UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES

EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2015

Commission File Number: 001-35371

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	61-1630631
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

410 17th Street, Suite 1400	
Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

(720) 440-6100

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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	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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. As of July 23, 2015, the registrant had 49,748,846 shares of common stock outstanding.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2015	December 31, 2014
	(in thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,340	$ 2,584
Accounts receivable:		
Oil and gas sales	46,755	54,574
Joint interest and other	26,702	37,202
Prepaid expenses and other	13,870	12,522
Inventory of oilfield equipment	10,340	15,353
Derivative asset	55,419	86,240
Total current assets	168,426	208,475
Property and equipment (successful efforts method), at cost:		
Proved properties	2,203,152	1,924,380
Less: accumulated depreciation, depletion and amortization	(716,954)	(592,073)
Total proved properties, net	1,486,198	1,332,307
Unproved properties	198,098	206,721
Wells in progress	130,575	139,208
Natural gas plant, net of accumulated depreciation of $9,640 in 2015 and $8,457 in 2014	66,770	67,840
Other property and equipment, net of accumulated depreciation of $7,804 in 2015 and $6,087 in 2014	9,333	10,401
Total property and equipment, net	1,890,974	1,756,477
Long-term derivative asset	11,310	17,765
Other noncurrent assets	22,176	23,372
Total assets	$ 2,092,886	$ 2,006,089
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 4)	$ 120,858	$ 145,788
Oil and gas revenue distribution payable	38,566	40,659
Contractual obligation for land acquisition	12,000	12,000
Total current liabilities	171,424	198,447
Long-term liabilities:		
Long-term debt (note 5)	850,006	840,619

Contractual obligation for land acquisition	11,884	11,186
Ad valorem taxes	19,668	28,635
Deferred income taxes	129,122	165,667
Asset retirement obligations	22,264	21,464
Total liabilities	1,204,368	1,266,018
Commitments and contingencies (note 6)		
Stockholders' equity:		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none outstanding	—	—
Common stock, $.001 par value, 225,000,000 shares authorized, 49,750,590 and 41,287,270 issued and outstanding in 2015 and 2014, respectively	50	41
Additional paid-in capital	799,534	591,511
Retained earnings	88,934	148,519
Total stockholders' equity	888,518	740,071
Total liabilities and stockholders' equity	$ 2,092,886	$ 2,006,089

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands, except shares and per share amounts)			
Operating net revenues:				
Oil and gas sales	$ 90,422	$ 151,682	$ 163,498	$ 279,077
Operating expenses:				
Lease operating expense	20,895	18,018	40,159	35,099
Severance and ad valorem taxes	4,148	16,263	10,644	27,013
Exploration	5,748	96	6,246	1,179
Depreciation, depletion and amortization	69,925	54,117	128,929	95,248
Abandonment and impairment of unproved properties	14,527	—	19,996	—
General and administrative (including $4,359, $7,353, $7,787, and $14,150, respectively, of stock compensation)	21,602	24,547	38,474	48,261
Total operating expenses	136,845	113,041	244,448	206,800
Income (loss) from operations	(46,423)	38,641	(80,950)	72,277
Other income (expense):				
Derivative gain (loss)	(5,478)	(27,307)	13,378	(36,085)
Interest expense	(14,468)	(9,434)	(28,706)	(18,769)
Other income	198	167	148	216
Total other expense	(19,748)	(36,574)	(15,180)	(54,638)
Income (loss) from continuing operations before taxes	(66,171)	2,067	(96,130)	17,639
Income tax benefit (expense)	25,007	(796)	36,544	(6,791)
Income (loss) from continuing operations	$ (41,164)	$ 1,271	(59,586)	$ 10,848
Discontinued operations (note 3):				
Loss from operations associated with oil and gas properties held for sale	—	—	—	(85)
Gain (loss) on sale of oil and gas properties	—	(184)	—	6,330
Income tax benefit (expense)	—	71	—	(2,404)
Gain (loss) from discontinued operations	—	(113)	—	3,841
Net income (loss)	$ (41,164)	$ 1,158	$ (59,586)	$ 14,689
Comprehensive income (loss)	$ (41,164)	$ 1,158	$ (59,586)	$ 14,689
Basic and diluted income (loss) per share:				
Income (loss) from continuing operations	$ (0.83)	$ 0.03	$ (1.25)	$ 0.27
Income from discontinued operations	$ —	$ —	$ —	$ 0.09
Net income (loss) per common share	$ (0.83)	$ 0.03	$ (1.25)	$ 0.36
Basic weighted-average common shares outstanding	48,923,335	39,758,489	46,733,682	39,655,968
	48,923,335	39,857,028	46,733,682	39,780,195

Diluted weighted-average common shares
outstanding

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (59,586)	$ 14,689
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	128,929	95,316
Deferred income taxes	(36,544)	9,095
Abandonment and impairment of unproved properties	19,996	—
Dry hole expense	5,680	—
Stock-based compensation	7,787	14,150
Amortization of deferred financing costs and debt premium	1,226	542
Accretion of contractual obligation for land acquisition	698	381
Derivative (gain) loss	(13,378)	36,085
Gain on sale of oil and gas properties	—	(6,330)
Other	(43)	(14)
Changes in current assets and liabilities:		
Accounts receivable	18,319	(32,385)
Prepaid expenses and other assets	(1,348)	(2,575)
Accounts payable and accrued liabilities	(23,054)	29,114
Settlement of asset retirement obligations	(519)	(99)
Net cash provided by operating activities	48,163	157,969
Cash flows from investing activities:		
Acquisition of oil and gas properties	(11,914)	(3,091)
Proceeds from sale of oil and gas properties	—	6,000
Exploration and development of oil and gas properties	(282,993)	(275,890)
Natural gas plant capital expenditures	(113)	(271)
Derivative cash settlements	50,655	(8,142)
(Increase) decrease in restricted cash	—	(11,280)
Additions to property and equipment - non oil and gas	(649)	(3,989)
Net cash used in investing activities	(245,014)	(296,663)
Cash flows from financing activities:		
Proceeds from credit facility	87,000	—
Payments to credit facility	(77,000)	—
Proceeds from sale of common stock	209,300	—
Offering costs related to sale of common stock	(6,607)	—
Offering costs related to sale of Senior Notes	(93)	(277)
Payment of employee tax withholdings in exchange for the return of common stock	(2,448)	(4,766)
Deferred financing costs	(545)	(290)
Net cash provided by (used in) financing activities	209,607	(5,333)
Net change in cash and cash equivalents	12,756	(144,027)

Cash and cash equivalents:		
Beginning of period	2,584	180,582
End of period	$ 15,340	$ 36,555
Supplemental cash flow disclosure:		
Cash paid for interest	$ 27,396	$ 17,857
Cash paid for income taxes	$ 820	$ 100
Changes in working capital related to drilling expenditures, natural gas plant expenditures, and property acquisition	$ (12,935)	$ 10,920

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

NOTE 1 - ORGANIZATION AND BUSINESS

Bonanza Creek Energy, Inc. ("BCEI" or, together with our consolidated subsidiaries, the "Company") is engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Our oil and liquids-weighted assets are concentrated primarily in the Wattenberg Field in Colorado, which the Company has designated the Rocky Mountain region, and the Dorcheat Macedonia Field in southern Arkansas, which the Company has designated the Mid-Continent region.

NOTE 2 - BASIS OF PRESENTATION

These statements have been prepared in accordance with the Securities and Exchange Commission and accounting principles generally accepted in the United States of America ("GAAP") for interim financial information with the condensed consolidated balance sheets ("balance sheets") and the condensed consolidated statements of cash flows as of December 31, 2014, being derived from audited financial statements. The quarterly financial statements included herein do not necessarily include all of the disclosures as may be required under generally accepted accounting principles for complete financial statements. There has been no material change in the information disclosed in the notes to the consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K"), except as disclosed herein. These consolidated financial statements include all of the adjustments, which, in the opinion of management, are necessary for a fair presentation of the financial position and results of operations. All such adjustments are of a normal recurring nature only. The results of operations for the quarterly periods are not necessarily indicative of the results to be expected for the full fiscal year. The Company evaluated events subsequent to the balance sheet date of June 30, 2015 through the filing date of this report. Certain prior period amounts are reclassified to conform to the current period presentation, when necessary.

Principles of Consolidation

The balance sheets include the accounts of BCEI and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources, LLC, Bonanza Creek Energy Upstream LLC, Bonanza Creek Energy Midstream, LLC, Holmes Eastern Company, LLC and Rocky Mountain Infrastructure, LLC. All significant intercompany accounts and transactions have been eliminated.

Significant Accounting Policies

The significant accounting policies followed by the Company were set forth in Note 1 to the 2014 Form 10-K and are supplemented by the notes throughout this report. These unaudited condensed consolidated financial statements should be read in conjunction with the 2014 Form 10-K.

Recently Issued Accounting Standards

In March 2015, the Financial Accounting Standards Board issued Update No. 2015-03 – Interest – Imputation of Interest, Simplifying the Presentation of Debt Issuance Costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. This authoritative accounting guidance is effective for fiscal years beginning after December 15, 2015 and interim periods within those fiscal years on a retrospective basis. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

Rocky Mountain Infrastructure, LLC

During the first quarter of 2015, the Company's wholly owned subsidiary, Bonanza Creek Energy Operating Company, LLC, formed a wholly owned subsidiary, Rocky Mountain Infrastructure, LLC, to hold gathering systems and related infrastructure that service the Wattenberg Field. In May 2015, Bonanza Creek Energy

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Operating Company, LLC transferred approximately $46.5 million of gathering system assets to Rocky Mountain Infrastructure, LLC.

NOTE 3 - DISCONTINUED OPERATIONS

During June 2012, the Company began marketing, with intent to sell, all of its oil and gas properties in California classifying them as assets held for sale. Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. The Company determined that its intent to sell all of its assets in a region qualified as discontinued operations. The Company sold its remaining property in this region during the first quarter of 2014 for approximately $6.0 million and recorded a gain on sale of oil and gas properties in the amount of $6.3 million as of June 30, 2014.

The total revenues, expenses, and income associated with the operation of the oil and gas properties held for sale are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Net revenues:				
Oil and gas sales	$ —	$ —	$ —	$ 361
Operating expenses:				
Lease operating expense	—	—	—	366
Severance and ad valorem taxes	—	—	—	12
Depreciation, depletion and amortization	—	—	—	68
Total operating expenses	—	—	—	446
Loss from operations associated with oil and gas properties held for sale	$ —	$ —	$ —	$ (85)

NOTE 4 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses contain the following:

	As of June 30, 2015	As of December 31, 2014
	(in thousands)	
Drilling and completion costs	$ 69,909	$ 82,844
Accounts payable trade	5,812	5,493
Accrued general and administrative cost	10,281	13,541
Lease operating expense	3,432	3,569
Accrued reclamation cost	162	162
Accrued interest	14,225	14,839
Production and ad valorem taxes and other	17,037	25,340
Total accounts payable and accrued expenses	$ 120,858	$ 145,788

NOTE 5 - LONG-TERM DEBT

Long-term debt consisted of the following as of June 30, 2015 and December 31, 2014:

	As of June 30, 2015	As of December 31, 2014
	(in thousands)	
Revolving credit facility	$ 43,000	$ 33,000
6.75% Senior Notes due 2021	500,000	500,000
Unamortized premium on 6.75% Senior Notes	7,006	7,619
5.75% Senior Notes due 2023	300,000	300,000
Total long-term debt	$ 850,006	$ 840,619

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Credit Facility

The Company's senior secured revolving Credit Agreement, dated March 29, 2011, as amended (the "revolving credit facility"), was further amended on May 13, 2015 (the "2015 Amendment") to decrease the borrowing base from $600 million to $550 million with a total credit facility size of $1 billion remaining unchanged. The Company elected to limit bank commitments at $500 million while reserving the option to access, at the Company's request, the full $550 million borrowing base. The borrowing base is redetermined semiannually on May 15 and November 15. The revolving credit facility is collateralized by substantially all of the Company's assets and matures on September 15, 2017. As of June 30, 2015, the Company had $43 million outstanding under the revolving credit facility with an available borrowing capacity of $483 million, if the Company elected to take advantage of the entire borrowing base, after reduction for the outstanding letter of credit of $24 million. As of December 31, 2014, the Company had $33 million outstanding under the revolving credit facility with an available borrowing capacity of $543 million, if the Company elected to take advantage of the entire $600 million borrowing base available at that date, after reduction for the outstanding letter of credit of $24 million.

The revolving credit facility restricts, among other items, certain dividend payments, additional indebtedness, asset sales, loans, investments and mergers. The revolving credit facility also contains certain financial covenants, which require the maintenance of certain financial and leverage ratios, as defined by the revolving credit facility. The 2015 Amendment (i) permanently removed the maximum total debt to trailing twelve month debt to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense and other non-cash charges ("EBITDAX") covenant of 4.00 to 1.00 and (ii) introduced both a maximum senior secured debt (defined as borrowings under the revolving credit facility, balances drawn under letters of credit, and any outstanding second lien debt) to trailing twelve month EBITDAX covenant of 2.50 to 1.00 and a minimum trailing twelve month interest to trailing twelve month EBITDAX coverage covenant of 2.50 to 1.00. The revolving credit facility also contains a minimum current ratio covenant of 1.00 to 1.00. The Company was in compliance with all financial and non-financial covenants as of June 30, 2015, and through the filing date of this report.

Senior Unsecured Notes

The $500 million aggregate principal amount of 6.75% Senior Notes that mature on April 15, 2021 ("6.75% Senior Notes") and the $300 million aggregate principal amount of 5.75% Senior Notes that mature on February 1, 2023 ("5.75% Senior Notes" and together with the 6.75% Senior Notes, the "Senior Notes") are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and future unsecured senior debt, and are senior in right of payment to any future subordinated debt. The Senior Notes are jointly and severally guaranteed on a senior unsecured basis by our existing and future domestic subsidiaries that guarantee or are borrowers under our revolving credit facility. The Company has no independent assets or operations unrelated to its investments in its consolidated subsidiaries. There are no significant restrictions on the Company's ability or the ability of any subsidiary guarantor to obtain funds from its subsidiaries by such means as a dividend or loan. The Company is subject to certain covenants under the respective indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including certain dividends. The Company was in compliance with all covenants under its Senior Notes as of June 30, 2015, and through the filing date of this report.

NOTE 6 - COMMITMENTS AND CONTINGENT LIABILITIES

From time to time, the Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its condensed consolidated financial statements. In accordance with accounting authoritative guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations. As of the filing date of this report, there were no material pending or overtly threatened legal actions against the Company of which it is aware.

Commitments

A purchase and transportation agreement to deliver 12,580 barrels per day of crude oil over an initial five year term went into effect May 1, 2015. As of the filing date of this report, the Company did not have any shortfalls in delivering the minimum volumes committed.

There have been no material changes from the commitments disclosed in the notes to the Company’s consolidated financial statements included in the 2014 Form 10-K.

NOTE 7 - STOCK-BASED COMPENSATION

Restricted Stock under the Long Term Incentive Plan

The Company grants shares of restricted stock to directors, eligible employees and officers under its Long Term Incentive Plan, as amended and restated (“LTIP”). Each share of restricted stock represents one share of the Company’s common stock to be released from restriction upon completion of the vesting period. The awards typically vest in one-third increments over three years. Each share of restricted stock is entitled to a non forfeitable dividend, if the Company were to declare one, and has the same voting rights as a share of the Company’s common stock. Shares of restricted stock are valued at the closing price of the Company’s common stock on the grant date and are recognized as general and administrative expense over the vesting period of the award.

During the six months ended June 30, 2015, the Company granted 523,000 shares of restricted stock under the Company’s LTIP to certain employees and non-employee directors. The fair value of the issuance was $13.9 million. Total expense recorded for restricted stock for the three month periods ended June 30, 2015 and 2014, was $3.6 million and $7.0 million, respectively, and $6.5 million and $13.6 million for the six months ended June 30, 2015 and 2014, respectively. As of June 30, 2015, unrecognized compensation cost was $24.6 million and will be amortized through 2018.

A summary of the status and activity of non-vested restricted stock for the six months ended June 30, 2015 is presented below.

	Restricted Stock	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	589,529	$ 37.66
Granted	523,000	$ 26.58
Vested	(249,207)	$ 25.96
Forfeited	(26,641)	$ 34.34
Non-vested at end of quarter	836,681	$ 32.53

Performance Stock Units under the Long Term Incentive Plan

The Company grants performance stock units (“PSUs”) to certain officers under its LTIP. The number of shares of the Company’s common stock that may be issued to settle PSUs ranges from zero to two times the number of PSUs awarded. PSUs granted prior to 2014 are determined based on the Company’s performance over a three-year measurement period and vest in their entirety at the end of the measurement period. Satisfaction of the performance conditions for the PSUs granted in 2014 and thereafter are determined at the end of each annual measurement period over the course of the three-year performance cycle in an amount up to two-thirds of the target number of PSUs that are eligible for vesting (such that an amount equal to 200% of the target number of PSUs may be earned during the performance cycle). For all grants, the PSUs will be settled in shares of the Company’s common stock following the end of the three-year performance cycle. Any PSUs that have not vested at the end of

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the applicable measurement period are forfeited. The performance criterion for the PSUs is based on a comparison of the Company's total shareholder return ("TSR") for the measurement period compared with the TSRs of a group of peer companies for the same measurement period. Compensation expense associated with PSUs is recognized as general and administrative expense over the measurement period.

The fair value of each PSU is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of PSUs to be earned during the performance period. The following table presents the assumptions used to determine the fair value of the PSUs granted during the six month period ended June 30, 2015 and for the year ended December 31, 2014.

	For the Six Months Ended June 30, 2015	For the Year Ended December 31, 2014
Expected term of award	3	3
Risk-free interest rate	0.15% - 0.99%	0.12% - 0.9%
Expected volatility	65%	40% - 45%

During the six months ended June 30, 2015, the Company granted 144,363 PSUs under the LTIP to certain officers. The fair value of the issuance was $4.8 million. Total expense recorded for PSUs for the three month periods ended June 30, 2015 and 2014 was $852,000 and $392,000, respectively, and $1.3 million and $567,000 for the six month periods ended June 30, 2015 and 2014, respectively. As of June 30, 2015, there was $6.6 million of total unrecognized compensation expense related to unvested PSUs to be amortized through 2017.

A summary of the status and activity of PSUs for the six months ended June 30, 2015 is presented below:

	PSU	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year (1)	94,173	$ 37.55
Granted(1)	144,363	$ 33.44
Vested(1)	—	$ —
Forfeited(1)	(1,467)	$ 34.80
Non-vested at end of quarter(1)	237,069	$ 35.28

(1) The number of awards assumes that the associated performance condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

NOTE 8 - FAIR VALUE MEASUREMENTS

The Company follows fair value measurement authoritative guidance, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company’s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1:Quoted prices are available in active markets for identical assets or liabilities

Level 2:Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

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Level 3:Significant inputs to the valuation model are unobservable

Financial and non-financial assets and liabilities are to be classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables present the Company’s financial and non-financial assets and liabilities that were accounted for at fair value as of June 30, 2015 and December 31, 2014 and their classification within the fair value hierarchy:

	As of June 30, 2015		
	Level 1	Level 2	Level 3
	(in thousands)		
Derivative assets(1)	$ —	$ 66,729	$ —
Unproved properties(2)	$ —	$ —	$ 197,700

	As of December 31, 2014		
	Level 1	Level 2	Level 3
	(in thousands)		
Derivative assets(1)	$ —	$ 104,005	$ —
Proved properties(2)	$ —	$ —	$ 407,900
Asset retirement obligations(3)	$ —	$ —	$ 6,200

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents non-financial assets that are measured at fair value on a nonrecurring basis due to impairments. This is the fair value of the asset base that was subjected to impairment and does not reflect the entire asset balance as presented on the accompanying balance sheets. Please refer to the Unproved Oil and Gas Properties and Proved Oil and Gas Properties sections below for additional discussion.
(3) This represents the revision to estimates of the asset retirement obligation, which is a non-financial liability that is measured at fair value on a nonrecurring basis. Please refer to the Asset Retirement Obligation section below for additional discussion.

Derivatives

Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company's commodity swaps and collars are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. Presently, all of our derivative arrangements are concentrated with four counterparties all of which are lenders under the Company's revolving credit facility.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of risk-adjusted discount rates and price forecasts selected by the Company's management. The calculation of the risk-adjusted discount rate is a significant management estimate based on the best information available. Management believes that the risk-adjusted discount rate is representative of current market conditions and reflects the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on the NYMEX strip pricing, adjusted for basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above. There were no proved properties that needed to be measured at fair value at June 30, 2015. The Company impaired the Dorcheat Macedonia Field which had a carrying value of $519.2 million to its fair value of $391.9 million and recognized an impairment of $127.3 million for the year ended December 31, 2014. The Company impaired the McKamie Patton Field which had a carrying value of $41.0 million to its fair value of $16.0 million and recognized an impairment of $25.0 million for the year ended December 31, 2014. The Company impaired the McCallum Field which had a carrying value of $15.3 million to its fair value of zero and recognized an impairment of $15.3 for the year ended December 31, 2014.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be fully recoverable. To measure the fair value of unproved properties, the Company uses Level 3 inputs and the income valuation technique, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, remaining lease life, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company uses the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. The Company impaired non-core acreage in the Wattenberg Field due to lease expirations, which had a carrying value of $208.6 million to its fair value of $197.7 million and recognized an impairment of unproved properties for the six months ended June 30, 2015 of $10.9 million. The Company fully impaired the North Park Basin in June 2015, due to a strategic shift within the Company’s development plan, recognizing an impairment of unproved properties of $8.7 million. There were no unproved properties measured at fair value as of December 31, 2014.

Asset Retirement Obligation

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value as of June 30, 2015. The Company had $6.2 million of asset retirement obligations recorded at fair value as of December 31, 2014.

Long-term Debt

As of June 30, 2015, the Company had $500 million of outstanding 6.75% Senior Notes and $300 million of outstanding 5.75% Senior Notes, all of which are unsecured senior obligations. The 6.75% Senior Notes are recorded at cost plus the unamortized premium on the accompanying balance sheets at $507.0 million and $507.6 million as of June 30, 2015 and December 31, 2014, respectively. The fair value of the 6.75% Senior Notes as of June 30, 2015 and December 31, 2014 was $475.0 million and $440.0 million, respectively. The 5.75% Senior Notes are recorded at cost on the accompanying balance sheets at $300.0 million as of June 30, 2015 and December 31, 2014. The fair value of the 5.75% Senior Notes as of June 30, 2015 and December 31, 2014 was $269.3 million and $243.0 million, respectively. The Senior Notes are measured using Level 1 inputs based on a secondary market trading price. The Company’s revolving credit facility approximates fair value as the applicable interest rates are floating. The outstanding balance under the revolving credit facility as of June 30, 2015 and December 31, 2014 was $43.0 million and $33.0 million, respectively.

NOTE 9 - DERIVATIVES

The Company enters into commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into

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for other-than-trading purposes. The Company’s derivatives include swaps and collar arrangements for oil and gas and none of the derivative instruments qualify as having hedging relationships.

As of June 30, 2015, and as of the filing date of this report, the Company had the following derivative commodity contracts in place:

Settlement Period	Derivative Instrument	Total Volumes (Bbls/MMBtu per day)	Average Fixed Price	Average Short Floor Price	Average Floor Price	Average Ceiling Price	Fair Market Value of Assets (in thousands)
Oil							
3Q 2015	Swap	6,000	$ 72.16				$ 6,754
4Q 2015	Swap	6,000	$ 72.16				6,214
3Q 2015	2-Way Collar	6,500			$ 84.62	$ 95.49	14,763
4Q 2015	2-Way Collar	6,500			$ 84.62	$ 95.49	14,254
2016	3-Way Collar	5,500		$ 70.00	$ 85.00	$ 96.83	23,483
							$ 65,468
Gas							
3Q - 4Q 2015	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75	$ 1,261
							$ 1,261
Total							$ 66,729

Derivative Assets and Liabilities Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities.

The following table contains a summary of all the Company’s derivative positions reported on the accompanying balance sheets as of June 30, 2015 and December 31, 2014:

	As of June 30, 2015	
	Balance Sheet Location	Fair Value (in thousands)

Derivative Assets:		
Commodity contracts	Current assets	$ 55,419
Commodity contracts	Noncurrent assets	11,310
Derivative Liabilities:		
Commodity contracts	Current liabilities	—
Commodity contracts	Long-term liabilities	—
Total derivative asset		$ 66,729

	As of December 31, 2014 Balance Sheet Location	Fair Value (in thousands)
Derivative Assets:		
Commodity contracts	Current assets	$ 86,240
Commodity contracts	Noncurrent assets	17,765
Derivative Liabilities:		
Commodity contracts	Current liabilities	—
Commodity contracts	Long-term liabilities	—
Total derivative asset		$ 104,005

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The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Derivative cash settlement gain (loss):				
Oil contracts(1)	$ 14,507	$ (5,894)	$ 49,298	$ (7,594)
Gas contracts	682	(21)	1,357	(548)
Total derivative cash settlement gain (loss)(2)	$ 15,189	$ (5,915)	$ 50,655	$ (8,142)
Change in fair value loss	$ (20,667)	$ (21,392)	$ (37,277)	$ (27,943)
Total derivative gain (loss)(3)	$ (5,478)	$ (27,307)	$ 13,378	$ (36,085)

(1) During the three months ended June 30, 2015, the Company paid $10.5 million to convert its three-way collars, scheduled to settle during the third and fourth quarters of 2015, to two-way collars.
(2) Derivative cash settlement gain (loss) for the six months ended June 30, 2015 and 2014 is reported in the derivative cash settlements line item on the accompanying condensed consolidated statements of cash flows within the net cash used in investing activities.
(3) Total derivative gain (loss) for the six months ended June 30, 2015 and 2014 is reported in the derivative (gain) loss line item on the accompanying condensed consolidated statements of cash flows within the net cash provided by operating activities.

NOTE 10 - EARNINGS PER SHARE

The Company issues shares of restricted stock entitling the holders to receive non-forfeitable dividends, if and when, the Company was to declare a dividend, before vesting, thus making the awards participating securities. The awards are included in the calculation of earnings per share under the two-class method. The two-class method allocates earnings for the period between common shareholders and unvested participating shareholders.

The Company issues PSUs, which represent the right to receive, upon settlement of the PSUs, a number of shares of the Company’s common stock that range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the measurement period applicable to such PSUs. Please refer to Note 7 - Stock-Based Compensation, for additional discussion.

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The following table sets forth the calculation of income (loss) per basic and diluted shares from continuing and discontinued operations and net income (loss) for the three and six month periods ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands, except shares and per share amounts)			
Income (loss) from continuing operations:				
Income (loss) from continuing operations	$ (41,164)	$ 1,271	$ (59,586)	$ 10,848
Less: undistributed income (loss) to unvested restricted stock	(688)	23	(1,007)	205
Undistributed income (loss) to common shareholders	(40,476)	1,248	(58,579)	10,643
Basic income (loss) per common share from continuing operations	$ (0.83)	$ 0.03	$ (1.25)	$ 0.27
Diluted income (loss) per common share from continuing operations	$ (0.83)	$ 0.03	$ (1.25)	$ 0.27
Income (loss) from discontinued operations:				
Income (loss) from discontinued operations	$ —	$ (113)	$ —	$ 3,841
Less: undistributed income to unvested restricted stock	—	2	—	73
Undistributed income (loss) to common shareholders	—	(111)	—	3,768
Basic income per common share from discontinued operations	$ —	$ —	$ —	$ 0.09
Diluted income per common share from discontinued operations	$ —	$ —	$ —	$ 0.09
Net income (loss):				
Net income (loss)	$ (41,164)	$ 1,158	$ (59,586)	$ 14,689
Less: undistributed income (loss) to unvested restricted stock	(688)	21	(1,007)	277
Undistributed income (loss) to common shareholders	(40,476)	1,137	(58,579)	14,412
Basic net income (loss) per common share	$ (0.83)	$ 0.03	$ (1.25)	$ 0.36
Diluted net income (loss) per common share	$ (0.83)	$ 0.03	$ (1.25)	$ 0.36
Weighted-average shares outstanding - basic	48,923,335	39,758,489	46,733,682	39,655,968
Add: dilutive effect of contingent PSUs	—	98,539	—	124,227
Weighted-average shares outstanding - diluted	48,923,335	39,857,028	46,733,682	39,780,195

The Company was in a net loss position for the three and six month periods ended June 30, 2015, which made the 80,906 and 106,644 potentially dilutive shares anti-dilutive, respectively. The Company had no anti-dilutive shares for the three and six month periods ended June 30, 2014.

NOTE 11 - CAPITAL STOCK

On February 6, 2015, the Company completed a public offering of 8,050,000 shares of its common stock generating net proceeds of $202.7 million after deducting underwriter discounts, commissions and offering expenses of approximately $6.6 million. The Company used a portion of the net proceeds to repay all of the outstanding borrowings under its revolving credit facility and for general corporate purposes, including its drilling and development program and other capital expenditures.

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NOTE 12 - INCOME TAXES

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time. During the three and six month periods ended June 30, 2015, the effective tax rate was 37.8% and 38.0%, respectively. During the three and six month periods ended June 30, 2014, the effective tax rate was 38.5%.

The deferred income tax liability for an oil and gas exploration company is dependent on many variables such as estimating the economic lives of depleting oil and gas reserves and commodity prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

As of June 30, 2015, the Company had no unrecognized tax benefits. The Company’s management does not believe that there are any new items or changes in facts or judgments that should impact the Company's tax position during the first half of 2015. Given the substantial net operating loss carry forward at the federal level, neither significant interest expense nor penalties charged for any examining agents’ tax adjustments of income tax returns are anticipated, and any such adjustments would very likely adjust only net operating loss carry forward.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in our Annual Report on Form 10-K for the year ended December 31, 2014, as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

Executive Summary

We are a Denver-based exploration and production company focused on the extraction of oil and associated liquids-rich natural gas in the United States. Our predecessors were founded in 1999 and we went public in December of 2011. Our shares of common stock are listed for trading on the NYSE under the symbol “BCEI.”

Our operations are focused in the Wattenberg Field in Colorado, which we have designated the Rocky Mountain region, and the Dorcheat Macedonia Field in southern Arkansas, which we have designated the Mid-Continent region.

The Wattenberg Field is one of the premier oil and gas resource plays in the United States benefiting from a low cost structure and strong production efficiencies. Our management team has extensive experience acquiring and operating oil and gas properties and significant expertise in horizontal drilling and fracture stimulation, which we believe will continue to contribute to the development of our sizable inventory of projects, including those targeting the Niobrara and Codell formations in the Rocky Mountain region and oily Cotton Valley sands in the Mid-Continent region. Our corporate strategy is to create stockholder value by increasing sales volumes from our Wattenberg horizontal opportunities and develop additional resource potential in both of our core areas while capitalizing on well cost reduction gained through efficiencies, managing risk exposure through derivative contracts, and engaging in prudent evaluations of potential acquisitions. We operate approximately 98% of our proved reserves with an average working interest of approximately 89% providing us with significant control over the rate of development of our asset base. Despite the continued uncertainty surrounding the global economy and volatility in commodity prices, we believe the economic returns and economic growth generated by our portfolio of oil and gas assets position us well moving forward.

Effective as of January 1, 2015, the Company revised the agreements with its natural gas processors in the Rocky Mountain region to report operated sales volumes on a three stream basis, which allows for separate reporting of NGLs extracted from the natural gas stream and sold as a separate product. The contract revisions necessitated a change in our reporting of sales volumes. Prior period sales volumes, revenues, and prices have not been reclassified to conform to the current presentation given the prospective nature of the agreements. The NGL volumes identified by the Company’s gas purchasers are converted to an oil equivalent. The Company believes that this conversion will

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more accurately convey its production and sales volumes and will allow results to be more comparable with those of our peers. This revision will increase sales volumes and the percentage of sales volumes that relate to NGLs.

Financial and Operating Highlights

Our financial results and operational highlights included:

- Total liquidity of $498.3 million, consisting of a period-end cash balance plus funds available under our revolving credit facility, as compared with $525.6 million for the second quarter of 2014;

- Increased sales volumes by 23% to 2,551.5 MBoe in the second quarter of 2015 from 2,079.3 MBoe in the second quarter of 2014, with oil and NGL production representing 77% of total sales volumes in the second quarter of 2015;

- Cash operating costs, which consist of lease operating expense, severance and ad valorem taxes, and the cash portion of general and administrative expense, per barrel decreased by $8.18 per Boe to $16.58 per Boe as compared to the second quarter of 2014;

- Drilled 19 and completed 21 gross wells within our Rocky Mountain region and drilled 7 and completed 8 gross wells within our Mid-Continent region during the second quarter of 2015;

- Realized a 20% reduction in our drilling and completion costs on our standard reach laterals during the first half of 2015 when compared to the same period in 2014;

- Cash deployed for capital projects during the six months ended June 30, 2015 was $217.4 million;

- During the six months ended June 30, 2015, our new midstream subsidiary, Rocky Mountain Infrastructure, LLC, was created to more efficiently utilize $51.9 million of gathering and midstream assets that service the Wattenberg Field;

- During the second quarter of 2015, a third-party gas processing facility within the Wattenberg Field came on-line adding approximately 75 MMcf per day of its 200 MMcf per day processing capacity once it is fully lined out; and

- During the second quarter of 2015, the Company, along with a third-party midstream entity completed pipeline infrastructure that allowed for connectivity in our east and west legacy acreage in the Wattenberg Field relieving line pressure constraints.

Outlook for 2015

Because the global economic outlook, central bank policies and commodity price environment are uncertain, we have planned a flexible capital spending program for 2015. We currently estimate the mid-point of our total capital expenditures in 2015 to be approximately $420 million, allocating approximately 90% to the Wattenberg Field and 10% to southern Arkansas. Actual capital expenditures are subject to a number of factors, including economic conditions and commodity prices, and the Company may reduce or augment the capital budget as appropriate throughout the year. In July 2015, we narrowed the range of our annual sales volume guidance by lowering the top end of the range from 30,700 Boe per day to 29,000 Boe per day resulting in a revised mid-point of 28,400 per day.

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Results of Continuing Operations

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

The following table summarizes our revenues, sales volumes, and average sales prices for the periods indicated.

	Three Months Ended June 30,			
	2015	2014	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 76,503	$ 127,444	$ (50,941)	(40) %
Natural gas sales	6,931	19,734	(12,803)	(65) %
Natural gas liquids sales	6,988	4,504	2,484	55 %
Product revenue	$ 90,422	$ 151,682	$ (61,260)	(40) %
Sales Volumes:				
Crude oil (MBbls)	1,533.0	1,376.3	156.7	11 %
Natural gas (MMcf)	3,535.9	3,697.1	(161.2)	(4) %
Natural gas liquids (MBbls)	429.2	86.8	342.4	394 %
Crude oil equivalent (MBoe)(1)	2,551.5	2,079.3	472.2	23 %
Average Sales Prices (before derivatives)(2):				
Crude oil (per Bbl)	$ 49.90	$ 92.60	$ (42.70)	(46) %
Natural gas (per Mcf)	$ 1.96	$ 5.34	$ (3.38)	(63) %
Natural gas liquids (per Bbl)	$ 16.28	$ 51.89	$ (35.61)	(69) %
Crude oil equivalent (per Boe)(1)	$ 35.44	$ 72.95	$ (37.51)	(51) %
Average Sales Prices (after derivatives)(2):				
Crude oil (per Bbl)	$ 59.37	$ 88.31	$ (28.94)	(33) %
Natural gas (per Mcf)	$ 2.15	$ 5.33	$ (3.18)	(60) %
Natural gas liquids (per Bbl)	$ 16.28	$ 51.89	$ (35.61)	(69) %
Crude oil equivalent (per Boe)(1)	$ 41.39	$ 70.10	$ (28.71)	(41) %

(1) Effective as of January 1, 2015, the Company revised the agreements with its natural gas processors in the Rocky Mountain region to report operated sales volumes on a three stream basis, which allows for separate reporting of NGLs extracted from the natural gas stream and sold as a separate product. The contract revisions necessitated a change in our reporting of sales volumes. Prior period sales volumes, revenues, and prices have not been reclassified to conform to the current presentation given the prospective nature of the agreements.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

(3) The derivatives economically hedge the price we receive for crude oil and natural gas.

Revenues decreased by 40%, to $90.4 million, for the three months ended June 30, 2015 compared to $151.7 million for the three months ended June 30, 2014 largely due to a 51% decrease in oil equivalent pricing. The decreased pricing was offset by increased sales volumes of 23% for the three months ended June 30, 2015 compared to the same period in 2014. The increased volumes are a direct result of $357.2 million expended for drilling and completion during the last two quarters of 2014 and the $287.4 million expended during the first half of 2015. During the period from June 30, 2014 through June 30, 2015, we drilled 110 and completed 106 gross wells in the Rocky Mountain region and drilled 37 and completed 39 gross wells in the Mid-Continent region.

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The following table summarizes our operating expenses for the periods indicated.

	Three Months Ended June 30,			
	2015	2014	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating expense	$ 20,895	$ 18,018	$ 2,877	16 %
Severance and ad valorem taxes	4,148	16,263	(12,115)	(74) %
Exploration	5,748	96	5,652	5888 %
Depreciation, depletion and amortization	69,925	54,117	15,808	29 %
Abandonment and impairment of unproved properties	14,527	—	14,527	100 %
General and administrative	21,602	24,547	(2,945)	(12) %
Operating expenses	$ 136,845	$ 113,041	$ 23,804	21 %
Selected Costs ($ per Boe):				
Lease operating expense	$ 8.19	$ 8.67	$ (0.48)	(6) %
Severance and ad valorem taxes	1.63	7.82	(6.19)	(79) %
Exploration	2.25	0.05	2.20	4400 %
Depreciation, depletion and amortization	27.41	26.03	1.38	5 %
Abandonment and impairment of unproved properties	5.69	—	5.69	100 %
General and administrative	8.47	11.81	(3.34)	(28) %
Operating expenses	$ 53.64	$ 54.38	$ (0.74)	(1) %

Lease Operating Expense. Our lease operating expense increased $2.9 million, or 16%, to $20.9 million for the three months ended June 30, 2015 from $18.0 million for the three months ended June 30, 2014 and decreased on an equivalent basis from $8.67 per Boe to $8.19 per Boe. The increase in aggregate lease operating expense was related to increased sales volumes of 23% during the three months ended June 30, 2015 when compared to the same period in 2014. During the quarter ended June 30, 2015, two of the largest components of lease operating expense were compression and well servicing which increased $2.2 million and $155,000, respectively, over the comparable period in 2014. The Company has generated efficiencies to reduce operating costs and negotiated contract reductions while increasing production for the three months ended June 30, 2015 driving the per barrel rate down when compared to the same period in 2014.

Severance and ad valorem taxes. Our severance and ad valorem taxes decreased $12.1 million to $4.1 million for the three months ended June 30, 2015 from $16.2 million for the three months ended June 30, 2014. Severance and ad valorem taxes primarily correlate to revenue. Revenues decreased by 40% for the three months ended June 30, 2015 when compared to the same period in 2014 causing the severance and ad valorem taxes to decrease. Additionally, our ad valorem tax credits available for deduction increased in the second quarter of 2015 when compared to the same period in 2014 due to continued development of the Wattenberg Field which reduced our effective severance tax rate.

Exploration. Our exploration expense increased $5.6 million to $5.7 million during the three months ended June 30, 2015 from $100,000 for the three months ended June 30, 2014. During the three months ended June 30, 2015, we incurred $5.7 million of charges for exploratory wells located in the North Park Basin that we were unable to assign economic proved reserves to.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $15.8 million, or 29%, to $69.9 million for the three months ended June 30, 2015 from $54.1 million for the three months ended June 30, 2014. Our depreciation, depletion and amortization expense per Boe were commensurate between the three month periods ended June 30, 2015 and 2014.

Abandonment and impairment of unproved properties. Our abandonment and impairment of unproved properties increased 100% to $14.5 million for the three months ended June 30, 2015 when compared to the three months ended June 30, 2014. The Company incurred $5.4 million of impairment charges for non-core leases expiring within the Wattenberg Field and $8.7 million of impairment charges to fully impair the North Park Basin

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due to a strategic shift in our development plan during the three months ended June 30, 2015. There were no unproved properties impaired during the three months ended June 30, 2014.

General and administrative. Our general and administrative expense decreased $2.9 million, or 12%, to $21.6 million for the three months ended June 30, 2015 from $24.5 million for the comparable period in 2014 and decreased on an equivalent basis to $8.47 per Boe from $11.81 per Boe. The decrease in general and administrative expense for the three months ended June 30, 2015 when compared to the same period in 2014 was primarily due to executive departure costs that occurred in the second quarter of 2014.

Derivative gain (loss). Our derivative loss decreased $21.8 million to a loss of $5.5 million for the three month period ended June 30, 2015 from a $27.3 million loss for the comparable period in 2014. The decrease in loss incurred was primarily the result of realized prices being more than the contract prices to a lesser extent during the three months ended June 30, 2015 when compared to the three months ended June 30, 2014. During the second quarter of 2015, we paid $10.5 million to convert our three-way collars, scheduled to settle during the third and fourth quarters of 2015, to two-way collars. Please refer to Note 9 - Derivatives above for additional discussion.

Interest expense. Our interest expense for the three months ended June 30, 2015 increased $5.1 million, or 54%, to $14.5 million compared to $9.4 million for the three months ended June 30, 2014. The increase for the three months ended June 30, 2015 was primarily due to the issuance of $300 million of 5.75% Senior Notes at the beginning of the third quarter of 2014. Interest expense, including amortization of the premium and financing costs, on the Senior Notes for the three month periods ended June 30, 2015 and 2014 was $13.1 million and $8.5 million, respectively. Average debt outstanding for the three months ended June 30, 2015 was $824.0 million as compared to $500.0 million for the comparable period in 2014.

Income tax expense. Our estimate for federal and state income tax benefit for the three months ended June 30, 2015 was $25.0 million from continuing operations as compared to an $800,000 income tax expense for the three months ended June 30, 2014. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rates for the three month periods ended June 30, 2015 and 2014 were 37.8% and 38.5%, respectively, which differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes.

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Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The following table summarizes our revenues, sales volumes, and average sales prices for the periods indicated.

	Six Months Ended June 30,				
	2015	2014	Change	Percent Change	
	(In thousands, except percentages)				
Revenues:					
Crude oil sales	$ 135,923	$ 231,191	$ (95,268)	(41)	%
Natural gas sales	14,919	38,249	(23,330)	(61)	%
Natural gas liquids sales	12,656	9,630	3,026	31	%
CO2 sales	—	7	(7)	(100)	%
Product revenue	$ 163,498	$ 279,077	$ (115,579)	(41)	%
Sales Volumes:					
Crude oil (MBbls)	3,023.5	2,540.6	482.9	19	%
Natural gas (MMcf)	7,042.8	6,786.3	256.5	4	%
Natural gas liquids (MBbls)(1)	830.0	180.8	649.2	359	%
Crude oil equivalent (MBoe)(2)	5,027.3	3,852.4	1,174.9	30	%
Average Sales Prices (before derivatives)(3)					
Crude oil (per Bbl)	$ 44.96	$ 91.00	$ (46.04)	(51)	%
Natural gas (per Mcf)	$ 2.12	$ 5.64	$ (3.52)	(62)	%
Natural gas liquids (per Bbl)	$ 15.25	$ 53.26	$ (38.01)	(71)	%
Crude oil equivalent (per Boe)(2)	$ 32.52	$ 72.44	$ (39.92)	(55)	%
Average Sales Prices (after derivatives)(3)					
Crude oil (per Bbl)	$ 61.26	$ 88.01	$ (26.75)	(30)	%
Natural gas (per Mcf)	$ 2.31	$ 5.56	$ (3.25)	(58)	%
Natural gas liquids (per Bbl)	$ 15.25	$ 53.26	$ (38.01)	(71)	%
Crude oil equivalent (per Boe)(2)	$ 42.60	$ 70.33	$ (27.73)	(39)	%

(1) Effective as of January 1, 2015, the Company revised the agreements with its natural gas processors in the Rocky Mountain region to report operated sales volumes on a three stream basis, which allows for separate reporting of NGLs extracted from the natural gas stream and sold as a separate product. The contract revisions necessitated a change in our reporting of sales volumes. Prior period sales volumes, revenues, and prices have not been reclassified to conform to the current presentation given the prospective nature of the agreements.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

(3) The derivatives economically hedge the price we receive for crude oil and natural gas.

Revenues decreased by 41%, to $163.5 million, for the six months ended June 30, 2015 compared to $279.1 million for the six months ended June 30, 2014 largely due to a 55% decrease in oil equivalent pricing. The decreased pricing was offset by increased sales volumes of 30% for the six months ended June 30, 2015 compared to the same period in

2014. The increased volumes are a direct result of $357.2 million expended for drilling and completion during the last two quarters of 2014 and $287.4 million expended during the six months ended June 30, 2015. During the period from June 30, 2014 through June 30, 2015, we drilled 110 and completed 106 gross wells in the Rocky Mountain region and drilled 37 and completed 39 gross wells in the Mid-Continent region.

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The following table summarizes our operating expenses for the periods indicated.

	Six Months Ended June 30,				
	2015	2014	Change	Percent Change	
	(In thousands, except percentages)				
Expenses:					
Lease operating	$ 40,159	$ 35,099	$ 5,060	14	%
Severance and ad valorem taxes	10,644	27,013	(16,369)	(61)	%
Exploration	6,246	1,179	5,067	430	%
Depreciation, depletion and amortization	128,929	95,248	33,681	35	%
Abandonment and impairment of unproved properties	19,996	—	19,996	100	%
General and administrative	38,474	48,261	(9,787)	(20)	%
Operating expenses	$ 244,448	$ 206,800	$ 37,648	18	%
Selected Costs ($ per Boe):					
Lease operating	$ 7.99	$ 9.11	$ (1.12)	(12)	%
Severance and ad valorem taxes	2.12	7.01	(4.89)	(70)	%
Exploration	1.24	0.31	0.93	300	%
Depreciation, depletion and amortization	25.65	24.72	0.93	4	%
Abandonment and impairment of unproved properties	3.98	—	3.98	100	%
General and administrative	7.65	12.53	(4.88)	(39)	%
Operating expenses	$ 48.63	$ 53.68	$ (5.05)	(9)	%

Lease Operating Expense. Our lease operating expense increased $5.1 million, or 14%, to $40.2 million for the six months ended June 30, 2015 from $35.1 million for the six months ended June 30, 2014 and decreased on an equivalent basis from $9.11 per Boe to $7.99 per Boe. The increase in aggregate lease operating expense was related to increased sales volumes of 30% during the six months ended June 30, 2015 when compared to the same period in 2014. During the six month period ended June 30, 2015, two of the largest components of lease operating expense were compression and pumping services which increased $3.6 million and $500,000, respectively, over the comparable period in 2014. The Company has generated efficiencies to reduce operating costs and negotiated contract reductions while increasing production for the six months ended June 30, 2015 driving the per barrel rate down when compared to the same period in 2014.

Severance and ad valorem taxes. Our severance and ad valorem taxes decreased $16.4 million to $10.6 million for the six months ended June 30, 2015 from $27.0 million for the six months ended June 30, 2014. Severance and ad valorem taxes primarily correlate to revenue, which decreased by 41% for the six months ended June 30, 2015 when compared to the same period in 2014. Our ad valorem tax credits available for deduction increased in the first half of 2015 when compared to the same period in 2014 due to continued development of the Wattenberg Field which reduced our effective severance tax rate.

Exploration. Our exploration expense increased $5.0 million to $6.2 million during the six months ended June 30, 2015 from $1.2 million for the six months ended June 30, 2014. During the six months ended June 30, 2015, we incurred $5.7 million of charges for exploratory wells located in the North Park Basin that we were unable to assign economic proved reserves to and paid $500,000 in delay rentals. During the six months ended June 30, 2014, we incurred a $1.0 million dry hole charge related to a vertical well within the Wattenberg Field drilled to test the Lyons formation.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $33.7 million, or 35%, to $128.9 million for the six months ended June 30, 2015 from $95.2 million for the six months ended June 30, 2014. Our depreciation, depletion and amortization expense per Boe were commensurate between the six months ended June 30, 2015 and 2014.

Abandonment and impairment of unproved properties. Our abandonment and impairment of unproved properties increased 100% to $20.0 million for the six months ended June 30, 2015 when compared to the six months ended June 30, 2014. The Company incurred $10.9 million of impairment charges for non-core leases expiring within the Wattenberg Field and $8.7 million of impairment charges to fully impair the North Park Basin

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due to a strategic shift in our development plan during the six months ended June 30, 2015. There were no unproved properties impaired during the six months ended June 30, 2014.

General and administrative. Our general and administrative expense decreased $9.8 million, or 20%, to $38.5 million for the six months ended June 30, 2015 from $48.3 million for the comparable period in 2014 and decreased on an equivalent basis to $7.65 per Boe from $12.53 per Boe. The decrease in general and administrative expense for the six months ended June 30, 2015 when compared to the same period in 2014 was primarily due to executive departure costs that occurred in the first half of 2014.

Derivative gain (loss). Our derivative gain increased $49.5 million to $13.4 million for the six months ended June 30, 2015 from a $36.1 million loss for the comparable period in 2014. The gain was primarily the result of realized prices being less than the contract prices during the six months ended June 30, 2015 when compared to the six months ended June 30, 2014. During the six months ended June 30, 2015, we paid $10.5 million to convert our three-way collars, scheduled to settle during the third and fourth quarters of 2015, to two-way collars. Please refer to Note 9 - Derivatives above for additional discussion.

Interest expense. Our interest expense for the six months ended June 30, 2015 increased $9.9 million, to $28.7 million compared to $18.8 million for the six months ended June 30, 2014. The increase for the six months ended June 30, 2015 was primarily due to the issuance of $300 million of 5.75% Senior Notes at the beginning of the third quarter of 2014. Interest expense, including amortization of the premium and financing costs, on the Senior Notes for the six month periods ended June 30, 2015 and 2014 was $26.1 million and $17.1 million, respectively. Average debt outstanding for the six months ended June 30, 2015 was $822.8 million as compared to $500.0 million for the comparable period in 2014.

Income tax expense. Our estimate for federal and state income tax benefit for the six months ended June 30, 2015 was $36.5 million from continuing operations as compared to a $6.8 million income tax expense for the six months ended June 30, 2014. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rates for the six months ended June 30, 2015 and 2014 were 38.0% and 38.5%, respectively, which differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes.

Results for Discontinued Operations

The majority of the assets deemed held for sale and classified as discontinued operations were sold in 2012. The remaining property located in the Midway Sunset Field sold on March 21, 2014 for approximately $6.0 million and resulted in a $6.3 million gain as of June 30, 2014. Please refer to Note 3 — Discontinued Operations for additional discussion.

Liquidity and Capital Resources

We fund our operations, capital expenditures and working capital requirements with cash flows from our operating activities, borrowings under our revolving credit facility and by accessing the debt and capital markets.

We believe that our period-end cash balance plus funds available under our revolving credit facility and cash flow from operating activities will be sufficient to fund our business for at least the next 12 months. To the extent actual operating results differ from our anticipated results or our borrowing base under our revolving credit facility is redetermined at a substantially lower amount, our liquidity could be adversely affected. Our next redetermination is set to occur in November 2015. Due to continued volatility in commodity prices, it is possible that our borrowing base will be reduced at our next redetermination due to downward revisions in our lenders' commodity price decks, which in turn reduces the value of our proved reserves calculated thereunder, as well as the expiration of certain of our commodity derivatives.

As of June 30, 2015, our borrowing base was $550 million, and we elected to limit our bank commitments to $500 million while reserving the option to access the full $550 million, at the Company's request, prior to the next semiannual redetermination in November 2015. As of June 30, 2015, we had $43 million outstanding on our revolving credit facility, a $24 million letter of credit issued, and $483 million available borrowing capacity. Our weighted-average interest rates (excluding amortization of deferred financing costs and the accretion of our

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contractual obligation for land acquisition) on borrowings from our revolving credit facility were 1.68% and nil, respectively, for the six months ended June 30, 2015 and 2014. Our commitment fees were $1.1 million and $942,000, respectively, for the six months ended June 30, 2015 and 2014.

On February 6, 2015, the Company completed a public offering of 8,050,000 shares of its common stock generating net proceeds of $202.7 million after deducting underwriter discounts, commissions and offering expenses of approximately $6.6 million. The Company used a portion of the net proceeds to repay all of the then outstanding borrowings under its revolving credit facility and used the remaining net proceeds for general corporate purposes, including its drilling and development program and other capital expenditures.

For the remainder of 2015, we have 6,500 Bbls per day of oil hedged with two-way collars with an average ceiling of $95.49 per Bbl and average floor of $84.62 per Bbl. For the remainder of 2015, we have 6,000 Bbls per day of oil hedged with swaps with an average fixed price of $72.16 per Bbl. For the remainder of 2015, we have 15,000 Mcf per day of natural gas hedged with three-way collars with an average ceiling of $4.75 per Mcf, average floor of $4.00 per Mcf and average short floor of $3.50 per Mcf. These commodity derivatives, along with our swaps represent approximately 53% of our anticipated production for the remainder of 2015. In 2016, we have 5,500 Bbls per day of oil hedged with three-way collars with an average ceiling of $96.83 per Bbl, average floor of $85.00 per Bbl and average short floor of $70.00 per Bbl. We expect that our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please refer to Note 9 — Derivatives above for a summary of derivatives in place and Item 3. Quantitative and Qualitative Disclosures About Market Risks below for additional discussion.

The following table summarizes our cash flows and other financial measures for the periods indicated.

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Net cash provided by operating activities	$ 48,163	$ 157,969
Net cash used in investing activities	(245,014)	(296,663)
Net cash provided by (used in) financing activities	209,607	(5,333)
Cash and cash equivalents	15,340	36,555
Acquisition of oil and gas properties	11,914	3,091
Exploration and development of oil and gas properties	282,993	275,890

Cash flows provided by operating activities

During the six month period ended June 30, 2015, we generated $48.2 million of cash provided by operating activities, a decrease of $109.8 million from the comparable period in 2014. The decrease in cash flows from operating activities resulted primarily from a 55% decrease in oil equivalent pricing, compounded by increased lease operating expenses and was partially offset by a 30% increase in sales volumes during the six month period ended June 30, 2015 as compared to the six month period ended June 30, 2014. See Results of Continuing Operations above for more information on the factors driving these changes.

Cash flows used in investing activities

Expenditures for development of oil and natural gas properties are the primary use of our capital resources. Net cash used in investing activities for the six months ended June 30, 2015 decreased $51.6 million as compared to the same period in 2014. For the six months ended June 30, 2015, cash used for the acquisition of oil and gas properties was $11.9 million and cash used for the development of oil and natural gas properties was $283.0 million which was offset by net derivative cash receipts of $50.7 million, net of a $10.5 million payment to convert our three-way collars, scheduled to settle in the third and fourth quarters of 2015, to two-way collars. For the six months ended June 30, 2014, cash used for the acquisition of oil and gas properties was $3.1 million and cash used for the development of oil and natural gas properties was $275.9 million and derivative cash payments was $8.1 million.

Cash flows provided by (used in) financing activities

Net cash provided by financing activities for the six months ended June 30, 2015 increased $214.9 million, compared to the same period in 2014. The increase was primarily due to $202.7 million of net proceeds from the

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sale of common stock that occurred during the six months ended June 30, 2015 plus net proceeds of $10 million from our revolving credit facility, neither of which occurred in the comparable period in 2014.

New Accounting Pronouncements

Please refer to Note 2 — Basis of Presentation under Part I, Item 1 of this report for any recently issued or adopted accounting standards.

Critical Accounting Policies and Estimates

Information regarding our critical accounting policies and estimates is contained in Part II, Item 7 of our 2014 Form 10-K.

Effects of Inflation and Pricing

Inflation in the United States has been relatively low in recent years and dropped even lower during 2014, which did not have a material impact on our results of operations for the three and six month periods ended June 30, 2015 and 2014. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, asset retirement obligations, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. Although risk of inflation is always present, given current depressed oil and gas prices, we anticipate that costs of materials and services will continue to decline.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Contractual Obligations

There were no material changes in our contractual obligations and other commitments as disclosed in our 2014 Form 10-K.

Cautionary Note Regarding Forward-Looking Statements

This report contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended (the “Exchange Act”). When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “predict,” “potential,” “project,” “plan,” “will,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward looking statements include statements related to, among other things:

- reserves estimates;
- estimated sales volumes for 2015;
- inventory growth;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;

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· the Wattenberg Field being a premier oil and resource play in the United States;
· anticipated decline of costs of materials and services;
· compliance with debt covenants;
· ability to satisfy obligations related to ongoing operations;
· compliance with government regulations;
· adequacy of gathering systems and continuous improvement of such gathering systems;
· impact from the lack of available gathering systems and processing facilities in certain areas;
· natural gas, oil and natural gas liquid prices and factors affecting the volatility of such prices;
· impact of lower commodity prices;
· the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
· plans to drill or participate in wells including the intent to focus in specific areas or formations;
· loss of any purchaser of our products;
· our estimated revenues and losses;
· the timing and success of specific projects;
· intentions with respect to working interest percentages;
· management and technical team;
· outcomes and effects of litigation, claims and disputes;
· our business strategy;
· expectation that the Niobrara B and C benches and the Codell formation will be the primary sources of future production growth;
· our ability to replace oil and natural gas reserves;
· impact of recently issued accounting pronouncements;
· the Company's tax position and future tax adjustments;
· impact of the loss a single customer;
· timing and ability to meet certain volume commitments related to purchase and transportation agreements;
· the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes and other industry-related constraints;
· our financial position;
· the amount and availability of our borrowing base under our revolving credit facility and the effect of future borrowing base redeterminations;
· our cash flow and liquidity;
· our future production (including components of such production);
· the adequacy of our insurance; and
· other statements concerning our operations, economic performance and financial condition.

We have based these forward looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions and expected future developments

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as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- the risk factors discussed in Part I, Item 1A of our 2014 Form 10 K;
- declines or volatility in the prices we receive for our oil, natural gas liquids and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions and lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services and personnel;
- exploration and development risks;
- competition in the oil and natural gas industry;
- management’s ability to execute our plans to meet our goals;
- risks related to our derivative instruments;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take away capacity to provide adequate infrastructure for the products of our drilling program;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

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All forward looking statements speak only as of the date of this report. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Part II, Item 1A. Risk Factors and Part II, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this report. These cautionary statements qualify all forward looking statements attributable to us or persons acting on our behalf.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Oil and Natural Gas Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of, and compliance with, production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources.

Commodity Derivative Contracts

Our primary commodity risk management objective is to reduce volatility in our cash flows. We enter into derivative contracts for oil and natural gas using NYMEX futures or over the counter derivative financial instruments with counterparties who we believe are well capitalized and have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in derivative contracts, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

Presently, all of our derivative arrangements are concentrated with four counterparties, all of which are lenders under our revolving credit facility. If these counterparties fail to perform their obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of oil market prices exceeding our swap prices or collar ceilings requires us to make payment for the settlement of our derivatives, if owed by us, generally up to 15 business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between derivative settlement and payment for revenues earned.

Please refer to Note 9 - Derivatives of Part I, Item 1 of this report for a derivative summary table.

Interest Rates

As of June 30, 2015, we had $43 million outstanding under our revolving credit facility. Borrowings under our revolving credit facility bear interest at a fluctuating rate that is tied to an adjusted bank base rate or London Interbank Offered Rate, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow.

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Counterparty and Customer Credit Risk

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Four lenders under our revolving credit facility are counterparties on our derivative instruments currently in place and have investment grade credit ratings. We expect that any future derivative transactions we enter into will be with these or other lenders under our revolving credit facility that will carry an investment grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production from the Mid Continent and Rocky Mountain regions depends in part upon the availability, proximity and capacity of third party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services, pipelines and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

There have not been material changes to the interest rate risk analysis or oil and gas price sensitivity analysis disclosed in our 2014 Form 10-K.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2015. The term “disclosure controls and procedures,” as defined in Rules 13a 15(e) and 15d 15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive officer and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of June 30, 2015, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company's internal control system is supported by written policies and procedures, contains self-monitoring mechanisms and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Changes in Internal Control over Financial Reporting

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There were no changes in our internal control over financial reporting identified in management’s evaluation pursuant to Rules 13a 15(d) or 15d 15(d) of the Exchange Act during the quarter ended June 30, 2015 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other oil and gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this filing, there are no material pending or overtly threatened legal actions against us of which we are aware.

Item 1A. Risk Factors.

Our business faces many risks. Any of the risk factors discussed in this report or our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operation. For a discussion of our potential risks and uncertainties, see the information in Part I, Item 1A., Risk Factors, in our 2014 Form 10-K. There have been no material changes to our risk factors from those described in our 2014 Form 10-K.

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

Unregistered sales of securities. There were no sales of unregistered equity securities during the three month period ended June 30, 2015.

Issuer purchases of equity securities. The following table contains information about acquisitions of our equity securities during the three month period ended June 30, 2015.

	Total Number of	Average Price	Total Number of Shares Purchased as Part of	Maximum Number of Shares that May Be Purchased

	Shares Purchased(1)	Paid per Share	Publicly Announced Plans or Programs	Under Plans or Programs
April 1, 2015 — April 30, 2015	8,989	$ 27.52	—	—
May 1, 2015 — May 31, 2015	1,796	$ 23.63	—	—
June 1, 2015 — June 30, 2015	452	$ 20.30	—	—
Total	11,237	$ 26.60	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes required for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, nor do we have a publicly announced plan or program to repurchase shares of our common stock.

Our revolving credit facility and Senior Notes provide for restrictions on the payment of certain dividends.

Item 3.Defaults Upon Senior Securities.

None.

Item 4.Mine Safety Disclosures.

Not applicable.

Item 5.Other Information.

None.

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Item 6.Exhibits.

Exhibit No.	Description of Exhibit
10.1	Amendment No. 11 and Agreement, dated as of May 13, 2015, to the Credit Agreement, amount Bonanza Creek Energy Inc., the Guarantors, KeyBank National Association, as Administrative Agent and as Issuing Lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 15, 2015).
10.2*	Bonanza Creek Energy, Inc. Amended and Restated 2011 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 5, 2015).
10.3†*	Bonanza Creek Energy, Inc. Amended and Restated Executive Change in Control and Severance Plan.
10.4†*	Form of Restricted Stock Agreement (Employee) under the Amended and Restated 2011 Long Term Incentive Plan.
10.5†*	Form of Restricted Stock Agreement (Director) under the Amended and Restated 2011 Long Term Incentive Plan.
31.1†	Certification of the Principal Executive Officer pursuant to Rule 13a-14(a).
31.2†	Certification of the Principal Financial Officer pursuant to Rule 13a-14(a).
32.1†	Certification of the Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2†	Certification of the Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
101	The following materials from the Bonanza Creek Energy, Inc. Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations and Comprehensive Income, (iii) the Condensed Consolidated Statements of Cash Flows and (iv) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

† Filed or furnished herewith

* Management Contract or Compensatory Plan or Arrangement

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SIGNATURES

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.

	BONANZA CREEK ENERGY, INC.
Date: July 28, 2015	By: /s/ Richard J. Carty Richard J. Carty President and Chief Executive Officer (principal executive officer)
	By: /s/ William J. Cassidy William J. Cassidy Executive Vice President and Chief Financial Officer (principal financial officer)
	By: /s/ Wade E. Jaques Wade E. Jaques Vice President and Chief Accounting Officer (principal accounting officer)