Bonanza Creek Energy, Inc.
Form 10-Q
August 09, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2013

or

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

For the transition period from to

Commission File Number: 001-35371

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**61-1630631** (I.R.S. Employer Identification No.)
410 17th Street, Suite 1400 **Denver, Colorado** (Address of principal executive offices)	**80202** (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. x Yes o 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). x Yes o 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 o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

SEC 1296 (01-12) **Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.**

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes x No

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date. 40,287,018 shares of common stock were outstanding as of June 30, 2013.

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 46,084,655	$ 4,267,667
Accounts receivable:		
Oil and gas sales	42,461,451	38,600,436
Joint interest and other	10,967,129	5,484,620
Prepaid expenses and other	2,397,342	3,031,815
Inventory of oilfield equipment	7,482,039	1,740,934
Derivative asset	1,422,272	2,178,064
Total current assets	110,814,888	55,303,536
OIL AND GAS PROPERTIES using the successful efforts method of accounting:		
Proved properties	982,931,566	811,000,239
Unproved properties	75,340,925	72,928,364
Wells in progress	76,287,011	75,031,806
	1,134,559,502	958,960,409
Less: accumulated depreciation, depletion and amortization	(140,273,109)	(89,669,725)
	994,286,393	869,290,684
NATURAL GAS PLANT	74,815,106	73,087,603
Less: accumulated depreciation	(4,641,695)	(3,403,817)
	70,173,411	69,683,786
PROPERTY AND EQUIPMENT	7,715,715	5,089,795
Less: accumulated depreciation	(1,664,596)	(890,093)
	6,051,119	4,199,702
OIL AND GAS PROPERTIES HELD FOR SALE, LESS ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION	481,993	582,388
LONG-TERM DERIVATIVE ASSET	3,283,496	
OTHER ASSETS, net	10,001,336	3,429,711
TOTAL ASSETS	$ 1,195,092,636	$ 1,002,489,807
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 76,370,016	$ 72,850,272
Oil and gas revenue distribution payable	13,655,400	12,552,655
Contractual obligation for land acquisition	11,999,877	11,999,877
Derivative liability	3,495,537	5,200,202
Total current liabilities	105,520,830	102,603,006
LONG-TERM LIABILITIES:		
Long-term debt	300,000,000	158,000,000
Contractual obligation for land acquisition	33,652,283	33,271,631
Ad valorem taxes	12,581,086	11,179,370

Derivative liability				1,208,106
Deferred income taxes, net		126,646,793		110,376,606
Asset retirement obligations		8,267,566		7,333,584
TOTAL LIABILITIES		586,668,558		423,972,303
COMMITMENTS AND CONTINGENCIES (Note 7)				
STOCKHOLDERS EQUITY:				
Preferred stock, $.001 par value, 25,000,000 shares authorized, 0 outstanding				
Common stock, $.001 par value, 225,000,000 shares authorized, 40,287,018 and 40,115,536 issued and outstanding, respectively		40,287		40,116
Additional paid-in capital		523,361,035		519,425,356
Retained earnings		85,022,756		59,052,032
Total stockholders equity		608,424,078		578,517,504
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	1,195,092,636	$	1,002,489,807

See accompanying notes to these consolidated financial statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
NET REVENUES:				
Oil and gas sales	$ 84,517,472	$ 51,455,094	$ 162,824,485	$ 99,285,525
OPERATING EXPENSES:				
Lease operating	12,898,081	6,954,397	24,028,766	14,061,728
Severance and ad valorem taxes	5,352,065	2,769,425	10,164,819	6,365,234
Exploration	862,384	2,014,531	1,424,696	3,204,654
Depreciation, depletion and amortization	29,516,726	13,034,490	52,879,791	24,035,533
General and administrative (including $2,685,001, $795,774, $7,063,288, and $1,466,338, respectively, of stock-based compensation)	13,282,848	7,110,385	26,448,910	13,075,103
Total operating expenses	61,912,104	31,883,228	114,946,982	60,742,252
INCOME FROM OPERATIONS	22,605,368	19,571,866	47,877,503	38,543,273
OTHER INCOME (EXPENSE):				
Other income (loss)	(86,575)	45,437	50,358	7,710
Interest expense	(5,869,775)	(654,693)	(7,832,493)	(1,216,209)
Unrealized gain on fair value of commodity derivatives	9,049,127	15,368,221	5,440,475	11,992,390
Realized gain (loss) on settled commodity derivatives	(1,486,815)	130,332	(2,993,935)	(1,080,807)
Total other income (loss)	1,605,962	14,889,297	(5,335,595)	9,703,084
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	24,211,330	34,461,163	42,541,908	48,246,357
Income tax expense	(9,327,978)	(13,267,610)	(16,386,124)	(18,574,910)
INCOME FROM CONTINUING OPERATIONS	$ 14,883,352	$ 21,193,553	$ 26,155,784	$ 29,671,447
DISCONTINUED OPERATIONS (Note 3)				
Gain (loss) from operations associated with oil and gas properties held for sale	(273,979)	508,211	(300,997)	619,201
Income tax (expense) benefit	105,535	(195,661)	115,937	(238,392)
Income (loss) associated with oil and gas properties held for sale	(168,444)	312,550	(185,060)	380,809
NET INCOME	$ 14,714,908	$ 21,506,103	$ 25,970,724	$ 30,052,256
COMPREHENSIVE INCOME	$ 14,714,908	$ 21,506,103	$ 25,970,724	$ 30,052,256
BASIC AND DILUTED INCOME PER SHARE				
Income from continuing operations	$ 0.37	$ 0.53	$ 0.65	$ 0.75
Income (loss) from discontinued operations	$ (0.01)	$ .01	$	$ 01
Net income per common share	$ 0.36	$ 0.54	$ 0.65	$ 0.76
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK BASIC AND DILUTED	40,330,974	39,474,011	40,209,427	39,475,797

See accompanying notes to these consolidated financial statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 25,970,724	$ 30,052,256
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	53,084,435	25,614,523
Deferred income taxes	16,270,187	18,813,302
Stock-based compensation	7,063,288	1,466,338
Exploration		1,575,494
Amortization of deferred financing costs	664,923	464,377
Accretion of contractual obligation for land acquisition	380,652	
Valuation (increase) decrease in commodity derivatives	(5,440,475)	(11,992,390)
Other		3,334
(Increase) decrease in operating assets:		
Accounts receivable	(9,343,524)	(12,811,924)
Prepaid expenses and other assets	634,473	(31,491)
(Decrease) increase in operating liabilities:		
Accounts payable and accrued liabilities	(1,376,701)	3,381,752
Settlement of asset retirement obligations	(73,358)	(146,125)
Net cash provided by operating activities	87,834,624	56,389,446
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisition of oil and gas properties	(8,351,540)	(553,731)
Exploration and development of oil and gas properties	(162,688,720)	(102,945,699)
Natural gas plant capital expenditures	(3,987,470)	(6,510,563)
Decrease in restricted cash	79,478	232,580
Additions to property and equipment non oil and gas	(2,625,920)	(1,469,133)
Net cash (used) in investing activities	(177,574,172)	(111,246,546)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Increase in bank revolving credit	33,500,000	56,000,000
Payment on bank revolving credit	(191,500,000)	
Proceeds from sale of senior notes	300,000,000	
Offering costs related to sale of senior notes	(7,270,105)	
Payment of employee tax withholdings in exchange for the return of common stock	(3,127,438)	
Deferred financing costs	(45,921)	(627,196)
Net cash provided by financing activities	131,556,536	55,372,804
NET INCREASE IN CASH AND CASH EQUIVALENTS	41,816,988	515,704
CASH AND CASH EQUIVALENTS:		
Beginning of period	4,267,667	2,089,674
End of period	$ 46,084,655	$ 2,605,378
SUPPLEMENTAL CASH FLOW DISCLOSURE:		
Cash paid for interest	$ 2,320,886	$ 512,000
Cash paid for income taxes	$ 100,000	$
Changes in working capital related to drilling expenditures, natural gas plant expenditures, and property acquisition	$ 7,400,906	$ 39,577,503

See accompanying notes to these consolidated financial statements.

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of June 30, 2013 (unaudited)

1. ORGANIZATION AND BUSINESS:

Bonanza Creek Energy, Inc. (the Company or BCEI) is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of June 30, 2013, the Company s assets and operations are concentrated primarily in the Wattenberg Field in the Rocky Mountains and in Southern Arkansas.

2. BASIS OF PRESENTATION:

These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The quarterly financial statements included herein do not necessarily include all of the disclosures as may be required under generally accepted accounting principles. The readers of these quarterly financial statements should also read the audited consolidated financial statements and related notes of BCEI that were included in BCEI s Annual Report on Form 10-K filed with the SEC on March 15, 2013. 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.

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

Oil and Gas Producing Activities The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells will be capitalized at cost when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs will be charged to expense. The costs of development wells will be capitalized whether productive or nonproductive. Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred. Gains and losses arising from sales of properties will be included in income. However, sales that do not significantly affect a field s unit-of-production depletion rate will be accounted for as normal retirements with no gain or loss recognized. Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization (DD&A) of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company s expected cost to abandon its well interests.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property will be written down to fair value. Fair value for oil and natural gas properties is generally determined based on discounted future net cash flows.

3. DISCONTINUED OPERATIONS:

During June of 2012, the Company began marketing, with an intent to sell, all of its oil and gas properties in California. 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 these properties qualifies for discontinued operations. The carrying amounts of the major classes of assets and liabilities related to the operation of the remaining property that is held for sale as of June 30, 2013 and December 31, 2012 are presented below:

	As of June 30, 2013	As of December 31, 2012
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	$ 1,721,265	$ 1,721,265
Unproved properties	629	629
Wells in progress	100,936	39,245
Total property and equipment	1,822,830	1,761,139
Less accumulated depletion and depreciation	(1,340,837)	(1,178,751)
Net property and equipment	$ 481,993	$ 582,388

The current assets and liabilities related to the properties are immaterial. Total revenues and costs and expenses, and the income (loss) associated with the operation of the oil and gas properties held for sale are presented below.

	Three Months Ended June 30 2013	Three Months Ended June 30 2012	Six Months Ended June 30 2013	Six Months Ended June 30 2012
NET REVENUES:				
Oil and gas sales	$ 436,839	$ 2,013,861	$ 874,784	$ 3,725,759
OPERATING EXPENSES:				
Lease operating	602,053	733,547	905,324	1,401,290
Severance and ad valorem taxes	483	19,863	676	115,489
Exploration	7,979	187	65,137	10,789
Depreciation, depletion and amortization	100,303	752,053	204,644	1,578,990
TOTAL COSTS AND EXPENSES	710,818	1,505,650	1,175,781	3,106,558
INCOME (LOSS) FROM OPERATIONS ASSOCIATED WITH OIL AND GAS PROPERTIES HELD FOR SALE	$ (273,979)	$ 508,211	$ (300,997)	$ 619,201

4. RECENT ACCOUNTING PRONOUNCEMENTS

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-11, *Balance Sheet: Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). The objective of ASU 2011-11 is to require an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position. In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), which clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with FASB ASC Topic 815, *Derivative and Hedging,* including bifurcated embedded derivatives, repurchase agreements and reverse purchase agreements, and securities lending transactions that are either offset in accordance with FASB ASC Section 210-20-45 or Section 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 are effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The Company adopted ASU 2011-11 and ASU 2013-01 effective January 1, 2013, and adoption did not have an impact on the Company s consolidated financial statements other than additional disclosures.

In July 2012, the FASB issued Accounting Standards Update No. 2012-02, *Intangibles Goodwill and Other Testing Indefinite-Lived Intangible Assets for Impairment* (ASU 2012-02). The objective of ASU 2012-02 is to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by permitting an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired, as a basis for determining whether it is necessary to perform a quantitative impairment test. ASU 2012-02 is effective for interim and annual reporting periods beginning after September 15, 2012. The Company adopted ASU 2012-02 effective January 1, 2013, and adoption did not have an impact on the Company s consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* (ASU 2013-02). The objective of ASU 2013-02 is to improve the reporting of reclassifications out of AOCI by requiring an entity to report the effect of significant reclassifications out of AOCI on the respective line items in net income if the amount being reclassified is required under GAAP to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. ASU 2013-02 is effective for interim and annual reporting periods beginning after December 15, 2012. The Company adopted ASU 2013-02 effective January 1, 2013, and adoption did not have a significant impact on the Company s consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date* (ASU 2013-04). The objective of ASU 2013-04 is to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have a significant impact on the Company s consolidated financial statements.

In July 2013, the FASB issued *Update No. 2013-11 Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a consensus of the FASB Emerging Issues Task Force).* The update provides clarification on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The update is effective for public entities for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption is permitted. The Company has not yet evaluated the impact of the update on its financial statements.

5. ACCOUNTS PAYABLE AND ACCRUED EXPENSES:

Accounts payable and accrued expenses contain the following:

	As of June 30, 2013	As of December 31, 2012
Drilling and completion costs	$ 59,099,588	$ 51,698,682
Accounts payable trade	286,111	10,049,131
Accrued general and administrative cost	4,842,617	5,079,462
Lease operating expense	3,828,200	2,824,300
Accrued reclamation cost	400,000	400,000
Accrued interest	4,625,525	219,494
Accrued oil and gas hedging	668,368	238,365
Production taxes and other	2,619,607	2,340,838
	$ 76,370,016	$ 72,850,272

6. LONG-TERM DEBT:

Long-term debt consisted of the following at June 30, 2013 and December 31, 2012:

	As of June 30, 2013	As of December 31, 2012
Revolving credit facility	$	$ 158,000,000
6.75% Senior Notes	300,000,000	
	$ 300,000,000	$ 158,000,000

Revolving Credit Facility The Company s senior secured revolving Credit Agreement (the Revolver), dated March 29, 2011, as amended, with a syndication of banks, including KeyBank National Association as the administrative agent and issuing lender, provides for borrowings of up to $600 million. The Revolver provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate (LIBOR) or a bank base rate (Base Rate), at the Company s election. LIBOR borrowings bear interest at LIBOR plus 1.75% to 2.75% depending on the utilization level, and the Base Rate borrowings bear interest at the Bank Prime Rate, as defined plus .75% to 1.75%.

The borrowing base under the Revolver was $330.0 million as of June 30, 2013. The borrowing base is redetermined semiannually by May 15 and November 15 and may be re-determined up to one additional time between such scheduled determinations upon request by the Company or lenders holding 66 and 2/3% of the aggregate commitments. A letter of credit that was issued to the Colorado State Board of Land Commissioners in connection with the Company s lease of acreage in the Wattenberg Field reduces the borrowing base under the Revolver by approximately $48 million. The Revolver provides for commitment fees ranging from 0.375% to 0.50%, depending on utilization, and restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans and certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current ratio and a minimum debt coverage ratio, as defined. The Company was in compliance with these covenants as of June 30, 2013. The Revolver is collateralized by substantially all the Company s assets and matures on September 15, 2016. As of June 30, 2013, there was nil outstanding and a $48.0 million letter of credit issued under the Revolver, and the Company had $282.0 million available for future borrowings under the Revolver.

Senior Notes On April 9, 2013, the Company sold $300,000,000 of 6.75% Senior Notes (the Senior Notes). Interest on the Senior Notes accrues from April 9, 2013, and the Company will pay interest on April 15 and October 15 of each year, beginning on October 15, 2013. The Senior Notes mature on April 15, 2021. The Senior Notes are guaranteed on a senior unsecured basis by the Company s existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the Company s revolving credit facility. The Company may redeem the Senior Notes (i) at any time on or after April 15, 2017 at the redemption price equal to 100% together with accrued and unpaid interest, and (ii) prior to April 15, 2017 at the make-whole redemption prices described in the indenture together with accrued and unpaid interest. The net proceeds from the sale of the Senior Notes were approximately $292.7 million after deducting estimated expenses and underwriting discounts and commissions, and a portion of the proceeds were used to repay all of the then outstanding balance of $191,500,000 under our revolving credit facility.

The Company filed a Registration Statement on Form S-4 with the SEC, which became effective June 3, 2013 and registered the offering to exchange unregistered Senior Notes for registered Senior Notes, as well as the guarantees of the Senior Notes by the Company s subsidiaries. As of June 30, 2013, all of the existing subsidiaries of the Company are guarantors of the Senior Notes, and all such subsidiaries are 100 percent owned by the Company. The guarantees by the subsidiaries are full and unconditional (except for customary release provisions) and constitute joint and several obligations of the subsidiaries. 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.

7. COMMITMENTS AND CONTINGENT LIABILITIES:

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 consolidated financial statements. In accordance with *ASC 450*, *Contingencies*, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely 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.

Environmental The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration or regulation procedures as they relate to the drilling of oil and gas wells and associated operations. Relative to the Company s acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could fall upon the

Company.

Legal Proceedings From time to time, the Company is subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, the Company s 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 the Company of which it is aware.

Commitments The Company rents office facilities under various non-cancelable operating lease agreements. The Company s non-cancelable operating lease agreements result in total future minimum non-cancelable lease payments presented below. The Company also has principal payment requirements for its 6.75% Senior Notes and payments on a portion of the Wattenberg Field Lease Acquisition, all of which are presented below:

	Office Leases	Wattenberg Field Acquisition	Interest on Senior Notes	Repayment of Senior Notes	Total
2013	$ 781,426	$ 11,999,877	$ 10,125,000	$	$ 22,906,303
2014	2,028,651	11,999,877	20,250,000		34,278,528
2015	2,016,960	11,999,877	20,250,000		34,266,837
2016	1,742,910	11,999,877	20,250,000		33,992,787
2017 and thereafter	5,690,442		91,125,000	300,000,000	396,815,442
	$ 12,260,389	$ 47,999,508	$ 162,000,000	$ 300,000,000	$ 522,259,897

8. FAIR VALUE MEASUREMENTS AND ASSET RETIREMENT OBLIGATION:

The Company follows FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. 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 that are observable for the asset or liability; or
Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

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 table presents the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2013 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 361,086	$ 4,344,682
Commodity derivative liabilities	$	$ 3,178,593	$ 316,944

The following table presents the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 450,872	$ 1,727,192

Commodity derivative liabilities	$		$	5,173,140	$	1,235,168

Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company s commodity swaps 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. The Company s collars, which are designated as Level 3 within the valuation hierarchy, are not validated by observable transactions with respect to volatility. The counterparties in all of the commodity derivative financial instruments are lenders on the Company s senior secured revolving credit facility.

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs during the period from January 1, 2013 through June 30, 2013:

	Derivative Asset	Derivative Liability
Beginning net asset (liability) balance	$ 1,727,192	$ 1,235,168
Net (decrease) increase in fair value	(465,608)	(1,970,021)
Net realized gain on settlement		9,750
New derivatives	3,083,098	1,042,047
Transfers in (out) of Level 3		
Ending net asset (liability) balance	$ 4,344,682	$ 316,944

As of June 30, 2013, the Company s derivative commodity contracts are as follows:

Settlement Period Oil	Swap Volume Bbl/d	Fixed Price $	Collar Volume Bbl/d	Average Short Floor $	Average Floor $	Average Ceiling $
Q3 2013	2,852	88.15	5,022		87.99	101.46
Q4 2013	2,689	89.81	5,022		87.99	101.46
Q1 2014	633	90.80	5,617		86.33	97.09
Q2 2014	626	90.80	4,846		86.55	96.72
Q3 2014	620	90.80	4,326		86.16	96.57
Q4 2014	620	90.80	4,326		86.16	96.57
Q1 2014			1,000	60.00	85.00	99.50
Q2 2014			1,000	60.00	85.00	99.50
Q3 2014			1,000	60.00	85.00	99.50
Q4 2014			1,000	60.00	85.00	99.50
FY 15			1,500	60.00	80.00	98.15

Gas	MMBtu/d	$
Q3 2013	500	6.40
Q4 2013	166	6.40

Subsequent to June 30, 2013 the Company entered into the oil swap mentioned in Note 10 to the financial statements.

The table below contains a summary of all the Company s derivative positions reported on the consolidated balance sheet as of June 30, 2013:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 1,422,272
Commodity derivatives	Long-term derivative assets	3,283,496
Liability		
Commodity derivatives	Current derivative liability	(3,495,537)
Commodity derivatives	Long-term derivative liability	

Total	$	1,210,231

Realized gains and losses on commodity derivatives and the unrealized gains or losses are recorded in other income (expense).

Asset Retirement Obligation Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions.

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 discount rates and price forecasts selected by the Company s management. The calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 10 percent for the six months ended June 30, 2013. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate 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 New York Mercantile Exchange (NYMEX) strip pricing, adjusted for basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates.

9. STOCKHOLDERS EQUITY:

Management Incentive Plan On December 23, 2010, the Company established the Management Incentive Plan (the Plan or MIP) for the benefit of certain employees, officers and other individuals performing services for the Company. Ten thousand shares of Class B common stock were available under the Plan and these shares were converted into 437,787 shares of restricted common stock upon completion of our initial public offering (IPO). The conversion rate was determined based on a formula factoring in the rate of return to the pre-IPO common stockholders. The 437,787 shares of common stock that were granted to employees were valued at $17.00 per share on the grant date and vest over a three year period. Non-cash compensation expense of approximately $1,139,000 was recorded with respect to the MIP during the six month period ended June 30, 2013 and there was approximately $3,327,000 of unrecognized compensation costs related to the unvested restricted common stock granted under the MIP. That cost is expected to be recognized over a period of 1.5 years. The MIP has been terminated such that there will be no future grants thereunder.

BCEC Investment Trust The BCEC Investment Trust was formed to hold shares of our common stock received by Bonanza Creek Energy Company, LLC, our predecessor, in connection with our December 23, 2010 corporate restructuring. On February 5, 2013, 13,825 previously issued shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to former employees. While the shares had been issued in December 2010, for accounting purposes, the date of distribution to former employees was considered the grant date, and these shares were valued at the closing price of our common stock on the grant date, which was $34.18 per share. On February 11, 2013, 59,372 previously issued shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to certain current employees. While the shares had been issued in December 2010, for accounting purposes, the date of distribution to employees was considered the grant date, and these shares were valued at the closing price of our common stock on the grant date, which was $34.89 per share. These distributions resulted in a stock-based compensation expense of $2,544,000 related to the BCEC Investment Trust during the six month period ended June 30, 2013.

2011 Long Term Incentive Plan. During 2012, the Company granted 703,246 shares of restricted common stock under its 2011 Long Term Incentive Plan (the LTIP) to officers and certain key employees. For accounting purposes, these shares are valued at the closing price of our common stock on the grant date and compensation expense is recognized over the vesting period. These shares will vest annually in one-third increments over three years. Stock-based compensation expense of $2,038,000 was recorded during the six month period ended June 30, 2013, and there remains $7,208,000 of unrecognized compensation costs related to the unvested restricted common stock granted under the LTIP. That cost is expected to be recognized over the next 2.4 years.

On March 28, 2013, the Company granted 229,470 shares of restricted common stock under the LTIP to officers and certain key employees. For accounting purposes, these shares are valued at the closing price of our common stock on the grant date. On May 15, 2013, the Company granted an additional 14,361 shares of restricted common stock under the LTIP to newly hired key employees. These shares will vest annually in one-third increments over three years. Stock-based compensation expense of $781,000 was recorded during the six month period ended June 30, 2013 and there remains $8,574,000 of unrecognized compensation costs as of June 30, 2013 related to the unvested restricted stock granted under the LTIP. That cost is expected to be recognized over the next 2.9 years.

On March 28, 2013, the Company granted 34,354 Performance Stock Units (PSUs) under the LTIP to certain officers. 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 and is determined based on the Company s performance over a three-year measurement period. 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 measurement period. Expense associated with PSUs is recognized as general and administrative expense over the vesting period. The fair value of the PSUs was measured at the grant date with a stochastic process method using the Geometric Brownian Motion Model (GBM Model). Stock-based compensation expense of $99,000 was recorded during the six month period ended June 30, 2013 and there remained $961,000 of unrecognized compensation cost as of June 30, 2013 related to the unvested PSUs granted under the LTIP. That cost is expected to be recognized over the next 2.5 years.

10. SUBSEQUENT EVENTS:

On July 12, 2013 the Company paid approximately $12 million to the State of Colorado, State Board of Land Commissioners. This payment was related to the July 31, 2012 acquisition of 5,600 net acres in the Wattenberg Field and reduced the letter of credit securing the acquisition to $36 million.

On July 23, 2013 the Company entered into an oil swap at $99.55 per barrel covering 332 barrels per day during the quarter ended September 30, 2013 and 750 barrels per day during the period from October 1, 2013 through June 30, 2014.

On July 30, 2013, the Company acquired interests in four 80 acre units (272 net acres) within the Dorcheat-Macedonia Field for $1.6 million. The units are contiguous to the Company s existing operations in Southern Arkansas and are held by production.

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, 2012 (the 2012 Annual Report), as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q (this Report).

Executive Summary

Bonanza Creek Energy, Inc. (BCEI or, together with our consolidated subsidiaries, the Company, we, us, or our) is a Denver-based explorat 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 2011. Our shares of common stock are listed for trading on the NYSE under the symbol BCEI.

Despite the uncertainty surrounding the global economy and continued volatility in commodity prices, we believe our portfolio of oil and gas assets positions us well moving forward. Our operations are focused in the Wattenberg Field in Colorado and the Cotton Valley sands of southern Arkansas. The low risk, oily and stable production profile of our Arkansas assets provides a strong cash flow base from which to develop the Niobrara and Codell formations in Colorado. Our corporate strategy is to create shareholder value by increasing production in our current assets, while opportunistically seeking strategic acquisitions in other high return basins across the United States where we can apply our core competencies of horizontal drilling and fracture stimulation. We maintain a high working interest in our properties.

Second Quarter 2013 Financial and Operating Highlights

- On April 9, 2013, we sold $300 million in aggregate principal amount of 6.75% Senior Notes due 2021 (the Senior Notes) in a private offering. We received net proceeds of approximately $293.2 million from the sale of the Senior Notes, after deducting the initial purchasers discounts and commissions and estimated offering expenses. Effective June 3, 2013, we completed an offering to exchange unregistered Senior Notes for registered Senior Notes.

- We used $191.5 million of the proceeds from the Senior Notes to repay all outstanding borrowings under our revolving credit facility, which improved our total liquidity to $328.1 million at June 30, 2013, consisting of a period-end cash balance of $46.1 million plus $282 million available under our credit facility, as compared with $185.0 million at June 30, 2012.

- We increased production by 55% to 1,227.8 MBoe in the second quarter of 2013 from 793.3 MBoe in the second quarter of 2012, with oil and NGL production representing 71% of total production, despite negative impacts on production from vertical wells in the Wattenberg Field due to high gas gathering pipeline pressures and curtailment of production to comply with emissions standards.

- We generated net income of $14.7 million (including approximately $14.9 million from continuing operations), as compared with $21.5 million (including approximately $21.2 million from continuing operations) for the second quarter of 2012. The decrease in net income is related to a $5.2 million increase in interest expense and a $6.3 million decrease in the unrealized gain on fair value of commodity derivatives when compared to the second quarter of 2012.

Outlook for 2013

We continue to monitor the outlook for the global economy and numerous critical factors, including the United States federal budget deficit and long-term fiscal situation and the European debt crisis, and their potential impacts on global economic growth and commodity prices. Because the global economic outlook and commodity price environment are uncertain, we have planned a flexible capital spending program. We estimate our total capital expenditures for 2013 to be approximately $400 million, allocated approximately 80% to the Wattenberg Field and 20% 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 budget as appropriate. This capital investment is expected to produce 2013 average sales volumes of 14,500 to 16,000 Boe/d, while maintaining a strong oil and liquids profile.

Results for Continuing Operations

Three Months Ended June 30, 2013 Compared To Three Months Ended June 30, 2012

Revenues

The following table summarizes our revenues and production data for the periods indicated.

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 71,172	$ 44,000	$ 27,172	62%
Natural gas sales	9,448	4,296	5,152	120%
Natural gas liquids sales	3,893	3,151	742	24%
CO2 sales	4	8	(4)	(50)%
Product revenues	$ 84,517	$ 51,455	$ 33,062	64%

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	796.0	491.8	304.2	62%
Natural gas (MMcf)	2,114.4	1,406.6	707.8	50%
Natural gas liquids (MBbls)	79.4	67.0	12.4	19%
Crude oil equivalent (MBoe)(1)	1,227.8	793.2	434.6	55%

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
Average Sales Prices (before hedging)(2):				
Crude oil (per Bbl)	$ 89.41	$ 89.47	$ (0.06)	0%
Natural gas (per Mcf)	4.47	3.05	1.42	47%
Natural gas liquids (per Bbl)	49.03	47.03	2.00	4%
Crude oil equivalent (per Boe)(1)	68.83	64.86	3.97	6%

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
Average Sales Prices (after hedging)(2):				
Crude oil (per Bbl)	$ 87.41	$ 89.26	$ (1.85)	(2)%
Natural gas (per Mcf)	4.52	3.22	1.30	40%
Natural gas liquids (per Bbl)	49.03	47.03	2.00	4%
Crude oil equivalent (per Boe)(1)	67.62	65.02	2.60	4%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

(2) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

Revenues increased by 64%, to $84.5 million for the three months ended June 30, 2013 compared to $51.4 million for the three months ended June 30, 2012. Oil, natural gas, and natural gas liquids production increased 62%, 50%, and 19%, respectively, during the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. During the period from June 30, 2012 through June 30, 2013, we drilled and completed 95 gross (86.6 net) wells in the Rockies and 47 gross (43.2 net) wells in southern Arkansas. The increased volumes are a direct result of the $340.8 million expended for drilling and completion during the year ended December 31, 2012, and the $177.4 million expended during the six months ended June 30, 2013. Oil prices decreased from an average per barrel rate of $89.47 in the second quarter of 2012 to a per barrel rate of $89.41 in the comparable three month period that ended June 30, 2013. Increased oil volumes of 62% accounted for $27.2 million of the total $33.1 million increase in revenues for the Company for the three month period ended June 30, 2013 compared to the same period in 2012. Increased natural gas volumes and prices of 50% and 47%, respectively, accounted for $5.2 million of the total $33.1 million increase in revenues for the Company for the three month period ended June 30, 2013. Natural gas liquids volumes increased by 19% in 2013 with prices increasing by 4% to $49.03 from $47.03 for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. Our Wattenberg Field natural gas is sold without processing into dry gas and NGLs and, therefore, sells at a premium due to its very high BTU content. Our production of oil, natural gas, and natural gas liquids for the three months ended June 30, 2013 was approximately 65%, 29% and 6%, respectively.

While production volumes increased by 55% during the three months ended June 30, 2013, production volumes were adversely impacted by high gas gathering pipeline pressures, and emissions compliance. During the latter half of 2012 and throughout 2013, our Wattenberg Field production was adversely impacted by increasing line pressures on the gathering system operated by our third-party service provider. We and other operators in the field are working closely with our primary midstream provider in the Wattenberg Field who is implementing a multi-year facility expansion capable of significantly increasing long-term gathering and processing capacity. We expect increased gas processing capacity to be available to improve line pressures to some extent late in 2013. In addition, during the three months ended June 30, 2013, the Company deferred well maintenance activities to comply with emissions standards, effectively curtailing production from certain vertical wells.

Operating Expenses

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

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 12,898	$ 6,954	$ 5,944	85%
Severance and ad valorem taxes	5,352	2,769	2,583	93%
General and administrative	13,283	7,110	6,173	87%
Depreciation, depletion and amortization	29,517	13,035	16,482	126%
Exploration	862	2,015	(1,153)	(57)%
Operating expenses	$ 61,912	$ 31,883	$ 30,029	94%

	Three Months Ended June 30,			
	2013	2012	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 10.50	$ 8.77	$ 1.73	20%
Severance and ad valorem taxes	4.36	3.49	0.87	25%
General and administrative	10.82	8.96	1.86	21%
Depreciation, depletion and amortization	24.04	16.43	7.61	46%
Exploration	0.70	2.54	(1.84)	(72)%
Operating expenses	$ 50.42	$ 40.19	$ 10.23	25%

Lease Operating Expense. Our lease operating expenses increased $5.9 million, or 85%, to $12.9 million for the three months ended June 30, 2013 from $7.0 million for the three months ended June 30, 2012 and increased on an equivalent basis from $8.77 per Boe to $10.50 per Boe. The increase in lease operating expense was related to increased production volumes attributable to our drilling program and the operation of an additional gas plant that was constructed during 2012 but did not come on line until February of 2013. During the three months ended June 30, 2013, well servicing and pumping and gauging were also $2.8 million and $0.7 million higher, respectively, than the three months ended

June 30, 2012. Gas plant operating expense, which is a component of lease operating expense, increased $1.8 million, or 87%, to $3.8 million for the three month period ended June 30, 2013 from $2.0 million for the three month period ended June 30, 2012. Our lease operating expense per barrel increased due to lower production from vertical wells in the Wattenberg Field that were impacted by high gas gathering pipeline pressures and emission compliance standards, which resulted in production that was less than anticipated. In southern Arkansas, the replacement of essential gas plant processing equipment cost approximately $0.4 million to install, and our newly constructed gas plant is not yet operating at full capacity, which also increased our lease operating expense rate per Boe.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $2.6 million, or 93%, to $5.4 million for the three months ended June 30, 2013 from $2.8 million for the three months ended June 30, 2012. The increase was primarily related to a 55%

increase in production volumes for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The increase in severance and ad valorem taxes for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012 amounted to $0.7 million and $1.6 million, respectively.

General and administrative. Our general and administrative expense increased $6.2 million, or 87%, to $13.3 million for the three months ended June 30, 2013 from $7.1 million for the period ended June 30, 2012 and increased on an equivalent basis from $8.96 per Boe to $10.82 per Boe. During the three months ended June 30, 2013, wages and benefits, stock-based compensation and professional services were $2.9 million, $1.9 million and $0.7 million higher, respectively, than in the three month period ended June 30, 2012. The increase in general and administrative expense is primarily due to increased headcount and increased participation in the long term and short term incentive programs for the Company.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $16.5 million, or 126%, to $29.5 million for the three months ended June 30, 2013 from $13.0 million for the three months ended June 30, 2012. Our depreciation, depletion and amortization expense per Boe produced increased $7.61, or 46% to $24.04 for the three months ended June 30, 2013 as compared to $16.43 for the three months ended June 30, 2012. This increase per Boe is related to a 55% increase in production without a commensurate increase in proved developed reserves for the three months ended June 30, 2013. During the period from June 30, 2012 through June 30, 2013 the proved developed reserve volumes used in the calculation of depreciation, depletion and amortization increased 8% while the costs added to the depletion base increased 52%. At June 30, 2013 we revised the proved reserves associated with our vertical wells in the Rocky Mountain region downward 3,539 MBoe as a result of changes in focus from vertical to horizontal development and lower than expected performance due to high gas gathering pipeline pressures. We expect the per barrel depreciation, depletion and amortization rate in southern Arkansas to increase due to the nature of the infill development which is not accretive to proved reserve growth while costs continue to be added to the depletion base.

Exploration costs. Our exploration expense decreased $1.1 million to $0.9 million in the three months ended June 30, 2013 from $2.0 million in the three months ended June 30, 2012. During the three months ended June 30, 2013 a seismic acquisition project in the Wattenberg Field was completed which resulted in charges of approximately $0.7 million. During the three months ended June 30, 2012, a seismic acquisition project in the North Park Basin of Colorado was reprocessed which resulted in charges of approximately $0.5 million. One exploratory location in North Park where surface casing had been set and minimal work performed was also charged to exploration expense because the work had been performed during 2010 and management had no current plans to complete a well on this location. This resulted in a $1.5 million non-cash charge to our statement of operations during the three months ended June 30, 2012.

Interest expense. Our interest expense for the three months ended June 30, 2013 increased $5.2 million, or 797%, to $5.9 million compared to $0.7 million for the three months ended June 30, 2012. The increase for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 is primarily related to the issuance of $300 million in 6.75% Senior Notes on April 9, 2013. Interest expense for the Senior Notes during the three months ended June 30, 2013 was $4.8 million. The remaining interest increase of $0.4 million was the non-cash charge related to the amortization of deferred financing costs.

Realized loss on settled commodity derivatives. Realized losses on oil and gas hedging activities increased by $1.6 million from a gain of $0.1 million for the three months ended June 30, 2012 to a loss of $1.5 million for the three months ended June 30, 2013. The loss attributable to the quarter was related to an increase in hedged volumes period over period of 327,535 barrels in conjunction with an average floor of $88.05 while the average settlement of NYMEX WTI was $94.22 during the period.

Income tax expense. Our estimate for federal and state income taxes for the three months ended June 30, 2013 was $9.3 million from continuing operations as compared to $13.3 million for the three months ended June 30, 2012. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rate for the three month periods ended June 30, 2013 and 2012 was 38.5%, which differs from the U.S. statutory income rate primarily due to the effects of state income taxes.

Six Months Ended June 30, 2013 Compared To Six Months Ended June 30, 2012

Revenues

The following table summarizes our revenues and production data for the periods indicated.

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 136,849	$ 84,124	$ 52,725	63%
Natural gas sales	18,028	7,569	10,459	138%
Natural gas liquids sales	7,882	7,559	323	4%
CO2 sales	66	33	33	100%
Product revenues	$ 162,825	$ 99,285	$ 63,540	64%

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
Sales volumes:				
Crude oil (MBbls)	1,521.2	895.6	625.6	70%
Natural gas (MMcf)	3,960.5	2,352.1	1,608.4	68%
Natural gas liquids (MBbls)	154.1	135.8	18.3	13%
Crude oil equivalent (MBoe)(1)	2,335.4	1,423.4	912.0	64%

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
Average Sales Prices (before hedging)(2):				
Crude oil (per Bbl)	$ 89.96	$ 93.93	$ (3.97)	(4)%
Natural gas (per Mcf)	4.55	3.22	1.33	41%
Natural gas liquids (per Bbl)	51.15	55.66	(4.51)	(8)%
Crude oil equivalent (per Boe)(1)	69.69	69.73	(0.04)	(1)%

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
Average Sales Prices (after hedging)(2):				

Crude oil (per Bbl)	$ 87.83	$ 92.23	$ (4.40)	(5)%
Natural gas (per Mcf)	4.62	3.40	1.22	36%
Natural gas liquids (per Bbl)	51.15	55.66	(4.51)	(8)%
Crude oil equivalent (per Boe)(1)	68.41	68.97	(0.56)	(1)%

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(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

(2) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

Revenues increased by 64%, to $162.8 million for the six months ended June 30, 2013 compared to $99.3 million for the six months ended June 30, 2012. Oil, natural gas, and natural gas liquids production increased 70%, 68%, and 13%, respectively, during the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. During the period from June 30, 2012 through June 30, 2013, we drilled and completed 95 gross (86.6 net) wells in the Rockies and 47 gross (43.2 net) wells in southern Arkansas. The increased volumes are a direct result of the $340.8 million expended for drilling and completion during the year ended December 31, 2012, and the $177.4 million expended during the six months ended June 30, 2013. Oil volumes increased by 70% in 2013, but were offset by a sales price decline of 4% from $93.93 per barrel in the first half of 2012 to $89.96 per barrel for the first half of 2013, which accounted for a $52.7 million increase in revenues. Natural gas volumes increased by 68% in 2013, and were aided by an increase in sales price of 41% from $3.22 per Mcf to $4.55 per Mcf for these six month periods, which accounted for $10.5 million of the increase in revenues. Natural gas liquid volumes increased by 13% in 2013, but were offset by a sales prices decline of 8% from $55.66 per Bbl to $51.15 per Bbl for these six month periods. Our Wattenberg Field natural gas is sold without processing into dry gas and NGLs and, therefore, and sells at a premium due to its very high BTU content. Our production of oil, natural gas, and natural gas liquids for the six months ended June 30, 2013 was approximately 65%, 28% and 7%, of total production respectively.

Operating Expenses

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

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 24,029	$ 14,062	$ 9,967	71%
Severance and ad valorem taxes	10,165	6,365	3,800	60%
General and administrative	26,449	13,075	13,374	102%
Depreciation, depletion and amortization	52,880	24,036	28,844	120%
Exploration	1,424	3,205	(1,781)	(56)%
Operating expenses	$ 114,947	$ 60,743	$ 54,204	89%

	Six Months Ended June 30,			
	2013	**2012**	**Change**	**Percent Change**
Selected Costs ($ per Boe):				
Lease operating	$ 10.29	$ 9.88	$ 0.41	4%
Severance and ad valorem taxes	4.35	4.47	(0.12)	(3)%
General and administrative	11.33	9.19	2.14	23%
Depreciation, depletion and amortization	22.64	16.89	5.75	34%
Exploration	0.61	2.25	(1.64)	(73)%
Operating expenses	$ 49.22	$ 42.68	$ 6.54	15%

Lease Operating Expense. Our lease operating expenses increased $10 million, or 71%, to $24 million for the six months ended June 30, 2013 from $14.0 million for the six months ended June 30, 2012 and increased on an equivalent basis from $9.88 per Boe to $10.29 per Boe. The increase in lease operating expense was related to increased production volumes attributable to our drilling program and the operation of an additional gas plant that was constructed during 2012 but did not come on line until February of 2013. During the six months ended June 30, 2013, well servicing, compression, and pumping and gauging were also $4.9 million, $0.8 million, $0.8 million higher, respectively, than the six months ended June 30, 2012. Gas plant operating expense, which is a component of lease operating expense, increased $2.5 million, or 63%, to $6.5 million for the six month period ended June 30, 2013 from $4.0 million for the six month period ended June 30, 2012. Our lease operating expense per barrel increased due to lower production from vertical wells in the Wattenberg Field that were impacted by high gas gathering pipeline pressures and emission compliance standards which resulted in production that was less than anticipated. In southern Arkansas the replacement of essential gas plant processing equipment cost approximately $0.4 million to install and our newly constructed gas plant is not yet operating at full capacity which also increased our lease operating expense rate per Boe.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $3.8 million, or 60%, to $10.2 million for the six months ended June 30, 2013 from $6.4 million for the six months ended June 30, 2012. The increase was primarily related to a 64% increase in production volumes.

General and administrative. Our general and administrative expense increased $13.4 million, or 102%, to $26.5 million for the six months ended June 30, 2013 from $13.1 million for the six months ended June 30, 2012 and increased on an equivalent basis from $9.19 per Boe to $11.33 per Boe. During the six months ended June 30, 2013, wages and benefits, stock-based compensation and professional services were $4.8 million, $5.6 million and $1.3 million higher than the six month period ended June 30, 2012 due to our headcount increasing and increased participation in the long term and short term incentive programs of the Company. Included in the stock-based compensation for the six months ended June 30, 2013 is $2.5 million related to the February 2013 distribution of 73,197 shares of common stock that were fully vested and held by the BCEC Investment Trust to current and former employees. The BCEC Investment Trust was formed to hold shares of our common stock issued to Bonanza Creek Energy Company, LLC, our predecessor, in connection with our December 23, 2010 corporate restructuring.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $28.9 million, or 120%, to $52.9 million for the six months ended June 30, 2013 from $24.0 million for the six months ended June 30, 2012. Our depreciation, depletion and amortization expense per Boe produced increased $5.75, to $22.64 for the six months ended June 30, 2013 as compared to $16.89 for the six months ended June 30, 2012. This increase per Boe was primarily the result of a 64% increase in production without a commensurate increase in proved developed reserves for the six months ended June 30, 2013. During the period from June 30, 2012 through June 30, 2013, the proved developed reserve volumes used in the calculation of depreciation, depletion and amortization increased 8% while the costs added to the depletion base increased 52%. At June 30, 2013 we revised the proved reserves associated with our vertical wells in the Rocky Mountain region downward 3,539 MBoe as a result of changes in focus from vertical to horizontal development and lower than expected performance due to high gas gathering pipeline pressures. We expect the per barrel depreciation, depletion and amortization rate in southern Arkansas to increase due to the nature of the infill development which is not accretive to proved reserve growth while costs continue to be added to the depletion base.

Exploration costs. Our exploration expense decreased $1.8 million, or 56%, to $1.4 million in the six months ended June 30, 2013 from $3.2 million in the six months ended June 30, 2012. Seismic and 3D data acquisitions for the Wattenberg Field made up $1.0 million of the $1.4 million for the six months ended June 30, 2013. During the six months ended June 30, 2012, a seismic acquisition project in the North Park Basin of Colorado was reprocessed which resulted in charges of approximately of $0.5 million. One exploratory location in North Park where surface casing had been set and minimal work performed was also charged to exploration expense because the work had been performed during 2010 and management had no current plans to complete a well on this location. This resulted in a $1.5 million non-cash charge to our statement of operations during the three months ended June 30, 2012.

Interest expense. Our interest expense increased $6.6 million, or 544%, to $7.8 million for the six months ended June 30, 2013 from $1.2 million for the six months ended June 30, 2012. The increase for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 is primarily related to the issuance of $300 million in 6.75% Senior Notes on April 9, 2013. Interest expense for the Senior Notes was $4.8 million, of which $0.2 million was related to the amortization of debt issuance costs related to the Senior Notes offering, for the six months ended June 30, 2013. Interest expense on our revolving credit facility was $2.1 million for the six month period ended June 30, 2013. Approximately $0.8 million of our interest expense was related to non-cash charges for the amortization of debt issuance costs associated with our revolving credit facility and accretion of our contractual obligation for land acquisition, as compared to total interest expense of $1.2 million for the six month period ended June 30, 2012. The average outstanding long-term debt balance during the six months ended June 30, 2013 was $235.8 million as compared to $29.9 million for the six months ended June 30, 2012.

Realized loss on settled commodity derivatives. Realized losses on oil and gas hedging activities increased by $1.9, to $3.0 million, from $1.1 million, for the six months ended June 30, 2013. The increase in the realized loss period over period was primarily related to hedging losses in the amount of $1.5 million during the second quarter as compared to $0.1 million gain in the second quarter of 2012, as the NYMEX sweet crude oil price averaged $94.22 per barrel, during the quarter as compared to our oil hedges which had an average hedge price of $88.05 per barrel during these months.

Income tax expense. Our estimate for federal and state income taxes for the six months ended June 30, 2013 was $16.4 million from continuing operations as compared to $18.6 million for the six months ended June 30, 2012. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rate for the periods ended June 30, 2013 and 2012 was 38.5%, which differs from the U.S. statutory income rate primarily due to the effects of state income taxes.

Results for Discontinued Operations

During June of 2012, the Company began marketing, with an intent to sell, all of our oil and gas properties in California. 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 our intent to sell these properties qualifies for discontinued operations accounting and these assets will be presented as discontinued operations in the Company s statements of operations.

The operating results before income taxes for our California properties for the three month period ended June 30, 2013 were net revenues of $0.4 million, and operating expenses of $0.7 million, as compared to net revenues of $2.0 million, and operating expenses of $1.5 million for the three month period ended June 30, 2012. Sales volumes for the three month periods ended June 30, 2013 and 2012 were 51 Boe/d and 227 Boe/d, respectively.

The operating results before income taxes for our California properties for the six month period ended June 30, 2013 were net revenues of $0.9 million, and operating expenses of 1.2 million, as compared to net revenues of $3.7 million, and operating expenses of $3.1 million for the six month period ended June 30, 2012. Sales volumes for the six month periods ended June 30, 2013 and 2012 were 50 Boe/d and 158 Boe/d, respectively.

Liquidity and Capital Resources

We fund our operations, capital expenditures and working capital requirements with cash flows from our operating activities and borrowings under our revolving credit facility. Periodically, we access debt and capital markets and sell non-core properties to provide additional liquidity.

On April 9, 2013, we sold $300,000,000 of 6.75% Senior Notes (the Senior Notes). Interest on the Senior Notes will accrue from April 9, 2013, and will pay interest on April 15 and October 15 of each year, beginning on October 15, 2013. The Senior Notes mature on April 15, 2021. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by our existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under our revolving credit facility. We may redeem the Senior Notes (i) at any time on or after April 15, 2017 at the redemption price equal to 100% together with accrued and unpaid interest, and (ii) prior to April 15, 2017 at the make-whole redemption prices described in the indenture together with accrued and unpaid interest. The net proceeds from the sale of the Senior Notes were approximately $292.7 million after deducting estimated expenses and underwriting discounts and commissions, and a portion of the proceeds were used to repay all of the then outstanding balance of $191,500,000 under our revolving credit facility.

In the second quarter 2012, we began the divestiture process of our non-core properties in California. The California properties were treated as assets held for sale, and production, revenue and expenses associated with these properties were removed from continuing operations and reported as discontinued operations. During 2012, we sold a majority of our properties in California, for approximately $9.3 million in aggregate.

On July 31, 2012, we acquired leases in the Wattenberg Field from the State of Colorado, State Board of Land Commissioners. We paid approximately $12 million at closing and will pay approximately $12 million on July 31st of each of the next four years. These future payments are secured by a letter of credit which reduced the borrowing base under our credit facility by $48 million as of June 30, 2013. On July 12, 2013 the Company paid approximately $12 million to the State of Colorado which reduced the letter of credit securing the acquisition to $36 million.

On April 6, 2012, the administrative agent under our credit facility was changed to KeyBank, National Association. On May 8, 2012, we entered into an amendment with the lenders under our credit facility to, among other things, (i) increase our credit facility to $600 million, and (ii) make changes in the covenant applicable to hedging to allow greater flexibility for management to implement comprehensive hedging plans to adequately protect our operations and capital budgets. On May 15, 2013, our borrowing base was increased to $330 million, and as of June 30, 2013, we had nil outstanding, $48.0 million of letters of credit issued, and $282 million of borrowing capacity available under our credit facility. Our weighted-average interest rate on borrowings from our credit facility was 3.46% (excluding amortization of deferred financing costs and the accretion of our contractual obligation for land acquisition) during the six months ended June 30, 2013.

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 see Item 3. Quantitative and Qualitative Disclosures on Market Risks of this Quarterly Report on Form 10-Q.

We believe that our cash on hand, cash flow from operating activities and availability under our revolving credit facility will be sufficient to fund our planned capital expenditures and operating expenses and comply with our debt covenants during the next 12 months. To the extent actual operating results differ from our anticipated results, our liquidity could be adversely affected.

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In thousands)	
Net cash provided by operating activities	$ 87,835	$ 56,389
Net cash used in investing activities	(177,574)	(111,247)
Net cash provided by financing activities	131,557	55,373
Cash and cash equivalents	46,085	2,605
Acquisitions of oil and gas properties	8,352	554
Exploration and development of oil and gas properties and investment in gas processing facility	166,676	109,456

Cash flows provided by operating activities

Net cash provided by operating activities was $87.8 million for the six months ended June 30, 2013, compared to $56.4 million provided by operating activities for the six months ended June 30, 2012. The increase in cash from operating activities resulted primarily from an increase in revenues from increased production adjusted by cash utilized in connection with changes in working capital when comparing periods. Cash utilized by changes in working capital for the six months ended June 30, 2013 was $10.2 million compared to $9.6 million that was utilized by changes in working capital for the comparable period during 2012. Decreases in working capital of $10.2 million for the six months ended June 30, 2013 is comprised of increases in accounts receivable of $9.3 million and a decrease in accounts payable and accrued liabilities (exclusive of capital accruals) of $1.4 million. Decreases in working capital of $9.3 million for the six month period ended June 30, 2012 is comprised of increases in accounts receivable of $12.8 million offset by an increase in accounts payable and accrued liabilities (exclusive of capital accruals) of $3.4 million.

Cash flows used in investing activities

Expenditures for development of oil and natural gas properties and natural gas plants are the primary use of our capital resources. Net cash used in investing activities for the six months ended June 30, 2013 was $177.6 million, compared to $111.2 million used in investing activities for the six months ended June 30, 2012. For the six months ended June 30, 2013, cash used for the acquisition of oil and gas properties was $8.4 million, and cash used for the development of oil and natural gas properties (including cash used for natural gas plant capital expenditures) was $166.7 million. For the six months ended June 30, 2012, cash used for the acquisition of oil and gas properties was $0.6 million, and cash used for the development of oil and natural gas properties (including cash used for natural gas plant capital expenditures) was $109.5 million.

Cash provided by financing activities

Net cash provided by financing activities for the six months ended June 30, 2013 was $131.6 million related to borrowings on our line of credit in the amount of $33.5 million and our Senior Notes in the amount of $300 million which were offset by payments on our line of credit in the amount of $191.5 million. The offering costs for the Senior Notes were approximately $7.3 million and cash used to satisfy employee tax withholdings for restricted stock that vested during the period was $3.1 million. Net cash provided by financing activities for the six months ended June 30, 2012 was $55.4 million related to borrowings on our line of credit.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, please refer to Note 4 Recent Accounting Pronouncements in the Notes to the Financial Statements.

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the six month periods ended June 30, 2013 and 2012. 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.

Off-balance sheet arrangements

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

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. These forward-looking statements may include projections and estimates concerning our capital expenditures, our liquidity and capital resources, our estimated revenues and losses, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, our business strategy and other statements concerning our operations, economic performance and financial condition. When used in this Report, the words could, believe, anticipate, intend, estimate, expect, may, co predict, potential, project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements may include statements about:

- our financial position;
- estimates of loss contingencies;
- impact of changes in oil and gas prices;

- liability for environmental and restoration obligations;

- our cash flow and liquidity;

- anticipated amount and allocation of capital expenditures;

- high gas gathering pipeline pressures;

- sufficiency of our cash on hand, cash flow from operating activities and availability under our revolving credit facility to fund our planned capital expenditures and operating expenses and comply with our debt covenants;

- anticipated amount of production and percentage of liquids production;

- anticipated depreciation, depletion and amortization in southern Arkansas;

- access to adequate gathering systems and pipeline take-away capacity to execute our drilling program;

- compliance with local, state and federal regulation;

- fair value measurements;

- estimated discount rate;

- impact of derivative positions on our cash flows;

- inflationary pressures;

- creditworthiness of counterparties;

- change in internal controls and risk factors; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

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 as well as other factors we believe are appropriate under the circumstances. The actual results may differ materially from the results anticipated by these forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to, the following:

- declines or volatility in the prices we receive for our oil, liquids and natural gas;

- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;

- the continuing global economic slowdown that has and may continue to adversely affect consumption of oil and natural gas by businesses and consumers;

- 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 production 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 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;
- ability to acquire adequate supplies of water for drilling 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 retain key members of our senior management and key technical employees;
- ability to maintain effective internal controls;
- access to adequate gathering systems, pipeline take-away capacity and processing facilities to execute 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 Africa 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.

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 are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. 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 Prices. 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, 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 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. Utilizing the actual derivative contractual volumes at June 30, 2013, a 10% increase in underlying commodity prices would reduce the fair value of our derivative instruments by $29.9 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $26.1 million as of June 30, 2013. A gain or loss, however, eventually would be offset substantially by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company s commodity derivative transactions, see Note 8 Fair Value Measurements and Asset Retirement Obligations in the Notes to the financial statements included in this Quarterly Report on Form 10-Q.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We enter into hedges for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties who 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. In addition, to the extent that we engage in hedging activities, 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 hedging arrangements are concentrated with six counterparties, five of which are lenders under our credit facility. If this counterparty fails to perform its 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 hedge derivatives, if owed by us, generally up to three 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 hedge settlement and payment for revenues earned.

The following table provides a summary of derivative contracts as of June 30, 2013.

Settlement Period	Swap Volume	Fixed Price	Collar Volume	Average Short Floor	Average Floor	Average Ceiling	Fair Market Value of Asset (Liability) as of June 30, 2013

Oil	Bbl/d	$	Bbl/d	$	$	$	$
Q3 2013	2,852	88.15	5,022		87.99	101.46	(2,199,734)
Q4 2013	2,689	89.81	5,022		87.99	101.46	(776,028)
Q1 2014	633	90.80	5,617		86.33	97.09	31,506
Q2 2014	626	90.80	4,846		86.55	96.72	562,238
Q3 2014	620	90.80	4,326		86.16	96.57	945,567
Q4 2014	620	90.80	4,326		86.16	96.57	1,344,071