CARRIZO OIL & GAS INC
Form 10-Q
November 04, 2013

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 September 30, 2013
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 October 31, 2013 was 40,921,395.

CARRIZO OIL & GAS, INC.
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2013
INDEX

PART I. FINANCIAL INFORMATION
Item 1. Consolidated Financial Statements
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(In thousands, except per share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$5,728	$52,095
Accounts receivable, net	114,901	112,821
Accounts receivable - related party	5,930	9,815
Current assets held for sale	—	1,882
Fair value of derivative instruments	—	23,981
Deferred income taxes	5,209	—
Prepaids and other current assets	5,397	8,111
Total current assets	137,165	208,705
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full cost method of accounting		
Proved oil and gas properties, net	1,495,981	1,152,548
Unproved properties, not being amortized	395,291	323,688
Other property and equipment, net	9,800	11,438
TOTAL PROPERTY AND EQUIPMENT, NET	1,901,072	1,487,674
LONG-TERM ASSETS HELD FOR SALE	—	132,626
DEFERRED FINANCING COSTS, NET	21,728	23,914
FAIR VALUE OF DERIVATIVE INSTRUMENTS	7,410	5,180
DEFERRED INCOME TAXES	—	21,272
OTHER ASSETS	4,620	4,625
TOTAL ASSETS	$2,071,995	$1,883,996
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$77,876	$44,775
Revenue and royalties payable	103,250	82,300
Accrued drilling costs	57,161	60,729
Accrued interest	24,847	18,012
Other accrued liabilities	45,732	28,445
Advances for joint operations	34,528	8,069
Deferred income taxes	—	7,925
Current liabilities associated with assets held for sale	—	48,663
Liabilities of discontinued operations	10,670	—
Total current liabilities	354,064	298,918
LONG-TERM DEBT, NET OF DEBT DISCOUNT	987,074	967,808
LONG-TERM LIABILITIES ASSOCIATED WITH ASSETS HELD FOR SALE	—	23,547
LIABILITIES OF DISCONTINUED OPERATIONS	17,742	—
ASSET RETIREMENT OBLIGATIONS	6,341	4,489
DEFERRED INCOME TAXES	32,796	—
OTHER LIABILITIES	5,900	4,218
COMMITMENTS AND CONTINGENCIES		

SHAREHOLDERS’ EQUITY		
Common stock, $0.01 par value (90,000 shares authorized, 40,879 and 40,165 shares issued and outstanding as of September 30, 2013 and December 31, 2012, respectively)	409	402
Additional paid-in capital	682,479	667,096
Accumulated deficit	(14,810)	(82,482)
Total shareholders’ equity	668,078	585,016
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$2,071,995	$1,883,996

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For The Three Months Ended September 30,		For The Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per share amounts)			
OIL AND GAS REVENUES	$144,329	$96,197	$390,454	$260,730
COSTS AND EXPENSES				
Lease operating	12,934	7,145	34,926	22,599
Production tax	5,590	3,449	14,687	9,676
Ad valorem tax	2,125	2,327	6,848	8,238
Depreciation, depletion and amortization	55,234	46,518	151,232	121,459
General and administrative (inclusive of stock-based compensation expense of $9,872 and $5,091 for the three months ended September 30, 2013 and 2012, respectively, and $19,338 and $10,622 for the nine months ended September 30, 2013 and 2012, respectively)	19,715	12,354	53,722	36,974
Accretion related to asset retirement obligations	128	86	355	280
TOTAL COSTS AND EXPENSES	95,726	71,879	261,770	199,226
OPERATING INCOME	48,603	24,318	128,684	61,504
OTHER INCOME AND EXPENSES				
Gain (loss) on derivative instruments, net	(27,658)	(14,718)	(16,486)	26,975
Interest expense	(20,887)	(18,074)	(64,158)	(51,298)
Capitalized interest	7,485	5,917	21,791	17,951
Other income, net	28	20	95	254
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	7,571	(2,537)	69,926	55,386
INCOME TAX (EXPENSE) BENEFIT	(1,859)	592	(25,853)	(20,972)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$5,712	$(1,945)	$44,073	$34,414
NET INCOME (LOSS) FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(1,191)	1,015	23,599	2,583
NET INCOME (LOSS)	$4,521	$(930)	$67,672	$36,997
NET INCOME (LOSS) PER COMMON SHARE - BASIC				
Net income (loss) from continuing operations	$0.14	$(0.05)	$1.10	$0.87
Net income (loss) from discontinued operations	(0.03)	0.03	0.59	0.07
Net income (loss)	$0.11	$(0.02)	$1.69	$0.94
NET INCOME (LOSS) PER COMMON SHARE - DILUTED				
Net income (loss) from continuing operations	$0.14	$(0.05)	$1.09	$0.86
Net income (loss) from discontinued operations	(0.03)	0.03	0.58	0.07
Net income (loss)	$0.11	$(0.02)	$1.67	$0.93
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				
Basic	40,386	39,634	40,083	39,559
Diluted	40,927	39,634	40,601	39,992

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

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

	For The Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$67,672	$36,997
Net income from discontinued operations, net of income taxes	(23,599)	(2,583)
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities-		
Depreciation, depletion and amortization	151,232	121,459
Unrealized loss on derivative instruments, net	25,806	3,569
Accretion related to asset retirement obligations	355	280
Stock-based compensation, net of amounts capitalized	19,338	10,622
Allowance for doubtful accounts	(105)	(391)
Deferred income taxes	25,853	20,972
Amortization of debt discount and deferred financing costs, net of amounts capitalized	3,217	3,236
Other, net	1,894	2,646
Changes in operating assets and liabilities-		
Accounts receivable	1,910	(71,215)
Accounts payable	38,843	31,699
Accrued liabilities	2,049	23,325
Other, net	(4,212)	(3,977)
Net cash provided by operating activities - continuing operations	310,253	176,639
Net cash used in operating activities - discontinued operations	(400)	(402)
Net cash provided by operating activities	309,853	176,237
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures - oil and gas properties	(571,069)	(575,971)
Capital expenditures - other property and equipment	(687)	(3,689)
Increase (decrease) in capital expenditure payables and accruals	23,020	(14,583)
Proceeds from sales of oil and gas properties, net	20,753	207,250
Advances to operators	1,537	(852)
Advances for joint operations	26,459	(42,986)
Other, net	(3,414)	(5,389)
Net cash used in investing activities - continuing operations	(503,401)	(436,220)
Net cash provided by (used in) investing activities - discontinued operations	126,223	(29,442)
Net cash used in investing activities	(377,178)	(465,662)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings and issuances	437,000	1,036,000
Debt repayments	(419,325)	(783,000)
Payments of costs associated with revolving credit facility and debt issuance	(1,075)	(6,005)
Proceeds from stock options exercised	839	74
Net cash provided by financing activities - continuing operations	17,439	247,069
Net cash provided by financing activities - discontinued operations	3,000	28,532
Net cash provided by financing activities	20,439	275,601
NET DECREASE IN CASH AND CASH EQUIVALENTS	(46,886)	(13,824)

CASH AND CASH EQUIVALENTS, beginning of period	52,614	28,112
CASH AND CASH EQUIVALENTS, end of period	$5,728	$14,288

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 Niobrara Formation in Colorado, the Marcellus Shale in Pennsylvania, the Barnett Shale in North Texas, and the Utica Shale in Ohio.

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 all significant 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 for a fair presentation of 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 three and nine months ended September 30, 2013 are not necessarily indicative of the results to 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, 2012.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total shareholders' equity, net income, or net cash provided by or used in operating, investing or financing activities.

Discontinued Operations

On December 27, 2012, the Company agreed to sell Carrizo UK Huntington Ltd, a wholly owned subsidiary of the Company ("Carrizo UK"), and all of its interest in the Huntington Field discovery, where Carrizo UK owned a 15% non-operated working interest and certain overriding royalty interests. The sale closed on February 22, 2013. Accordingly, the Company classified the U.K. North Sea assets and associated liabilities as current and long-term assets held for sale and current and long-term liabilities associated with assets held for sale in the consolidated balance sheets as of December 31, 2012. Beginning March 31, 2013, the Company classified the remaining assets and liabilities associated with the U.K. North Sea as assets of discontinued operations and liabilities of discontinued operations in the consolidated balance sheets. The related results of operations and cash flows have been classified as discontinued operations, net of income taxes, in the consolidated statements of operations, statements of cash flows and condensed consolidating financial information. Unless otherwise indicated, the information in these notes relate to the Company's continuing operations. Information related to assets held for sale and 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 the amortization 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 timing of 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 include impairments of unproved properties, fair values of derivative instruments, stock-based compensation, collectability of receivables, disputed claims, interpretation of 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, 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 and cash equivalents include highly liquid investments with original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts

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. At September 30, 2013 and December 31, 2012, the Company’s allowance for doubtful accounts was $0.6 million and $1.4 million, respectively.

Concentration of Credit Risk

Substantially all of the Company’s accounts receivable result from oil and gas sales, joint interest billings to third-party working interest owners in the oil and gas industry or development advances to third-party operators for drilling and completion costs of wells in progress. This concentration of customers and joint interest owners 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. The Company generally has the right to offset revenue against related billings to joint interest owners.

Derivative instruments subject the Company to a concentration of credit risk. See “Note 8. Derivative Instruments” for further discussion of concentration of credit risk related to the Company’s 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. Internal costs, including payroll and stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized and totaled $3.8 million and $2.5 million for the three months ended September 30, 2013 and 2012, respectively, and $10.1 million and $9.5 million for the nine months ended September 30, 2013 and 2012, 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 rate is computed on a quarterly basis by dividing production by proved oil and gas reserves at the beginning of the quarter then applying such amount 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 depreciation, depletion and amortization (“DD&A”) per Boe was $20.01 and $19.76 for the three months ended September 30, 2013 and 2012, respectively, and $19.59 and $17.21 for the nine months ended September 30, 2013 and 2012, 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. Significant costs of unevaluated properties and exploratory wells in progress are assessed individually 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 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 capital expenditure plans. The Company expects to complete its evaluation of the majority of its unproved leasehold within the next five years and exploratory wells in progress within the next year. Individually insignificant costs of unevaluated properties 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 unevaluated leasehold and seismic costs and exploratory wells in progress of $7.5 million and $5.9 million for the three months ended September 30, 2013 and 2012, respectively, and $21.8 million and $18.0 million for the nine months ended September 30, 2013 and 2012, respectively. Interest is capitalized on the average balance of unevaluated leasehold and seismic costs and the average balance of exploratory wells in progress using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of 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. On February 22, 2013, the Company closed on the sale of Carrizo UK, which included all of the Company's proved reserves in its U.K. cost center. As a result, in the first quarter of 2013, the Company recognized a $37.3 million gain in “net income (loss) from discontinued operations, net of income taxes” in the consolidated statements of operations. Other than the sale of Carrizo UK noted above, the Company has not had any sales of oil and gas properties that significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center through September 30, 2013.

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 increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the ceiling test are calculated using the average market 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 used in the ceiling test computation 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.

Deferred Financing Costs

Deferred financing costs include legal fees, accounting fees, underwriting fees, printing costs, and other direct costs associated with the issuance of debt securities and costs associated with the revolving credit facility. The capitalized costs are amortized to interest expense, net of amounts capitalized using the effective interest method over the terms of the debt securities or credit facility.

Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, receivables, payables, derivative instruments 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 instruments are based on a third-party pricing model that uses market data obtained from third-party sources, including (a) quoted forward prices for oil and gas, (b) discount rates and (c) volatility factors. The carrying amounts of long-term debt under the Company’s revolving credit facility approximate fair value as the borrowings bear interest at variable rates of interest. The carrying amounts of the Company’s senior notes and convertible senior notes may not approximate fair value because 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 oil and gas properties require expenditures to plug and abandon wells and restore the surface after the reserves have been depleted. The asset retirement obligation is recognized as a liability at its fair value when the well is drilled with an associated increase in oil and gas property costs. Asset retirement obligations require estimates of the costs to plug and abandon wells, the costs to restore the surface, the remaining lives of wells based on oil and gas reserve estimates and future inflation rates. The obligations are discounted using a credit-adjusted risk-free interest rate which is accreted to their expected settlement values over the estimated productive lives of the oil and gas properties. Estimated costs consider historical experience, third party estimates and state regulatory requirements and do not consider salvage values. At least annually, the Company reassesses its asset retirement obligations to determine whether a change in the estimated obligation is necessary. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in estimated costs to plug and abandon wells and restore the surface and changes in the estimated remaining lives of the oil and gas properties. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement, which is included in proved oil and gas property costs.

On an interim basis, the Company reassesses the estimated cash flows underlying the obligation when indicators suggest the estimated cash flows underlying the obligation have materially changed and updates its estimated obligation if necessary.

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 the products are 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 for oil and gas revenues whereby revenue is recognized for all oil and gas 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 oil and gas reserves. Oil and gas sales volumes are not significantly different from the Company's share of production and as of September 30, 2013 and December 31, 2012, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage commodity price risk associated with a portion of its forecasted oil and gas production. Derivative instruments are recognized at their balance sheet date fair value as assets or liabilities in the consolidated balance sheets. Although the derivative instruments provide an economic hedge of the Company's exposure to commodity price risk associated with a portion of its forecasted oil and gas production, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, unrealized 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 operations. Realized gains and losses as a result of cash settlements with counterparties to the Company's derivative instruments are also recorded as gain (loss) on derivative instruments, net in the consolidated statements of operations. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty and subject to master netting agreements.

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. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades. See "Note 8. Derivative Instruments" for further discussion of the Company's derivative instruments.

Stock-Based Compensation

The Company grants stock options, stock appreciation rights ("SARs") that may be settled in cash or common stock at the option of the Company, SARs that may only be settled in cash, restricted stock awards and units to directors, employees and independent contractors. The Company recognized the following stock-based compensation expense for the periods indicated which is reflected as general and administrative expense in the consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Stock Appreciation Rights	$6,752	$1,536	$10,691	$226
Restricted Stock Awards and Units	5,232	4,598	13,551	13,179
	11,984	6,134	24,242	13,405
Less: amounts capitalized	(2,112)	(1,043)	(4,904)	(2,783)
Total Stock-Based Compensation Expense	$9,872	$5,091	$19,338	$10,622
Income Tax Benefit	$(3,627)	$(1,937)	$(7,097)	$(4,042)

Stock Options and SARs. For stock options and SARs that the Company expects to settle in common stock, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally three years). For SARs that the Company expects to settle in cash, stock-based compensation expense is based on the fair value remeasured at each reporting period, recognized over the vesting period (generally three years) and classified as other accrued 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 long-term liabilities. Subsequent to vesting, the liability for SARs that the Company expects to settle in cash is remeasured in earnings at each reporting period based on fair value until the awards are settled. The Company recognizes stock-based compensation expense over the vesting period for stock options and SARs using the straight-line method, except for awards with performance conditions, in which case the Company uses the graded vesting method. Stock options typically expire ten years after the date of grant. SARs typically expire between four and seven years after the date of grant. The Company uses the Black-Scholes-Merton option pricing model to compute the fair value of stock options and SARs.

Restricted Stock Awards and Units. For restricted stock awards and units, stock-based compensation expense is based on the grant-date fair value 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. The fair value of restricted stock awards and units is based on the price of the Company's common stock on the grant date. 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.

Income Taxes

Deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. The Company routinely assesses the realizability of its deferred tax assets and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments by taxing jurisdiction. If the Company concludes that it is more likely than not that some portion or all of the 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.

Net Income (Loss) From Continuing Operations Per Common Share

Supplemental net income (loss) from continuing operations per common share information is provided below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per share amounts)			
Net income (loss) from continuing operations	$5,712	$(1,945)	$44,073	$34,414
Basic weighted average common shares outstanding	40,386	39,634	40,083	39,559
Effect of dilutive instruments	541	—	518	433
Diluted weighted average common shares outstanding	40,927	39,634	40,601	39,992
Net income (loss) from continuing operations per common share				
Basic	$0.14	$(0.05)	$1.10	$0.87
Diluted	$0.14	$(0.05)	$1.09	$0.86

Basic net income (loss) from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) 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, stock options, SARs expected to be settled in common stock, warrants and convertible debt. The Company excludes shares related to restricted stock awards, units and stock options from the calculation of diluted weighted average shares outstanding when the grant date prices are greater than the average market prices of the common shares for the period as the effect would be antidilutive to the computation. The shares excluded for the three and nine months ended September 30, 2013 and nine months ended September 30, 2012 were not significant. The Company did not include 402,750 shares in the calculation of dilutive shares for the three months ended September 30, 2012 due to the net loss reported in the period. Shares of common stock subject to issuance upon the conversion of the Company's convertible senior notes did not have an effect on the calculation of dilutive shares for the three and nine months ended September 30, 2013 or 2012, because the conversion price was in excess of the market price of the common stock for those periods.

Recently Adopted Accounting Pronouncements

Effective January 1, 2013, the Company adopted the provisions of ASU No. 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, and began providing enhanced disclosures regarding the effect or potential effect of netting arrangements on an entity's financial position by improving information about financial instruments and derivative instruments that either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. Reporting entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The Company adopted this new disclosure requirement effective January 1, 2013. The adoption did not have a material effect on the Company's 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 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.

During the third quarter, the Company received the remaining $6.8 million of deferred consideration, which was previously presented in assets of discontinued operations in the consolidated balance sheets. The liabilities of discontinued operations of $28.4 million 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 assets and liabilities related to the sale of Carrizo UK.

The following table summarizes the amounts included in net income (loss) from discontinued operations, net of income taxes presented in the consolidated statements of operations for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
OIL AND GAS REVENUES	$—	$—	$—	$—
COSTS AND EXPENSES				
General and administrative	408	56	709	68
Accretion related to asset retirement obligations	—	104	36	258
TOTAL COST AND EXPENSES	408	160	745	326
OPERATING LOSS	(408)	(160)	(745)	(326)
OTHER INCOME AND EXPENSES				
Gain on sale of discontinued operations	—	—	37,294	—
Decrease (increase) in estimated future obligations	(1,187)	—	1,378	—
Gain (loss) on derivative instruments, net	(18)	(135)	(93)	(543)
Interest expense	—	(871)	(253)	(2,669)
Capitalized interest	—	871	253	2,669
Other income (expense), net	106	4	438	(590)
INCOME (LOSS) FROM DISCONTINUED OPERATIONS BEFORE INCOME TAXES	(1,507)	(291)	38,272	(1,459)
INCOME TAX (EXPENSE) BENEFIT	316	1,306	(14,673)	4,042
NET INCOME (LOSS) FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	$(1,191)	$1,015	$23,599	$2,583

Income Taxes

Carrizo UK is a disregarded entity for U.S. 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.

Foreign Currency

The U.S. dollar was the functional currency for the Company's operations in the U.K. North Sea. Transaction gains or losses that occurred due to the realization of assets and the settlement of liabilities denominated in a currency other than the functional currency were recorded as Other income (expense), net.

4. Property and Equipment, Net

At September 30, 2013 and December 31, 2012, property and equipment, net consisted of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
Proved oil and gas properties	$2,207,220	$1,713,827
Accumulated depreciation, depletion and amortization	(711,239)	(561,279)
Proved oil and gas properties, net	1,495,981	1,152,548
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	302,391	238,833
Exploratory wells in progress	41,926	43,803
Capitalized interest	50,974	41,052
Total unproved properties, not being amortized	395,291	323,688
Other property and equipment	16,323	17,079
Accumulated depreciation	(6,523)	(5,641)
Other property and equipment, net	9,800	11,438
Total property and equipment, net	$1,901,072	$1,487,674

Utica Shale Joint Venture. On January 15, 2013, we exercised our option for an additional 40% in the remaining properties held through our joint venture with ACP II Marcellus LLC (“ACP II”), which is also one of our joint venture partners in the Marcellus Shale, and ACP III Utica LLC (“ACP III”), both affiliates of Avista Capital Holdings, LP, a private equity firm (collectively with ACP II and ACP III, “Avista”) by paying $63.1 million. Following the option exercise, the Company elected to acquire additional properties on an equal basis with Avista. In connection with the January 2013 exercise of the Company's option to increase its participating interest in the Avista Utica joint venture properties, its right to receive distributions associated with properties owned by ACP III through “B Units” interest in ACP III that the Company acquired at the formation of the Utica joint venture was terminated.

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 specific transaction 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 rate 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 rate 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Income tax expense (benefit) at the statutory rate	$2,650	$(889)	$24,474	$19,384
State income taxes, net of U.S. federal income tax effect	(791)	334	1,275	1,421
Other, net	—	(37)	104	167
Income tax expense (benefit)	$1,859	$(592)	$25,853	$20,972

As of September 30, 2013, the Company had U.S. income tax loss carryforwards of approximately $174.4 million. The U.S. loss carryforwards expire between 2019 and 2032 if not utilized in earlier periods. The realization of the deferred tax assets related to the U.S. loss carryforwards is dependent on the Company’s ability to generate sufficient future taxable income, which the Company expects to be able to generate within the applicable carryforward periods. Accordingly, the Company believes that it is more likely than not that its deferred tax assets related to the U.S. loss carryforwards will be fully realized.

At September 30, 2013, the Company had no material uncertain tax positions and the tax years since 1999 remain open to review by federal and various state tax jurisdictions.

6. Long-Term Debt

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

	September 30, 2013	December 31, 2012
	(In thousands)	
8.625% Senior Notes	$600,000	$600,000
Unamortized discount for 8.625% Senior Notes	(4,351)	(4,849)
7.50% Senior Notes	300,000	300,000
4.375% Convertible Senior Notes	4,425	73,750
Unamortized discount for 4.375% Convertible Senior Notes	—	(1,093)
Senior Secured Revolving Credit Facility	87,000	—
	$987,074	$967,808

Convertible Senior Notes

On June 3, 2013, the Company completed a required tender offer to repurchase the 4.375% convertible senior notes due 2028, with $4.4 million aggregate principal amount of convertible senior notes remaining outstanding. The holders of the Company's remaining $4.4 million aggregate principal amount of convertible senior notes may require it to repurchase the remaining notes on June 1, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100% of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may also redeem notes at any time at a redemption price equal to 100% of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

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 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 revolving credit facility).

On October 9, 2013, a fourth amendment to the senior secured revolving credit facility (the "Fourth Amendment") was executed. The Fourth Amendment (i) extended the maturity date of the credit facility from January 27, 2016 to July 2, 2018, (ii) increased the aggregate maximum credit commitments of the lenders from $750.0 million to $1.0 billion, (iii) approved a borrowing base of $530.0 million until the closing of the sale of substantially all of the Company's Barnett Shale assets, at which time the approved borrowing base was automatically reduced to $470.0 million and such reduced borrowing base will remain in effect until redetermined or adjusted in accordance with the credit agreement governing the Company's revolving credit facility and (iv) eliminated covenants requiring the Company's maintenance of a specified Senior Debt to EBITDA ratio and a specified EBITDA to Interest Expense ratio.

As of September 30, 2013, the Company was subject to certain covenants under the terms of the revolving credit facility which include the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00; (2) a Current Ratio of not less than 1.00 to 1.00; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the revolving credit facility). As of September 30, 2013, the ratio of Total Debt to EBITDA was 2.44 to 1.00, the Current Ratio was 1.73 to 1.00, the ratio of Senior Debt to EBITDA was 0.20 to 1.00 and the ratio of EBITDA to Interest Expense was 5.02 to 1.00. Total Debt and Senior Debt, as defined in the credit agreement governing the revolving credit facility, is net of cash and cash equivalents. 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 related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

At September 30, 2013, the Company had $87.0 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 3.44%. At September 30, 2013, the Company also had $0.9 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. Upon closing of the Company's Barnett Shale assets on October 31, 2013, the borrowing base was automatically reduced to $470.0 million. Future availability under the borrowing base is subject to the terms and covenants of the revolving credit facility. The revolving credit facility is generally used to fund ongoing working capital needs and the remainder of the Company’s capital expenditure plan to the extent such amounts exceed the cash flow 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 natural 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 various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in its forward cash flows supporting its capital expenditure plan. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable commodity price. These agreements are settled in cash at termination or expiration. The Company's current strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 60 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at September 30, 2013 and December 31, 2012 was a net asset of $3.9 million and $29.2 million, respectively. The following sets forth a summary of the distribution of net fair value of the Company’s derivative instruments for each counterparty in a net asset position:

Counterparty	September 30, 2013		December 31, 2012	
Credit Suisse	57	%	40	%
Societe Generale	27	%	22	%
BNP Paribas	13	%	33	%
Regions	2	%	—	%
BBVA Compass	1	%	3	%
Wells Fargo	—	%	2	%
Total	100	%	100	%

Master netting agreements are in place with each of these counterparties. Because the counterparties are investment grade financial institutions, 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. Because Credit Suisse, Societe Generale, Regions, BBVA Compass and Wells Fargo are lenders in the Company’s revolving credit facility, the Company is not required to post collateral with respect to derivative instruments in a net liability position with these counterparties as the contracts are secured by the revolving credit facility.

The following sets forth a summary of the Company's crude oil derivative positions at average NYMEX prices as of September 30, 2013:

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)
Q4 2013	Swaps	4,000	$94.15			
	Collars	6,100	$87.75	$105.68		
FY 2014	Swaps	5,996	$92.36			
	Collars	3,000	$88.33	$104.26		
	Three-way collars	500	$85.00	$107.75	$65.00	$20.00
FY 2015	Swaps	3,250	$90.64			
	Collars	700	$90.00	$100.65		
	Three-way collars	1,000	$85.00	$105.00	$65.00	$20.00
FY 2016	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 September 30, 2013:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
Q4 2013	Swaps	55,000	$4.58	
FY 2014	Swaps	40,000	$4.07	
	Calls	10,000		$5.50
FY 2015	Swaps	10,000	$4.33	

For the three and nine months ended September 30, 2013 and 2012, the Company recorded the following related to its oil and gas derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Realized gain on derivative instruments, net	$1,313	$9,450	$9,320	$30,544
Unrealized loss on derivative instruments, net	(28,971)	(24,168)	(25,806)	(3,569)
Gain (loss) on derivative instruments, net	$(27,658)	$(14,718)	$(16,486)	$26,975

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 present the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	September 30, 2013		
Description	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Assets:			
Derivative instruments	$17,679	$(10,269)	$7,410
Liabilities:			
Derivative instruments	(13,793)	10,269	(3,524)
Total	$3,886	$—	$3,886

	December 31, 2012		
Description	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Assets:			
Derivative instruments	$36,452	$(7,291)	$29,161
Liabilities:			
Derivative instruments	(7,291)	7,291	—
Total	$29,161	$—	$29,161

The fair values of the Company's derivative instruments are based on a third-party pricing model that uses market data obtained from third-party sources, including (a) quoted forward prices for oil and gas, (b) discount rates and (c) volatility factors. The estimates of fair value 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 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 assets and liabilities for derivative instruments included in the consolidated balance sheets are presented on a net basis when such amounts are with the same counterparty and subject to master netting agreements. The derivative instruments assets are classified in fair value of derivative instruments and the derivative instruments liabilities are classified in other accrued liabilities on the consolidated balance sheets. The Company had no transfers in or out of Levels 1 or 2 for the nine months ended September 30, 2013 or 2012.

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 convertible senior notes, based on quoted market prices, as of September 30, 2013 and December 31, 2012.

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
8.625% Senior Notes	$595,649	$647,768	$595,151	$645,000
7.50% Senior Notes	300,000	316,500	300,000	308,250
4.375% Convertible Senior Notes	4,425	4,436	72,657	73,842

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 September 30, 2013 and December 31, 2012, and for the three and nine months ended September 30, 2013 and 2012 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

	September 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	$1,799,935	$182,326	$—	$(1,845,096)	$137,165
Property and equipment, net	652	1,877,367	1,624	21,429	1,901,072
Investments in subsidiaries	61,297	—	—	(61,297)	—
Other assets	51,136	—	—	(17,378)	33,758
Total assets	$1,913,020	$2,059,693	$1,624	$(1,902,342)	$2,071,995
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	$234,737	$1,952,129	$1,624	$(1,845,096)	$343,394
Current liabilities of discontinued operations	10,670	—	—	—	10,670
Long-term liabilities	993,043	46,267	—	(7,199)	1,032,111
Long-term liabilities of discontinued operations	17,742	—	—	—	17,742
Shareholders' equity (deficit)	656,828	61,297	—	(50,047)	668,078
Total liabilities and shareholders' equity	$1,913,020	$2,059,693	$1,624	$(1,902,342)	$2,071,995

	December 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	$1,689,430	$130,487	$—	$(1,613,094)	$206,823
Current assets held for sale	—	—	1,882	—	1,882
Property and equipment, net	23,041	1,443,064	—	21,569	1,487,674
Investments in subsidiaries	14,588	—	—	(14,588)	—
Long-term assets held for sale	12,670	—	119,956	—	132,626
Other assets	46,913	16,928	—	(8,850)	54,991
Total assets	$1,786,642	$1,590,479	$121,838	$(1,614,963)	$1,883,996
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	$179,221	$1,631,887	$—	$(1,560,853)	$250,255
Current liabilities associated with assets held for sale	9,880	—	38,783	—	48,663
Long-term liabilities	973,003	3,512	—	—	976,515
Long-term liabilities associated with assets held for sale	—	—	23,547	—	23,547
Shareholders' equity (deficit)	624,538	(44,920)	59,508	(54,110)	585,016
Total liabilities and shareholders' equity	$1,786,642	$1,590,479	$121,838	$(1,614,963)	$1,883,996

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME

	For the Three Months Ended September 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$2,428	$141,901	$—	$—	$144,329
Cost and expenses	20,994	74,640	—	92	95,726
Operating income (loss)	(18,566)	67,261	—	(92)	48,603
Other income (expense), net	(36,314)	(4,718)	—	—	(41,032)
Income (loss) from continuing operations before income taxes	(54,880)	62,543	—	(92)	7,571
Income tax (expense) benefit	19,208	(21,784)	—	717	(1,859)
Equity in income (loss) of subsidiaries	40,759	—	—	(40,759)	—
Net income (loss) from continuing operations	5,087	40,759	—	(40,134)	5,712
Net income from discontinued operations, net of income taxes	(1,191)	—	—	—	(1,191)
Net income (loss)	$3,896	$40,759	$—	$(40,134)	$4,521

	For the Three Months Ended September 30, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$4,459	$91,738	$—	$—	$96,197
Cost and expenses	15,256	56,135	—	488	71,879
Operating income (loss)	(10,797)	35,603	—	(488)	24,318
Other income (expense), net	(16,407)	(10,448)	—	—	(26,855)
Income (loss) from continuing operations before income taxes	(27,204)	25,155	—	(488)	(2,537)
Income tax (expense) benefit	9,531	(8,796)	—	(143)	592
Equity in income (loss) of subsidiaries	17,374	—	—	(17,374)	—
Net income (loss) from continuing operations	(299)	16,359	—	(18,005)	(1,945)
Net income from discontinued operations, net of income taxes	—	—	1,015	—	1,015
Net income (loss)	$(299)	$16,359	$1,015	$(18,005)	$(930)

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME

	For the Nine Months Ended September 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$6,075	$384,379	$—	$—	$ 390,454
Cost and expenses	57,427	204,204	—	139	261,770
Operating income (loss)	(51,352)	180,175	—	(139)	128,684
Other income (expense), net	(41,995)	(16,763)	—	—	(58,758)
Income (loss) from continuing operations before income taxes	(93,347)	163,412	—	(139)	69,926
Income tax (expense) benefit	32,671	(57,194)	—	(1,330)	(25,853)
Equity in income (loss) of subsidiaries	106,218	—	—	(106,218)	—
Net income (loss) from continuing operations	45,542	106,218	—	(107,687)	44,073
Net income from discontinued operations, net of income taxes	23,599	—	—	—	23,599
Net income (loss)	$69,141	$106,218	$—	$(107,687)	$ 67,672

	For the Nine Months Ended September 30, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$15,856	$244,874	$—	$—	$ 260,730
Cost and expenses	62,608	150,242	—	(13,624)	199,226
Operating income (loss)	(46,752)	94,632	—	13,624	61,504
Other income (expense), net	18,890	(25,008)	—	—	(6,118)
Income (loss) from continuing operations before income taxes	(27,862)	69,624	—	13,624	55,386
Income tax (expense) benefit	9,760	(24,360)	—	(6,372)	(20,972)
Equity in income (loss) of subsidiaries	47,847	—	—	(47,847)	—
Net income (loss) from continuing operations	29,745	45,264	—	(40,595)	34,414
Net income from discontinued operations, net of income taxes	—	—	2,583	—	2,583
Net income (loss)	$29,745	$45,264	$2,583	$(40,595)	$ 36,997

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Nine Months Ended September 30, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by (used in) operating activities - continuing operations	$(22,222)	$332,475	$—	$—	$ 310,253
Net cash provided by (used in) investing activities - continuing operations	(170,725)	(601,936)	(1,624)	270,884	(503,401)
Net cash provided by (used in) financing activities - continuing operations	17,439	269,260	1,624	(270,884)	17,439
Net cash provided by (used in) discontinued operations	129,342	—	(519)	—	128,823
Net increase (decrease) in cash and cash equivalents	(46,166)	(201)	(519)	—	(46,886)
Cash and cash equivalents, beginning of period	51,894	201	519	—	52,614
Cash and cash equivalents, end of period	$5,728	$—	$—	$—	$ 5,728

	For the Nine Months Ended September 30, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by operating activities - continuing operations	$31,974	$144,665	$—	$—	$ 176,639
Net cash provided by (used in) investing activities - continuing operations	(306,682)	(379,182)	—	249,644	(436,220)
Net cash provided by (used in) financing activities - continuing operations	264,344	232,369	—	(249,644)	247,069
Net cash used in discontinued operations		—	(1,312)	—	(1,312)
Net increase (decrease) in cash and cash equivalents	(10,364)	(2,148)	(1,312)	—	(13,824)
Cash and cash equivalents, beginning of period	19,134	7,263	1,715	—	28,112
Cash and cash equivalents, end of period	$8,770	$5,115	$403	$—	$ 14,288

11. Subsequent Events

During the third quarter of 2013, the Company agreed in three separate transactions to sell certain non-core assets, including substantially all of its remaining Barnett Shale assets, certain non-core assets in East Texas, and acreage in non-core areas of the Marcellus Shale, for an aggregate agreed upon sales price of $248.5 million and the assumption of certain liabilities and contractual obligations, subject to customary closing conditions and purchase price adjustments. In one of these transactions, the Company agreed to sell substantially all of its remaining Barnett Shale assets (the "Barnett Transaction") to affiliates of EnerVest Ltd. ("EnerVest") for an agreed upon purchase price of $218.0 million, subject to closing and post-closing purchase price adjustments and the assumption by EnerVest of certain liabilities and contractual obligations. The Barnett Transaction had an effective date of July 1, 2013. The Company closed the sale of its non-core East Texas assets in early September for $8.7 million. The Company closed the Barnett Transaction and the sale of its non-core Marcellus Shale assets in late October and as of October 31, 2013, the Company has received aggregate net proceeds related to these two asset sales totaling approximately $209.7 million. In addition, as a consequence of certain post-closing adjustments and holdbacks, the Company could receive up to an additional $23.8 million in cash proceeds related to such sales.

In connection with the Barnett Transaction, the Company entered into derivative instruments on behalf of EnerVest. These derivative instruments were novated to EnerVest upon the closing of the Barnett Transaction. As of September 30, 2013, these derivative instruments were in a net asset position and had a fair market value of $0.5 million.

Avista Transaction. Effective September 2011, the Company entered into a joint venture in the Utica Shale with Avista. On October 31, 2013, the Company completed the acquisition of acreage located primarily in Guernsey and Noble counties, Ohio from Avista. The transaction had an effective date of July 1, 2013, and the Company paid Avista $73.2 million in cash, subject to post-closing adjustments. The Company had an ownership in the working interest of the properties acquired through the Avista Utica Shale Joint Venture. The properties in the Avista Utica Joint Venture were held with an equal interest by the Company and Avista. The agreement provides for post-closing price and acreage adjustments and indemnities.

In connection with the Avista Transaction, the Company terminated the previously existing Avista Utica Shale Joint Venture agreements. After giving effect to the Avista Transaction, the Company and Avista remain working interest partners in the Utica Shale with the Company acting as the operator of the jointly owned properties which are now subject to standard joint operating agreements. The Company and Avista have established a new area of mutual interest that has been significantly reduced in coverage area and now applies only to certain of those areas in which the Company and Avista jointly own properties.

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 “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, 2012, and the unaudited consolidated financial statements included in this quarterly report.

Overview

Our third quarter 2013 included oil and gas revenues of $144.3 million and production of 2.8 MMBoe. The key drivers affecting our results for the three months ended September 30, 2013 included the following:

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

	For the Three Months Ended September 30, 2013				As of September 30, 2013				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	19	14.7	11	8.6	32	24.1	106	83.3	3
Niobrara	15	4.7	14	4.7	8	2.3	64	25.2	2
Marcellus	6	1.8	5	1.7	26	8.0	54	18.4	1
Barnett	—	—	—	—	—	—	86	55.9	—
Total	40	21.2	30	15.0	66	34.4	310	182.8	6

Production. Our third quarter 2013 production of 2.8 MMBoe increased 17% from the third quarter 2012 production of 2.4 MMBoe. The increase in production from the third quarter of 2012 to the third quarter of 2013 was primarily due to increased production from new wells, partially offset by normal production decline and the impact of the sale of a portion of our working interest in connection with entering into our Niobrara joint venture transactions in the fourth quarter of 2012.

Commodity prices. Our average realized oil price during the third quarter of 2013 was $104.71 per barrel, or 8% higher compared to $96.66 for the third quarter of 2012. Our average realized natural gas price during the third quarter of 2013 was $2.38 per Mcf, or 24% higher than the $1.92 during the third quarter of 2012. Although natural gas prices have increased compared to the same period in 2012, the overall market for natural gas remains challenging, making the current market and outlook, and therefore the expenditure of capital, for crude oil more attractive. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Commodity prices are beyond our control and have been and are expected to remain volatile.

Recent Developments. During the third quarter of 2013, we agreed in three separate transactions to sell certain non-core assets, including substantially all of our remaining Barnett Shale assets, certain non-core assets in East Texas, and acreage in non-core areas of the Marcellus Shale, for an aggregate agreed upon sales price of $248.5 million and the assumption of certain liabilities and contractual obligations, subject to customary closing conditions and purchase price adjustments. In one of these transactions, we agreed to sell substantially all of our remaining Barnett Shale assets (the "Barnett Transaction") to affiliates of EnerVest Ltd. ("EnerVest") for an agreed upon purchase price of $218.0 million subject to closing and post-closing purchase price adjustments and the assumption of certain liabilities and contractual obligations. The Barnett Transaction had an effective date of July 1, 2013. We closed the sale of our non-core East Texas assets in early September for $8.7 million. We closed the Barnett Transaction and the sale of our non-core Marcellus Shale assets in late October and as of October 31, 2013, we had received aggregate net proceeds related to these two asset sales totaling approximately $209.7 million. In addition, as a consequence of certain post-closing adjustments and holdbacks, we could receive up to an additional $23.8 million in cash proceeds related to such sales. We intend to use the net proceeds from these two sale transactions to repay borrowings under our revolving credit facility, initially fund the Avista Transaction described below and to partially fund the remainder of our 2013 capital expenditures plan.

We currently expect that the Barnett Transaction will result in a loss on the sale in the fourth quarter of 2013 as the proved reserves attributable to the Barnett Transaction represent 40% of the Company's proved reserves as of September 30, 2013 and therefore the sale is expected to significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to our U.S. cost center. Additionally, we currently anticipate that the Barnett Transaction will result in an increase in our future depreciation, depletion and amortization rate, and therefore will negatively affect our future reported earnings.

On October 31, 2013, we completed the acquisition of approximately 5,900 net acres located primarily in Guernsey and Noble counties, Ohio from Avista (the “Avista Transaction”). The transaction had an effective date of July 1, 2013, and the Company paid Avista approximately $73.2 million in cash, subject to post-closing adjustments. We had an ownership in the working interest of the properties acquired through the Avista Utica Joint Venture. The properties in the Avista Utica Joint Venture were held with an equal interest by the Company and Avista. The Avista Transaction was funded with proceeds from the sale of substantially all of our remaining properties in the Barnett Shale. The agreement provides for post-closing price and acreage adjustments and indemnities.

Results of Operations

Three Months Ended September 30, 2013, Compared to the Three Months Ended September 30, 2012

Revenues from oil and gas production for the three months ended September 30, 2013 increased 50% to $144.3 million from $96.2 million for the same period in 2012 primarily due to the significant increase in oil production and oil and gas prices. Production volumes for the three months ended September 30, 2013 and 2012 were 2.8 MMBoe and 2.4 MMBoe, respectively. The increase in production from the third quarter of 2012 to the third quarter of 2013 was primarily due to increased production from new wells, partially offset by normal production decline and our Niobrara joint venture transactions in the fourth quarter of 2012. Average realized oil prices increased 8% to $104.71 per barrel from $96.66 per barrel in the same period in 2012. Average realized gas prices increased 24% to $2.38 per Mcf in the third quarter of 2013 from $1.92 per Mcf in the same period in 2012.

The following table summarizes production volumes, average realized prices and oil and gas revenues for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		2013 Period Compared to 2012 Period	
	2013	2012	Increase (Decrease)	% Increase (Decrease)
Production volumes -				
Crude oil (MBbls)	1,125	796	329	41 %
NGLs (MBbls)	202	78	124	159 %
Natural gas (MMcf)	8,603	8,877	(274)	(3)%
Total Natural gas and NGLs (MMcfe)	9,815	9,345	470	5 %
Total barrels of oil equivalent (MBoe)	2,761	2,354	407	17 %
Daily production volumes by product -				
Crude oil (Bbls/d)	12,228	8,652	3,576	41 %
NGLs (Bbls/d)	2,196	848	1,348	159 %
Natural gas (Mcf/d)	93,511	96,489	(2,978)	(3)%
Total Natural gas and NGLs (Mcfe/d)	106,685	101,576	5,109	5 %
Total barrels of oil equivalent (Boe/d)	30,011	25,587	4,424	17 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	13,960	8,583	5,377	63 %
Niobrara	2,061	1,715	346	20 %
Barnett	7,609	9,805	(2,196)	(22)%
Marcellus	6,069	4,271	1,798	42 %
Other	312	1,213	(901)	(74)%
Total barrels of oil equivalent (Boe/d)	30,011	25,587	4,424	17 %
Average realized prices -				
Crude oil ($ per Bbl)	$104.71	$96.66	$8.05	8 %
NGLs ($ per Bbl)	29.83	28.53	1.30	5 %
Natural gas ($ per Mcf)	2.38	1.92	0.46	24 %
Total Natural gas and NGLs average realized price ($ per Mcfe)	$2.70	$2.06	$0.64	31 %
Total average realized price ($ per Boe)	$52.27	$40.87	$11.40	28 %
Oil and gas revenues (In thousands) -				
Crude oil	$117,797	$76,945	$40,852	53 %
NGLs	6,025	2,225	3,800	171 %
Natural gas	20,507	17,027	3,480	20 %
Total oil and gas revenues	$144,329	$96,197	$48,132	50 %

Lease operating expenses were $12.9 million ($4.68 per Boe) for the three months ended September 30, 2013 as compared to lease operating expenses of $7.1 million ($3.04 per Boe) for the same period in 2012. The $5.8 million increase in lease operating expenses is primarily due to increased production from new wells. The increase in operating cost per Boe is primarily due to the higher operating cost per Boe associated with the increased oil production.

Production taxes were $5.6 million (or 3.9% of oil and gas revenues) for the three months ended September 30, 2013 as compared to $3.4 million (or 3.6% of oil and gas revenues) for the same period in 2012. The increase in production taxes is due primarily to increased oil production. The increase in production taxes as a percentage of oil and gas revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

Depreciation, depletion and amortization (“DD&A”) expense for the third quarter of 2013 increased $8.7 million to $55.2 million ($20.01 per Boe) from the DD&A expense for the third quarter of 2012 of $46.5 million ($19.76 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 significant increases in crude oil reserves in the Eagle Ford that were added throughout 2012, which have a higher finding cost per Boe than our natural gas reserves.

General and administrative expense increased to $19.7 million for the three months ended September 30, 2013 from $12.4 million for the corresponding period in 2012. The increase was primarily due to an increase in personnel during the third quarter of 2013 as compared to the same period of 2012 as well as increased stock-based compensation expense which was primarily driven by an increase in the fair value of stock appreciation rights.

The net loss on derivative instruments of $27.7 million in the third quarter of 2013 consisted of a $29.0 million unrealized loss on derivatives and a $1.3 million realized gain on derivatives. The net loss on derivative instruments of $14.7 million in the third quarter of 2012 was comprised of a $24.2 million unrealized loss on derivatives and a $9.5 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended September 30, 2013 were $20.9 million and $7.5 million, respectively, as compared to $18.1 million and $5.9 million, respectively, for the same period in 2012. The increase in interest expense was primarily due to interest on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued late in the third quarter of 2012 partially offset by the repurchase of the 4.375% convertible senior notes during the second quarter of 2013.

The estimated annual effective income tax rates for 2013 and 2012 were 36.7%, and 38.1%, respectively. The effective income tax rate for the third quarter of 2013 was 24.6% which was lower than the expected tax rate due to changes in current year state tax estimates. The effective income tax rate for the third quarter 2012 was 23.3% which was lower than the expected tax rate due to the pre-tax loss impact on state tax estimates.

Nine Months Ended September 30, 2013, Compared to the Nine Months Ended September 30, 2012

Revenues from oil and gas production for the nine months ended September 30, 2013 increased 50% to $390.5 million from $260.7 million for the same period in 2012 primarily due to a significant increase in oil production and gas prices. Production volumes for the nine months ended September 30, 2013 and 2012 were 7.7 MMBoe and 7.1 MMBoe, respectively. The increase in production from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 was primarily due to increased production from new wells, partially offset by normal production decline, the sale of a significant portion of our remaining Barnett Shale properties to Atlas Resource Partners, L.P. (“Atlas”), and our Niobrara joint venture transactions in the fourth quarter of 2012. Average realized oil prices increased 2% to $102.60 per barrel from $100.93 per barrel in the same period in 2012. Average realized gas prices increased 55% to $2.64 per Mcf for the nine months ended September 30, 2013 from $1.70 per Mcf in the same period in 2012.

The following table summarizes production volumes, average realized prices and oil and gas revenues for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,		2013 Period Compared to 2012 Period	
	2013	2012	Increase (Decrease)	% Increase (Decrease)
Production volumes -				
Crude oil (MBbls)	3,032	2,030	1,002	49 %
NGLs (MBbls)	408	191	217	114 %
Natural gas (MMcf)	25,680	29,011	(3,331)	(11)%
Total Natural gas and NGLs (MMcfe)	28,128	30,157	(2,029)	(7)%
Total barrels of oil equivalent (MBoe)	7,720	7,056	664	9 %
Daily production volumes by product -				
Crude oil (Bbls/d)	11,106	7,409	3,697	50 %
NGLs (Bbls/d)	1,495	697	798	114 %
Natural gas (Mcf/d)	94,066	105,880	(11,814)	(11)%
Total Natural gas and NGLs (Mcfe/d)	103,033	110,062	(7,029)	(6)%
Total barrels of oil equivalent (Boe/d)	28,278	25,752	2,526	10 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	12,184	7,277	4,907	67 %
Niobrara	1,621	1,229	392	32 %
Barnett	8,131	12,617	(4,486)	(36)%
Marcellus	6,016	3,164	2,852	90 %
Other	326	1,465	(1,139)	(78)%
Total barrels of oil equivalent (Boe/d)	28,278	25,752	2,526	10 %
Average realized prices -				
Crude oil ($ per Bbl)	$102.60	$100.93	$1.67	2 %
NGLs ($ per Bbl)	28.26	34.88	(6.62)	(19)%
Natural gas ($ per Mcf)	2.64	1.70	0.94	55 %
Total Natural gas and NGLs average realized price ($ per Mcfe)	$2.82	$1.85	$0.97	52 %
Total average realized price ($ per Boe)	$50.58	$36.95	$13.63	37 %
Oil and gas revenues (In thousands) -				
Crude oil	$311,084	$204,890	$106,194	52 %
NGLs	11,532	6,662	4,870	73 %

Natural gas	67,838	49,178	18,660	38	%
Total oil and gas revenues	$390,454	$260,730	$129,724	50	%

Lease operating expenses were $34.9 million ($4.52 per Boe) for the nine months ended September 30, 2013 as compared to lease operating expenses of $22.6 million ($3.20 per Boe) for the same period in 2012. The $12.3 million increase in lease

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operating expenses is primarily due to increased production from new wells partially offset by the sale to Atlas. The increase in operating cost per Boe is primarily due to the higher operating cost per Boe associated with the increased oil production.

Production taxes were $14.7 million (or 3.8% of oil and gas revenues) for the nine months ended September 30, 2013 as compared to $9.7 million (or 3.7% of oil and gas revenues) for the same period in 2012. The increase in production taxes is due primarily to increased oil production. The increase in production taxes as a percentage of oil and gas revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

Ad valorem taxes decreased to $6.8 million ($0.89 per Boe) for the nine months ended September 30, 2013 from $8.2 million ($1.17 per Boe) for the same period in 2012. The decrease in ad valorem taxes is due primarily to the sale of Barnett properties to Atlas and the Commonwealth of Pennsylvania's February 2012 enactment of an “impact fee” on the drilling of unconventional natural gas wells recognized in the first quarter of 2012, partially offset by an increase in ad valorem taxes for new wells drilled in 2012. Because of the retroactive nature of the impact fee, approximately $1.0 million of the impact fee recognized during the first half of 2012 was attributable to wells drilled prior to 2012.

DD&A expense for the nine months ended September 30, 2013 increased $29.7 million to $151.2 million ($19.59 per Boe) from the DD&A expense for the nine months ended September 30, 2012 of $121.5 million ($17.21 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 Atlas sale as well as the significant increase in crude oil reserves in the Eagle Ford that were added throughout 2012, which have a higher finding cost per Boe than our natural gas reserves.

General and administrative expense increased to $53.7 million for the nine months ended September 30, 2013 from $37.0 million for the corresponding period in 2012. The increase was primarily due to an increase in personnel during the second quarter of 2013 as compared to the same period of 2012 and increased stock-based compensation expense which was primarily driven by an increase in the fair value of stock appreciation rights.

The net loss on derivative instruments of $16.5 million in the nine months ended September 30, 2013 consisted of a $25.8 million unrealized loss on derivatives and a $9.3 million realized gain on derivatives. The net gain on derivative instruments of $27.0 million in the nine months ended September 30, 2012 was comprised of a $3.6 million unrealized loss on derivatives and a $30.5 million realized gain on derivatives.

Interest expense and capitalized interest for the nine months ended September 30, 2013 were $64.2 million and $21.8 million, respectively, as compared to $51.3 million and $18.0 million, respectively, for the same period in 2012. The increase in interest expense was primarily due to interest on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued late in the third quarter of 2012 partially offset by a decrease in interest expense attributable to reduced borrowings under our revolving credit facility and the repurchase of the 4.375% convertible senior notes during the second quarter of 2013.

The estimated annual effective tax rates for 2013 and 2012 were 36.7% and 38.1%, respectively. The effective income tax rates for the nine months ended September 30, 2013 and 2012 were 37.0% and 37.9%, respectively. The effective income tax rate for the nine months ended September 30, 2013 was higher than the estimated annual effective tax rate due to change in state tax estimates. The effective tax rate for the nine months ended September 30, 2012 was lower than the estimated annual effective tax rate due to change in state tax estimates.

Included in net income of $67.7 million for the nine months ended September 30, 2013 was $23.6 million, net of income taxes, related to the sale of Carrizo UK Huntington Ltd (“Carrizo UK”), which is included in net income from discontinued operations, net of income taxes in the accompanying consolidated statements of operations.

Liquidity and Capital Resources

Capital Expenditures Plan and Funding Strategy. The 2013 capital expenditures plan currently includes $550.0 to $560.0 million for drilling and completion and $240 million for leasehold and seismic. We intend to finance the remainder of our 2013 capital expenditures plan primarily from the sources described below under "—Sources and Uses of Cash." Our capital expenditures plan could vary depending upon various factors, including the availability and cost of drilling rigs and completion services, land and industry partner issues, our available cash flow and financing, success of drilling and completion 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 September 30, 2013:

	Capital Expenditures for the Three Months Ended			Year to Date
	March 31, 2013	June 30, 2013	September 30, 2013	September 30, 2013
	(In thousands)			
Eagle Ford	$101,735	$88,210	$96,992	$286,937
Marcellus	18,888	19,459	9,840	48,187
Niobrara	11,817	22,106	13,461	47,384
Barnett and Other	4,257	3,460	6,246	13,963
Total drilling and completion	136,697	133,235	126,539	396,471
Total leasehold and seismic	89,274	30,182	26,348	145,804
Total	$225,971	$163,417	$152,887	$542,275

The capital expenditures presented above exclude capitalized interest, capitalized overhead and asset retirement obligations.

For 2014, our expected capital expenditures plan (which remains subject to our Board's approval) is $600.0 to $620.0 million for drilling and completion and $75 million for leasehold and seismic.

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 programs. In addition, on October 31, 2013, we completed the acquisition of acreage located in Ohio from Avista, for a purchase price of approximately $73.2 million in cash, including closing adjustments and reimbursements of certain past costs. For the nine months ended September 30, 2013, we funded our capital expenditures with cash provided by operations, cash on hand, net proceeds from the sale of assets, including the sales of non-core assets, 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 and market conditions for oilfield services. We hedge a portion of our forecasted production to mitigate the risk of a decline in oil and gas prices.
- Revolving credit facility. As of November 1, 2013, we had no borrowings outstanding and $0.9 million in letters of credit outstanding under the revolving credit facility, which reduce the amounts available under the revolving credit facility. The amount we are able to borrow with respect to the borrowing base of the revolving credit facility is subject to compliance with, and limited by, the financial covenants and other provisions of the credit agreement governing our revolving credit facility.
- Asset sales. In order to fund our capital expenditures plan, we may consider the sale of certain properties or assets, provided we are able to sell such assets on terms that are acceptable to us. During the third quarter of 2013, we agreed in three separate transactions to sell certain non-core assets, including substantially all of our remaining Barnett Shale assets, certain non-core assets in East Texas, and acreage in non-core areas of the Marcellus Shale, for an aggregate agreed upon sale price of $248.5 million and the assumption of certain liabilities and contractual obligations, subject to customary closing conditions and purchase price adjustments. As of November 1, 2013, we have received aggregate net proceeds related to the three separate transactions of approximately $218.4 million. In addition, as a consequence of certain post-closing adjustments and holdbacks, we could receive up to an additional $23.8 million in cash proceeds related to such sales.

- 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 including those 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.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations were $310.3 million and $176.6 million for the nine months ended September 30, 2013 and 2012, respectively. The increase was primarily due to increased crude oil production and gas prices in the first nine months of 2013 as compared to the same period in 2012.

Net cash used in investing activities from continuing operations were $503.4 million and $436.2 million for the nine months ended September 30, 2013 and 2012, respectively. The increase related primarily to lower proceeds received from sales of oil and gas properties in the first nine months of 2013 as compared to the same period in 2012.

Net cash provided by financing activities from continuing operations were $17.4 million and $247.1 million for the nine months ended September 30, 2013 and 2012, respectively. The decrease related primarily to the proceeds from the issuance of $300.0 million of 7.50% Senior Notes in September 2012.

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, proceeds from the sale of assets, carry resulting from our Niobrara joint venture transactions and borrowings under our revolving credit facility will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities from continuing operations 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 that will support our capital expenditures plan, we hedge a portion of our forecasted production and, as of September 30, 2013, we had hedged approximately 55,000 MMBtu/d of natural gas for the remainder of 2013. Additionally, we had hedged approximately 10,100 Bbls/d of oil for the remainder of 2013. Our borrowing base under our revolving credit facility is $470.0 million as of October 31, 2013. As of November 1, 2013, we had no borrowings outstanding under our revolving credit facility and had issued $0.9 million in letters of credit, which reduce the amounts available under our revolving credit facility. 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. Upon closing of the sale of Barnett Shale assets on October 31, 2013, the borrowing base was automatically reduced to $470.0 million. The next borrowing base redetermination is scheduled to occur in the Spring of 2014.

If cash provided by operating activities from continuing operations, proceeds from asset sales, funds available 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 2013 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 planned 2013 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 internally generated cash flows, proceeds from asset sales 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 September 30, 2013 (in thousands):

	2013	2014	2015	2016	2017	2018 and Beyond	Total
Long-term debt (1)	$—	$—	$—	$87,000	$—	$904,425	$991,425
Interest on long-term debt (2)	26,737	77,441	77,441	74,663	74,444	119,331	450,057
Operating leases	435	1,846	1,792	1,770	1,770	7,964	15,577
Drilling and completion services (3)	25,099	37,325	9,892	1,165	—	—	73,481
Pipeline volume commitments (3)	3,616	13,406	13,294	7,735	2,941	12,850	53,842
Asset retirement obligations and other (4)	2,230	11,902	8,787	4,212	1,743	6,505	35,379
Total Contractual Obligations (5)	$58,117	$141,920	$111,206	$176,545	$80,898	$1,051,075	$1,619,761

(1) At September 30, 2013, we had $87.0 million of borrowings outstanding under the revolving credit facility which matures in 2016. On October 9, 2013 the credit facility was amended to extend the maturity date from 2016 to 2018.

(2) Interest on long-term debt is based on the 8.625% Senior Notes, the 7.50% Senior Notes, 4.375% Convertible Senior Notes, and our revolving credit facility average interest rate of 3.44%.

(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 September 30, 2013. 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.

(5) As a result of the non-core assets sales in October 2013, certain of the contractual obligations as of September 30, 2013 presented in the table above were reduced by an estimated $16.7 million as these obligations were assumed by the purchasers of such assets.

Financing Arrangements

Convertible Senior Notes

In May 2008, we issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028. These notes are convertible, using a net share settlement process, into a combination of cash and common stock that entitles holders of our convertible senior notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of our conversion obligation in excess of such principal amount. On June 3, 2013, we completed a tender offer to repurchase the convertible senior notes, with $4.4 million aggregate principal amount of convertible senior notes remaining outstanding. As of September 30, 2013, $4.4 million aggregate principal amount of convertible senior notes remained outstanding.

The holders of our remaining $4.4 million aggregate principal amount of convertible senior notes may require us to repurchase the remaining notes on June 1, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100% of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. We may also redeem notes at any time at a redemption price equal to 100% of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any. We currently have no intention to redeem the remaining convertible senior notes prior to June 1, 2018.

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 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 (as defined under our revolving credit facility) will be required to guarantee our obligations under our revolving credit facility.

On October 9, 2013, a fourth amendment to the senior secured revolving credit facility (the "Fourth Amendment") was executed. The Fourth Amendment (i) extended the maturity date of the credit facility from January 27, 2016 to July 2, 2018, (ii) increased the aggregate maximum credit commitments of the lenders from $750.0 million to $1.0 billion (subject to availability under the borrowing base),and (iii) approved a borrowing base of $530.0 million until the closing of the sale of substantially all of our Barnett Shale assets, at which time the approved borrowing base availability was automatically reduced to $470.0 million and such reduced borrowing base will remain in effect until redetermined or adjusted in accordance with the credit agreement governing our revolving credit facility and (iv) eliminated covenants requiring the Company's maintenance of a specified Senior Debt to EBITDA ratio and a specified EBITDA to Interest Expense ratio. The borrowing base will be redetermined by the lenders at least semi-annually, generally on each May 1 and November 1, with the next redetermination expected in Spring 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.

In addition, pursuant to the Fourth Amendment, the annual interest rate on each base rate borrowing has been decreased to (a) the greatest of the Agent's Prime Rate, the Federal Funds Effective Rate plus 0.5% and the adjusted LIBO Rate for a three-month interest period on such day plus 1.00%, plus (b) a margin between 0.50% and 1.50% (depending on the then-current level of borrowing base usage). The interest rate on each Eurodollar loan has been decreased to the adjusted LIBO Rate for the applicable interest period plus a margin between 1.50% and 2.50% (depending on the then-current level of borrowing base usage). As of September 30, 2013, 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: (1) a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00; (2) a Current Ratio of not less than 1.00 to 1.00; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the revolving credit facility). As of September 30, 2013, the ratio of Total Debt to EBITDA was 2.44 to 1.00, the Current Ratio was 1.73 to 1.00, the ratio of Senior Debt to EBITDA was 0.20 to 1.00 and the ratio of EBITDA to Interest Expense was 5.02 to 1.00. Total Debt and Senior Debt, as defined in the credit agreement governing the revolving credit facility, are net of cash and cash equivalents.

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).

At September 30, 2013, we had $87.0 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 3.44%. At September 30, 2013, we had $0.9 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. Upon closing of the sale of Barnett Shale assets, the borrowing base was automatically reduced to $470.0 million. Future availability under the borrowing base is subject to the terms and covenants of the revolving credit facility. The revolving credit facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties 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 consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from the estimates. These policies and estimates are described in our Annual Report on Form 10-K for the year ended December 31, 2012. 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.

The table below presents results of the U.S. full cost ceiling test along with various pricing scenarios to demonstrate the sensitivity of our full cost ceiling test to changes in 12 month average oil and gas prices. The prices included represent the unweighted average market prices for sales of oil and gas on the first calendar day of each month during the 12-month period ended September 30, 2013. This sensitivity analysis is as of September 30, 2013 and, accordingly, does not consider drilling results, production and prices subsequent to September 30, 2013 that may require revisions to our proved reserve estimates.

	12 Month Average		Cushion/(Impairment)	Increase/(Decrease) from Cushion
U.S. Full Cost Pool Scenarios	Oil Price ($/Bbl)	Gas Price ($/Mcf)	(in millions)	(in millions)
September 30, 2013 Actual	$102.66	$2.80	$217	$—
Oil and Gas Price Sensitivity				
Oil and Gas +10%	$112.16	$3.15	$402	$185
Oil and Gas -10%	$93.16	$2.44	$32	$(185)
Oil Price Sensitivity				
Oil +10%	$112.16	$2.80	$356	$139
Oil -10%	$93.16	$2.80	$78	$(139)
Gas Price Sensitivity				
Gas +10%	$102.66	$3.15	$263	$46
Gas -10%	$102.66	$2.44	$171	$(46)

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, 2012.

We use various types of derivative instruments to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure plan. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination or expiration. Our current strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 60 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at September 30, 2013 and December 31, 2012 was a net asset of $3.9 million and $29.2 million, respectively. The following sets forth a summary of the distribution of net fair value of our derivative instruments for each counterparty in a net asset position:

Counterparty	September 30, 2013		December 31, 2012	
Credit Suisse	57	%	40	%
Societe Generale	27	%	22	%
BNP Paribas	13	%	33	%
Regions	2	%	—	%
BBVA Compass	1	%	3	%
Wells Fargo	—	%	2	%
Total	100	%	98	%

Master netting agreements are in place with each of these counterparties. Because the counterparties are investment grade financial institutions, 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. Because Credit Suisse, Wells Fargo, Societe Generale, Regions and BBVA Compass are lenders under our revolving credit facility, we are not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties, as the contracts are secured by our revolving credit facility.

The following sets forth a summary of our crude oil derivative positions at average NYMEX prices as of September 30, 2013:

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)
Q4 2013	Swaps	4,000	$94.15			
	Collars	6,100	$87.75	$105.68		
FY 2014	Swaps	5,996	$92.36			
	Collars	3,000	$88.33	$104.26		
	Three-way collars	500	$85.00	$107.75	$65.00	$20.00
FY 2015	Swaps	3,250	$90.64			
	Collars	700	$90.00	$100.65		
	Three-way collars	1,000	$85.00	$105.00	$65.00	$20.00
FY 2016	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 September 30, 2013:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
Q4 2013	Swaps	55,000	$4.58	
FY 2014	Swaps	40,000	$4.07	
	Calls	10,000		$5.50
FY 2015	Swaps	10,000	$4.33	

For the three and nine months ended September 30, 2013 and 2012, we recorded the following related to our oil and gas derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Realized gain on derivative instruments, net	$1,313	$9,450	$9,320	$30,544
Unrealized loss on derivative instruments, net	(28,971)	(24,168)	(25,806)	(3,569)
Gain (loss) on derivative instruments, net	$(27,658)	$(14,718)	$(16,486)	$26,975

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 “Risk Factors” and other sections of our Annual Report on Form 10-K for the year ended December 31, 2012 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, 2012. 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, 2012.

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 September 30, 2013 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 September 30, 2013 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, 2012.

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
Avista Utica Shale Joint Venture. Effective September 2011, the Company's wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture in the Utica Shale with ACP II Marcellus LLC (“ACP II”), and ACP III Utica LLC (“ACP III”), both affiliates of Avista Capital Partners, LP, a private equity fund (Avista Capital Partners, LP together with its affiliates, “Avista”). Under the terms of this Utica Shale joint venture, the Company and Avista had the right to contribute cash and properties to acquire and develop acreage in the Utica Shale play.
ACP II is also the Company’s joint venture partner in the Marcellus Shale. In connection with its Avista Marcellus joint venture, the Company was issued in 2008, “B Units” in ACP II that entitled the Company to increasing percentages of ACP II’s distributions to Avista if specified internal rates of return and return on investment thresholds with respect to Avista’s investment in ACP II were achieved.
The Avista Utica joint venture agreements established an area of mutual interest between the Company and Avista and provided the Company options on specified categories of properties to increase its participating interest in such properties to equal Avista’s. Under the joint venture agreements, the Company served as operator of the Avista Utica joint venture properties and agreed to provide certain management services to Avista related to the Utica joint venture. Avista or its designee has the right to become a co-operator of the joint venture properties if (i) Avista sells substantially all of its interests in the Avista Utica joint venture properties or (ii) the Company default under the terms of any pledge of its interest in the Avista Utica joint venture properties. Additionally, the Company’s “B Unit” interest in ACP II incorporated ACP II’s interests in the Avista Utica joint venture, and the Company was granted similar “B Units” in ACP III.
In October 2012, the Company sold substantially all of its interests in oil and gas properties dedicated to the Avista Utica joint venture in the northern portion of the Utica Shale play to a third party. Simultaneously with the closing of this Utica Shale transaction, Avista sold substantially all of its interests in the same oil and gas properties. In connection with these sale transactions, the Company elected to exercise its option to increase its participating interest in the same oil and gas properties on a “net proceeds basis” so that the Company received net proceeds with respect to 50% of the properties subject to the sale rather than the 10% the Company initially held. Pursuant to the terms of the Avista Utica joint venture agreement, as amended, the Company paid $24.0 million for the 40% additional interest in the acreage subject to the sale and certain other Avista Utica joint venture properties. Therefore, effective as of the closing, both parties owned the joint venture properties equally and both parties shared equally in their right to receive the proceeds from the purchaser. As a result of the reduction required for the $24.0 million option exercise price due from the Company and the repayment of other amounts owed between the two joint venture parties, the net proceeds received by the Company from the sale was $51.7 million and the net proceeds received by Avista from the sale was $72.9 million. Concurrently with the exercise and closing of the Company's option to increase its participating interest in such oil and gas properties, its right to receive distributions associated with properties owned by ACP II in the Avista Utica joint venture through “B Units” interest in ACP II was terminated.
Following the sale transactions described above, on October 24, 2012, the Company and Avista amended the Utica Shale joint venture agreements to provide that the expiration date of its remaining option to increase its participating interest in the Avista Utica joint venture properties was accelerated from March 2013 to January 15, 2013. The Company exercised this option on January 15, 2013 by paying $63.1 million for an additional 40% interest in approximately 11,000 acres pursuant to the terms of the Avista Utica joint venture agreement. The Company and Avista also agreed that after the option was exercised, the Company’s participating interest in subsequently acquired properties within the area of mutual interest continued to be 10% and Avista’s participating interest continued to be 90%, and the Company was granted an additional option to increase its 10% ownership in such subsequently acquired properties to 50% at 8.625% above acreage cost and associated improvements (compounded monthly following Avista’s contribution of purchase proceeds). Instead of exercising this option, the Company and Avista agreed that the Company could instead elect to acquire additional properties on an equal basis with Avista. In connection with the January 2013 exercise of the Company's option to increase its participating interest in the Avista Utica joint venture

properties, its right to receive distributions associated with properties owned by ACP III through “B Units” interest in ACP III that the Company acquired at the formation of the Utica joint venture was terminated.

The area of mutual interest for the Utica joint venture, consisting of the portions of the State of Ohio that are prospective for Utica Shale exploration, was to have remained in place until the earliest to occur of the following events, at which time the area of mutual interest would only continue to apply to those areas where the joint venture is active: (i) September 1, 2014, (ii) ACP III’s investment reaches $170.0 million and Avista declines to participate in specified Utica acquisitions or other specified conditions are met, (iii) upon ACP II's or ACP III's request to be designated (or have its designee designated) as a co-operator of the properties, (iv) upon the Company's required designation of ACP II or ACP III (or either's designee) as a co-operator of the applicable properties in connection with a default by the Company under the terms of any pledge of its interest in the Utica joint venture properties, (v) the sale by Avista of substantially all of its interest in the Utica joint venture properties or (vi) termination of the ACP III management services agreement. Each party's ability to transfer its interest in the Utica joint venture to third parties was generally subject to "tag along" rights. Avista's tag along rights did not apply upon a change of control of the Company.

Avista Transaction. On October 31, 2013, the Company completed the acquisition of approximately 5,900 net acres located primarily in Guernsey and Noble counties, Ohio from Avista (the "Avista Transaction"). The transaction had an effective date of July 1, 2013, and the Company paid Avista approximately $73.2 million in cash, subject to post-closing adjustments. The Company had an ownership in the working interest of the properties acquired through the Utica Joint Venture. The properties in the Utica Joint Venture were held on an equal basis by the Company and Avista. The agreement provides for post-closing price and acreage adjustments and indemnities. The Avista Transaction was initially funded with proceeds from the sale of substantially all of our remaining properties in the Barnett Shale as disclosed below.

In connection with the Avista Transaction, the Company terminated the Utica Shale Joint Venture agreements described above. After giving effect to the Avista Transaction, the Company and Avista remain working interest partners in approximately 10,000 acres in the Utica Shale net to the Company with the Company acting as the operator of the jointly owned properties which are now subject to standard joint operating agreements. The Company has established a new area of mutual interest that has been significantly reduced in coverage area and now applies only to certain of those areas in which the Company and Avista jointly own properties.

Carrizo Relationship with Avista. Steven A. Webster, Chairman of the Company's Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which entity has the ability to control Avista and its affiliates. As previously disclosed, the Company has been a party to prior arrangements with affiliates of Avista Capital Holdings LP.

The terms of the joint ventures with Avista in the Utica Shale and the Marcellus Shale as well as the Avista Transaction and the other acquisition transactions described above with Avista were approved by a special committee of the Company's disinterested directors. In determining whether to approve or disapprove a transaction, such special committee has in the Avista Transaction and generally in other transactions since the beginning of the last fiscal year, determined whether the transaction is desirable and in the best interest of the Company. In transactions prior to the recent Avista Transaction, the special committee has evaluated whether transactions are fair to the Company and its shareholders on the same basis as comparable arm's length transactions. The committee has applied in the Avista Transaction, and may in other transactions also apply, standards under relevant debt agreements if required.

Barnett Shale Transaction. On October 31, 2013, the Company closed on the previously announced definitive agreement to sell, effective July 1, 2013, substantially all of its remaining oil and gas assets in the Barnett Shale (the "EnerVest Properties") to EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., EV Properties, L.P., and EnerVest Holding, L.P. (collectively, "EnerVest"). The effective date of this sale was July 1, 2013. The Company received net cash proceeds of approximately $188.9 million at the closing and, as a consequence of certain post-closing adjustments and holdbacks, the Company could receive up to an additional $20.2 million in cash proceeds. EnerVest also agreed to assume certain liabilities and contractual obligations. The parties each agreed to provide certain indemnities to the other. Estimated total proved reserves associated with the EnerVest Properties, as determined by the Company's third party engineers at year-end 2012, were approximately 303.5 Bcf. The Company plans to use the proceeds to repay borrowings under its revolving credit facility, to initially fund the Avista Transaction and to partially fund the remainder of our 2013 capital expenditures plan. The Company currently expects that the EnerVest Properties will result in a loss on the sale in the fourth quarter of 2013 as the proved reserves attributable to the EnerVest Properties represent 40% of the Company's proved reserves as of September 30, 2013 and therefore the sale is expected to significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the Company's U.S. cost center. Additionally, the Company currently anticipates that the EnerVest Properties will result in an increase in its future depreciation, depletion and amortization rate, and therefore will negatively affect its future reported earnings.

A copy of the purchase and sale agreement and the first amendment to the purchase and sale agreement are filed as Exhibits 2.1 and 2.2 to this Form 10-Q and are incorporated herein by reference. The foregoing description of the purchase and sale agreement as amended does not purport to be complete and is qualified in its entirety by reference to the full text of such agreements.

Revenues, expenses and related earnings from the EnerVest Properties will be reported in the Company's financial results through October 31, 2013.

The accompanying Pro Forma Financial Statements (see Exhibit 99.1) give effect to the sale of the Divested Properties as described in such statements and are incorporated herein by reference:

- Unaudited Pro Forma Condensed Consolidated Balance Sheet as of September 30, 2013
- Unaudited Pro Forma Condensed Consolidated Statements of Operations for the Nine Months Ended September 30, 2013 and for the Year Ended December 31, 2012

The accompanying Unaudited Pro Forma Condensed Consolidated Statement of Operations for the Year Ended December 31, 2012 also includes the effect to the sale of a significant portion of the Company's Barnett Shale assets to Atlas Resource Partners, L.P. which closed in the second quarter of 2012.

The pro forma adjustments do not reflect any use of proceeds from the sale other than repayment of amounts outstanding under the Company’s senior secured revolving credit facility with the remaining proceeds invested in cash and cash equivalents.

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
*2.1	–	Purchase and Sale Agreement, dated as of September 3, 2013, among affiliates of EnerVest, Ltd. and Carrizo Oil & Gas, Inc., CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, Inc. The schedules to the Purchase and Sale Agreement have been omitted pursuant to item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.
*2.2	–	First Amendment to the Purchase and Sale Agreement, dated as of September 5, 2013, among affiliates of EnerVest, Ltd. and Carrizo Oil & Gas, Inc., CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, Inc. supplementally upon request.
*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.
*99.1		Unaudited Pro Forma Condensed Consolidated Balance Sheet of Carrizo Oil & Gas, Inc. as of September 30, 2013 and Unaudited Pro Forma Condensed Consolidated Statements of Operations for the Nine Months Ended September 30, 2013 and for the Year Ended December 31, 2012.
*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: November 4, 2013	By: /s/ Paul F. Boling Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer)
Date: November 4, 2013	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)