CARRIZO OIL & GAS INC
Form 10-Q
August 05, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2014

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

For the transition period from to

Commission File Number: 000-29187-87

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	76-0415919 (IRS Employer Identification No.)
500 Dallas Street, Suite 2300, Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

(713) 328-1000
(Registrant’s telephone number)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act (Check one):

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

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

The number of shares outstanding of the registrant’s common stock, par value $0.01 per share, as of July 31, 2014 was 46,028,577.

CARRIZO OIL & GAS, INC.
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2014
INDEX

PART I. FINANCIAL INFORMATION
Item 1. Consolidated Financial Statements
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)
(Unaudited)

	June 30, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$8,622	$157,439
Accounts receivable, net	134,492	111,195
Deferred income taxes	15,235	4,201
Other current assets	4,363	6,926
Total current assets	162,712	279,761
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,675,941	1,408,484
Unproved properties, not being amortized	458,393	377,437
Other property and equipment, net	7,767	8,294
Total property and equipment, net	2,142,101	1,794,215
Debt issuance costs	21,604	22,899
Other assets	4,011	13,885
Total Assets	$2,330,428	$2,110,760
Liabilities and Shareholders’ Equity		
Current liabilities		
Accounts payable	$75,364	$57,146
Revenues and royalties payable	83,531	79,136
Accrued capital expenditures	87,318	87,031
Accrued interest	17,462	17,430
Advances for joint operations	5,349	19,967
Liabilities of discontinued operations	8,550	10,936
Derivative liabilities	39,455	9,947
Other current liabilities	59,035	41,242
Total current liabilities	376,064	322,835
Long-term debt	1,021,606	900,247
Liabilities of discontinued operations	16,491	17,336
Deferred income taxes	27,365	16,856
Asset retirement obligations	9,365	6,576
Other liabilities	9,624	5,306
Total liabilities	1,460,515	1,269,156
Commitments and contingencies		
Shareholders’ equity		
Common stock, $0.01 par value, 90,000,000 shares authorized; 46,018,977 issued and outstanding as of June 30, 2014 and 45,468,675 issued and outstanding as of December 31, 2013	460	455
Additional paid-in capital	899,957	879,948
Accumulated deficit	(30,504)	(38,799)
Total shareholders’ equity	869,913	841,604

Total Liabilities and Shareholders’ Equity	$2,330,428	$2,110,760

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues				
Crude oil	$165,962	$105,805	$296,324	$193,287
Natural gas liquids	5,983	2,766	11,871	5,507
Natural gas	21,530	25,653	42,492	47,331
Total revenues	193,475	134,224	350,687	246,125
Costs and Expenses				
Lease operating	17,378	11,797	29,983	21,992
Production taxes	8,182	4,584	14,273	9,097
Ad valorem taxes	1,906	2,863	3,334	4,723
Depreciation, depletion and amortization	80,746	50,528	145,340	96,225
General and administrative	27,682	17,834	55,943	34,007
(Gain) loss on derivatives, net	39,950	(25,726)	60,630	(11,172)
Interest expense, net	11,931	13,989	24,356	28,965
Other (income) expense, net	413	(27)	987	(67)
Total costs and expenses	188,188	75,842	334,846	183,770
Income From Continuing Operations Before Income Taxes	5,287	58,382	15,841	62,355
Income tax expense	(2,073)	(22,545)	(6,006)	(23,994)
Income From Continuing Operations	3,214	35,837	9,835	38,361
Income (Loss) From Discontinued Operations, Net of Income Taxes	(895)	1,132	(1,540)	24,790
Net Income	$2,319	$36,969	$8,295	$63,151
Net Income (Loss) Per Common Share - Basic				
Income from continuing operations	$0.07	$0.89	$0.22	$0.96
Income (loss) from discontinued operations, net of income taxes	(0.02)	0.03	(0.04)	0.62
Net income	$0.05	$0.92	$0.18	$1.58
Net Income (Loss) Per Common Share - Diluted				
Income from continuing operations	$0.07	$0.88	$0.21	$0.95
Income (loss) from discontinued operations, net of income taxes	(0.02)	0.03	(0.03)	0.61
Net income	$0.05	$0.91	$0.18	$1.56
Weighted Average Common Shares Outstanding				
Basic	45,213	40,078	45,109	39,928
Diluted	46,158	40,610	45,988	40,469

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2014	2013
Cash Flows From Operating Activities		
Net income	$8,295	$63,151
(Income) loss from discontinued operations, net of income taxes	1,540	(24,790)
Adjustments to reconcile income from continuing operations to net cash provided by operating activities from continuing operations		
Depreciation, depletion and amortization	145,340	96,225
Non-cash (gain) loss on derivatives, net	42,842	(3,166)
Stock-based compensation	29,139	9,466
Deferred income taxes	305	23,994
Non-cash interest expense, net	1,346	2,386
Other, net	1,594	251
Changes in operating assets and liabilities-		
Accounts receivable	(23,139)	(4,938)
Accounts payable	4,526	73,771
Accrued liabilities	(14,040)	(19,035)
Other, net	(2,102)	(3,593)
Net cash provided by operating activities from continuing operations	195,646	213,722
Net cash used in operating activities from discontinued operations	(903)	(80)
Net cash provided by operating activities	194,743	213,642
Cash Flows From Investing Activities		
Capital expenditures - oil and gas properties	(474,011)	(372,582)
Capital expenditures - other property and equipment	(375)	(1,196)
Proceeds from sales of oil and gas properties, net	7,434	10,681
Other, net	1,913	11,030
Net cash used in investing activities from continuing operations	(465,039)	(352,067)
Net cash provided by (used in) investing activities from discontinued operations	(4,679)	128,179
Net cash used in investing activities	(469,718)	(223,888)
Cash Flows From Financing Activities		
Long-term borrowings under revolving credit facility	293,000	165,000
Repayments of long-term borrowings under revolving credit facility	(172,000)	(206,325)
Payments of debt issuance costs	(594)	(962)
Excess tax benefits from stock-based compensation	5,678	—
Proceeds from stock options exercised	74	766
Net cash provided by (used in) financing activities from continuing operations	126,158	(41,521)
Net cash provided by financing activities from discontinued operations	—	3,000
Net cash provided by (used in) financing activities	126,158	(38,521)
Net Decrease in Cash and Cash Equivalents	(148,817)	(48,767)
Cash and Cash Equivalents, Beginning of Period	157,439	52,614
Cash and Cash Equivalents, End of Period	$8,622	$3,847

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

CARRIZO OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Nature of Operations

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, the “Company”), is actively engaged in the exploration, development, and production of oil and gas primarily from resource plays located in the United States. The Company’s current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Utica Shale in Ohio, the Niobrara Formation in Colorado, and the Marcellus Shale in Pennsylvania.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles (“GAAP”). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. The consolidated financial statements reflect all necessary adjustments, all of which were of a normal recurring nature and are in the opinion of management necessary to present fairly, in all material respects, the Company’s interim financial position, results of operations and cash flows. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (the “SEC”). The operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. The consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2013.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications had no material impact on prior period amounts.

Discontinued Operations

On February 22, 2013, the Company closed on the sale of Carrizo UK Huntington Ltd, a wholly owned subsidiary of the Company (“Carrizo UK”), and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy Inc. (“Iona Energy”) for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK’s senior secured multicurrency credit facility as of the closing date. The liabilities, results of operations and cash flows associated with Carrizo UK have been classified as discontinued operations in the consolidated financial statements. Unless otherwise indicated, the information in these notes relate to the Company’s continuing operations. Information related to discontinued operations is included in “Note 3. Discontinued Operations” and “Note 10. Condensed Consolidating Financial Information.”

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. The Company evaluates subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves, which are used in calculating depreciation, depletion, and amortization (“DD&A”) of proved oil and gas property costs, the present value of future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated costs and timing of cash outflows underlying asset retirement obligations. Oil and gas reserve estimates, and therefore calculations based on such reserve estimates, are subject to numerous inherent uncertainties, the accuracy of which, is a function of the quality and quantity of available data, the application of engineering and geological interpretation and judgment to available data and the interpretation of mineral leaseholds and other contractual arrangements, including adequacy of title, drilling requirements and royalty obligations. These estimates also depend on assumptions regarding quantities and production rates of recoverable oil and gas reserves, oil and gas prices, timing and amounts of development costs and operating expenses, all of which will vary from those assumed in the Company's estimates. Other significant estimates are involved in determining impairments of unevaluated leasehold costs, fair values of derivative assets and liabilities, stock-based compensation, collectability of receivables, and in evaluating disputed claims, interpreting contractual arrangements (including royalty obligations and notional interest calculations) and contingencies. Estimates are based on current assumptions that may be materially affected by the results of subsequent drilling and completion, testing and production as well as subsequent changes in oil and gas prices, counterparty creditworthiness, interest rates and the market value and volatility of the Company's common stock.

Cash and Cash Equivalents

Cash equivalents include highly liquid investments with original maturities of three months or less.

Accounts Receivable and Accounts Payable

The Company establishes an allowance for doubtful accounts when it determines that it will not collect all or a part of an accounts receivable balance. The Company assesses the collectability of its accounts receivable on a quarterly basis and adjusts the allowance as necessary using the specific identification method. The allowance for doubtful accounts was not significant at June 30, 2014 and December 31, 2013. Accounts receivable from related parties at June 30, 2014 and December 31, 2013 was $4.6 million and $6.6 million, respectively. Accounts payable to related parties at June 30, 2014 and December 31, 2013 was $3.7 million and $2.8 million, respectively.

Concentration of Credit Risk

The Company's accounts receivable consists primarily of receivables from oil and gas purchasers and joint interest owners in properties the Company operates. This concentration of accounts receivable from customers and joint interest owners in the oil and gas industry may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not require collateral from its customers and joint interest owners. The Company generally has the right to withhold future revenue distributions to recover any non-payment of joint interest billings.

The Company's derivative instruments in a net asset position also subject the Company to a concentration of credit risk. See "Note 8. Derivative Instruments".

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to costs centers established on a country-by-country basis. The internal cost of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized and totaled $5.3 million and $4.2 million for the three months ended June 30, 2014 and 2013, respectively, and $10.7 million and $6.3 million for the six months ended June 30, 2014 and 2013, respectively. Internal costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production amortization rate is computed on a quarterly basis by dividing current quarter production by proved oil and gas reserves at the beginning of the quarter then applying such amortization rate to capitalized oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average DD&A per Boe of proved oil and gas properties was $26.34 and $19.38 for the three months ended June 30, 2014 and 2013, respectively, and $26.49 and $19.11 for the six months ended June 30, 2014 and 2013, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties, the cost of exploratory wells in progress, and related capitalized interest. Exploratory wells in progress and individually significant unevaluated leaseholds are assessed on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs along with associated capitalized interest are added to the oil and gas property costs subject to amortization. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling and completion capital expenditure plans. The Company expects to complete its evaluation of the majority of its unevaluated leaseholds within the next five years and exploratory wells in progress within the next year. Individually insignificant unevaluated leaseholds are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. The Company capitalized interest costs associated with its unproved properties totaling \$8.6 million and \$7.5 million for the three months ended June 30, 2014 and 2013, respectively, and \$16.3 million and \$14.3 million for the six months ended June 30, 2014 and 2013, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of proved and unproved oil and gas properties are recognized as a reduction of capitalized oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For the three months and six months ended June 30, 2014 and 2013, the Company did not have any sales of oil and gas properties that significantly altered such relationship.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the “cost center ceiling” equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of unproved properties not being amortized, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices in the future increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from five to ten years.

Debt Issuance Costs

Debt issuance costs associated with the revolving credit facility are amortized to interest expense on a straight-line basis over the term of the facility. Debt issuance costs associated with the senior notes are amortized to interest expense using the effective interest method over the terms of the related notes.

Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, receivables, payables, derivative assets and liabilities and long-term debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the Company’s derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The carrying amounts of long-term debt under the Company’s revolving credit facility approximate fair value as borrowings bear interest at variable rates of interest. The carrying amounts of the Company’s senior notes and other long-term debt may not approximate fair value because carrying amounts are net of any unamortized discount and the notes bear interest at fixed rates of interest. See “Note 6. Long-Term Debt” and “Note 9. Fair Value Measurements.”

Asset Retirement Obligations

The Company’s asset retirement obligations represent the present value of the estimated future costs associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Determining asset retirement obligations requires estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates. The resulting estimate of future cash outflows are discounted using a credit-adjusted risk-free interest rate that corresponds with the timing of the cash outflows. Cost estimates consider historical experience, third party estimates, the requirements of oil and gas leases and applicable local, state and federal laws, but do not consider estimated salvage values. Asset retirement obligations are recognized when the well is drilled or when the production equipment and facilities are installed with an associated increase in oil and gas property costs. Asset retirement obligations are accreted to their expected settlement values with any difference between the actual cost of settling the asset retirement obligations and recorded amount being recognized as an adjustment to proved oil and gas property costs. On an interim basis, when indicators suggest there have been material changes in the estimates underlying the obligation, the Company reassesses its asset retirement obligations to determine whether any revisions to the obligations are necessary. At least annually, the Company reassesses all of its asset retirement obligations to determine whether any revisions to the obligations are necessary. Revisions typically occur due to changes in estimated costs or well economic lives, or if federal or state regulators enact new requirements regarding plugging and abandoning oil and gas wells.

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable.

Revenue Recognition

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability is reasonably assured. The Company follows the sales method of accounting whereby revenues from the production of natural gas from properties in which the Company has an interest with other producers are recognized for production sold to purchasers, regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as an asset or liability to the extent that the Company has an imbalance on a specific property that is in excess of its remaining proved reserves. Sales volumes are not significantly different from the Company's share of production and as of June 30, 2014 and December 31, 2013, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce its exposure to commodity price volatility for a substantial, but varying, portion of its forecasted oil and gas production up to 36 months and thereby achieve a more predictable level of cash flows to support the Company's drilling and completion capital expenditure program. All derivative instruments are recorded on the consolidated balance sheets as either an asset or liability measured at fair value. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments provide an economic hedge of the Company's exposure to commodity price volatility, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain (loss) on derivative instruments, net in the consolidated statements of income in the period in which the changes occur. The net cash flows resulting from the payments to and receipts from counterparties as a result of derivative settlements are classified as cash flows from operating activities. The Company does not enter into derivative instruments for speculative or trading purposes.

The Company's Board of Directors establishes risk management policies and reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. See "Note 8. Derivative Instruments" for further discussion of the Company's derivative instruments.

Stock-Based Compensation

The Company recognized the following stock-based compensation expense associated with stock appreciation rights to be settled in cash ("SARs"), restricted stock awards and units and performance share awards for the periods indicated which is reflected as general and administrative expense in the consolidated statements of income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Stock appreciation rights	$11,116	$7	$19,572	$3,939
Restricted stock awards and units	8,224	4,462	13,925	8,319
Performance share awards	319	—	333	—
	19,659	4,469	33,830	12,258
Less: amounts capitalized	(2,681)	(1,486)	(4,691)	(2,792)
Total stock-based compensation expense	$16,978	$2,983	$29,139	$9,466
Income tax benefit	$5,943	$1,107	$10,199	$3,470

Stock Appreciation Rights. For SARs, stock-based compensation expense is based on the fair value liability (using the Black-Scholes-Merton option pricing model) remeasured at each reporting period, recognized over the vesting period (generally three years) using the graded vesting method. For periods subsequent to vesting and prior to exercise, stock-based compensation expense is based on the fair value liability remeasured at each reporting period based on the intrinsic value of the SAR. The liability for SARs are classified as “Other current liabilities” for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified as “Other liabilities.” SARs typically expire between four and seven years after the date of grant.

Restricted Stock Awards and Units. For restricted stock awards and units granted to employees, stock-based compensation expense is based on the price of the Company's common stock on the grant date and recognized over the vesting period (generally one to three years) using the straight-line method, except for award or units with performance conditions, in which case the Company uses the graded vesting method. For restricted stock awards and units granted to independent contractors, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period (generally three years) using the straight-line method.
Performance Share Awards. For performance share awards, stock-based compensation expense is based on the grant-date fair value (using a Monte Carlo valuation model) and recognized over the three year vesting period using the straight-line method. The number of shares of common stock issuable upon vesting range from zero to 200% of the number of performance share awards granted based on the Company's total shareholder return relative to an industry peer group over a three year performance period.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at each reporting period for the future tax consequences of cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company’s financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. The Company routinely assesses the realizability of its deferred tax assets by taxing jurisdiction and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments. If the Company concludes that it is more likely than not that some portion or all of the benefit from deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense.

Income From Continuing Operations Per Common Share

Supplemental income from continuing operations per common share information is provided below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Income From Continuing Operations	$3,214	$35,837	$9,835	$38,361
Basic weighted average common shares outstanding	45,213	40,078	45,109	39,928
Effect of dilutive instruments	945	532	879	541
Diluted weighted average common shares outstanding	46,158	40,610	45,988	40,469
Income From Continuing Operations Per Common Share				
Basic	$0.07	$0.89	$0.22	$0.96
Diluted	$0.07	$0.88	$0.21	$0.95

Basic income from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted income from continuing operations per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the period which include restricted stock awards and units, performance share awards, stock options and warrants. The Company excludes the number of awards, units, options and warrants from the calculation of diluted weighted average shares outstanding when the grant date or exercise prices are greater than the average market prices of the Company’s common stock for the corresponding period as the effect would be antidilutive to the computation. The Company includes the number of potentially dilutive common shares attributable to the performance share awards based on the number of shares, if any, that would be issuable as if the end of the period was the end of the performance period. The number of awards, units, options, warrants and performance share awards excluded for the three and six months ended June 30, 2014 and 2013 were not significant.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry specific guidance in Subtopic 932-605, Extractive Activities- Oil and

Gas- Revenue Recognition. This ASU requires entities to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods and services. This ASU is effective for annual and interim periods beginning in 2017, and is required to be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption, with no early adoption permitted. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

3. Discontinued Operations

On February 22, 2013, the Company closed on the sale of Carrizo UK, and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. The liabilities of discontinued operations of $25.0 million and $28.3 million as of June 30, 2014 and December 31, 2013, respectively, relate to an accrual for estimated future obligations related to the sale. See "Note 2. Summary of Significant Accounting Policies—Use of Estimates" for further discussion of estimates and assumptions that may affect the reported amounts of liabilities related to the sale of Carrizo UK.

The following table summarizes the amounts included in income (loss) from discontinued operations, net of income taxes presented in the consolidated statements of income for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Revenues	$—	$—	$—	$—
Costs and Expenses				
General and administrative	466	296	903	301
Accretion related to asset retirement obligations	—	—	—	36
Gain on sale of discontinued operations	—	—	—	(37,294)
Increase (decrease) in estimated future obligations	913	(2,565)	1,448	(2,565)
(Gain) loss on derivatives, net	(2)	31	18	75
Other (income) expense, net	—	(308)	—	(332)
Income (Loss) From Discontinued Operations Before Income Taxes	(1,377)	2,546	(2,369)	39,779
Income tax (expense) benefit	482	(1,414)	829	(14,989)
Income (Loss) From Discontinued Operations, Net of Income Taxes	($895)	$1,132	($1,540)	$24,790

Income Taxes

Carrizo UK is a disregarded entity for U.S. federal income tax purposes. Accordingly, the income tax (expense) benefit reflected above includes the Company's U.S. deferred income tax (expense) benefit associated with the income (loss) from discontinued operations before income taxes. The related U.S. deferred tax assets and liabilities have been classified as deferred income taxes of continuing operations in the consolidated balance sheets.

4. Property and Equipment, Net

As of June 30, 2014 and December 31, 2013, total property and equipment, net consisted of the following:

	June 30, 2014	December 31, 2013
	(In thousands)	
Proved properties	$2,593,298	$2,182,226
Accumulated depreciation, depletion and amortization	(917,357)	(773,742)
Proved properties, net	1,675,941	1,408,484
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	379,315	302,232
Exploratory wells in progress	22,798	30,196
Capitalized interest	56,280	45,009
Total unproved properties, not being amortized	458,393	377,437
Other property and equipment	15,610	15,260
Accumulated depreciation	(7,843)	(6,966)
Other property and equipment, net	7,767	8,294

Total property and equipment, net	$2,142,101	$1,794,215

5. Income Taxes

The Company's estimated annual effective income tax rates are used to allocate expected annual income tax expense to interim periods. The rates are the ratio of estimated annual income tax expense to estimated annual income before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the discrete item occurs. The estimated annual effective income tax rates are applied to the year-to-date income before income taxes by taxing jurisdiction to determine the income tax expense allocated to the interim period. The Company updates its estimated annual effective income tax rates at the end of each quarterly period considering the geographic mix of income based on the tax jurisdictions in which the Company operates. Actual results that are different from the assumptions used in estimating the annual effective income tax rates will impact future income tax expense. Income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate income tax rate of 35% to income from continuing operations before income taxes as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Income tax expense at the statutory rate	($1,850)	($20,427)	($5,544)	($21,824)
State income tax expense, net of U.S. federal income tax benefit	(222)	(2,049)	(414)	(2,063)
Other, net	(1)	(69)	(48)	(107)
Income tax expense	($2,073)	($22,545)	($6,006)	($23,994)

6. Long-Term Debt

Long-term debt consisted of the following as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(In thousands)	
8.625% Senior Notes due 2018	$600,000	$600,000
Unamortized discount for 8.625% Senior Notes	(3,819)	(4,178)
7.50% Senior Notes due 2020	300,000	300,000
Other long-term debt due 2028	4,425	4,425
Senior Secured Revolving Credit Facility due 2018	121,000	—
Total long-term debt	$1,021,606	$900,247

Senior Secured Revolving Credit Facility

The Company is party to a senior secured revolving credit facility with Wells Fargo Bank, National Association as the administrative agent. The revolving credit facility provides for a borrowing capacity up to the lesser of (i) the borrowing base (as defined in the senior credit agreement governing the revolving credit facility) and (ii) $1.0 billion. The revolving credit facility matures on July 2, 2018. The revolving credit facility is secured by substantially all of the Company's U.S. assets and is guaranteed by all of the Company's existing Material Domestic Subsidiaries (as defined in the credit agreement governing the revolving credit facility).

As a result of the Spring 2014 borrowing base redetermination, effective April 10, 2014, the borrowing base was increased to $570.0 million from $470.0 million. The borrowing base will be redetermined by the lenders at least semi-annually on or around each May 1 and November 1, with the next redetermination expected in the Fall of 2014. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

The Company is subject to certain covenants under the terms of the revolving credit facility, as amended, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00; and (2) a Current Ratio of not less than 1.00 to 1.00; (each of the capitalized terms used in the foregoing clauses (1) and (2) being as defined in the credit agreement governing the revolving credit facility). At June 30, 2014, the ratio of Total Debt to EBITDA was 2.19 to 1.00 and the Current Ratio was 1.96 to 1.00. As defined in the credit agreement governing the revolving credit facility, Total Debt is net of cash and cash equivalents and the Current Ratio includes an add back of the available borrowing capacity. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts outstanding under the revolving credit facility are dependent on the timing of cash flows from operations, capital expenditures, sales of oil and gas properties and securities offerings.

As of June 30, 2014, the Company had $121.0 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 2.71%. As of June 30, 2014, the Company also had $0.9 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. The amount available for borrowing with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility. The revolving credit facility is generally used to fund ongoing working capital needs and the Company's capital expenditure plan to the extent such amounts exceed cash flows from operations, proceeds from the sale of oil and gas properties and securities offerings.

7. Commitments and Contingencies

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The results of operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

8. Derivative Instruments

The Company uses commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce its exposure to commodity price volatility for a substantial, but varying, portion of its forecasted oil and gas production up to 36 months and thereby achieve a more predictable level of cash flows to support the Company's drilling and completion capital expenditure program. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative instruments for speculative or trading purposes.

The Company typically has numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value of derivative instruments where the Company is in a net asset position with its counterparties as of June 30, 2014 and December 31, 2013 totaled $0.4 million and $9.3 million, respectively, and is summarized by counterparty in the table below:

Counterparty	June 30, 2014		December 31, 2013	
Royal Bank of Canada	100	%	—	%
Credit Suisse	—	%	46	%
Societe Generale	—	%	31	%
Wells Fargo	—	%	23	%
Total	100	%	100	%

The counterparties to the Company's derivative instruments are lenders under the Company's credit agreement. Because each of the lenders have investment grade credit ratings, the Company believes it has minimal credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the financial viability of its counterparties.

The fair value of derivative instruments where the Company is in a net liability position with its counterparties as of June 30, 2014 and December 31, 2013 totaled $44.1 million and $10.1 million, respectively. Because these counterparties are lenders under the Company's credit agreement, these counterparties are secured equally with the holders of the Company's bank debt, which eliminates the need to post collateral when the Company is in a net liability position.

For the three months ended June 30, 2014 and 2013, the Company recorded in the consolidated statements of income a loss on derivative instruments, net of $40.0 million and a gain on derivative instruments, net of $25.7 million, respectively. For the six months ended June 30, 2014 and 2013, the Company recorded in the consolidated statements of income a loss on derivative instruments, net of $60.6 million and a gain on derivative instruments, net of $11.2 million, respectively.

The following sets forth a summary of the Company's crude oil derivative positions at average NYMEX prices as of June 30, 2014:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
July - December 2014	Fixed Price Swaps	11,500	$93.55			
	Costless Collars	3,000	$88.33	$104.26		
	Three-way Collars	500	$85.00	$107.75	$65.00	$20.00
January - December 2015	Fixed Price Swaps	10,370	$92.97			
	Costless Collars	700	$90.00	$100.65		
	Three-way Collars	1,000	$85.00	$105.00	$65.00	$20.00
January - December 2016	Fixed Price Swaps	1,500	$90.74			
	Three-way Collars	667	$85.00	$104.00	$65.00	$20.00

The following sets forth a summary of the Company's natural gas derivative positions at average NYMEX prices as of June 30, 2014:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
July - December 2014	Fixed Price Swaps	58,690	$4.20	
	Calls	10,000		$5.50
January - December 2015	Fixed Price Swaps	30,000	$4.29	

9. Fair Value Measurements

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

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables summarize the location and amounts of the Company's assets and liabilities measured at fair value on a recurring basis as presented in the consolidated balance sheets as of June 30, 2014 and December 31, 2013. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	June 30, 2014		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Other current assets	$1,852	($1,604)	$248
Other assets	1,866	(1,688)	178
Derivative liabilities			
Derivative liabilities	(41,059)	1,604	(39,455)
Other liabilities	(6,352)	1,688	(4,664)
Total	($43,693)	$—	($43,693)

	December 31, 2013		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Other current assets	$2,389	($2,389)	$—
Other assets	11,709	(2,425)	9,284
Derivative liabilities			
Derivative liabilities	(12,336)	2,389	(9,947)
Other liabilities	(2,613)	2,425	(188)
Total	($851)	$—	($851)

The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparty for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

The derivative asset and liability fair values reported in the consolidated balance sheets are as of a particular point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. The Company typically has numerous hedge positions that span several time periods and often result in both derivative assets and liabilities with the same counterparty, which positions are all offset to a single derivative asset or liability in the consolidated balance sheets. The Company nets the fair values of its derivative assets and liabilities associated with derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company had no transfers in or out of Levels 1 or 2 for the six months ended June 30, 2014 or 2013.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, receivables, payables and long-term debt which are classified as Level 1 under the fair value hierarchy. The carrying amounts of cash and cash equivalents, receivables, and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

The following table presents the carrying amounts and fair values of the Company's senior notes and other long-term debt, based on quoted market prices, as of June 30, 2014 and December 31, 2013.

	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
8.625% Senior Notes due 2018	$596,181	$635,250	$595,822	$644,978
7.50% Senior Notes due 2020	300,000	330,000	300,000	327,000
Other long-term debt due 2028	4,425	4,226	4,425	4,115

10. Condensed Consolidating Financial Information

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information as of June 30, 2014 and December 31, 2013, and for the three and six months ended June 30, 2014 and 2013 on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company's oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)
(Unaudited)

	June 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$1,893,775	$255,888	$—	($1,986,951)	$162,712
Total property and equipment, net	4,246	2,095,610	23,647	18,598	2,142,101
Investment in subsidiaries	158,416	—	—	(158,416)	—
Other assets	99,816	353	—	(74,554)	25,615
Total Assets	$2,156,253	$2,351,851	$23,647	($2,201,323)	$2,330,428
Liabilities and Shareholders' Equity					
Current liabilities	$247,841	$2,091,524	$23,650	($1,986,951)	$376,064
Long-term liabilities	1,048,092	101,908	—	(65,549)	1,084,451
Total shareholders' equity	860,320	158,419	(3)	(148,823)	869,913
Total Liabilities and Shareholders' Equity	$2,156,253	$2,351,851	$23,647	($2,201,323)	$2,330,428

	December 31, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$1,820,069	$168,718	$—	($1,709,026)	$279,761
Total property and equipment, net	2,797	1,768,553	2,058	20,807	1,794,215
Investment in subsidiaries	61,619	—	—	(61,619)	—
Other assets	69,686	—	—	(32,902)	36,784
Total Assets	$1,954,171	$1,937,271	$2,058	($1,782,740)	$2,110,760
Liabilities and Shareholders' Equity					
Current liabilities	$201,486	$1,828,314	$2,061	($1,709,026)	$322,835
Long-term liabilities	922,571	47,335	—	(23,585)	946,321
Total shareholders' equity	830,114	61,622	(3)	(50,129)	841,604
Total Liabilities and Shareholders' Equity	$1,954,171	$1,937,271	$2,058	($1,782,740)	$2,110,760

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(in thousands)
(Unaudited)

	Three Months Ended June 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$1,206	$192,269	$—	$—	$193,475
Total costs and expenses	78,089	109,088	—	1,011	188,188
Income (loss) from continuing operations before income taxes	(76,883)	83,181	—	(1,011)	5,287
Income tax (expense) benefit	26,908	(29,381)	—	400	(2,073)
Equity in income of subsidiaries	53,800	—	—	(53,800)	—
Income from continuing operations	3,825	53,800	—	(54,411)	3,214
Loss from discontinued operations, net of income taxes	(895)	—	—	—	(895)
Net income	$2,930	$53,800	$—	($54,411)	$2,319

	Three Months Ended June 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$2,086	$132,138	$—	$—	$134,224
Total costs and expenses	1,771	74,254	—	(183)	75,842
Income from continuing operations before income taxes	315	57,884	—	183	58,382
Income tax expense	(110)	(20,365)	—	(2,070)	(22,545)
Equity in income of subsidiaries	37,519	—	—	(37,519)	—
Income from continuing operations	37,724	37,519	—	(39,406)	35,837
Income from discontinued operations, net of income taxes	1,132	—	—	—	1,132
Net income	$38,856	$37,519	$—	($39,406)	$36,969

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$2,772	$347,915	$—	$—	$350,687
Total costs and expenses	133,640	198,997	—	2,209	334,846
Income (loss) from continuing operations before income taxes	(130,868)	148,918	—	(2,209)	15,841
Income tax (expense) benefit	45,803	(52,121)	—	312	(6,006)
Equity in income of subsidiaries	96,797	—	—	(96,797)	—
Income from continuing operations	11,732	96,797	—	(98,694)	9,835
Loss from discontinued operations, net of income taxes	(1,540)	—	—	—	(1,540)
Net income	$10,192	$96,797	$—	($98,694)	$8,295
	Six Months Ended June 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$3,647	$242,478	$—	$—	$246,125
Total costs and expenses	42,114	141,609	—	47	183,770
Income (loss) from continuing operations before income taxes	(38,467)	100,869	—	(47)	62,355
Income tax (expense) benefit	13,463	(35,410)	—	(2,047)	(23,994)
Equity in income of subsidiaries	65,459	—	—	(65,459)	—
Income from continuing operations	40,455	65,459	—	(67,553)	38,361
Income from discontinued operations, net of income taxes	24,790	—	—	—	24,790
Net income	$65,245	$65,459	$—	($67,553)	$63,151

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($122,961)	$318,607	$—	$—	$195,646
Net cash used in investing activities from continuing operations	(146,432)	(464,288)	(21,554)	167,235	(465,039)
Net cash provided by financing activities from continuing operations	126,158	145,681	21,554	(167,235)	126,158
Net cash used in discontinued operations	(5,582)	—	—	—	(5,582)
Net decrease in cash and cash equivalents	(148,817)	—	—	—	(148,817)
Cash and cash equivalents, beginning of period	157,439	—	—	—	157,439
Cash and cash equivalents, end of period	$8,622	$—	$—	$—	$8,622

	Six Months Ended June 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities from continuing operations	$4,319	$209,403	$—	$—	$213,722
Net cash used in investing activities from continuing operations	(142,476)	(428,774)	—	219,183	(352,067)
Net cash provided by (used in) financing activities from continuing operations	(41,521)	219,183	—	(219,183)	(41,521)
Net cash provided by (used in) discontinued operations	131,618	—	(519)	—	131,099
Net decrease in cash and cash equivalents	(48,060)	(188)	(519)	—	(48,767)
Cash and cash equivalents, beginning of period	51,894	201	519	—	52,614
Cash and cash equivalents, end of period	$3,834	$13	$—	$—	$3,847

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

The following is management's discussion and analysis of the significant factors that affected the Company's financial position and results of operations during the periods included in the accompanying unaudited consolidated financial statements. You should read this in conjunction with the discussion under "Item 7A. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2013, and the unaudited consolidated financial statements included in this quarterly report.

General Overview

For the second quarter of 2014, we recognized total revenues of $193.5 million and production of 3.0 MMBoe. The key drivers to our success for the three months ended June 30, 2014 included the following:

Drilling. See the table below for details of our operated drilling and completion activity in our primary areas of activity:

	Three Months Ended June 30, 2014				As of June 30, 2014				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	18	13.5	26	20.8	21	15.7	164	128.9	3
Niobrara	8	3.3	12	4.5	2	0.5	100	42.7	1
Marcellus	—	—	9	2.4	11	4.3	75	24.1	—
Utica	—	—	—	—	—	—	1	0.9	1
Total	26	16.8	47	27.7	34	20.5	340	196.6	5

Production. Our second quarter 2014 crude oil production of 1.7 MMBbls, or 18,440 Bbls/d, increased 57% from our second quarter 2013 production of 1.1 MMBbls, or 11,747 Bbls/d, primarily due to production from new wells in the Eagle Ford. Our second quarter 2014 natural gas production of 6.9 Bcf, or 75,593 Mcf/d, decreased 18% from our second quarter 2013 production of 8.3 Bcf, or 91,736 Mcf/d. This was primarily due to the sale of our remaining oil and gas properties in the Barnett to EnerVest Energy Institution Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and EV Properties, L.P. (collectively, "EnerVest") in October 2013 partially offset by production from new wells in Marcellus.

Prices. Our average realized crude oil price during the second quarter of 2014 was $98.90 per Bbl, relatively flat as compared to our average realized price of $98.98 per Bbl in the same period in 2013. Our average realized natural gas price during the second quarter of 2014 increased 2% to $3.13 per Mcf from $3.07 per Mcf in the same period in 2013. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are largely dependent on commodity prices, which are beyond our control and have been and are expected to remain volatile.

Results of Operations

Three Months Ended June 30, 2014, Compared to the Three Months Ended June 30, 2013

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the three months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		2014 Period Compared to 2013 Period	
	2014	2013	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	1,678	1,069	609	57 %
NGLs (MBbls)	208	105	103	98 %
Natural gas (MMcf)	6,879	8,348	(1,469)	(18%)
Total Natural gas and NGLs (MMcfe)	8,127	8,978	(851)	(9%)
Total barrels of oil equivalent (MBoe)	3,032	2,565	467	18 %
Daily production volumes by product -				
Crude oil (Bbls/d)	18,440	11,747	6,693	57 %
NGLs (Bbls/d)	2,286	1,154	1,132	98 %
Natural gas (Mcf/d)	75,593	91,736	(16,143)	(18%)
Total Natural gas and NGLs (Mcfe/d)	89,308	98,659	(9,351)	(9%)
Total barrels of oil equivalent (Boe/d)	33,319	28,187	5,132	18 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	19,978	12,239	7,739	63 %
Niobrara	2,542	1,839	703	38 %
Barnett	—	8,136	(8,136)	(100%)
Marcellus	9,895	5,647	4,248	75 %
Utica and other	904	326	578	177 %
Total barrels of oil equivalent (Boe/d)	33,319	28,187	5,132	18 %
Average realized prices -				
Crude oil ($ per Bbl)	$98.90	$98.98	($0.08)	— %
NGLs ($ per Bbl)	28.76	26.34	2.42	9 %
Natural gas ($ per Mcf)	3.13	3.07	0.06	2 %
Total Natural gas and NGLs ($ per Mcfe)	$3.39	$3.17	$0.22	7 %
Total average realized price ($ per Boe)	$63.81	$52.33	$11.48	22 %
Revenues (In thousands) -				
Crude oil	$165,962	$105,805	$60,157	57 %
NGLs	5,983	2,766	3,217	116 %
Natural gas	21,530	25,653	(4,123)	(16%)
Total revenues	$193,475	$134,224	$59,251	44 %

Revenues for the three months ended June 30, 2014 increased 44% to $193.5 million from $134.2 million for the same period in 2013 primarily due to the significant increase in oil production. Production volumes for the three months ended June 30, 2014 and 2013 were 3.0 and 2.6 MMBoe, respectively. The increase in production from the second quarter of 2013 to the second quarter of 2014 was primarily due to increased production from new wells in the Eagle Ford and Marcellus, partially offset by normal production declines and the sale of Barnett to EnerVest in October 2013. Average realized oil prices remained relatively flat at $98.90 per Bbl and $98.98 per Bbl for the second quarter of 2014 and 2013, respectively. Average realized natural gas prices increased 2% to $3.13 per Mcf in the second quarter of 2014 from $3.07 per Mcf in the same period in 2013. Average realized NGL prices increased 9% to $28.76

per Bbl in the second quarter of 2014 from $26.34 per Bbl in the same period in 2013.
Lease operating expenses for the three months ended June 30, 2014 increased to $17.4 million ($5.73 per Boe) from $11.8 million ($4.60 per Boe) for the same period in 2013. The increase in lease operating expenses is primarily due to increased operating

costs associated with increased production from new wells in the Eagle Ford, partially offset by the sale of Barnett to EnerVest. The increase in lease operating expense per Boe is primarily due to the sale of lower operating cost per Boe gas properties in the Barnett as well as increased production from higher operating cost per Boe oil properties in the Eagle Ford.

Production taxes increased to $8.2 million (4.2% of revenues) for the three months ended June 30, 2014 from $4.6 million (3.4% of revenues) for the same period in 2013 as a result of increased oil production, primarily in the Eagle Ford. The increase in production taxes as a percentage of revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to natural gas production.

Ad valorem taxes decreased to $1.9 million for the three months ended June 30, 2014 as compared to $2.9 million for the same period in 2013. The decrease in ad valorem taxes is primarily due to the sale of Barnett to EnerVest.

Depreciation, depletion and amortization (“DD&A”) expense for the second quarter of 2014 increased to $80.7 million ($26.63 per Boe) from $50.5 million ($19.70 per Boe) in the second quarter of 2013. The increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is largely due to the impact of the significant decrease in natural gas reserves in the Barnett as a result of the sale to EnerVest as well as the increase in crude oil reserves, primarily in the Eagle Ford, which have a higher finding cost per Boe than our natural gas reserves. The components of our DD&A expense were as follows:

	Three Months Ended June 30,	
	2014	2013
	(In thousands)	
DD&A of proved oil and gas properties	$79,859	$49,711
Depreciation of other property and equipment	437	465
Amortization of other assets	297	232
Accretion of asset retirement obligations	153	120
Total DD&A	$80,746	$50,528

General and administrative expense increased to $27.7 million for the three months ended June 30, 2014 from $17.8 million for the corresponding period in 2013. The increase was primarily due to increased stock-based compensation expense associated with SARs as a result of a larger increase in stock price during the three months ended June 30, 2014 as compared to the corresponding period in 2013. This increase was partially offset due to the timing of the award of annual bonuses to employees and executives, which occurred during the first quarter of 2014 as compared to the second quarter of 2013.

The loss on derivative instruments, net for the three months ended June 30, 2014 amounted to $40.0 million primarily due to the upward shift in the futures curve of forecasted commodity prices for crude oil from April 1, 2014 (or the subsequent date during on which new contracts were entered into) to June 30, 2014. The gain on derivative instruments, net for the three months ended June 30, 2013 amounted to $25.7 million primarily due to the downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from April 1, 2013 (or the subsequent date on which prior year contracts were entered into) to June 30, 2013.

Interest expense, net for the three months ended June 30, 2014 was $11.9 million as compared to $14.0 million for the same period in 2013. The decrease in interest expense, net was primarily due to the repurchase of the 4.375% convertible senior notes in June 2013 as well as an increase in the amount of interest that was capitalized due to a higher average balance of unproved properties.

The effective income tax rate for the second quarter of 2014 and 2013 was 39.2% and 38.6%, respectively. These rates are higher than the U.S. federal statutory corporate income tax rate of 35% primarily due to the impact of state income taxes.

Six Months Ended June 30, 2014, Compared to the Six Months Ended June 30, 2013

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,		2014 Period Compared to 2013 Period	
	2014	2013	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	3,030	1,907	1,123	59 %
NGLs (MBbls)	374	206	168	82 %
Natural gas (MMcf)	12,097	17,077	(4,980)	(29 %)
Total Natural gas and NGLs (MMcfe)	14,341	18,313	(3,972)	(22 %)
Total barrels of oil equivalent (MBoe)	5,420	4,959	461	9 %
Daily production volumes by product -				
Crude oil (Bbls/d)	16,740	10,536	6,204	59 %
NGLs (Bbls/d)	2,066	1,138	928	82 %
Natural gas (Mcf/d)	66,834	94,348	(27,514)	(29 %)
Total Natural gas and NGLs (Mcfe/d)	79,232	101,177	(21,945)	(22 %)
Total barrels of oil equivalent (Boe/d)	29,945	27,398	2,547	9 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	18,024	11,280	6,744	60 %
Niobrara	2,348	1,397	951	68 %
Barnett	—	8,399	(8,399)	(100 %)
Marcellus	8,665	5,989	2,676	45 %
Utica and other	908	333	575	173 %
Total barrels of oil equivalent (Boe/d)	29,945	27,398	2,547	9 %
Average realized prices -				
Crude oil ($ per Bbl)	$97.80	$101.36	($3.56)	(4 %)
NGLs ($ per Bbl)	31.74	26.73	5.01	19 %
Natural gas ($ per Mcf)	3.51	2.77	0.74	27 %
Total Natural gas and NGLs ($ per Mcfe)	$3.79	$2.89	$0.90	31 %
Total average realized price ($ per Boe)	$64.70	$49.63	$15.07	30 %
Revenues (In thousands) -				
Crude oil	$296,324	$193,287	$103,037	53 %
NGLs	11,871	5,507	6,364	116 %
Natural gas	42,492	47,331	(4,839)	(10 %)
Total revenues	$350,687	$246,125	$104,562	42 %

Revenues for the six months ended June 30, 2014 increased 42% to $350.7 million from $246.1 million for the same period in 2013 primarily due to the increase in oil production and gas prices, partially offset by the decrease in gas production and oil prices. Production volumes for the six months ended June 30, 2014 and 2013 were 5.4 MMBoe and 5.0 MMBoe, respectively. The increase in production from the six months ended June 30, 2013 to the six months ended June 30, 2014 was primarily due to increased production from new wells in the Eagle Ford and Marcellus, partially offset by normal production declines and the sale of Barnett to EnerVest. Average realized oil prices decreased 4% to $97.80 per barrel from $101.36 per barrel in the same period in 2013. Average realized gas prices increased 27% to $3.51 per Mcf for the six months ended June 30, 2014 from $2.77 per Mcf in the same period in 2013. Average realized NGL prices increased 19% to $31.74 per Bbl for the six months ended June 30, 2014 from

$26.73 per Bbl in the same period in 2013.

Lease operating expenses were $30.0 million ($5.53 per Boe) for the six months ended June 30, 2014 as compared to lease operating expenses of $22.0 million ($4.43 per Boe) for the same period in 2013. The $8.0 million increase in lease operating expenses is primarily due to increased operating costs associated with increased production from new wells in the Eagle Ford, partially offset by the sale of Barnett to EnerVest. The increase in lease operating expense per Boe is primarily due to the sale of lower operating cost per Boe gas properties in the Barnett as well as increased production from higher operating cost per Boe oil properties in the Eagle Ford.

Production taxes were $14.3 million (or 4.1% of revenues) for the six months ended June 30, 2014 as compared to $9.1 million (or 3.7% of revenues) for the same period in 2013. The increase in production taxes is due primarily to increased oil production, primarily in the Eagle Ford, partially offset by the sale of Barnett to EnerVest. The increase in production taxes as a percentage of revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to natural gas production.

Ad valorem taxes decreased to $3.3 million for the six months ended June 30, 2014 from $4.7 million for the same period in 2013. The decrease in ad valorem taxes is due primarily to lower actual ad valorem taxes than previously estimated for the year ended December 31, 2013 and the sale of Barnett to EnerVest.

DD&A expense for the six months ended June 30, 2014 increased $49.1 million to $145.3 million ($26.82 per Boe) from the DD&A expense for the six months ended June 30, 2013 of $96.2 million ($19.40 per Boe). The increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is largely due to the impact of the significant decrease in natural gas reserves in the Barnett as a result of the sale to EnerVest as well as the increase in crude oil reserves, primarily in the Eagle Ford, which have a higher finding cost per Boe than our natural gas reserves. The components of our DD&A expense were as follows:

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
DD&A of proved oil and gas properties	$143,572	$94,753
Depreciation of other property and equipment	876	807
Amortization of other assets	601	438
Accretion of asset retirement obligations	291	227
Total DD&A	$145,340	$96,225

General and administrative expense increased to $55.9 million for the six months ended June 30, 2014 from $34.0 million for the corresponding period in 2013. The increase was primarily due to increased stock-based compensation expense associated with SARs as a result of a larger increase in stock price during the six months ended June 30, 2014 as compared to the same period of 2013 as well as a higher level of restricted stock outstanding during 2014 as compared to 2013.

The loss on derivative instruments, net for the six months ended June 30, 2014 amounted to $60.6 million primarily due to the upward shift in the futures curve of forecasted commodity prices for crude oil from January 1, 2014 (or the subsequent date new contracts were entered into) to June 30, 2014. The gain on derivative instruments, net for the six months ended June 30, 2013 amounted to $11.2 million primarily due to the downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from January 1, 2013 (or the subsequent date prior year contracts were entered into) to June 30, 2013.

Interest expense, net for the six months ended June 30, 2014 was $24.4 million as compared to $29.0 million for the same period in 2013. The decrease in interest expense was primarily due to the repurchase of the 4.375% convertible senior notes in June 2013 as well as an increase in the amount of interest that was capitalized due to a higher average balance of unproved properties.

The effective income tax rates for the six months ended June 30, 2014 and 2013 were 37.9% and 38.5%, respectively. These rates are higher than the U.S. federal statutory corporate income tax rate of 35% primarily due to the impact of state income taxes.

Liquidity and Capital Resources

2014 Capital Expenditure Plan and Funding Strategy. Our 2014 drilling and completion capital expenditure plan is $690.0 million to $710.0 million. Our 2014 leasehold and seismic capital expenditure plan is $130.0 million. We expect to allocate the majority of the leasehold and seismic capital to acreage acquisitions in the Eagle Ford and Utica shales. We currently intend to finance the remainder of our 2014 capital expenditure plan primarily from the sources described below under "—Sources and Uses of Cash." Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. Below is a summary of capital expenditures through June 30, 2014:

	Three Months Ended		Six Months Ended
	March 31, 2014	June 30, 2014	June 30, 2014
	(In thousands)		
Drilling and completion			
Eagle Ford	$128,870	$154,350	$283,220
Niobrara	24,204	29,726	53,930
Utica	2,238	4,396	6,634
Marcellus	13,736	9,931	23,667
Other	1,649	(289)	1,360
Total drilling and completion	170,697	198,114	368,811
Leasehold and seismic	27,268	73,406	100,674
Total	$197,965	$271,520	$469,485

Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative expense, capitalized interest and asset retirement obligations.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and completion programs and, to a lesser extent, our leasehold and seismic data acquisition programs. For the six months ended June 30, 2014, we funded our capital expenditures with cash provided by operations cash on hand, and borrowings under our revolving credit facility. Potential sources of future liquidity include the following:

- Cash provided by operations. Cash flows from operations are highly dependent on commodity prices. As such, we hedge a portion of our forecasted production to mitigate the risk of a decline in oil and gas prices.
- Borrowings under our revolving credit facility. At July 31, 2014, we had $103.0 million of borrowings outstanding and $0.6 million in letters of credit outstanding under the revolving credit facility, which reduce the amounts available under our revolving credit facility. The amount we are able to borrow with respect to the borrowing base of the revolving credit facility, which borrowing base is $570.0 million as of April 10, 2014, is subject to compliance with the financial covenants and other provisions of the credit agreement governing our revolving credit facility.
- Asset sales. In order to fund our capital expenditure plan, we may consider the sale of certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth, provided we are able to sell such assets on terms that are acceptable to us.
- Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.
- Joint ventures. Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage or purchase a portion of interests, or both.
- Lease purchase option arrangements. Lease option agreements and land banking arrangements, such as those we have previously entered into in other plays.
- Other sources. We may consider sale/leaseback transactions of certain capital assets, such as our remaining pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations was $195.6 million and $213.7 million for the six months ended June 30, 2014 and 2013, respectively. The change was primarily due to increased crude oil revenues, offset by increases in operating expenses, net cash paid/received for derivative settlements, and the net change in working capital related to operating activities.

Net cash used in investing activities from continuing operations were $465.0 million and $352.1 million for the six months ended June 30, 2014 and 2013, respectively and relate primarily to oil and gas capital expenditures associated with our capital expenditure plan.

Net cash provided by and net cash used in financing activities from continuing operations were $126.2 million and $41.5 million for the six months ended June 30, 2014 and 2013, respectively. The increase was primarily due to net borrowings under our revolving credit facility in 2014 compared to net repayments in 2013.

Liquidity and Cash Flow Outlook

Economic downturns may adversely affect our ability to access capital markets in the future. We currently believe that cash provided by operating activities and borrowings under our revolving credit facility will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities is primarily driven by production and commodity prices. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows to support our drilling and completion capital expenditure program, we hedge a portion of our forecasted production and, as of June 30, 2014, our hedge positions for the remainder of 2014 comprised 58,690 MMBtu/d of natural gas and 15,000 Bbls/d of crude oil. As of July 31, 2014, our borrowing base under our revolving credit facility is $570.0 million with $103.0 million of borrowings outstanding. Additionally, as described under "—Sources and Uses of Cash" above, the amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility. The borrowing base under our revolving credit facility is affected by our lenders' assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base. The next borrowing base redetermination is expected to occur in the Fall of 2014.

If cash provided by operating activities from continuing operations, borrowings under our revolving credit facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund the remainder of our 2014 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer a portion of our remaining 2014 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from asset sales, securities offerings or borrowings to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of June 30, 2014 (in thousands):

	July-December 2014	2015	2016	2017	2018	2019 and Thereafter	Total
Long-term debt (1)	$—	$—	$—	$—	$721,000	$304,425	$1,025,425
Interest on long-term debt (2)	38,861	77,723	77,723	77,723	76,110	46,823	394,963
Operating leases	1,395	3,774	3,752	3,881	3,974	14,242	31,018
Drilling and completion services (3)	14,089	26,030	21,277	20,057	3,864	—	85,317
Pipeline volume commitments (3)	3,358	7,440	3,201	1,565	1,565	10,948	28,077
Asset retirement obligations and other (4)	6,311	7,966	7,963	2,976	1,412	9,376	36,004
Total Contractual Obligations	$64,014	$122,933	$113,916	$106,202	$807,925	$385,814	$1,600,804

(1) Long-term debt consists of the principal amounts of the 8.625% Senior Notes due 2018, the 7.50% Senior Notes due 2020, other long-term debt due 2028 and $121.0 million of borrowings outstanding as of June 30, 2014 under our revolving credit facility which matures in 2018.

(2)

Cash payments for interest on the 8.625% Senior Notes due 2018, the 7.50% Senior Notes due 2020, other long-term debt due 2028 and our revolving credit facility which matures in 2018 are estimated assuming no principal repayments until the due dates of the instruments. Cash interest payments on our revolving credit facility were calculated using the weighted average interest rate of the outstanding borrowings under the revolving credit facility of 2.71%.

(3) Drilling and completion services and pipeline volume commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will generally be billed for their working interest share of such costs.

(4) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of June 30, 2014. Certain of such estimates and assumptions are inherently unpredictable and will differ from actuals results. See “Note 2. Summary of Significant Accounting Policies - Use of Estimates” for further discussion of estimates and assumptions that may affect the reported amounts.

Financing Arrangements

8.625% Senior Notes

As of June 30, 2014, we had $600.0 million aggregate principal amount of 8.625% Senior Notes due 2018 issued and outstanding. The 8.625% Senior Notes are guaranteed by all of our existing Material Domestic Subsidiaries (as defined in the credit agreement governing our revolving credit facility). The 8.625% Senior Notes mature on October 15, 2018, with interest payable semi-annually. On and after October 15, 2014, we may redeem all or a portion of our 8.625% Senior Notes at redemption prices decreasing from 104.313% to 100% of the principal amount on October 15, 2017, plus accrued and unpaid interest. We could seek to refinance the 8.625% Senior Notes in connection with such a redemption or a repurchase of notes.

Senior Secured Revolving Credit Facility

We are party to a senior secured revolving credit facility with Wells Fargo Bank, National Association as the administrative agent. The revolving credit facility is secured by substantially all of our U.S. assets and is guaranteed by all of our existing Material Domestic Subsidiaries (as defined in the credit agreement governing the revolving credit facility). Any subsidiary of ours that does not currently guarantee our obligations under our revolving credit facility that subsequently becomes a Material Domestic Subsidiary will be required to guarantee our obligations under our revolving credit facility.

As a result of the Spring 2014 borrowing base redetermination, effective April 10, 2014, the borrowing base was increased to $570.0 million from $470.0 million. The borrowing base will be redetermined by the lenders at least semi-annually on or around each May 1 and November 1, with the next redetermination expected in Fall 2014. The amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

We are subject to certain covenants under the terms of the revolving credit facility, as amended, which include, but are not limited to, the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio Total Debt to EBITDA of not more than 4.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) and (2) being as defined in the credit agreement governing the revolving credit facility). At June 30, 2014, the ratio of Total Debt to EBITDA was 2.19 to 1.00 and the Current Ratio was 1.96 to 1.00. As defined in the credit agreement governing the revolving credit facility, Total Debt is net of cash and cash equivalents and the Current Ratio includes an add back of the available borrowing capacity.

Our revolving credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

Our revolving credit facility is subject to customary events of default, including a change in control (as defined in the credit agreement governing our revolving credit facility). If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing our revolving credit facility) may accelerate amounts due under the revolving credit facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

As of June 30, 2014, we had $121.0 million of borrowings outstanding under the revolving credit facility and had $0.9 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. The amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility. The revolving credit facility is generally used to fund ongoing working capital needs and the remainder of our capital expenditure plan to the extent such amounts exceed the cash flows from operations and proceeds from asset sales and securities offerings.

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates are inherently unpredictable and will differ from actual results. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, income taxes and commitments and contingencies. These policies and estimates are described in our Annual Report on Form 10-K for the year ended December 31, 2013. We evaluate subsequent events through the date the financial statements are issued.

The table below presents results of the full cost ceiling test as of June 30, 2014 along with various pricing scenarios to demonstrate the sensitivity of our cost center ceiling to changes in 12 month average benchmark oil and gas prices underlying our average realized prices. This sensitivity analysis is as of June 30, 2014, and, accordingly, does not consider drilling results, production and prices subsequent to June 30, 2014 that may require revisions to our proved reserve estimates.

	12 Month Average Realized Prices		Excess of cost center ceiling over net capitalized costs	Increase (Decrease) in excess of cost center ceiling over net capitalized costs
Full Cost Pool Scenarios	Crude Oil ($/Bbl)	Natural Gas ($/Mcf)	(In millions)	(In millions)
June 30, 2014 Actual	$97.83	$3.48	$444	
Oil and Gas Price Sensitivity				
Oil and Gas +10%	$107.84	$3.89	$697	$253
Oil and Gas -10%	$87.83	$3.06	$191	($253)
Oil Price Sensitivity				
Oil +10%	$107.84	$3.48	$670	$226
Oil -10%	$87.83	$3.48	$218	($226)
Gas Price Sensitivity				
Gas +10%	$97.83	$3.89	$470	$26
Gas -10%	$97.83	$3.06	$418	($26)

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry specific guidance in Subtopic 932-605, Extractive Activities- Oil and Gas- Revenue Recognition. This ASU requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods and services. This ASU is effective for annual and interim periods beginning in 2017, and is required to be adopted either retrospectively or as an accumulative-effect adjustment as of the date of adoption, with no early adoption permitted. We are currently evaluating the impact of the adoption of this ASU on our consolidated financial statements.

Volatility of Oil and Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital are substantially dependent upon prevailing prices of oil and gas.

We review the carrying value of our oil and gas properties on a quarterly basis using the full cost method of accounting. See “Summary of Critical Accounting Policies—Oil and Gas Properties,” in our Annual Report on Form 10-K for the year ended December 31, 2013.

We use commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce our exposure to commodity price volatility for a substantial, but varying, portion of our forecasted oil and gas production up to 36 months and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. We do not enter into derivative instruments for speculative or trading purposes.

We typically have numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period. We net our derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value of derivative instruments where we are in a net asset position with our counterparties as of June 30, 2014 and December 31, 2013 totaled $0.4 million and $9.3 million, respectively, and is summarized by counterparty in the table below:

Counterparty	June 30, 2014	December 31, 2013
Royal Bank of Canada	100 %	— %
Credit Suisse	— %	46 %
Societe Generale	— %	31 %
Wells Fargo	— %	23 %
Total	100 %	100 %

The counterparties to our derivative instruments are lenders under our credit agreement. Because each of the lenders have investment grade credit ratings, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the net asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the financial viability of our counterparties.

The fair value of derivative instruments where we are in a net liability position with our counterparties at June 30, 2014 and December 31, 2013 totaled $44.1 million and $10.1 million, respectively. Because these counterparties are lenders under our credit agreement, these counterparties are secured equally with the holders of our bank debt, which eliminates the need to post collateral when we are in a net liability position.

For the three months ended June 30, 2014 and 2013, we recorded in the consolidated statements of income a loss on derivative instruments, net of $40.0 million and a gain on derivative instruments, net of $25.7 million, respectively. For the six months ended June 30, 2014 and 2013, we recorded in the consolidated statements of income a loss on derivative instruments, net of $60.6 million and a gain on derivative instruments, net of $11.2 million, respectively.

The following sets forth a summary of our crude oil derivative positions at average NYMEX prices as of June 30, 2014:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
July - December 2014	Fixed Price Swaps	11,500	$93.55			
	Costless Collars	3,000	$88.33	$104.26		
	Three-way Collars	500	$85.00	$107.75	$65.00	$20.00
January - December 2015	Fixed Price Swaps	10,370	$92.97			
	Costless Collars	700	$90.00	$100.65		
	Three-way Collars	1,000	$85.00	$105.00	$65.00	$20.00
January - December 2016	Fixed Price Swaps	1,500	$90.74			
	Three-way Collars	667	$85.00	$104.00	$65.00	$20.00

The following sets forth a summary of our natural gas derivative positions at average NYMEX prices as of June 30, 2014:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
July - December 2014	Fixed Price Swaps	58,690	$4.20	
	Calls	10,000		$5.50

January - December 2015	Fixed Price Swaps	30,000	$4.29

Forward-Looking Statements

The statements contained in all parts of this document, including, but not limited to, those relating to the Company's or management's intentions, beliefs, expectations, hopes, projections, assessment of risks, estimations, plans or predictions for the future, including our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, timing and amounts of production, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of oil and gas exploration, capital expenditure plans, planned evaluation of prospects, probability of prospects having oil and gas, expected production or reserves, pipeline connections, increases in reserves, acreage, working capital requirements, commodity price risk management activities and the impact on our average realized prices, the availability of expected sources of liquidity to implement the Company's business strategies, accessibility of borrowings under our credit facility, future exploration activity, drilling, completion and fracturing of wells, land acquisitions, production rates, forecasted production, growth in production, development of new drilling programs, participation of our industry partners, exploration and development expenditures, the impact of our business strategies, the benefits, results, effects, availability of and results of new and existing joint ventures and sales transactions, receipt of receivables, drilling carry, proceeds from sales, and all and any other statements regarding future operations, financial results, business plans and cash needs and other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words "anticipate," "estimate," "expect," "may," "project," "plan," "believe" and similar expressions are intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, actions and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under our credit facility, evaluations of the Company by lenders under our credit facility the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information, property acquisition risks, availability of equipment, actions by our midstream and other industry partners, weather, availability of financing, actions by lenders, our ability to obtain permits and licenses, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture partners, results of exploration activities, the availability of and completion of land acquisitions, completion and connection of wells, and other factors detailed in the "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the year ended December 31, 2013 and in our other filings with the SEC, including this quarterly report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For information regarding our exposure to certain market risks, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" of our Annual Report on Form 10-K for the year ended December 31, 2013. There have been no material changes to the disclosure regarding our exposure to certain market risks made in our Annual Report on Form 10-K for the year ended December 31, 2013.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of June 30, 2014 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended June 30, 2014 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

Item 1A. Risk Factors

There were no material changes to the factors discussed in "Part I. Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2013.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

The following exhibits are required by Item 601 of Regulation S-K and are filed as part of this report:

Exhibit Number		Exhibit Description
10.1	–	Amended and Restated Incentive Plan of Carrizo Oil & Gas, Inc. effective as of May 15, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 16, 2014).
*31.1	–	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	–	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	–	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	–	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	–	Interactive Data Files

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

	Carrizo Oil & Gas, Inc. (Registrant)
Date: August 5, 2014	By: /s/ Paul F. Boling Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer)
Date: August 5, 2014	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)