CONTINENTAL RESOURCES, INC
Form 10-Q
August 03, 2016
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-32886

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
374,561,751 shares of our $0.01 par value common stock were outstanding on July 31, 2016.

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

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:
“Bbl” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.
“Boe” Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.
“Btu” British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.
“completion” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.
“DD&A” Depreciation, depletion, amortization and accretion.
“developed acreage” The number of acres allocated or assignable to productive wells or wells capable of production.
“development well” A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
“dry hole” Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.
“enhanced recovery” The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.
“exploratory well” A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.
“field” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
“formation” A layer of rock which has distinct characteristics that differs from nearby rock.
"gross acres" or "gross wells" Refers to the total acres or wells in which a working interest is owned.
“horizontal drilling” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.
“MBbl” One thousand barrels of crude oil, condensate or natural gas liquids.
“MBoe” One thousand Boe.
“Mcf” One thousand cubic feet of natural gas.
“MMBoe” One million Boe.
“MMBtu” One million British thermal units.
“MMcf” One million cubic feet of natural gas.
“net acres” or "net wells" Refers to the sum of the fractional working interests owned in gross acres or gross wells.
“NYMEX” The New York Mercantile Exchange.
“play” A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

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

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

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

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“royalty interest” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

“SCOOP” Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love Counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.

"STACK" Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec and Osage formations overlying the Woodford formation. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer Counties of Oklahoma.

“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“working interest” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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

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

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

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

Forward-looking statements are based on the Company’s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate or will not change over time. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under Part II, Item 1A. Risk Factors and elsewhere in this report, if any, our Annual Report on Form 10-K for the year ended December 31, 2015, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

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

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

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

| | June 30, 2016 | December 31, 2015 |
|---|---|---|
| In thousands, except par values and share data | (Unaudited) | |
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $16,560 | $11,463 |
| Receivables: | | |
| Crude oil and natural gas sales | 385,483 | 378,622 |
| Affiliated parties | 96 | 122 |
| Joint interest and other, net | 260,784 | 232,293 |
| Derivative assets | 16,693 | 93,922 |
| Inventories | 102,896 | 94,151 |
| Prepaid expenses and other | 14,700 | 11,766 |
| Total current assets | 797,212 | 822,339 |
| Net property and equipment, based on successful efforts method of accounting | 13,541,129 | 14,063,328 |
| Noncurrent derivative assets | 3,045 | 14,560 |
| Other noncurrent assets | 18,350 | 19,581 |
| Total assets | $14,359,736 | $14,919,808 |
| | | |
| Liabilities and shareholders' equity | | |
| Current liabilities: | | |
| Accounts payable trade | $412,851 | $553,285 |
| Revenues and royalties payable | 186,258 | 187,000 |
| Payables to affiliated parties | 185 | 69 |
| Accrued liabilities and other | 192,359 | 176,947 |
| Derivative liabilities | 24,227 | 3,583 |
| Current portion of long-term debt | 2,179 | 2,144 |
| Total current liabilities | 818,059 | 923,028 |
| Long-term debt, net of current portion | 7,149,279 | 7,115,644 |
| Other noncurrent liabilities: | | |
| Deferred income tax liabilities, net | 1,896,238 | 2,090,228 |
| Asset retirement obligations, net of current portion | 105,277 | 101,251 |
| Noncurrent derivative liabilities | 9,290 | 3,706 |
| Other noncurrent liabilities | 14,644 | 17,051 |
| Total other noncurrent liabilities | 2,025,449 | 2,212,236 |
| Commitments and contingencies (Note 7) | | |
| Shareholders' equity: | | |
| Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding | — | — |
| Common stock, $0.01 par value; 1,000,000,000 shares authorized; 374,581,304 shares issued and outstanding at June 30, 2016; 372,959,080 shares issued and outstanding at December 31, 2015 | 3,746 | 3,730 |
| Additional paid-in capital | 1,360,933 | 1,345,624 |
| Accumulated other comprehensive loss | (2,903) | (3,354) |
| Retained earnings | 3,005,173 | 3,322,900 |
| Total shareholders' equity | 4,366,949 | 4,668,900 |

| | | |
|---|---|---|
| Total liabilities and shareholders' equity | $14,359,736 | $14,919,808 |

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

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands, except per share data | 2016 | 2015 | 2016 | 2015 |
| Revenues | | | | |
| Crude oil and natural gas sales | $525,711 | $790,102 | $929,302 | $1,371,294 |
| Crude oil and natural gas sales to affiliates | — | — | — | 1,400 |
| Gain (loss) on crude oil and natural gas derivatives, net | (82,257) | (4,737) | (40,145) | 28,018 |
| Crude oil and natural gas service operations | 7,757 | 11,009 | 15,227 | 21,306 |
| Total revenues | 451,211 | 796,374 | 904,384 | 1,422,018 |
| | | | | |
| Operating costs and expenses | | | | |
| Production expenses | 74,083 | 91,667 | 152,724 | 183,021 |
| Production expenses to affiliates | — | 68 | — | 1,654 |
| Production taxes and other expenses | 39,141 | 61,545 | 69,634 | 109,908 |
| Exploration expenses | 1,674 | 109 | 4,739 | 14,449 |
| Crude oil and natural gas service operations | 3,576 | 7,092 | 6,618 | 10,986 |
| Depreciation, depletion, amortization and accretion | 441,761 | 452,957 | 905,752 | 839,469 |
| Property impairments | 66,112 | 76,872 | 145,039 | 224,432 |
| General and administrative expenses | 36,246 | 44,190 | 68,654 | 89,571 |
| Net gain on sale of assets and other | (100,835) | (20,573) | (99,127) | (22,643) |
| Total operating costs and expenses | 561,758 | 713,927 | 1,254,033 | 1,450,847 |
| Income (loss) from operations | (110,547) | 82,447 | (349,649) | (28,829) |
| Other income (expense): | | | | |
| Interest expense | (81,922) | (78,442) | (162,875) | (153,505) |
| Other | 435 | 540 | 819 | 886 |
| | (81,487) | (77,902) | (162,056) | (152,619) |
| Income (loss) before income taxes | (192,034) | 4,545 | (511,705) | (181,448) |
| Provision (benefit) for income taxes | (72,632) | 4,142 | (193,978) | (49,880) |
| Net income (loss) | $(119,402) | $403 | $(317,727) | $(131,568) |
| Basic net income (loss) per share | $(0.32) | $— | $(0.86) | $(0.36) |
| Diluted net income (loss) per share | $(0.32) | $— | $(0.86) | $(0.36) |
| | | | | |
| Comprehensive income (loss): | | | | |
| Net income (loss) | $(119,402) | $403 | $(317,727) | $(131,568) |
| Other comprehensive income (loss), net of tax: | | | | |
| Foreign currency translation adjustments | 25 | 625 | 451 | (2,480) |
| Total other comprehensive income (loss), net of tax | 25 | 625 | 451 | (2,480) |
| Comprehensive income (loss) | $(119,377) | $1,028 | $(317,276) | $(134,048) |

The accompanying notes are an integral part of these condensed consolidated financial statements.
2

Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statement of Shareholders' Equity

| In thousands, except share data | Shares outstanding | Common stock | Additional paid-in capital | Accumulated other comprehensive loss | Retained earnings | Total shareholders' equity |
|---|---|---|---|---|---|---|
| Balance at December 31, 2015 | 372,959,080 | $ 3,730 | $ 1,345,624 | $ (3,354) | $ 3,322,900 | $ 4,668,900 |
| Net loss (unaudited) | — | — | — | — | (317,727) | (317,727) |
| Other comprehensive income, net of tax (unaudited) | — | — | — | 451 | — | 451 |
| Stock-based compensation (unaudited) | — | — | 21,041 | — | — | 21,041 |
| Restricted stock: | | | | | | |
| Granted (unaudited) | 2,007,078 | 20 | — | — | — | 20 |
| Repurchased and canceled (unaudited) | (279,019) | (3) | (5,732) | — | — | (5,735) |
| Forfeited (unaudited) | (105,835) | (1) | — | — | — | (1) |
| Balance at June 30, 2016 (unaudited) | 374,581,304 | $ 3,746 | $ 1,360,933 | $ (2,903) | $ 3,005,173 | $ 4,366,949 |

The accompanying notes are an integral part of these condensed consolidated financial statements.
3

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

| | Six months ended June 30, | |
|---|---|---|
| In thousands | 2016 | 2015 |
| Cash flows from operating activities | | |
| Net loss | $(317,727) | $(131,568) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 908,021 | 838,216 |
| Property impairments | 145,039 | 224,432 |
| Non-cash loss on derivatives, net | 114,972 | 8,599 |
| Stock-based compensation | 21,046 | 27,429 |
| Benefit for deferred income taxes | (193,990) | (49,890) |
| Dry hole costs | 206 | 8,003 |
| Gain on sale of assets, net | (97,016) | (22,643) |
| Other, net | 4,752 | 5,388 |
| Changes in assets and liabilities: | | |
| Accounts receivable | (34,939) | 138,882 |
| Inventories | (8,745) | 1,938 |
| Other current assets | (2,125) | 50,561 |
| Accounts payable trade | (53,859) | (106,174) |
| Revenues and royalties payable | (742) | (17,589) |
| Accrued liabilities and other | 15,347 | (60,162) |
| Other noncurrent assets and liabilities | (2,519) | 1,390 |
| Net cash provided by operating activities | 497,721 | 916,812 |
| | | |
| Cash flows from investing activities | | |
| Exploration and development | (625,126) | (1,972,887) |
| Purchase of producing crude oil and natural gas properties | — | (557) |
| Purchase of other property and equipment | (4,867) | (22,449) |
| Proceeds from sale of assets and other | 112,199 | 32,590 |
| Net cash used in investing activities | (517,794) | (1,963,303) |
| | | |
| Cash flows from financing activities | | |
| Credit facility borrowings | 638,000 | 1,375,000 |
| Repayment of credit facility | (606,000) | (315,000) |
| Repayment of other debt | (1,064) | (1,032) |
| Debt issuance costs | (40) | (2,110) |
| Repurchase of restricted stock for tax withholdings | (5,735) | (5,192) |
| Net cash provided by financing activities | 25,161 | 1,051,666 |
| Effect of exchange rate changes on cash | 9 | (4,098) |
| Net change in cash and cash equivalents | 5,097 | 1,077 |
| Cash and cash equivalents at beginning of period | 11,463 | 24,381 |
| Cash and cash equivalents at end of period | $16,560 | $25,458 |

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

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

## Note 1. Organization and Nature of Business

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

A substantial portion of the Company's operations are concentrated in the North region, with that region comprising approximately 64% of the Company's crude oil and natural gas production and approximately 73% of its crude oil and natural gas revenues for the six months ended June 30, 2016. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. In recent years, the Company has significantly expanded its activity in the South region with its discovery of the SCOOP play and its increased activity in the Northwest Cana and STACK plays. The South region comprised approximately 36% of the Company's crude oil and natural gas production and approximately 27% of its crude oil and natural gas revenues for the six months ended June 30, 2016.

The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the six months ended June 30, 2016, crude oil accounted for approximately 62% of the Company's total production and approximately 87% of its crude oil and natural gas revenues.

## Note 2. Basis of Presentation and Significant Accounting Policies

### Basis of presentation

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

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States ("U.S. GAAP"), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Quarterly Report on Form 10-Q ("Form 10-Q") together with the Company's Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Form 10-K"), which includes a summary of the Company's significant accounting policies and other disclosures.

The condensed consolidated financial statements as of June 30, 2016 and for the three and six month periods ended June 30, 2016 and 2015 are unaudited. The condensed consolidated balance sheet as of December 31, 2015 was derived from the audited balance sheet included in the 2015 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these condensed consolidated financial statements.

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

Earnings per share

Basic and diluted net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects

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

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, 2016 and 2015.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands, except per share data | 2016 | 2015 | 2016 | 2015 |
| Income (loss) (numerator): | | | | |
| Net income (loss) - basic and diluted | $(119,402) | $ 403 | $(317,727) | $(131,568) |
| Weighted average shares (denominator): | | | | |
| Weighted average shares - basic | 370,435 | 369,510 | 370,248 | 369,448 |
| Non-vested restricted stock (1) | — | 1,363 | — | — |
| Weighted average shares - diluted | 370,435 | 370,873 | 370,248 | 369,448 |
| Net income (loss) per share: | | | | |
| Basic | $(0.32) | $ — | $(0.86) | $(0.36) |
| Diluted | $(0.32) | $ — | $(0.86) | $(0.36) |

(1) During the three and six months ended June 30, 2016 and the six months ended June 30, 2015, the Company had a net loss and therefore the potential dilutive effect of approximately 1,940,700, 1,486,200, and 1,472,300 weighted average restricted shares, respectively, were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computations.

Inventories

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

The components of inventory as of June 30, 2016 and December 31, 2015 consisted of the following:

| In thousands | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Tubular goods and equipment | $16,245 | $ 15,633 |
| Crude oil | 86,651 | 78,518 |
| Total | $102,896 | $ 94,151 |

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at period-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. The Company’s policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. The Company recorded valuation allowances of $0.2 million and $0.3 million for the three and six months ended June 30, 2016, respectively, and $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 for which the Company does not expect to realize a benefit.

New accounting pronouncements not yet adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2016-02, Leases (Topic 842), which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for interim and annual reporting periods beginning after December 15, 2018 and requires adoption by application of a modified retrospective transition approach. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

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In March 2016, the FASB issued Accounting Standards Update 2016-09, Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which changes how companies account for certain aspects of share-based payment awards, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2016 and shall be adopted either prospectively, retrospectively or using a modified retrospective transition approach depending on the topic covered in the standard. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures. The Company expects to continue its current accounting practice of estimating forfeitures in determining the amount of stock-based compensation expense to recognize.

Note 3. Supplemental Cash Flow Information
The following table discloses supplemental cash flow information about cash paid for interest and income tax payments and refunds. Also disclosed is information about investing activities that affects recognized assets and liabilities but has not yet resulted in cash receipts or payments.

| | Six months ended June 30, | |
|---|---|---|
| In thousands | 2016 | 2015 |
| Supplemental cash flow information: | | |
| Cash paid for interest | $156,358 | $148,454 |
| Cash paid for income taxes | — | 27 |
| Cash received for income tax refunds | 20 | 50,000 |
| Non-cash investing activities: | | |
| Asset retirement obligation additions and revisions, net | 1,042 | 4,945 |

As of June 30, 2016 and December 31, 2015, the Company had $196.3 million and $282.8 million, respectively, of accrued capital expenditures included in "Net property and equipment" and "Accounts payable trade" in the condensed consolidated balance sheets. As of June 30, 2015 and December 31, 2014, the Company had $410.3 million and $797.5 million, respectively, of accrued capital expenditures.

Note 4. Derivative Instruments
Crude oil and natural gas derivatives
The Company may utilize crude oil and natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of crude oil and natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.
The Company recognizes all crude oil and natural gas derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its crude oil and natural gas derivative instruments as hedges for accounting purposes and, as a result, marks such derivative instruments to fair value and recognizes the changes in fair value in the unaudited condensed consolidated statements of comprehensive income (loss) under the caption “Gain (loss) on crude oil and natural gas derivatives, net”, which is a component of "Total revenues".
With respect to a crude oil or natural gas fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a crude oil or natural gas collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.

The Company’s crude oil and natural gas derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Inter-Continental Exchange (“ICE”) pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. The estimated fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars and written call options, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars and written call options requires the use of an option-pricing model. See Note 5. Fair Value Measurements.

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At June 30, 2016, the Company had outstanding crude oil and natural gas derivative contracts with respect to future production as set forth in the tables below. The hedged volumes reflected below represent an aggregation of multiple derivative contracts that have varying durations and may not be realized on a ratable basis over the periods indicated.
Crude Oil - ICE Brent

| Period and Type of Contract | Bbls | Ceiling Price |
|---|---|---|
| July 2016 - December 2016 | | |
| Written call options - ICE Brent (1) | 736,000 | $107.70 |

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

| Natural Gas - NYMEX Henry Hub | | Swaps | Collars Floors | | Ceilings | |
|---|---|---|---|---|---|---|
| Period and Type of Contract | MMBtus | Weighted Average Price | Range | Weighted Average Price | Range | Weighted Average Price |
| July 2016 - December 2016 | | | | | | |
| Swaps - Henry Hub | 78,110,000 | $ 3.00 | | | | |
| January 2017 - December 2017 | | | | | | |
| Swaps - Henry Hub | 25,550,000 | $ 3.35 | | | | |
| Collars - Henry Hub | 65,700,000 | | $2.40 - $3.00 | $ 2.47 | $2.92 - $3.88 | $ 3.08 |

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands | 2016 | 2015 | 2016 | 2015 |
| Cash received on derivatives: | | | | |
| Natural gas fixed price swaps | $38,778 | $5,551 | $77,967 | $23,942 |
| Natural gas collars | — | 7,631 | — | 12,675 |
| Cash received on derivatives, net | 38,778 | 13,182 | 77,967 | 36,617 |
| Non-cash gain (loss) on derivatives: | | | | |
| Crude oil written call options | 6 | 3 | 38 | 3,927 |
| Natural gas fixed price swaps | (101,308) | (9,296) | (98,915) | (2,804) |
| Natural gas collars | (19,733) | (8,626) | (19,235) | (9,722) |
| Non-cash gain (loss) on derivatives, net | (121,035) | (17,919) | (118,112) | (8,599) |
| Gain (loss) on crude oil and natural gas derivatives, net | $(82,257) | $(4,737) | $(40,145) | $28,018 |

Diesel fuel derivatives
In March 2016, the Company entered into diesel fuel swap derivative contracts to economically hedge against the variability in cash flows associated with future purchases of diesel fuel for use in drilling activities. The Company has hedged approximately 19 million gallons of diesel fuel over the period from July 2016 to December 2017 at a weighted average price of $1.41 per gallon. With respect to these diesel fuel swap contracts, the counterparty is

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

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The Company recognizes its diesel fuel derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value is based upon various factors, including commodity exchange prices, over-the-counter quotations, the risk-free interest rate, and time to expiration. The Company has not designated its diesel fuel derivative instruments as hedges for accounting purposes and, as a result, marks the derivative instruments to fair value and recognizes the changes in fair value in the unaudited condensed consolidated statements of comprehensive income (loss) under the caption “Operating costs and expenses—Net gain on sale of assets and other.” For the three and six months ended June 30, 2016, the Company recognized non-cash gains of $4.2 million and $3.1 million, respectively, associated with its diesel fuel derivatives.

Balance sheet offsetting of derivative assets and liabilities

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

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

| In thousands | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Commodity derivative assets: | | |
| Gross amounts of recognized assets | $37,249 | $120,385 |
| Gross amounts offset on balance sheet | (17,511) | (11,903) |
| Net amounts of assets on balance sheet | 19,738 | 108,482 |
| Commodity derivative liabilities: | | |
| Gross amounts of recognized liabilities | (51,028) | (19,192) |
| Gross amounts offset on balance sheet | 17,511 | 11,903 |
| Net amounts of liabilities on balance sheet | $(33,517) | $(7,289) |

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

| In thousands | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Derivative assets | $16,693 | $ 93,922 |
| Noncurrent derivative assets | 3,045 | 14,560 |
| Net amounts of assets on balance sheet | 19,738 | 108,482 |
| Derivative liabilities | (24,227) | (3,583) |
| Noncurrent derivative liabilities | (9,290) | (3,706) |
| Net amounts of liabilities on balance sheet | (33,517) | (7,289) |
| Total derivative assets (liabilities), net | $(13,779) | $ 101,193 |

Note 5. Fair Value Measurements

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

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

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- Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of June 30, 2016 and December 31, 2015.

| | Fair value measurements at June 30, 2016 using: | | | |
|---|---|---|---|---|
| In thousands | Level 1 | Level 2 | Level 3 | Total |
| Derivative assets (liabilities): | | | | |
| Swaps | $ — | $ 8,652 | $ — | $ 8,652 |
| Collars | — | (22,430 ) | — | (22,430 ) |
| Written call options | — | (1 ) | — | (1 ) |
| Total | $ — | $ (13,779 ) | $ — | $ (13,779 ) |

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

Assets Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips adjusted for differentials, operating costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable

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inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

| Unobservable Input | Assumption |
|---|---|
| Future production | Future production estimates for each property |
| Forward commodity prices | Forward NYMEX strip prices through 2020 (adjusted for differentials), escalating 3% per year thereafter |
| Operating costs | Estimated costs for the current year, escalating 3% per year thereafter |
| Productive life of field | Ranging from 0 to 33 years |
| Discount rate | 10% |

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

Proved properties were reviewed for impairment at June 30, 2016 and June 30, 2015. For the three and six months ended June 30, 2016, estimated future net cash flows were determined to be in excess of cost basis, therefore no impairment was recorded for the Company’s proved crude oil and natural gas properties. For the three and six months ended June 30, 2015, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows at that time and, therefore, were impaired. Impairments of proved properties for the three and six months ended June 30, 2015 totaled $5.0 million and $75.0 million, respectively, and were primarily concentrated in an emerging area with minimal production and costly reserve additions ($41.2 million, including $5.0 million in the 2015 second quarter), the Medicine Pole Hills units ($14.7 million), various legacy 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 as of June 30, 2015.

Certain unproved crude oil and natural gas properties were impaired during the three and six months ended June 30, 2016 and 2015, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands | 2016 | 2015 | 2016 | 2015 |
| Proved property impairments | $— | $5,028 | $— | $75,043 |
| Unproved property impairments | 66,112 | 71,844 | 145,039 | 149,389 |
| Total | $66,112 | $76,872 | $145,039 | $224,432 |

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Financial Instruments Not Recorded at Fair Value

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

| In thousands | June 30, 2016 Carrying Amount | June 30, 2016 Estimated Fair Value | December 31, 2015 Carrying Amount | December 31, 2015 Estimated Fair Value |
|---|---|---|---|---|
| Debt: | | | | |
| Revolving credit facility | $885,000 | $885,000 | $853,000 | $853,000 |
| Term loan | 498,556 | 500,000 | 498,274 | 500,000 |
| Note payable | 13,251 | 12,000 | 14,309 | 12,500 |
| 7.375% Senior Notes due 2020 | 196,878 | 206,000 | 196,574 | 179,200 |
| 7.125% Senior Notes due 2021 | 395,732 | 414,000 | 395,365 | 388,300 |
| 5% Senior Notes due 2022 | 1,997,004 | 1,940,000 | 1,996,831 | 1,480,400 |
| 4.5% Senior Notes due 2023 | 1,483,470 | 1,398,800 | 1,482,451 | 1,061,000 |
| 3.8% Senior Notes due 2024 | 990,443 | 877,500 | 989,932 | 700,300 |
| 4.9% Senior Notes due 2044 | 691,124 | 590,800 | 691,052 | 430,500 |
| Total debt | $7,151,458 | $6,824,100 | $7,117,788 | $5,605,200 |

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

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

The fair values of the 7.375% Senior Notes due 2020 (“2020 Notes”), the 7.125% Senior Notes due 2021 (“2021 Notes”), the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 ("2023 Notes"), the 3.8% Senior Notes due 2024 ("2024 Notes"), and the 4.9% Senior Notes due 2044 ("2044 Notes") are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

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

Note 6. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $46.9 million and $49.6 million at June 30, 2016 and December 31, 2015, respectively, consists of the following.

| In thousands | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Revolving credit facility | $885,000 | $ 853,000 |
| Term loan | 498,556 | 498,274 |
| Note payable | 13,251 | 14,309 |
| 7.375% Senior Notes due 2020 | 196,878 | 196,574 |
| 7.125% Senior Notes due 2021 | 395,732 | 395,365 |
| 5% Senior Notes due 2022 | 1,997,004 | 1,996,831 |
| 4.5% Senior Notes due 2023 | 1,483,470 | 1,482,451 |
| 3.8% Senior Notes due 2024 | 990,443 | 989,932 |
| 4.9% Senior Notes due 2044 | 691,124 | 691,052 |
| Total debt | $7,151,458 | $ 7,117,788 |
| Less: Current portion of long-term debt | 2,179 | 2,144 |
| Long-term debt, net of current portion | $7,149,279 | $ 7,115,644 |

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Revolving Credit Facility

The Company has an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.75 billion at June 30, 2016, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

The Company had $885 million and $853 million of outstanding borrowings on its revolving credit facility at June 30, 2016 and December 31, 2015, respectively. Borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The weighted-average interest rate on outstanding borrowings at June 30, 2016 was 2.2%.

The Company had approximately $1.86 billion of borrowing availability on its revolving credit facility at June 30, 2016 and incurs commitment fees based on currently assigned credit ratings of 0.30% per annum on the daily average amount of unused borrowing availability under its revolving credit facility.

The revolving credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the revolving credit facility covenants at June 30, 2016.

Senior Notes

The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company’s outstanding senior note obligations at June 30, 2016.

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

(1) On or after these dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the decreasing redemption prices specified in the respective senior note indentures (together, the “Indentures”) plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to these dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the “make-whole” redemption prices or amounts specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

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

The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, and consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at June 30, 2016. Two of the Company’s subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company’s other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes as of June 30, 2016.

Term Loan

In November 2015, the Company borrowed $500 million under a three-year term loan agreement, the proceeds of which were used to repay a portion of the borrowings then outstanding on the Company's revolving credit facility. The term loan matures in full on November 4, 2018 and bears interest at a variable market-based interest rate plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The interest rate on the term loan at June 30, 2016 was 1.95%.

The term loan contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.0, consistent with the covenant requirement in the Company's revolving credit facility. The Company was in compliance with the term loan covenants at June 30, 2016.

Note Payable

In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.2 million is reflected as a current liability under the caption "Current portion of long-term debt" in the condensed consolidated balance sheets as of June 30, 2016.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of June 30, 2016. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of June 30, 2016, the Company had drilling rig contracts with various terms extending to year-end 2019 to ensure rig availability in its key operating areas. Future commitments as of June 30, 2016 total approximately $319 million, of which $97 million is expected to be incurred in the remainder of 2016, $136 million in 2017, $62 million in 2018, and $24 million in 2019.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on 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, 2016 under the pipeline transportation arrangements amount to approximately $893 million, of which $107 million is expected to be incurred in the remainder of 2016, $207 million in 2017, $208 million in 2018, $154 million in 2019, $47 million in 2020, and $170 million thereafter.

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

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a "hybrid class action" in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate "issues" for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the "hybrid" motion was briefed by plaintiffs and the Company. A hearing on the "hybrid" class certification was held on June 1st and 2nd, 2015. On June 11, 2015, the trial court certified a "hybrid" class as requested by plaintiffs. The Company has appealed the trial court's class certification order, which will be reviewed de novo by the appellate court. The appeal briefing is complete and ready for determination by the court. An unsuccessful mediation was conducted on December 7, 2015. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the action will have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. Although not currently at issue in the “hybrid” certification, plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, which may increase with the passage of time, a majority of which would be comprised of interest. The Company disputes plaintiffs’ claims, disputes that the case meets the requirements for a class action and is

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vigorously defending the case. The Company will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.

The Company is involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of both June 30, 2016 and December 31, 2015, the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $6.1 million for various matters, none of which are believed to be individually significant.

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

Note 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2013 Long-Term Incentive Plan ("2013 Plan") as discussed below. The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the unaudited condensed consolidated statements of comprehensive income (loss), was $11.8 million and $16.2 million for the three months ended June 30, 2016 and 2015, respectively, and $21.0 million and $27.4 million for the six months ended June 30, 2016 and 2015, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved 19,680,072 shares of common stock that may be issued pursuant to the plan. As of June 30, 2016, the Company had 15,177,005 shares of restricted stock available to grant to employees and directors under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company’s common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock 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, 2016 is presented below.

| | Number of non-vested shares | Weighted average grant-date fair value |
|---|---|---|
| Non-vested restricted shares outstanding at December 31, 2015 | 3,249,611 | $ 48.20 |
| Granted | 2,007,078 | 21.56 |
| Vested | (1,033,278) | 39.38 |
| Forfeited | (105,835 ) | 43.70 |
| Non-vested restricted shares outstanding at June 30, 2016 | 4,117,576 | $ 37.54 |

The grant date fair value of restricted stock represents the closing market price of the Company’s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value at the vesting date of restricted stock that vested during the six months ended June 30, 2016 was approximately $21.5 million. As of June 30, 2016, there was approximately $81 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.9 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, 2016 and 2015:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands | 2016 | 2015 | 2016 | 2015 |
| Beginning accumulated other comprehensive loss, net of tax | $(2,928) | $(3,490) | $(3,354) | $(385) |
| Foreign currency translation adjustments | 25 | 625 | 451 | (2,480) |
| Income taxes (1) | — | — | — | — |
| Other comprehensive income (loss), net of tax | 25 | 625 | 451 | (2,480) |
| Ending accumulated other comprehensive loss, net of tax | $(2,903) | $(2,865) | $(2,903) | $(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).

Note 10. Property Dispositions

In April 2016, the Company sold approximately 132,000 net acres of undeveloped leasehold acreage located in Wyoming to a third party for cash proceeds of $110.0 million. The proceeds were used to pay down a portion of outstanding borrowings on the Company's revolving credit facility. In connection with the transaction, the Company recognized a pre-tax gain of $96.9 million. The disposed properties represented an immaterial portion of the Company's total acreage and included no production or proved reserves.

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

Note 11. Subsequent Event

On August 2, 2016, the Company entered into an agreement to sell non-strategic producing and non-producing properties in the SCOOP play in Oklahoma to a third party for cash proceeds of $281 million. The disposition is expected to close in October 2016. The properties to be disposed represent an immaterial portion of the Company's total acreage, proved reserves, production, and revenues. The Company expects to use the sales proceeds to reduce outstanding debt.

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

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2015. Our operating results for the periods discussed below may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described in Part II, Item 1A. Risk Factors included in this report, if any, and in our Annual Report on Form 10-K for the year ended December 31, 2015, along with Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995 at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development and production of crude oil and natural gas. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas and expect this to continue in the future. Our operations are primarily focused on exploration and development activities in the Bakken field of North Dakota and Montana and the SCOOP, STACK, and Northwest Cana areas of Oklahoma.

Business Environment and Outlook

Commodity prices showed some signs of stabilization and recovery in the second quarter of 2016, but still remain volatile and unpredictable due to domestic and global supply and demand factors. In light of the challenges facing our industry, our primary business strategies for 2016 continue to focus on: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) high-grading investments based on rates of return and opportunities to convert undeveloped acreage to acreage held by production, and (3) balancing capital spending with cash flows to minimize new borrowings and maintain ample liquidity.

2016 Highlights

Production

Production for the second quarter of 2016 averaged 219,323 Boe per day, a decrease of 5% from the first quarter of 2016 and 3% lower than the second quarter of 2015. Year to date production averaged 225,063 Boe per day, a 4% increase from the comparable 2015 period.

North Dakota Bakken production averaged 114,554 Boe per day for the second quarter of 2016, an 11% decrease from the first quarter of 2016 and 10% lower than the second quarter of 2015. Year to date, North Dakota Bakken production averaged 121,861 Boe per day, a 2% decrease from the comparable 2015 period.

SCOOP production averaged 64,669 Boe per day for the second quarter of 2016, in line with the first quarter of 2016 and 3% higher than the second quarter of 2015. Year to date, SCOOP production averaged 64,642 Boe per day, a 15% increase over the comparable 2015 period.

Combined production from STACK and Northwest Cana averaged 14,610 Boe per day for the second quarter of 2016, an increase of 31% from the first quarter of 2016 and 231% higher than the second quarter of 2015. Year to date, combined STACK and Northwest Cana production averaged 12,868 Boe per day, a 228% increase over the comparable 2015 period.

The South region comprised 38% of our total production for the 2016 second quarter compared to 34% for the 2016 first quarter and 31% for the 2015 second quarter. The South region comprised 36% of our total production for year to date 2016 compared to 30% for the comparable 2015 period.

Revenues

Crude oil and natural gas revenues for the 2016 second quarter decreased 33% compared to the 2015 second quarter driven by a 30% decrease in realized commodity prices coupled with a 5% decrease in total sales volumes.

Year to date crude oil and natural gas revenues decreased 32% from the comparable 2015 period driven by a 35% decrease in realized commodity prices, the effect of which was partially offset by a 4% increase in total sales volumes.

Average crude oil sales prices for the second quarter and year to date periods of 2016 decreased 23% and 29%, respectively, from the comparable 2015 periods.

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Crude oil sales volumes for the second quarter and year to date periods of 2016 decreased 13% and 5%, respectively, from the comparable 2015 periods.
Average natural gas sales prices for the second quarter and year to date periods of 2016 decreased 43% and 46%, respectively, from the comparable 2015 periods.
Natural gas sales volumes for the second quarter and year to date periods of 2016 increased 13% and 23%, respectively, from the comparable 2015 periods.

Capital expenditures and drilling activity

Capital expenditures excluding acquisitions totaled approximately $209.4 million for the second quarter of 2016, bringing year to date 2016 non-acquisition capital expenditures to $529.3 million compared to $1.57 billion for year to date 2015.
For the second quarter of 2016 we participated in the drilling and completion of 67 gross (15 net) wells, bringing our 2016 year to date total to 161 gross (34 net) wells compared to 528 gross (184 net) wells for year to date 2015.
Our inventory of drilled but uncompleted ("DUC") wells in North Dakota totaled 156 gross (126 net) operated wells at June 30, 2016 compared to 142 gross (114 net) operated wells at March 31, 2016 and 135 gross (107 net) operated wells at December 31, 2015.
Our DUC inventory in Oklahoma totaled 44 gross (25 net) operated wells at June 30, 2016 compared to 42 gross (26 net) operated wells at March 31, 2016 and 35 gross (25 net) operated wells at December 31, 2015.

Credit facility and liquidity

At June 30, 2016, we had $16.6 million of cash and cash equivalents and approximately $1.86 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $885 million of outstanding borrowings on our credit facility at June 30, 2016 compared to $940 million at March 31, 2016 and $853 million at December 31, 2015. At July 31, 2016, outstanding credit facility borrowings totaled $820 million.

Property disposition

In April 2016, we sold approximately 132,000 net acres of non-core undeveloped leasehold acreage located in Wyoming to a third party for cash proceeds of $110.0 million. The proceeds were used to pay down a portion of outstanding borrowings on our revolving credit facility. In connection with the transaction we recognized a pre-tax gain of approximately $96.9 million.

Financial and operating highlights

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

- Volumes of crude oil and natural gas produced,
- Crude oil and natural gas prices realized, and
- Per unit operating and administrative costs.

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Average daily production: | | | | |
| Crude oil (Bbl per day) | 133,044 | 149,897 | 139,756 | 146,722 |
| Natural gas (Mcf per day) | 517,677 | 459,898 | 511,837 | 420,123 |
| Crude oil equivalents (Boe per day) | 219,323 | 226,547 | 225,063 | 216,742 |
| Average sales prices: | | | | |
| Crude oil ($/Bbl) | $38.38 | $49.84 | $31.76 | $44.46 |
| Natural gas ($/Mcf) | $1.31 | $2.31 | $1.33 | $2.48 |
| Crude oil equivalents ($/Boe) | $26.36 | $37.82 | $22.73 | $34.93 |
| Crude oil sales price discount to NYMEX ($/Bbl) | $(7.21) | $(8.18) | $(7.51) | $(9.05) |
| Natural gas sales price discount to NYMEX ($/Mcf) | $(0.65) | $(0.33) | $(0.69) | $(0.31) |
| Production expenses ($/Boe) | $3.72 | $4.39 | $3.74 | $4.70 |
| Production taxes (% of oil and gas revenues) | 7.4% | 7.8% | 7.5% | 8.0% |
| DD&A ($/Boe) | $22.15 | $21.68 | $22.16 | $21.36 |
| Total general and administrative expenses ($/Boe) (1) | $1.82 | $2.11 | $1.68 | $2.28 |
| Net income (loss) (in thousands) | $(119,402) | $403 | $(317,727) | $(131,568) |
| Diluted net income (loss) per share | $(0.32) | $— | $(0.86) | $(0.36) |

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

Three months ended June 30, 2016 compared to the three months ended June 30, 2015

Results of Operations

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

| In thousands, except sales price data | Three months ended June 30, 2016 | 2015 |
|---|---|---|
| Crude oil and natural gas sales | $525,711 | $790,102 |
| Loss on crude oil and natural gas derivatives, net | (82,257) | (4,737) |
| Crude oil and natural gas service operations | 7,757 | 11,009 |
| Total revenues | 451,211 | 796,374 |
| Operating costs and expenses (1) | (561,758) | (713,927) |
| Other expenses, net | (81,487) | (77,902) |
| Income (loss) before income taxes | (192,034) | 4,545 |
| (Provision) benefit for income taxes | 72,632 | (4,142) |
| Net income (loss) | $(119,402) | $403 |
| Production volumes: | | |
| Crude oil (MBbl) | 12,107 | 13,641 |
| Natural gas (MMcf) | 47,109 | 41,851 |
| Crude oil equivalents (MBoe) | 19,958 | 20,616 |
| Sales volumes: | | |
| Crude oil (MBbl) | 12,090 | 13,917 |
| Natural gas (MMcf) | 47,109 | 41,851 |
| Crude oil equivalents (MBoe) | 19,941 | 20,892 |
| Average sales prices: | | |
| Crude oil ($/Bbl) | $38.38 | $49.84 |
| Natural gas ($/Mcf) | 1.31 | 2.31 |
| Crude oil equivalents ($/Boe) | 26.36 | 37.82 |

(1) Net of gain on sale of assets of $96.9 million and $20.5 million for the three months ended June 30, 2016 and 2015, respectively.

Production

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

| | Three months ended June 30, 2016 Volume | Percent | 2015 Volume | Percent | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|
| Crude oil (MBbl) | 12,107 | 61 % | 13,641 | 66 % | (1,534) | (11 %) |
| Natural gas (MMcf) | 47,109 | 39 % | 41,851 | 34 % | 5,258 | 13 % |
| Total (MBoe) | 19,958 | 100 % | 20,616 | 100 % | (658) | (3 %) |

| | Three months ended June 30, 2016 MBoe | Percent | 2015 MBoe | Percent | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|
| North Region | 12,448 | 62 % | 14,150 | 69 % | (1,702) | (12 %) |
| South Region | 7,510 | 38 % | 6,466 | 31 % | 1,044 | 16 % |
| Total | 19,958 | 100 % | 20,616 | 100 % | (658) | (3 %) |

The 11% decrease in crude oil production for the second quarter was driven by decreased production from our properties in North Dakota Bakken, Montana Bakken and the Red River units due to a combination of natural declines in production and reduced drilling and completion activities in those areas. North Dakota Bakken crude oil production decreased 1,377 MBbls, or 14%, and Montana Bakken production decreased 242 MBbls, or 24%, while production in the Red River units decreased 145 MBbls, or 13%, over the prior year second quarter. These decreases were partially offset by an increase of 281

MBbls in crude oil production from our STACK/Northwest Cana properties due to additional wells being completed and producing resulting from a shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma.

The 13% increase in natural gas production for the second quarter was driven by increased production from our properties in the STACK, Northwest Cana and SCOOP plays due to additional wells being completed and producing subsequent to June 30, 2015. Natural gas production in STACK/Northwest Cana increased 3,881 MMcf, or 173%, and SCOOP production increased 1,042 MMcf, or 4%, over the prior year second quarter. Additionally, North Dakota Bakken natural gas production increased 990 MMcf, or 8%, due to an increase in gas capture from non-operated properties and resulting increase in volumes produced and delivered to market. These increases were partially offset by decreases in production from various areas in our North and South regions primarily due to natural declines in production.

The increase in natural gas production as a percentage of our total production from 34% in the second quarter of 2015 to 39% in the second quarter of 2016 primarily resulted from significant increases in STACK, Northwest Cana and SCOOP production over the past year due to the aforementioned shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma. Our properties in STACK, Northwest Cana and SCOOP typically produce a higher concentration of liquids-rich natural gas compared to oil-weighted properties in the Bakken. For the remainder of 2016, we expect to continue focusing our well completion activities on our Oklahoma properties. Accordingly, we expect our natural gas production may increase to approximately 40% of our total production for the full year of 2016. As crude oil prices recover, we expect to increase our completion activities in the Bakken and shift our production back to a higher proportion of crude oil.

Revenues

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

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the second quarter of 2016 were $525.7 million, a 33% decrease from sales of $790.1 million for the 2015 second quarter due to decreases in commodity prices and sales volumes.

Our crude oil sales prices averaged $38.38 per barrel in the 2016 second quarter, a decrease of 23% compared to $49.84 for the 2015 second quarter due to lower crude oil market prices. The differential between NYMEX West Texas Intermediate ("WTI") calendar month crude oil prices and our realized crude oil prices averaged $7.21 per barrel for the 2016 second quarter compared to $8.18 for the 2015 second quarter. The improved differential was due to increased use of pipeline transportation to move our North region crude oil to market with less dependence on more costly rail transportation, along with significant growth in our South region production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma.

Our natural gas sales prices averaged $1.31 per Mcf for the 2016 second quarter, a 43% decrease compared to $2.31 per Mcf for the 2015 second quarter due to lower market prices for natural gas and natural gas liquids (“NGLs”) along with the amendment of certain natural gas sales agreements in 2016. The majority of our natural gas production is sold at our lease locations to midstream purchasers with price realizations impacted by the volume and value of NGLs that purchasers extract from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.65 per Mcf for the 2016 second quarter compared to a discount of $0.33 per Mcf for the 2015 second quarter. NGL prices remained depressed in the 2016 second quarter in conjunction with low crude oil prices, which, along with our amended natural gas sales agreements, reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing. If NGL prices do not recover from current levels, the prices we receive for the sale of our natural gas stream for the remainder of 2016 may continue to be lower than Henry Hub benchmark prices.

Commodity prices showed some signs of stabilization and recovery in the second quarter of 2016, but still remain volatile and we are unable to predict the impact future price changes may have on our full year 2016 revenues and differentials.

For the second quarter of 2016, our crude oil sales volumes decreased 13% from the comparable 2015 period, while our natural gas sales volumes increased 13%, reflecting the shift in our well completion activities away from oil-weighted properties in the Bakken to areas in Oklahoma with higher concentrations of liquids-rich natural gas.

Derivatives. Changes in natural gas prices during the second quarter of 2016 had an unfavorable impact on the fair value of our natural gas derivatives, which resulted in negative revenue adjustments of $82.3 million for the period, representing $121.0 million of non-cash losses on derivatives partially offset by $38.7 million of cash gains. Our revenues may continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in natural gas prices.

Operating Costs and Expenses

Production Expenses. Production expenses decreased $17.6 million, or 19%, from $91.7 million for the second quarter of 2015 to $74.1 million for the second quarter of 2016. Production expenses on a per-Boe basis decreased to $3.72 for the 2016 second quarter compared to $4.39 for the 2015 second quarter. These decreases primarily resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, increased availability and use of water gathering and recycling facilities over the prior year period, and a higher portion of our production coming from natural gas wells in Oklahoma which typically have lower operating costs compared to crude oil wells in the Bakken.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $22.4 million, or 36%, to $39.1 million for the second quarter of 2016 compared to $61.5 million for the second quarter of 2015 primarily due to lower crude oil and natural gas revenues resulting from decreases in commodity prices over the prior year period. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of crude oil and natural gas revenues were 7.4% for the second quarter of 2016 compared to 7.8% for the second quarter of 2015, the decrease of which resulted from significant growth over the past year in our STACK, Northwest Cana and SCOOP operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to North Dakota. We expect our average production tax rate for the remainder of 2016 will continue to trend lower than 2015 levels as our operations in Oklahoma continue to grow in significance and given the passing of legislation in North Dakota in 2015 that decreased the combined production tax rate from 11.5% to 10.0% of crude oil revenues in North Dakota effective January 1, 2016.

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

| | Three months ended June 30, | |
|---|---|---|
| In thousands | 2016 | 2015 |
| Geological and geophysical costs | $1,468 | $109 |
| Exploratory dry hole costs | 206 | — |
| Exploration expenses | $1,674 | $109 |

The increase in geological and geophysical expenses in the 2016 second quarter was due to changes in the timing and amount of costs incurred by the Company and billed to joint interest owners between periods.

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A decreased $11.2 million, or 2%, to $441.8 million for the second quarter of 2016 compared to $453.0 million for the second quarter of 2015 primarily due to a 5% decrease in total 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 | 2016 | 2015 |
| Crude oil and natural gas | $21.69 | $21.32 |
| Other equipment | 0.38 | 0.31 |
| Asset retirement obligation accretion | 0.08 | 0.05 |
| Depreciation, depletion, amortization and accretion | $22.15 | $21.68 |

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

timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.
Property Impairments. Total property impairments decreased $10.8 million, or 14%, to $66.1 million for the 2016 second quarter compared to $76.9 million for the 2015 second quarter. There were no proved property impairments recognized in the second quarter of 2016 compared to $5.0 million of such impairments in the second quarter of 2015. This decrease resulted from differences in the timing and severity of commodity price declines and resulting impact on fair value assessments and impairments between periods. As a result of the impairments and DD&A recognized to date coupled with an improvement in commodity prices in June 2016, our proved properties are carried at values that did not exceed estimated future net cash flows at June 30, 2016 and required no impairment during the 2016 second quarter.

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

Impairments of non-producing properties decreased $5.7 million, or 8%, to $66.1 million for the 2016 second quarter compared to $71.8 million for the 2015 second quarter. The decrease was due to a lower balance of unamortized leasehold costs in the current year due in part to reduced land capital expenditures along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration.

General and Administrative ("G&A") Expenses. Total G&A expenses decreased $7.9 million, or 18%, to $36.2 million for the second quarter of 2016 from $44.2 million for second quarter of 2015. Total G&A expenses include non-cash charges for equity compensation of $11.8 million and $16.2 million for the second quarters of 2016 and 2015, respectively. G&A expenses other than equity compensation totaled $24.4 million for the 2016 second quarter, a decrease of $3.6 million, or 13%, compared to the 2015 second quarter.

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 | 2016 | 2015 |
| General and administrative expenses | $1.22 | $1.34 |
| Non-cash equity compensation | 0.60 | 0.77 |
| Total general and administrative expenses | $1.82 | $2.11 |

The decrease in G&A expenses other than equity compensation was primarily due to a reduction in employee related costs and other efforts to reduce spending in response to depressed commodity prices. The decrease in equity compensation expense was primarily 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 2016.

Interest Expense. Interest expense increased $3.5 million, or 4%, to $81.9 million for the second quarter of 2016 compared to $78.4 million for the second quarter of 2015 due to an increase in our weighted average outstanding long-term debt obligations and higher borrowing costs incurred on our credit facility and three-year term loan resulting from downgrades of our credit rating in February 2016. Our weighted average outstanding long-term debt balance for the 2016 second quarter was approximately $7.3 billion with a weighted average interest rate of 4.3% compared to averages of $7.1 billion and 4.3% for the 2015 second quarter. The increase in outstanding debt resulted from borrowings incurred subsequent to June 30, 2015 to fund our capital spending.

Income Taxes. We recorded an income tax benefit for the second quarter of 2016 of $72.6 million compared to income tax expense of $4.1 million for the second quarter of 2015, resulting in effective tax rates of approximately 38% and 91%, respectively, after taking into account permanent taxable differences and valuation allowances. For the second quarters of 2016 and 2015, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax income (loss) generated by our operations in the United States. Our effective tax rate for the 2015 second quarter 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, 2016 compared to the six months ended June 30, 2015

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 | 2016 | 2015 |
| Crude oil and natural gas sales | $929,302 | $1,372,694 |
| Gain (loss) on crude oil and natural gas derivatives, net | (40,145) | 28,018 |
| Crude oil and natural gas service operations | 15,227 | 21,306 |
| Total revenues | 904,384 | 1,422,018 |
| Operating costs and expenses (1) | (1,254,033) | (1,450,847) |
| Other expenses, net | (162,056) | (152,619) |
| Loss before income taxes | (511,705) | (181,448) |
| Benefit for income taxes | 193,978 | 49,880 |
| Net loss | $(317,727) | $(131,568) |
| Production volumes: | | |
| Crude oil (MBbl) | 25,436 | 26,557 |
| Natural gas (MMcf) | 93,154 | 76,043 |
| Crude oil equivalents (MBoe) | 40,961 | 39,231 |
| Sales volumes: | | |
| Crude oil (MBbl) | 25,356 | 26,628 |
| Natural gas (MMcf) | 93,154 | 76,043 |
| Crude oil equivalents (MBoe) | 40,882 | 39,301 |
| Average sales prices: | | |
| Crude oil ($/Bbl) | $31.76 | $44.46 |
| Natural gas ($/Mcf) | 1.33 | 2.48 |
| Crude oil equivalents ($/Boe) | 22.73 | 34.93 |

(1) Net of gain on sale of assets of $97.0 million and $22.6 million for the six months ended June 30, 2016 and 2015, respectively.

Production

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

| | Six months ended June 30, 2016 | | 2015 | | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|
| | Volume | Percent | Volume | Percent | | |
| Crude oil (MBbl) | 25,436 | 62 % | 26,557 | 68 % | (1,121) | (4 %) |
| Natural gas (MMcf) | 93,154 | 38 % | 76,043 | 32 % | 17,111 | 23 % |
| Total (MBoe) | 40,961 | 100 % | 39,231 | 100 % | 1,730 | 4 % |

| | Six months ended June 30, 2016 | | 2015 | | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|
| | MBoe | Percent | MBoe | Percent | | |
| North Region | 26,240 | 64 % | 27,576 | 70 % | (1,336) | (5 %) |
| South Region | 14,721 | 36 % | 11,655 | 30 % | 3,066 | 26 % |
| Total | 40,961 | 100 % | 39,231 | 100 % | 1,730 | 4 % |

The 4% decrease in crude oil production for year to date 2016 was driven by decreased production from our properties in North Dakota Bakken, Montana Bakken and the Red River units due to a combination of natural declines in production and reduced drilling and completion activities in those areas. North Dakota Bakken crude oil production decreased 1,001 MBbls, or 5%, and Montana Bakken production decreased 607 MBbls, or 28%, while production in the Red River units decreased 275 MBbls, or 13%, over the prior year period. These decreases were partially offset by increases in production from our properties

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in the STACK/Northwest Cana and SCOOP plays which increased 503 MBbls and 378 MBbls, respectively, due to additional wells being completed and producing resulting from a shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma.

The 23% increase in natural gas production for year to date 2016 was driven by increased production from our properties in the STACK/Northwest Cana and SCOOP plays due to additional wells being completed and producing subsequent to June 30, 2015. Natural gas production in STACK/Northwest Cana increased 6,771 MMcf, or 173%, and SCOOP production increased 7,236 MMcf, or 17%, over the prior year period. Additionally, North Dakota Bakken production increased 3,942 MMcf, or 17%, due to an increase in gas capture from non-operated properties and resulting increase in volumes produced and delivered to market. 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 reduction in capital spending and deferral of certain well completion activities has adversely impacted our rate of production and our 4% growth in total production realized for year to date 2016 compared to year to date 2015 is not expected to be sustained for the remainder of 2016. We expect our rate of production to slow for the remainder of 2016 and may average between 210,000 and 220,000 Boe per day for the full year of 2016 compared to average daily production of 221,715 Boe per day for full year 2015.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for year to date 2016 were $929.3 million, a 32% decrease from sales of $1.37 billion for the same period in 2015 due to a significant decrease in commodity prices partially offset by an increase in total sales volumes.

Our crude oil sales prices averaged $31.76 per barrel for year to date 2016, a decrease of 29% compared to $44.46 for year to date 2015 due to lower crude oil market prices. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for year to date 2016 was $7.51 per barrel compared to $9.05 for year to date 2015. The improved differential was due to increased use of pipeline transportation to move our North region crude oil to market with less dependence on more costly rail transportation, along with significant growth in our South region production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma.

Our natural gas sales prices averaged $1.33 per Mcf for year to date 2016, a 46% decrease compared to $2.48 for year to date 2015 due to lower market prices for natural gas and NGLs along with the amendment of certain natural gas sales agreements in 2016. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.69 per Mcf for year to date 2016 compared to a discount of $0.31 per Mcf for the comparable 2015 period. NGL prices in the first half of 2016 remained depressed in conjunction with low crude oil prices, which, along with our amended natural gas sales agreements, reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing. If NGL prices do not recover from current levels, the prices we receive for the sale of our natural gas stream for the remainder of 2016 may continue to be lower than Henry Hub benchmark prices.

For year to date 2016, our crude oil sales volumes decreased 5% from the comparable 2015 period, while our natural gas sales volumes increased 23%, reflecting the shift in our well completion activities away from oil-weighted properties in the Bakken to areas in Oklahoma with higher concentrations of liquids-rich natural gas.

At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes and caused crude oil sales volumes to be lower than crude oil production by 80 MBbls for year to date 2016.

Derivatives. Changes in natural gas prices during the six months ended June 30, 2016 had an unfavorable impact on the fair value of our natural gas derivatives, which resulted in negative revenue adjustments of $40.1 million for the period, representing $118.1 million of non-cash losses on derivatives partially offset by $78.0 million of cash gains.

Operating Costs and Expenses

Production Expenses. Production expenses decreased $32.0 million, or 17%, from $184.7 million for year to date 2015 to $152.7 million for year to date 2016. Production expenses on a per-Boe basis decreased to $3.74 for year to date 2016 compared to $4.70 for the comparable 2015 period. These decreases primarily resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, increased availability and use of water gathering and recycling facilities over the prior year period, and a higher portion of our production coming from natural gas wells in Oklahoma which typically have lower operating costs compared to crude oil wells in the Bakken.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $40.3 million, or 37%, to $69.6 million for year to date 2016 compared to $109.9 million for year to date 2015 primarily due to lower crude oil and natural gas revenues resulting from decreases in commodity prices over the prior year period. Production taxes as a percentage of crude oil and natural gas revenues were 7.5% for year to date 2016 compared to 8.0% for year to date 2015, the decrease of which resulted from significant growth over the past year in our STACK, Northwest Cana and SCOOP operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to North Dakota. We expect our average production tax rate for the remainder of 2016 will continue to trend lower than 2015 levels as our operations in Oklahoma continue to grow in significance and given the passing of legislation in North Dakota in 2015 that decreased the combined production tax rate from 11.5% to 10.0% of crude oil revenues in North Dakota effective January 1, 2016.

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

| | Six months ended June 30, | |
|---|---|---|
| In thousands | 2016 | 2015 |
| Geological and geophysical costs | $4,533 | $6,446 |
| Exploratory dry hole costs | 206 | 8,003 |
| Exploration expenses | $4,739 | $14,449 |

The decrease in geological and geophysical expenses in 2016 was due to changes in the timing and amount of costs incurred by the Company and billed to joint interest owners between periods.

Dry hole costs incurred in 2015 primarily reflect costs associated with an unsuccessful well in a prospect in our North region. There have been no significant dry hole costs incurred in 2016.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $66.3 million, or 8%, to $905.8 million for year to date 2016 compared to $839.5 million for the comparable period in 2015 primarily due to a 4% increase in total sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

| | Six months ended June 30, | |
|---|---|---|
| $/Boe | 2016 | 2015 |
| Crude oil and natural gas | $21.71 | $20.98 |
| Other equipment | 0.37 | 0.32 |
| Asset retirement obligation accretion | 0.08 | 0.06 |
| Depreciation, depletion, amortization and accretion | $22.16 | $21.36 |

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 at year-end 2015 and in 2016 prompted by depressed commodity prices. If commodity prices decline further, additional downward revisions of proved reserves may occur in the future, which may be significant and would result in an increase in our DD&A rate. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments decreased $79.4 million, or 35%, to $145.0 million for year to date 2016 compared to $224.4 million for year to date 2015 primarily due to a decrease in proved property impairments. There were no proved property impairments recognized for year to date 2016 compared to $75.0 million of such impairments for year to date 2015. This decrease resulted from differences in the timing and severity of commodity price declines and resulting impact on fair value assessments and impairments between periods. The prolonged decrease in commodity prices in 2015 triggered significant impairments of proved properties throughout 2015. As a result of the impairments and DD&A recognized to date coupled with an improvement in commodity prices in June 2016, our proved properties are carried at values that did not exceed estimated future net cash flows at June 30, 2016 and required no impairment during the six month period.

If commodity prices decline further, downward revisions of reserves may be significant in the future and could result in impairments of proved properties in the remainder of 2016. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on future impairments, if any.

General and Administrative Expenses. Total G&A expenses decreased $20.9 million, or 23%, to $68.7 million for year to date 2016 from $89.6 million for the comparable period in 2015. Total G&A expenses include non-cash charges for equity compensation of $21.0 million and $27.4 million for year to date 2016 and year to date 2015, respectively. G&A expenses other than equity compensation totaled $47.7 million for year to date 2016, a decrease of $14.5 million, or 23%, compared to the comparable 2015 period.

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 | 2016 | 2015 |
| General and administrative expenses | $1.16 | $1.58 |
| Non-cash equity compensation | 0.52 | 0.70 |
| Total general and administrative expenses | $1.68 | $2.28 |

The decrease in G&A expenses other than equity compensation was primarily due to a reduction in employee related costs and other efforts to reduce spending in response to depressed commodity prices. The decrease in equity compensation expense was primarily 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 2016.

Interest Expense. Year to date interest expense increased $9.4 million, or 6%, to $162.9 million compared to $153.5 million for the comparable 2015 period due to an increase in our weighted average outstanding long-term debt obligations and higher borrowing costs incurred on our credit facility and three-year term loan resulting from downgrades of our credit rating in February 2016. Our weighted average outstanding long-term debt balance for year to date 2016 was approximately $7.2 billion with a weighted average interest rate of 4.3% compared to averages of $6.7 billion and 4.5% for the comparable period in 2015. The increase in outstanding debt resulted from borrowings incurred subsequent to June 30, 2015 to fund our capital spending.

Income Taxes. We recorded an income tax benefit for the six months ended June 30, 2016 of $194.0 million compared to a benefit of $49.9 million for the prior year period, resulting in effective tax rates of approximately 38% and 27%, respectively, after taking into account permanent taxable differences and valuation allowances. For year to date 2016 and 2015, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax losses generated by our operations in the United States. Our 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 the first half of 2015 for which we do not believe we will realize a benefit.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt and equity securities. At June 30, 2016, we had $16.6 million of cash and cash equivalents and approximately $1.86 billion of borrowing availability on our revolving credit facility after considering outstanding borrowings and letters of credit. We are focused on balancing our 2016 capital spending with cash flows in order to minimize new borrowings and maintain ample liquidity. At July 31, 2016, outstanding borrowings totaled $820 million with approximately $1.93 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit.

Based on our 2016 capital expenditure budget, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our revolving credit facility, three-year term loan, and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of June 30, 2016, including those described in Note 7. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements, recognizing we may be required to meet such commitments even if our business plan assumptions were to change.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $497.7 million and $916.8 million for the six months ended June 30, 2016 and 2015, respectively. The decrease in operating cash flows was primarily due to lower crude oil and natural gas revenues driven by lower realized commodity prices, partially offset by lower production expenses, production taxes, and general and administrative expenses and an increase in cash gains on matured natural gas derivatives.

If the commodity price environment existing in the second quarter of 2016 persists or worsens and our rate of production continues to slow, we expect our operating cash flows for the remainder of 2016 will continue to be lower than 2015 levels, the extent of which is uncertain due to the unpredictable nature of commodity prices.

Cash flows used in investing activities

During the six months ended June 30, 2016 and 2015, we had cash flows used in investing activities (excluding proceeds from asset sales) of $630.0 million and $2.0 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Property acquisitions totaled $14.3 million and $43.2 million for the six months ended June 30, 2016 and 2015, respectively. The decrease in capital spending was driven by a decrease in our capital budget and related drilling activity for 2016. Our cash capital expenditures for 2016 include the payment of amounts owed at December 31, 2015 in connection with our 2015 drilling program and associated $86.5 million decrease in accruals for capital expenditures for the six months ended June 30, 2016.

The use of cash for capital expenditures during the six months ended June 30, 2016 was partially offset by $112.2 million of proceeds received from asset dispositions primarily related to the April 2016 sale of non-core undeveloped leasehold acreage in Wyoming for proceeds of $110.0 million.

We expect our capital spending for the remainder of 2016 will continue to be lower than 2015 levels due to the significant decrease in our budgeted capital spending to $920 million for 2016, a reduction of 63% compared to $2.5 billion of capital spending in 2015.

Cash flows from financing activities

Net cash provided by financing activities for the six months ended June 30, 2016 was $25.2 million primarily resulting from net borrowings of $32 million on our revolving credit facility during the period. The net increase in borrowings was comprised of $87 million of net borrowings in the 2016 first quarter partially offset by $55 million of net repayments in the 2016 second quarter. The second quarter net repayments resulted from a $110.0 million reduction of credit facility debt using proceeds from the sale of undeveloped leasehold acreage in Wyoming in April 2016, partially offset by additional borrowings during the quarter.

Net cash provided by financing activities for the six months ended June 30, 2015 was $1.05 billion primarily resulting from $1.06 billion of net borrowings on our revolving credit facility during that period.

We are seeking to generally balance our 2016 capital expenditures with cash flows to minimize new borrowings in 2016.

Future Sources of Financing

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

Our 2016 capital expenditures budget has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our revolving credit facility if needed to fund our operations. We may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise if such financing can be arranged on favorable terms. Additionally, we may choose to sell assets or enter into strategic joint development opportunities in order to obtain funding for our operations and capital program.

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

Revolving credit facility

We have an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.75 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. The commitments are from a syndicate of 17 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of July 31, 2016, we had approximately $1.93 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness.

The commitments under our revolving credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating, such as the downgrades by Standard & Poor's Ratings Services ("S&P") and Moody's Investor Services, Inc. ("Moody's") that occurred in February 2016 in response to weakened oil and gas industry conditions, do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants. The downgrades of our credit rating did, however, trigger a 0.250% increase in our credit facility's interest rate and a 0.075% increase in the rate of commitment fees paid on unused borrowing availability under our credit facility.

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

We were in compliance with our revolving credit facility covenants at June 30, 2016 and expect to maintain compliance for at least the next 12 months. At June 30, 2016, our consolidated net debt to total capitalization ratio, as defined in our revolving credit facility as amended, was 0.59 to 1.00. As we continue to focus on balancing our 2016 capital spending with cash flows to minimize new borrowings, we do not believe the revolving credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing to a material extent if needed to support our business. At June 30, 2016, our total debt would have needed to independently increase by approximately $2.2 billion, or 31%, above existing levels at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $1.2 billion (excluding the after-tax impact of any non-cash impairment charges), or 27% below existing levels at June 30, 2016 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Joint development agreement funding

In September 2014, we entered into an agreement with a U.S. subsidiary of SK E&S Co. Ltd ("SK") of South Korea to jointly develop a significant portion of the Company's Northwest Cana natural gas properties. Pursuant to the agreement SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest within our Northwest Cana properties until approximately $270 million has been expended by SK on our behalf. As of June 30, 2016, approximately $175 million of the carry to be expended by SK on our behalf had yet to be realized and is expected to be realized through 2019.

Proceeds from pending sale of assets

On August 2, 2016, we entered into an agreement to sell non-strategic producing and non-producing properties in the SCOOP play in Oklahoma to a third party for cash proceeds of $281 million. The disposition is expected to close in October 2016. We expect to use the sales proceeds to reduce outstanding debt.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at June 30, 2016. We have no near-term senior note maturities, with our earliest scheduled maturity being our $200 million of 2020 Notes due in October 2020. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Note 6. Long-Term Debt in Notes to Unaudited Condensed Consolidated Financial Statements.

We were in compliance with our senior note covenants at June 30, 2016 and expect to maintain compliance for at least the next 12 months. We do not believe the senior note covenants will materially limit our ability to undertake additional debt financing. Downgrades or other negative rating actions with respect to the credit ratings assigned to our senior unsecured debt, such as the downgrades by S&P and Moody's that occurred in February 2016, do not trigger additional senior note covenants.

Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes as of June 30, 2016.

Term loan

We have a $500 million unsecured term loan that matures in full in November 2018 and bears interest at variable market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. Downgrades or other negative rating actions with respect to our credit rating, such as the S&P and Moody's downgrades that occurred in February 2016, do not trigger a security requirement or change in covenants for the term loan. The February 2016 downgrades of our credit rating did, however, trigger a 0.125% increase in our term loan's interest rate. The interest rate on the term loan was 1.95% at June 30, 2016.

Capital expenditures

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

Our capital expenditures budget for 2016 is $920 million excluding acquisitions, which is expected to be allocated as follows:

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

For the six months ended June 30, 2016, we invested approximately $529.3 million in our capital program, excluding $14.3 million of unbudgeted acquisitions, excluding $86.5 million of capital costs associated with decreased accruals for capital expenditures, and including $0.1 million of seismic costs. Our 2016 year to date capital expenditures were allocated as follows by quarter:

| In millions | 1Q 2016 | 2Q 2016 | YTD 2016 |
|---|---|---|---|
| Exploration and development drilling | $290.0 | $179.6 | $469.6 |
| Land costs | 19.9 | 18.8 | 38.7 |
| Capital facilities, workovers and other corporate assets | 9.9 | 11.0 | 20.9 |
| Seismic | 0.1 | — | 0.1 |
| Capital expenditures, excluding acquisitions | 319.9 | 209.4 | 529.3 |
| Acquisitions of producing properties | — | — | — |
| Acquisitions of non-producing properties | 4.4 | 9.9 | 14.3 |

| | | | |
|---|---|---|---|
| Total acquisitions | 4.4 | 9.9 | 14.3 |
| Total capital expenditures | $324.3 | $219.3 | $543.6 |

Our non-acquisition capital spending budget for 2016 has been set based on an expectation of available cash flows and is designed to target capital expenditures and cash flows being relatively balanced for 2016 at an assumed average WTI benchmark crude oil price of approximately $37 per barrel for the year, with any cash flow deficiencies being funded by borrowings under our revolving credit facility. Over the six months ended June 30, 2016, WTI crude oil benchmark prices have averaged approximately $40 per barrel.

The actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, access to capital, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may continue to scale back our spending should commodity prices decrease from current levels. 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, 2016. We believe our cash flows from operations, our remaining cash balance, and amounts available under our revolving credit facility will be sufficient to satisfy our commitments.

Off-balance sheet arrangements

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

Critical Accounting Policies

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

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General. We are exposed to a variety of market risks including commodity price risk, credit risk, and interest rate risk. We seek to address these risks through a program of risk management which may include the use of derivative instruments.

Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the six months ended June 30, 2016, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $510 million for each $10.00 per barrel change in crude oil prices at June 30, 2016 and $187 million for each $1.00 per Mcf change in natural gas prices at June 30, 2016.

To reduce price risk caused by market fluctuations in crude oil and natural gas prices, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. Our crude oil production and sales for the remainder of 2016 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Changes in natural gas prices during the six months ended June 30, 2016 had an overall unfavorable impact on the fair value of our derivative instruments. For the six months ended June 30, 2016, we recognized cash gains on natural gas derivatives of $78.0 million which were more than offset by non-cash mark-to-market losses on natural gas derivatives of $118.1 million.

The fair value of our natural gas derivative instruments at June 30, 2016 was a net liability of $16.9 million. An assumed increase in the forward prices used in the June 30, 2016 valuation of our natural gas derivatives of $1.00 per MMBtu would increase our natural gas derivative liability to approximately $161 million at June 30, 2016. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would change our natural gas derivative valuation to a net asset of approximately $120 million at June 30, 2016.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($385 million in receivables at June 30, 2016), our joint interest receivables ($261 million at June 30, 2016), and counterparty credit risk associated with our derivative instrument receivables ($20 million at June 30, 2016).

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

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $85 million at June 30, 2016, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

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

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our revolving credit facility and three-year term loan. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. In February 2016, our corporate credit rating was downgraded by S&P and Moody's in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. These downgrades caused the interest rates on our revolving credit facility borrowings and three-year term loan to increase by 0.250% and 0.125%, respectively. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates.

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

We had an aggregate of $1.32 billion of variable rate borrowings outstanding on our revolving credit facility and three-year term loan at July 31, 2016. The impact of a 0.25% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.3 million per year and a $2.0 million decrease in net income per year.

## ITEM 4. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the

Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded the Company's disclosure controls and procedures were effective as of June 30, 2016 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2016, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

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

PART II. Other Information

ITEM 1. Legal Proceedings

See Note 7. Commitments and Contingencies–Litigation in Part I, Item I. Financial Statements–Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of the legal matter involving the Company, Billy J. Strack and Daniela A. Renner.

ITEM 1A. Risk Factors

In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our 2015 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q, if any, and in our 2015 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.
There have been no material changes in our risk factors from those disclosed in our 2015 Form 10-K.

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

(a) Recent Sales of Unregistered Securities – Not applicable.
(b) Use of Proceeds – Not applicable.
(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers – The following table provides information about purchases of shares of our common stock during the three months ended June 30, 2016:

| Period | Total number of shares purchased (1) | Average price paid per share (2) | Total number of shares purchased as part of publicly announced plans or programs | Maximum number of shares that may yet be purchased under the plans or programs |
|---|---|---|---|---|
| April 1, 2016 to April 30, 2016 | — | — | — | — |
| May 1, 2016 to May 31, 2016 | 14,913 | $ 40.16 | — | — |
| June 1, 2016 to June 30, 2016 | 1,102 | 44.50 | — | — |
| Total | 16,015 | $ 40.46 | — | — |

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

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

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

The exhibits required to be filed pursuant to Item 601 of Regulation S-K are set forth 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 3, 2016 | By: | /s/ John D. Hart |
| | | | John D. Hart |
| | | | Sr. Vice President, Chief Financial Officer and Treasurer |
| | | | (Duly Authorized Officer and Principal Financial Officer) |

Index to Exhibits

| | |
|---|---|
| 3.1 | Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference. |
| 3.2 | Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference. |
| 10.1*† | Summary of Non-Employee Director Compensation Approved as of May 19, 2016 to be effective July 1, 2016. |
| 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
† Management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.