1,372,800
3.8% Senior Notes due 2024	989,431	910,800	988,940	868,700
4.9% Senior Notes due 2044	690,981	589,300	690,912	572,400
Total debt	$6,990,156	$6,785,700	$5,928,878	$5,485,700

The fair value of credit facility borrowings approximates carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is 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.

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Note 6. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $50.3 million and $52.6 million at June 30, 2015 and December 31, 2014, respectively, consists of the following. See Note 2. Basis of Presentation and Significant Accounting Policies—Adoption of new accounting pronouncement for a discussion of the impact on long-term debt from the Company's June 30, 2015 adoption of ASU 2015-03.

In thousands	June 30, 2015	December 31, 2014
Credit facility	$1,225,000	$165,000
Note payable	15,349	16,375
7.375% Senior Notes due 2020	196,278	195,997
7.125% Senior Notes due 2021	395,007	394,668
5% Senior Notes due 2022	1,996,664	1,996,507
4.5% Senior Notes due 2023	1,481,446	1,480,479
3.8% Senior Notes due 2024	989,431	988,940
4.9% Senior Notes due 2044	690,981	690,912
Total debt	$6,990,156	$5,928,878
Less: Current portion of long-term debt	2,110	2,078
Long-term debt, net of current portion	$6,988,046	$5,926,800

Credit Facility

The Company has an unsecured credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

The Company had $1.23 billion and $165 million of outstanding borrowings on its credit facility at June 30, 2015 and December 31, 2014, respectively. Borrowings bear interest at market-based interest rates plus a margin that is based on the terms of the borrowing and the credit ratings assigned to the Company's senior unsecured debt. The weighted-average interest rate on outstanding borrowings at June 30, 2015 was 1.7%.

The Company had approximately $1.27 billion of borrowing availability on its credit facility at June 30, 2015 and incurs commitment fees based on currently assigned credit ratings of 0.225% per annum on the daily average amount of unused borrowing availability.

The 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 this covenant at June 30, 2015.

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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 June 30, 2015.

	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)	Oct 1, 2015	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 and 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 June 30, 2015. 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. The Company's other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

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 $2.1 million is reflected as a current liability under the caption "Current portion of long-term debt" in the condensed consolidated balance sheets as of June 30, 2015.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of June 30, 2015. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of June 30, 2015, the Company had drilling rig contracts with various terms extending through March 2019. These contracts were entered into in the ordinary course of business to ensure rig availability to allow the Company to execute its business objectives in its strategic plays. Future commitments as of June 30, 2015 total approximately $536 million, of which $121 million is expected to be incurred in the remainder of 2015, $220 million in 2016, $129 million in 2017, $61 million in 2018, and $5 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 June 30, 2015 under the operational pipeline transportation arrangements amount to approximately $1.1 billion, of which $104 million is expected to be incurred in the remainder of 2015, $213 million in 2016, $210 million in 2017, $205 million in 2018, $170 million in 2019, and $217 million thereafter.

Further, the Company was a party to a five year firm transportation commitment (the "Agreement") for a future crude oil pipeline project being considered for development that is not yet operational. The project requires the granting of regulatory approvals and requires additional construction efforts by the counterparty before being completed. The project has faced significant delays and has failed to gain the necessary permits and approvals. As a result of the persistent delays and continuous uncertainty, the Agreement’s basic assumptions and purpose have become commercially impracticable. Accordingly, in 2015 the Company provided a shipper termination notice pursuant to the Agreement and formally provided the counterparty with the Company’s termination of the Agreement in its entirety. The Company's previously disclosed commitments under the Agreement totaled approximately $260 million, which is no longer expected to be incurred.

The Company’s pipeline commitments are for production primarily in the North region where the Company allocates a significant portion of its capital expenditures. 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 entered into 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 the normal course of drilling operations. Over the remaining contract term, the Company has committed to purchase approximately 21 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 June 30, 2015 total approximately $61 million, of which $30 million is expected to be incurred in the remainder of 2015 and $31 million is expected to be incurred in 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 alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the Petition 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. In addition, 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 also filed an Amended Motion for Class Certification 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 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 appealed the trial court’s class certification order, which will be reviewed de novo by the appellate court. 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 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 June 30, 2015 and December 31, 2014, the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $3.7 million and $2.9 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.

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Note 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan (“2005 Plan”) and 2013 Long-Term Incentive Plan ("2013 Plan") as discussed below. The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the unaudited condensed consolidated statements of comprehensive income (loss), was $16.2 million and $15.0 million for the three months ended June 30, 2015 and 2014, respectively, and $27.4 million and $26.0 million for the six months ended June 30, 2015 and 2014, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved a maximum of 19,680,072 shares of common stock that may be issued pursuant to the plan. The 2013 Plan replaced the Company's 2005 Plan as the instrument used to grant long-term incentive awards and no further awards will be granted under the 2005 Plan. However, restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. As of June 30, 2015, the Company had a maximum of 16,958,144 shares of restricted stock available to grant to officers, directors and select 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 six months ended June 30, 2015 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2014	2,678,764	$49.40
Granted	1,338,699	47.77
Vested	(360,172)	45.95
Forfeited	(160,647)	52.69
Non-vested restricted shares outstanding at June 30, 2015	3,496,644	$48.98

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. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value of restricted stock that vested during the six months ended June 30, 2015 at the vesting date was approximately $17.0 million. As of June 30, 2015, there was approximately $98 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 1.6 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 and six months ended June 30, 2015:

In thousands	Three months ended June 30, 2015	Six months ended June 30, 2015
Beginning accumulated other comprehensive loss, net of tax	$(3,490)	$(385)
Foreign currency translation adjustments	625	(2,480)
Income tax (expense) benefit (1)	—	—
Other comprehensive income (loss), net of tax	625	(2,480)
Ending accumulated other comprehensive loss, net of tax	$(2,865)	$(2,865)

(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) for the period.

Note 10. Property Dispositions

In May 2015, the Company assigned certain non-producing leasehold acreage in Oklahoma to a third party for $25.9 million and recognized a pre-tax gain on the transaction of $20.5 million. The assigned properties represented an immaterial portion of the Company's leasehold acreage.

During the six months ended June 30, 2014, the Company sold certain non-strategic properties in various areas to third parties for proceeds totaling $39.0 million. In connection with the transactions, the Company recognized pre-tax losses totaling $6.4 million. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

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 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, 2014. 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, 2014, 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 play in Oklahoma.

Business Environment and Outlook

Commodity prices have remained depressed through June 30, 2015 and continue to be volatile and unpredictable. Management's plans and related capital projections for the remainder of 2015 are reflective of the depressed commodity price environment. Our 2015 capital budget has been established based on an expectation of available cash flows from operations and availability under our credit facility. We will continue to monitor our capital spending closely based on actual and projected cash flows and could scale back our remaining 2015 spending should commodity prices remain at current levels or decrease. Conversely, a significant improvement in crude oil prices could result in an increase in our capital expenditures.

Under our current capital plan, we are seeking to generally align our capital expenditures with operating cash flows for the remainder of 2015, which we expect will slow our rate of capital spending, credit facility borrowings, and production growth in the third and fourth quarters compared to levels achieved through June 30, 2015. Accordingly, our results achieved through June 30, 2015 may not be indicative of the results to be achieved for the remainder of 2015.

Management believes we are positioned to withstand the current weakness in commodity prices and remains confident in the Company's underlying financial strength to manage the challenges presented in this price environment. We believe the depth and quality of our asset base coupled with our financial strength allow us to be adaptable in a variety of price environments. We will continue to manage through this downturn focusing on operating efficiencies, reducing costs, and maintaining our financial strength.

2015 Highlights

Production

Production for the second quarter of 2015 averaged 226,547 Boe per day, an increase of 10% from the first quarter of 2015 and 35% higher than the second quarter of 2014. Year to date production averaged 216,742 Boe per day, a 35% increase over the comparable 2014 period.

North Dakota Bakken production averaged 127,872 Boe per day for the second quarter of 2015, a 6% increase over the first quarter of 2015 and 35% higher than the second quarter of 2014. Year to date, North Dakota Bakken production averaged 124,434 Boe per day, a 39% increase over the comparable 2014 period.

SCOOP production averaged 62,546 Boe per day for the second quarter of 2015, a 25% increase over the first quarter of 2015 and 83% higher than the second quarter of 2014. Year to date, SCOOP production averaged 56,249 Boe per day, a 77% increase over the comparable 2014 period.

SCOOP comprised 28% of our total production for the 2015 second quarter compared to 24% for the 2015 first quarter and 20% for the 2014 second quarter. SCOOP comprised 26% of our total production for year to date 2015 compared to 20% for the comparable 2014 period.

Revenues

Crude oil and natural gas revenues for the 2015 second quarter decreased 31% compared to the 2014 second quarter driven by a 49% decrease in realized commodity prices, the effect of which was partially offset by a 36% increase in total sales volumes.

Year to date crude oil and natural gas revenues decreased 36% from the comparable 2014 period driven by a 53% decrease in realized commodity prices, the effect of which was partially offset by a 37% increase in total sales volumes.

Average crude oil sales prices for the second quarter and year to date periods of 2015 decreased 46% and 51%, respectively, from the comparable 2014 periods.

Crude oil sales volumes for the second quarter and year to date periods of 2015 increased 30% and 34%, respectively, from the comparable 2014 periods.

Average natural gas sales prices for the second quarter and year to date periods of 2015 decreased 57% and 60%, respectively, from the comparable 2014 periods.

Natural gas sales volumes for the second quarter and year to date periods of 2015 increased 49% and 43%, respectively, from the comparable 2014 periods.

Proved property impairments

Depressed commodity prices and downward revisions to proved reserves in the second quarter of 2015 adversely impacted the recoverability of capitalized costs in certain operating areas and contributed to the recognition of non-cash impairment charges for proved properties totaling $5.0 million for the second quarter, bringing year to date proved property impairments to $75.0 million through June 30, 2015. These impairments were primarily concentrated in non-core areas of our North and South regions.

Capital expenditures and drilling activity

We invested approximately $585.5 million in our capital program in the second quarter of 2015, excluding $6.4 million of unbudgeted acquisitions, bringing our year to date non-acquisition capital expenditures to $1.57 billion through June 30, 2015.

For the second quarter and year to date periods of 2015 we participated in the completion of the following number of wells by area:

	Three months ended June 30, 2015		Six months ended June 30, 2015	
	Gross	Net	Gross	Net
North Dakota Bakken	158	56	367	116
Montana Bakken	1	—	9	6
SCOOP	55	18	131	54
Northwest Cana	5	2	5	2
Other	4	—	16	6
Total wells	223	76	528	184

As of June 30, 2015, we operated 27 rigs on our properties, down from 49 operated rigs at December 31, 2014.

Credit facility and liquidity

At June 30, 2015, we had $25.5 million of cash and cash equivalents and $1.27 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $1.23 billion of outstanding borrowings on our credit facility at June 30, 2015 compared to $955 million at March 31, 2015 and $165 million at December 31, 2014. At July 31, 2015, we continued to have $1.23 billion of outstanding borrowings and $1.27 billion of borrowing availability on our credit facility.

Credit facility borrowings, net of repayments, totaled $270 million for the 2015 second quarter compared to $790 million for the 2015 first quarter, the decrease of which resulted from higher crude oil market prices compared to the first quarter and a reduced level of capital expenditures from our efforts to align capital expenditures with operating cash flows in the second quarter.

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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Average daily production:				
Crude oil (Bbl per day)	149,897	116,441	146,722	111,447
Natural gas (Mcf per day)	459,898	309,074	420,123	292,847
Crude oil equivalents (Boe per day)	226,547	167,953	216,742	160,255
Average sales prices:				
Crude oil ($/Bbl)	$49.84	$92.31	$44.46	$91.12
Natural gas ($/Mcf)	$2.31	$5.43	$2.48	$6.20
Crude oil equivalents ($/Boe)	$37.82	$74.09	$34.93	$74.53
Crude oil sales price differential to NYMEX ($/Bbl)	$(8.18)	$(10.69)	$(9.05)	$(9.90)
Natural gas sales price premium (differential) to NYMEX ($/Mcf)	$(0.33)	$0.76	$(0.31)	$1.41
Production expenses ($/Boe)	$4.39	$5.50	$4.70	$5.62
Production taxes (% of oil and gas revenues)	7.8%	8.3%	8.0%	8.0%
DD&A ($/Boe)	$21.68	$21.28	$21.36	$20.88
General and administrative expenses ($/Boe) (1)	$1.34	$2.08	$1.58	$2.24
Non-cash equity compensation ($/Boe)	$0.77	$0.98	$0.70	$0.91
Net income (loss) (in thousands)	$403	$103,538	$(131,568)	$329,772
Diluted net income (loss) per share	$—	$0.28	$(0.36)	$0.89
EBITDAX (in thousands) (2)	$647,009	$867,938	$1,086,435	$1,643,345

(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, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided below under the heading Non-GAAP Financial Measures.

Three months ended June 30, 2015 compared to the three months ended June 30, 2014

Results of Operations

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

	Three months ended June 30,	
In thousands, except sales price data	2015	2014
Crude oil and natural gas sales	$790,102	$1,138,085
Loss on derivative instruments, net	(4,737)	(262,524)
Crude oil and natural gas service operations	11,009	10,534
Total revenues	796,374	886,095
Operating costs and expenses	(713,927)	(649,701)
Other expenses, net	(77,902)	(72,048)
Income before income taxes	4,545	164,346
Provision for income taxes	(4,142)	(60,808)
Net income	$403	$103,538
Production volumes:		
Crude oil (MBbl)	13,641	10,596
Natural gas (MMcf)	41,851	28,126
Crude oil equivalents (MBoe)	20,616	15,284
Sales volumes:		
Crude oil (MBbl)	13,917	10,674
Natural gas (MMcf)	41,851	28,126
Crude oil equivalents (MBoe)	20,892	15,362
Average sales prices:		
Crude oil ($/Bbl)	$49.84	$92.31
Natural gas ($/Mcf)	2.31	5.43
Crude oil equivalents ($/Boe)	37.82	74.09

Production

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

	Three months ended June 30,				Volume increase	Volume percent increase
	2015		2014			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	13,641	66 %	10,596	69 %	3,045	29 %
Natural gas (MMcf)	41,851	34 %	28,126	31 %	13,725	49 %
Total (MBoe)	20,616	100 %	15,284	100 %	5,332	35 %

	Three months ended June 30,				Volume increase	Volume percent increase
	2015		2014			
	MBoe	Percent	MBoe	Percent		
North Region	14,150	69 %	11,253	74 %	2,897	26 %
South Region	6,466	31 %	4,031	26 %	2,435	60 %
Total	20,616	100 %	15,284	100 %	5,332	35 %

The 29% increase in crude oil production for the second quarter was driven by increased production from our properties in the Bakken field and SCOOP play. Production in the Bakken field increased 2,172 MBbls, or 26%, over the prior year second quarter, while SCOOP production increased 959 MBbls, or 118%. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease in production from our properties in the Red River units totaling 124 MBbls, or 10%, compared to the prior year second quarter due to a combination of natural declines in production and reduced drilling activity.

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The 49% increase in natural gas production for the second quarter was driven by increased production from our properties in the Bakken field and SCOOP play due to additional wells being completed and producing and gas from existing wells being connected to natural gas processing plants subsequent to June 30, 2014. Natural gas production in the Bakken field increased 4,663 MMcf, or 55%, over the prior year second quarter, while SCOOP production increased 9,690 MMcf, or 70%. 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.

Our 35% quarter-over-quarter growth in total production is not expected to be sustained for the remainder of 2015. Our ongoing reduction in capital spending for 2015 is expected to have a more significant impact on our year-over-year production growth in the third and fourth quarters and we expect our production for the second half of 2015 will generally be flat compared to production for the first half of 2015.

Revenues

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

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the second quarter of 2015 were $790.1 million, a 31% decrease from sales of $1,138.1 million for the same period in 2014 primarily due to a significant decrease in commodity prices.

Our crude oil sales prices averaged $49.84 per barrel in the 2015 second quarter compared to $92.31 for the 2014 second quarter. Market prices for crude oil remained depressed in the 2015 second quarter, resulting in significantly lower realized sales prices compared to the prior year. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel was $8.18 for the 2015 second quarter compared to $10.69 for the 2014 second quarter. The improved differential was due in part to increased availability and use of pipeline transportation to move our crude oil to market with less dependence on more costly rail transportation.

Our average natural gas sales price for the 2015 second quarter decreased to $2.31 per Mcf compared to $5.43 for the 2014 second quarter due to lower market prices for natural gas and natural gas liquids ("NGLs"). Our natural gas production is primarily sold at the wellhead with price realizations being impacted by the volume and value of NGLs that purchasers retrieve from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a differential of $0.33 per Mcf for the 2015 second quarter compared to a premium of $0.76 for the 2014 second quarter. NGL prices remained depressed in the 2015 second quarter in conjunction with 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.

Crude oil, natural gas and NGL prices remain volatile and we are unable to predict the impact future price changes may have on our full year 2015 revenues and differentials.

Our sales volumes for the second quarter of 2015 increased 5,530 MBoe, or 36%, over the comparable period in 2014 primarily due to an increase in producing wells due to the success of our drilling programs in the Bakken field and SCOOP play. 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. Operating efficiencies achieved during the second quarter on new third party pipeline systems provided for improved transportation of our crude oil to market, which resulted in the sale of crude oil previously stored in inventory at March 31, 2015 and caused crude oil sales volumes to be higher than crude oil production by 276 MBbls for the second quarter of 2015.

Derivatives. Changes in commodity prices during the second quarter of 2015 had a negative impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $4.7 million for the period. 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 commodity prices.

The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

In thousands	Three months ended June 30, 2015	2014
Cash received (paid) on derivatives:		
Crude oil derivatives	$—	$(51,952)
Natural gas derivatives	13,182	(12,191)
Cash received (paid) on derivatives, net	13,182	(64,143)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	3	(205,851)
Natural gas derivatives	(17,922)	7,470
Non-cash gain (loss) on derivatives, net	(17,919)	(198,381)
Gain (loss) on derivative instruments, net	$(4,737)	$(262,524)

Operating Costs and Expenses

Production Expenses. Production expenses increased 9% to $91.7 million for the second quarter of 2015 from $84.5 million for the second quarter of 2014. This increase was primarily the result of an increase in the number of producing wells and resulting 36% increase in sales volumes over the prior year period.

Production expense per Boe decreased to $4.39 for the 2015 second quarter compared to $5.50 for the 2014 second quarter. This per-Boe decrease resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, a higher portion of our production coming from natural gas wells in the SCOOP area which typically have lower operating costs compared to other areas, and a 36% increase in sales volumes from new well completions.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $35.5 million, or 37%, to $61.5 million for the second quarter of 2015 compared to $97.0 million for the second quarter of 2014 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 as a percentage of crude oil and natural gas revenues were 7.8% for the second quarter of 2015 compared to 8.3% for the second quarter of 2014, the difference of which resulted from changes in the mix of crude oil and natural gas sales volumes and values and the proportion of taxable revenues coming from North Dakota and Oklahoma between periods.

Production taxes are generally based on the wellhead values of production and vary by state. Some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, certain horizontal wells are taxed at a lower rate during their initial months of production which subsequently increases after a specified period of time or when specified production volumes are achieved.

Through June 30, 2015, revenues from new wells in Oklahoma were taxed at 1% for the first 48 months of production, after which the tax rate increases to 7%. Effective July 1, 2015, the tax rate on new Oklahoma wells spud after that date was changed to 2% for the first 36 months of production and 7% thereafter.

At June 30, 2015, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax for a combined tax of 11.5% of crude oil revenues. In April 2015, new legislation was signed into law in North Dakota that eliminated the then-existing price-based oil extraction tax incentives and set a lower oil extraction tax rate. The new law reduces the oil extraction tax from 6.5% to 5% effective January 1, 2016, resulting in a total tax of 10% on crude oil revenues when combined with the 5% production tax which was not changed by the new law. Under the new law, the oil extraction tax will increase from 5% to 6%, for a total tax rate of 11%, if the average WTI oil price is above $90 per barrel (indexed for inflation) for three consecutive months. The oil extraction tax will revert back to 5% if the average WTI oil price falls below $90 per barrel for three consecutive months.

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 June 30,	
In thousands	2015	2014
Geological and geophysical costs	$109	$6,732
Exploratory dry hole costs	—	4,473
Exploration expenses	$109	$11,205

The decrease in geological and geophysical expenses in the second quarter of 2015 was due to changes in the timing and amount of costs incurred by the Company and recouped from joint interest partners between periods.

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $126.1 million, or 39%, to $453.0 million for the second quarter of 2015 compared to $326.9 million for the second quarter of 2014 primarily due to a 36% 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 June 30,	
$/Boe	2015	2014
Crude oil and natural gas	$21.32	$20.93
Other equipment	0.31	0.30
Asset retirement obligation accretion	0.05	0.05
Depreciation, depletion, amortization and accretion	$21.68	$21.28

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. The increase in our DD&A rate for crude oil and natural gas properties in the current period resulted from downward revisions of proved reserves in 2015 prompted by depressed commodity prices.

If commodity prices remain at current levels or decline further, additional revisions of proved reserves may occur in the future, which may be significant and could result in a further increase in our DD&A rate in the second half of 2015. We are unable to predict the timing and amount of future reserve revisions, nor the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments decreased $2.4 million, or 3%, to $76.9 million for the second quarter of 2015 compared to $79.3 million for the 2014 second quarter.

Impairments of proved properties totaled $5.0 million for the second quarter of 2015 compared to $27.5 million for the second quarter of 2014. The 2015 second quarter impairments reflect fair value adjustments prompted by depressed commodity prices in an emerging area with limited production history and costly reserve additions. Estimated proved reserves are a key component in assessing proved properties for impairment. If commodity prices remain at current levels or decline further, downward revisions of proved reserves may be significant in the future and could result in additional impairments of proved properties in the second half of 2015. We are unable to predict the timing and amount of future reserve revisions, nor the impact such revisions may have on future impairments, if any.

Impairments of non-producing properties increased $20.0 million for the second quarter of 2015 to $71.8 million compared to $51.8 million for the second quarter of 2014. The increase was primarily due to higher rates of amortization being applied to undeveloped leasehold costs resulting from changes in management’s estimates of undeveloped properties not expected to be developed before lease expiration, particularly in response to decreased commodity prices which have altered our drilling plans. Our rates of amortization may continue to increase in future periods if commodity prices remain at current levels or decline further and additional changes are made to drilling plans.

General and Administrative ("G&A") Expenses. G&A expenses decreased $2.7 million, or 6%, to $44.2 million for the second quarter of 2015 from $46.9 million for the 2014 second quarter. G&A expenses include non-cash charges for equity compensation of $16.2 million and $15.0 million for the second quarters of 2015 and 2014, respectively.

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

	Three months ended June 30,	
$/Boe	2015	2014
General and administrative expenses	$1.34	$2.08
Non-cash equity compensation	0.77	0.98
Total general and administrative expenses	$2.11	$3.06

The decrease in G&A expenses on a per-Boe basis in 2015 was driven by curtailed spending, deferral of hiring, and smaller increases in personnel costs compared to the prior year in response to depressed commodity prices, coupled with a 36% increase in sales volumes from new well completions.

The decrease in equity compensation expense on a per-Boe basis was primarily due to the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

Interest Expense. Interest expense increased $5.6 million, or 8%, to $78.4 million for the second quarter of 2015 compared to $72.8 million for the second quarter of 2014 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the 2015 second quarter was approximately $7.1 billion with a weighted average interest rate of 4.3% compared to averages of $5.6 billion and 5.0% for the 2014 second quarter. The increase in outstanding debt resulted from borrowings incurred subsequent to June 30, 2014 to fund our 2014 and 2015 capital programs.

Income Taxes. We recorded income tax expense for the second quarter of 2015 of $4.1 million compared to $60.8 million for the second quarter of 2014, resulting in effective tax rates of approximately 91% and 37%, respectively, after taking into account permanent taxable differences and valuation allowances. For the 2015 second quarter, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax income generated by our operations in the United States. Our 2015 second quarter effective tax rate was increased by a $1.3 million valuation allowance recognized against deferred tax assets associated with $6.4 million of operating loss carryforwards generated by our Canadian subsidiary in the 2015 second quarter for which we do not believe we will realize a benefit.

Six months ended June 30, 2015 compared to the six months ended June 30, 2014

Results of Operations

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

	Six months ended June 30,	
In thousands, except sales price data	2015	2014
Crude oil and natural gas sales	$1,372,694	$2,140,418
Gain (loss) on derivative instruments, net	28,018	(302,198)
Crude oil and natural gas service operations	21,306	20,370
Total revenues	1,422,018	1,858,590
Operating costs and expenses	(1,450,847)	(1,200,879)
Other expenses, net	(152,619)	(134,264)
Income (loss) before income taxes	(181,448)	523,447
(Provision) benefit for income taxes	49,880	(193,675)
Net income (loss)	$(131,568)	$329,772
Production volumes:		
Crude oil (MBbl)	26,557	20,172
Natural gas (MMcf)	76,043	53,005
Crude oil equivalents (MBoe)	39,231	29,006
Sales volumes:		
Crude oil (MBbl)	26,628	19,887
Natural gas (MMcf)	76,043	53,005
Crude oil equivalents (MBoe)	39,301	28,721
Average sales prices:		
Crude oil ($/Bbl)	$44.46	$91.12
Natural gas ($/Mcf)	2.48	6.20
Crude oil equivalents ($/Boe)	34.93	74.53

Production

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

	Six months ended June 30,				Volume increase	Volume percent increase
	2015		2014			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	26,557	68 %	20,172	70 %	6,385	32 %
Natural gas (MMcf)	76,043	32 %	53,005	30 %	23,038	43 %
Total (MBoe)	39,231	100 %	29,006	100 %	10,225	35 %

	Six months ended June 30,				Volume increase	Volume percent increase
	2015		2014			
	MBoe	Percent	MBoe	Percent		
North Region	27,576	70 %	21,371	74 %	6,205	29 %
South Region	11,655	30 %	7,635	26 %	4,020	53 %
Total	39,231	100 %	29,006	100 %	10,225	35 %

The 32% increase in crude oil production for year to date 2015 was driven by increased production from our properties in the Bakken field and SCOOP play. Production in the Bakken field increased 4,836 MBbls, or 30%, over the prior year period, while SCOOP production increased 1,746 MBbls, or 116%. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease in production from our properties in the Red River units totaling 235 MBbls, or 10%, compared to the prior year due to a combination of natural declines in production and reduced drilling activity.

The 43% increase in natural gas production for year to date 2015 was driven by increased production from our properties in the Bakken field and SCOOP play due to additional wells being completed and producing and gas from existing wells being connected to natural gas processing plants subsequent to June 30, 2014. Natural gas production in the Bakken field increased 9,249 MMcf, or 59%, over the prior year, while SCOOP production increased 16,043 MMcf, or 63%. 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.

Our 35% year-over-year growth in total production is not expected to be sustained for the remainder of 2015. Our ongoing reduction in capital spending for 2015 is expected to have a more significant impact on our year-over-year production growth in the third and fourth quarters and we expect our production for the second half of 2015 will generally be flat compared to production for the first half of 2015.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for year to date 2015 were $1.37 billion, a 36% decrease from sales of $2.14 billion for the same period in 2014 primarily due to a significant decrease in commodity prices.

Our crude oil sales prices averaged $44.46 per barrel for year to date 2015 compared to $91.12 for year to date 2014. Market prices for crude oil have remained depressed in the first half of 2015, resulting in significantly lower realized sales prices compared to the prior year. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for year to date 2015 was $9.05 per barrel compared to $9.90 for year to date 2014. The improved differential was due in part to increased availability and use of pipeline transportation in the current year to move our crude oil to market with less dependence on more costly rail transportation.

Our average natural gas sales price for year to date 2015 decreased to $2.48 per Mcf compared to $6.20 for year to date 2014 due to lower market prices for natural gas and NGLs. Our natural gas production is primarily sold at the wellhead with price realizations being impacted by the volume and value of NGLs that purchasers retrieve from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a differential of $0.31 per Mcf for year to date 2015 compared to a premium of $1.41 for the comparable 2014 period. NGL prices in the first half of 2015 have remained depressed in conjunction with low crude oil prices, which has reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing.

Crude oil, natural gas and NGL prices remain volatile and we are unable to predict the impact future price changes may have on our full year 2015 revenues and differentials.

Our sales volumes for year to date 2015 increased 10,580 MBoe, or 37%, over the comparable period in 2014 primarily due to an increase in producing wells due to the success of our drilling programs in the Bakken field and SCOOP play.

Derivatives. Changes in commodity prices during the six months ended June 30, 2015 had a favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $28.0 million for the period. The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Six months ended June 30,	
In thousands	2015	2014
Cash received (paid) on derivatives:		
Crude oil derivatives	$—	$(75,059)
Natural gas derivatives	36,617	(22,348)
Cash received (paid) on derivatives, net	36,617	(97,407)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	3,927	(186,878)
Natural gas derivatives	(12,526)	(17,913)
Non-cash gain (loss) on derivatives, net	(8,599)	(204,791)
Gain (loss) on derivative instruments, net	$28,018	$(302,198)

Crude Oil and Natural Gas Service Operations. Revenues from our service operations primarily consist of income generated from water transportation, water recycling activities, and the sale of reclaimed crude oil. The increase in operating income generated by our service operations in the first six months of 2015 over the first six months of 2014 was driven by the expansion of Company-owned water recycling facilities in the SCOOP area.

Operating Costs and Expenses

Production Expenses. Production expenses increased 14% to $184.7 million for year to date 2015 from $161.4 million during the comparable 2014 period. This increase was primarily the result of an increase in the number of producing wells and resulting 37% increase in sales volumes over the prior year period.

Production expense per Boe decreased to $4.70 for year to date 2015 compared to $5.62 for year to date 2014. This per Boe decrease resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, a higher portion of our production coming from natural gas wells in the SCOOP area which typically have lower operating costs compared to other areas, and a 37% increase in sales volumes from new well completions.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $65.4 million, or 37%, to $109.9 million for year to date 2015 compared to $175.3 million for year to date 2014 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 as a percentage of crude oil and natural gas revenues were 8.0% for both year to date 2015 and year to date 2014.

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

	Six months ended June 30,	
In thousands	2015	2014
Geological and geophysical costs	$6,446	$11,635
Exploratory dry hole costs	8,003	4,383
Exploration expenses	$14,449	$16,018

The decrease in geological and geophysical expenses in 2015 was due to changes in the timing and amount of costs incurred by the Company and recouped from joint interest partners between periods.

Dry hole costs incurred in 2015 primarily reflect costs associated with an unsuccessful well in a prospect in our North region that is in the early stages of exploration.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $239.8 million, or 40%, to $839.5 million for year to date 2015 compared to $599.7 million for the comparable period in 2014 primarily due to a 37% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Six months ended June 30,	
$/Boe	2015	2014
Crude oil and natural gas	$20.98	$20.53
Other equipment	0.32	0.29
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$21.36	$20.88

The increase in our DD&A rate for crude oil and natural gas properties in the current period resulted from downward revisions of proved reserves in 2015 prompted by depressed commodity prices. If commodity prices remain at current levels or decline further, additional revisions of proved reserves may occur in the future, which may be significant and could result in a further increase in our DD&A rate in the second half of 2015. We are unable to predict the timing and amount of future reserve revisions, nor the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments increased $86.9 million, or 63%, to $224.4 million for year to date 2015 compared to $137.5 million for year to date 2014.

Impairments of proved properties increased $43.7 million for year to date 2015 to $75.0 million compared to $31.3 million for year to date 2014 due to higher write-downs resulting from depressed commodity prices in 2015 that adversely impacted the recoverability of capitalized costs in certain operating areas. The 2015 impairments were primarily concentrated in an emerging area with limited production history and costly reserve additions ($41.2 million, including $5.0 million in the second quarter), the Medicine Pole Hills units ($14.7 million), various non-core areas in the South region ($11.0 million), and non-Bakken areas of North Dakota and Montana ($8.1 million).

If commodity prices remain at current levels or decline further, downward revisions of proved reserves may be significant in the future and could result in additional impairments of proved properties in the second half of 2015. We are unable to predict the timing and amount of future reserve revisions, nor the impact such revisions may have on future impairments, if any.

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Impairments of non-producing properties increased $43.2 million for year to date 2015 to $149.4 million compared to $106.2 million for year to date 2014. The increase was primarily due to higher rates of amortization being applied to undeveloped leasehold costs resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration, particularly in response to decreased commodity prices which have altered our drilling plans. Our rates of amortization may continue to increase in future periods if commodity prices remain at current levels or decline further and additional changes are made to drilling plans.

General and Administrative Expenses. G&A expenses decreased $0.9 million, or 1%, to $89.6 million for year to date 2015 from $90.5 million for the comparable period in 2014. G&A expenses include non-cash charges for equity compensation of $27.4 million and $26.0 million for year to date 2015 and year to date 2014, respectively.

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

	Six months ended June 30,	
$/Boe	2015	2014
General and administrative expenses	$1.58	$2.24
Non-cash equity compensation	0.70	0.91
Total general and administrative expenses	$2.28	$3.15

The decrease in G&A expenses on a per-Boe basis in 2015 was driven by curtailed spending, deferral of hiring, and smaller increases in personnel costs compared to the prior year in response to depressed commodity prices, coupled with a 37% increase in sales volumes from new well completions.

The decrease in equity compensation expense on a per-Boe basis was due to an increase in the estimated rate of forfeitures of unvested restricted stock based on historical experience, which resulted in lower recognition of expense in 2015, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

Interest Expense. Year to date interest expense increased $17.7 million, or 13%, to $153.5 million compared to $135.8 million for the comparable 2014 period due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for year to date 2015 was approximately $6.7 billion with a weighted average interest rate of 4.5% compared to averages of $5.3 billion and 5.0% for the comparable period in 2014. The increase in outstanding debt resulted from borrowings incurred subsequent to June 30, 2014 to fund our 2014 and 2015 capital programs.

Income Taxes. We recorded an income tax benefit for the six months ended June 30, 2015 of $49.9 million compared to income tax expense of $193.7 million for the prior year period, resulting in effective tax rates of approximately 27% and 37%, respectively, after taking into account permanent taxable differences and valuation allowances. For year to date 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 2015 effective tax rate was reduced by a $12.4 million valuation allowance recognized against deferred tax assets associated with $50.2 million of operating loss carryforwards generated by our Canadian subsidiary in 2015 for which we do not believe we will realize a benefit.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt and equity securities. At June 30, 2015, we had $25.5 million of cash and cash equivalents and $1.27 billion of borrowing availability on our credit facility after considering $1.23 billion of outstanding borrowings and letters of credit. At July 31, 2015, we continued to have $1.23 billion of outstanding borrowings and $1.27 billion of borrowing availability on our credit facility.

Based on our planned capital expenditures, our forecasted operating cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of June 30, 2015, 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 $916.8 million and $1,432.5 million for the six months ended June 30, 2015 and 2014, respectively. The decrease in operating cash flows was primarily due to lower crude oil and natural gas revenues driven by lower realized commodity prices along with increases in production expenses and interest expense associated with the growth of our Company and an increase in producing well count over the past year, all partially offset by lower production taxes and an increase in cash gains on matured derivatives.

If commodity prices remain at current levels or decline further, we expect our operating cash flows for the remainder of 2015 will continue to be lower than 2014 levels.

Cash flows used in investing activities

During the six months ended June 30, 2015 and 2014, we had cash flows used in investing activities (excluding proceeds from asset sales) of $1,995.9 million and $2,116.3 million, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $43.2 million and $107.6 million for the six months ended June 30, 2015 and 2014, respectively. Cash capital expenditures excluding acquisitions totaled $1,952.7 million and $2,008.7 million for the six months ended June 30, 2015 and 2014, respectively. Our cash capital expenditures for 2015 include the payment of amounts owed at December 31, 2014 in connection with our 2014 drilling program and associated $387.1 million decrease in accruals for capital expenditures for the six months ended June 30, 2015.

The use of cash for capital expenditures in 2015 and 2014 was partially offset by proceeds received from asset dispositions, which totaled $32.6 million and $39.0 million for the six months ended June 30, 2015 and 2014, respectively.

Cash flows from financing activities

Net cash provided by financing activities for the six months ended June 30, 2015 was $1,051.7 million primarily resulting from net borrowings incurred on our credit facility during the period. Our 2015 operating cash flows were adversely impacted by decreased commodity prices, leading to a $1,060 million net increase in credit facility borrowings incurred for the payment of amounts owed in connection with our 2014 drilling program and to fund a portion of our 2015 drilling program.

Net cash provided by financing activities for the six months ended June 30, 2014 was $1,393.3 million primarily resulting from the receipt of $1.68 billion of net proceeds from the issuances of $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 in May 2014, partially offset by net repayments of $275 million on our credit facility.

Our levels of capital expenditures and credit facility borrowings incurred through June 30, 2015 are not expected to be continued at the same rate for the remainder of 2015. Under our current capital plan, we are seeking to generally align our capital expenditures with operating cash flows for the remainder of 2015 which we expect will result in reduced capital spending and credit facility borrowings in the third and fourth quarters compared to levels incurred through year to date June 30, 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 credit facility, including our ability to increase our borrowing capacity thereunder, 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 the next 12 months. Our capital expenditures budget for the remainder of 2015 is reflective of the depressed commodity price environment and has been established based on an expectation of available cash flows from operations and availability under our credit facility. If operating cash flows are materially impacted by a further decline in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability on our 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 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 finance future capital expenditures primarily through cash flows from operations and through borrowings under our 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.

Credit facility

We have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.5 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 15 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of July 31, 2015, we had $1.23 billion of outstanding borrowings and $1.27 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit.

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

Our 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 credit facility covenants at June 30, 2015 and expect to maintain compliance for at least the next 12 months. At June 30, 2015, our consolidated net debt to total capitalization ratio, as defined in our credit facility as amended, was 0.57 to 1.00. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent. At June 30, 2015, our total debt would have needed to independently increase by approximately $2.9 billion, or 41%, 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 $1.5 billion, or 29%, below existing levels at June 30, 2015 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.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at June 30, 2015. 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 June 30, 2015 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 or equity financing. A downgrade or other negative rating action with respect to the credit ratings assigned to our senior unsecured debt does not trigger additional senior note covenants that are more restrictive than the existing covenants at June 30, 2015.

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. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Capital expenditures

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

Our capital expenditures budget for 2015 is $2.7 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$2,370
Land costs	180
Capital facilities, workovers and other corporate assets	138
Seismic	12
Total 2015 capital budget, excluding acquisitions	$2,700

During the six months ended June 30, 2015, we participated in the completion of 528 gross (184 net) wells and invested approximately $1,569.3 million in our capital program, excluding $43.2 million of unbudgeted acquisitions, excluding $387.1 million of capital costs associated with decreased accruals for capital expenditures, and including $3.8 million of seismic costs. Our 2015 year to date capital expenditures were allocated as follows by quarter:

In millions	1Q 2015	2Q 2015	YTD 2015
Exploration and development drilling	$914.2	$518.3	$1,432.5
Land costs	27.1	19.9	47.0
Capital facilities, workovers and other corporate assets	40.9	45.1	86.0
Seismic	1.6	2.2	3.8
Capital expenditures, excluding acquisitions	983.8	585.5	1,569.3
Acquisitions of producing properties	0.1	0.4	0.5
Acquisitions of non-producing properties	36.7	6.0	42.7
Total acquisitions	36.8	6.4	43.2
Total capital expenditures	$1,020.6	$591.9	$1,612.5

Our 2015 capital program is focused primarily on development drilling in the North Dakota Bakken and SCOOP plays, focusing on core areas of the plays that have the greatest potential to improve recoveries and rates of return. Our year to date capital expenditures incurred through June 30, 2015 are slightly below budget at mid-year. If our current rate of spending continues, our capital expenditures may be as much as $150 million below our full year 2015 budget of $2.7 billion by year-end.

Our 2015 capital program has been established based on an expectation of available cash flows from operations and availability under our 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 will continue to monitor our capital spending closely based on actual and projected cash flows and could scale back our remaining 2015 spending should commodity prices remain at current levels or decrease. 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 June 30, 2015. We believe our cash flows from operations, our remaining cash balance, and amounts available under our credit facility, including our ability to increase our borrowing capacity thereunder, 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 2014 Form 10-K.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our 2014 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, non-cash equity compensation expense, and losses on extinguishment of debt. 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 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 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 income (loss) to EBITDAX for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
In thousands	2015	2014	2015	2014
Net income (loss)	$403	$103,538	$(131,568)	$329,772
Interest expense	78,442	72,841	153,505	135,816
Provision (benefit) for income taxes	4,142	60,808	(49,880)	193,675
Depreciation, depletion, amortization and accretion	452,957	326,871	839,469	599,732
Property impairments	76,872	79,316	224,432	137,524
Exploration expenses	109	11,205	14,449	16,018
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	4,737	262,524	(28,018)	302,198
Cash received (paid) on derivatives, net	13,182	(64,143)	36,617	(97,407)
Non-cash (gain) loss on derivatives, net	17,919	198,381	8,599	204,791
Non-cash equity compensation	16,165	14,978	27,429	26,017
EBITDAX	$647,009	$867,938	$1,086,435	$1,643,345

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

	Six months ended June 30,	
In thousands	2015	2014
Net cash provided by operating activities	$916,812	$1,432,453
Current income tax provision	10	3,104
Interest expense	153,505	135,816
Exploration expenses, excluding dry hole costs	6,446	11,635
Gain (loss) on sale of assets, net	22,643	(6,363)
Other, net	(4,135)	(11,317)
Changes in assets and liabilities	(8,846)	78,017

EBITDAX	$1,086,435	$1,643,345

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, interest rate risk and foreign currency exchange 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 pricing applicable to 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 six months ended June 30, 2015, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $536 million for each $10.00 per barrel change in crude oil prices and $153 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds to be used for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize favorable 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 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Changes in commodity prices during the six months ended June 30, 2015 had an overall favorable impact on the fair value of our derivative instruments. For the six months ended June 30, 2015, we recognized cash gains on derivatives of $36.6 million partially offset by a non-cash mark-to-market loss on derivatives of $8.6 million.

The fair value of our crude oil derivative instruments at June 30, 2015 was a net liability of $0.8 million. An assumed increase in the forward prices used in the June 30, 2015 valuation of our crude oil derivatives of $10.00 per barrel would increase our crude oil derivative liability to approximately $2.3 million at June 30, 2015. Conversely, an assumed decrease in forward prices of $10.00 per barrel would decrease our crude oil derivative liability to approximately $0.3 million at June 30, 2015.

The fair value of our natural gas derivative instruments at June 30, 2015 was a net asset of $71.9 million. An assumed increase in the forward prices used in the June 30, 2015 valuation of our natural gas derivatives of $1.00 per MMBtu would change our derivative valuation to a net liability of approximately $43.0 million at June 30, 2015. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $190.4 million at June 30, 2015.

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 ($546 million in receivables at June 30, 2015), our joint interest receivables ($451 million at June 30, 2015), and counterparty credit risk associated with our derivative instrument receivables ($72 million at June 30, 2015).

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 support 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 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 $86 million at June 30, 2015, 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 credit facility. 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 $1.23 billion of outstanding borrowings on our credit facility at July 31, 2015 with a weighted average interest rate of 1.7%. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $12.3 million per year and a $7.6 million decrease in net income per year.

Foreign Currency Exchange Risk. The assets, liabilities, revenues, expenses and cash flows associated with our Canadian subsidiary are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiary are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flows are translated using an average exchange rate during the reporting period. A 10% change in the Canadian-to-U.S. dollar exchange rate would not materially impact our June 30, 2015 balance sheet.

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 that the Company’s disclosure controls and procedures were effective as of June 30, 2015 to ensure that 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 that 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 June 30, 2015, 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

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 alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the Petition 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. In addition, 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 also filed an Amended Motion for Class Certification 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 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 appealed the trial court's class certification order, which will be reviewed de novo by the appellate court. 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.

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 2014 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 2014 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 2014 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 June 30, 2015:

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)

April 1, 2015 to April 30, 2015	6,855	$49.96	—	—
May 1, 2015 to May 31, 2015	32,514	47.46	—	—
June 1, 2015 to June 30, 2015	6,647	45.82	—	—
Total	46,016	$47.59	—	—

(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 Internal Revenue Service.

(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:	August 5, 2015	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.
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.
10.1	Amendment No. 1 dated May 4, 2015 to the Revolving Credit Agreement dated as of May 16, 2014 among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC, as guarantors, the lenders party thereto, and MUFG Union Bank, N.A., as Administrative Agent, filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended March 31, 2015 (Commission File No. 001-32886) filed May 6, 2015 and incorporated herein by reference.
10.2*†	Summary of Non-Employee Director Compensation Approved as of May 19, 2015 to be effective July 1, 2015.
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
‡ This exhibit is being filed pursuant to Item 601(b)(3)(i) of Regulation S-K which requires a conformed version of our charter reflecting all amendments in one document. The exhibit reflects our Third Amended and Restated Certificate of Incorporation as filed with the Oklahoma Secretary of State on May 17, 2007 revised for the amendment filed on June 15, 2015, which changed the first sentence of Article Four by increasing the total number of authorized shares from 525,000,000 to 1,025,000,000 and the total authorized common shares from 500,000,000 to 1,000,000,000 as approved by shareholders on May 19, 2015.
† Management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.