CARRIZO OIL & GAS INC
Form 10-Q
November 08, 2012

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, 2012

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, 2012 was 40,084,954.

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012
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PART I. FINANCIAL INFORMATION
Item 1. Consolidated Financial Statements
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

	September 30, 2012 (Unaudited)	December 31, 2011
	(In thousands, except per share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14,288	$ 28,112
Accounts receivable, net		
Oil and gas sales	33,192	21,988
Joint interest billing	47,784	31,050
Related party	43,375	—
Other	2,434	1,740
Advances to operators	949	97
Fair value of derivative instruments	23,120	27,877
Prepaids and other current assets	5,904	9,533
Total current assets	171,046	120,397
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full cost method of accounting		
Proved oil and gas properties, net	1,111,632	842,041
Unproved properties and significant development projects, not being amortized	481,058	459,735
Other property and equipment, net	11,325	8,738
TOTAL PROPERTY AND EQUIPMENT, NET	1,604,015	1,310,514
DEFERRED FINANCING COSTS, NET	25,020	23,217
INVESTMENT	2,523	2,523
FAIR VALUE OF DERIVATIVE INSTRUMENTS	12,093	9,617
DEFERRED INCOME TAXES	40,135	59,755
OTHER ASSETS	1,864	1,657
TOTAL ASSETS	$ 1,856,696	$ 1,527,680
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 55,124	$ 25,672
Revenue and royalties payable	72,821	54,600
Current taxes payable	—	1,048
Accrued drilling costs	61,498	92,179
Accrued interest	26,390	12,059
Other accrued liabilities	30,068	21,414
Advances for joint operations	11,193	54,179
Current maturities of long-term debt	21,150	—
Deferred income taxes	7,399	9,685
Other current liabilities	1,648	484
Total current liabilities	287,291	271,320
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT	992,813	729,300
ASSET RETIREMENT OBLIGATIONS	10,188	11,242

FAIR VALUE OF DERIVATIVE INSTRUMENTS	140	9
OTHER LIABILITIES	4,640	5,954
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS’ EQUITY		
Common stock, $0.01 par value (90,000 shares authorized, 40,056 and 39,563 shares issued and outstanding at September 30, 2012 and December 31, 2011, respectively)	402	395
Additional paid-in capital	662,193	647,429
Accumulated deficit	(100,971)	(137,969)
Total shareholders’ equity	561,624	509,855
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$ 1,856,696	$ 1,527,680

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

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

	For The Three Months Ended September 30,		For The Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
OIL AND GAS REVENUES	$96,197	$51,668	$260,730	$146,398
COSTS AND EXPENSES				
Lease operating	7,145	7,292	22,599	21,385
Production tax	3,449	1,325	9,676	3,732
Ad valorem tax	2,327	1,026	8,238	2,698
Depreciation, depletion and amortization	46,518	20,325	121,459	57,596
General and administrative (inclusive of stock-based compensation expense (benefit) of $5,091 and ($4,060) for the three months ended September 30, 2012 and 2011, respectively, and $10,622 and $6,595 for the nine months ended September 30, 2012 and 2011, respectively)	12,412	4,712	37,044	28,052
Accretion related to asset retirement obligations	190	71	538	215
TOTAL COSTS AND EXPENSES	72,041	34,751	199,554	113,678
OPERATING INCOME	24,156	16,917	61,176	32,720
OTHER INCOME AND EXPENSES				
Gain (loss) on derivative instruments, net	(14,853)	25,656	26,432	37,534
Loss on extinguishment of debt	—	—	—	(897)
Interest expense	(18,945)	(13,386)	(53,967)	(38,001)
Capitalized interest	6,788	6,029	20,620	16,937
Other income (expense), net	26	17	(334)	78
INCOME (LOSS) BEFORE INCOME TAXES	(2,828)	35,233	53,927	48,371
INCOME TAX (EXPENSE) BENEFIT	1,898	(13,590)	(16,930)	(18,252)
NET INCOME (LOSS)	$(930)	$21,643	$36,997	$30,119
NET INCOME (LOSS) PER COMMON SHARE				
Basic	$(0.02)	$0.56	$0.94	$0.77
Diluted	$(0.02)	$0.55	$0.93	$0.76
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				
Basic	39,634	38,914	39,559	38,927
Diluted	39,634	39,368	39,992	39,483

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

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

	For The Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$36,997	$30,119
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	121,459	57,596
Unrealized (gain) loss on derivative instruments, net	3,898	(13,998)
Accretion related to asset retirement obligations	538	215
Loss on extinguishment of debt	—	897
Stock-based compensation, net of amounts capitalized	10,622	6,595
Allowance for doubtful accounts	(391)	(58)
Deferred income taxes	16,930	17,582
Amortization of debt discount and deferred financing costs, net of amounts capitalized	3,236	2,396
Other, net	3,235	7,019
Changes in operating assets and liabilities-		
Accounts receivable	(71,215)	(13,228)
Accounts payable	31,699	28,359
Accrued liabilities	23,206	15,519
Other, net	(3,977)	(8,707)
Net cash provided by operating activities	176,237	130,306
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures, including other property and equipment, capitalized interest, overhead and asset retirement obligations	(607,094)	(373,789)
Increase (decrease) in capital expenditure payables and accruals	(16,591)	16,216
Proceeds from sales of oil and gas properties, net	207,250	168,617
Advances to operators	(852)	323
Advances for joint operations	(42,986)	3,377
Other, net	(5,389)	(496)
Net cash used in investing activities	(465,662)	(185,752)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings and issuances	1,101,540	501,164
Debt repayments	(820,000)	(437,660)
Payments of debt issuance and retirement costs	(6,013)	(8,415)
Proceeds from stock options exercised	74	47
Net cash provided by financing activities	275,601	55,136
NET DECREASE IN CASH AND CASH EQUIVALENTS	(13,824)	(310)
CASH AND CASH EQUIVALENTS, beginning of period	28,112	4,128
CASH AND CASH EQUIVALENTS, end of period	$14,288	$3,818

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

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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 in the United States (the "U.S.") and United Kingdom (the "U.K."). 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 Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania and West Virginia, and the U.K. North Sea where the Huntington Field project is currently under development.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries 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, 2012 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, 2011.

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, shareholders’ equity, net income, or net cash provided by/used in operating, investing or financing activities.

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. Actual results could differ from these estimates. 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 tests, estimates of future taxable income used in assessing the realizability of deferred tax assets, and asset retirement obligations. Other significant estimates include the impairment of unproved properties, fair values of derivative instruments, stock-based compensation, the collectability of outstanding receivables, and contingencies. Proved oil and gas reserve estimates have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality and quantity of available data and the application of engineering and geological interpretation and judgment to available data. Subsequent drilling results, testing and production may justify revisions of such estimates. Accordingly, proved oil and gas reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, proved oil and gas reserve estimates are vulnerable to changes in average market prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices of oil and gas, the creditworthiness of counterparties, interest rates and the market value and volatility of the Company's common stock. Future changes in these assumptions may affect these significant estimates materially in the near term.

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, 2012 and December 31, 2011, the Company’s allowance for doubtful accounts was $1.3 million and $2.3 million, respectively.

Concentration of Credit Risk

Substantially all of the Company’s accounts receivable result from oil and gas sales, joint interest billings to working interest owners in the oil and gas industry or drilling and completion advances to third-party operators for development 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 7. 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 $2.5 million and $2.0 million for the three months ended September 30, 2012 and 2011, respectively, and $9.5 million and $7.5 million for the nine months ended September 30, 2012 and 2011, 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 oil and natural gas liquids to gas equivalents at the ratio of one barrel of oil or natural gas liquids to six thousand cubic feet of gas, 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 on oil and gas properties was $19.76 and $10.84 for the three months ended September 30, 2012 and 2011, respectively, and $17.21 and $10.43 for the nine months ended September 30, 2012 and 2011, respectively.

Unproved properties and significant development projects, not being amortized include unevaluated leasehold and seismic costs associated with specific unevaluated properties, significant development projects in cost centers with no production and on which exploration or development activities are in progress, related capitalized interest and the cost of exploratory wells in progress. 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 unevaluated leasehold and seismic costs within the next two to 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 significant development projects, not being amortized of $6.8 million and $6.0 million for the three months ended September 30, 2012 and 2011, respectively, and $20.6 million and $16.9 million for the nine months ended September 30, 2012 and 2011, respectively. Interest is capitalized on the average balance of unevaluated leasehold and seismic costs or the capitalized oil and gas property costs of significant development projects, not being amortized using a weighted-average interest rate based on outstanding borrowings of the relevant cost center.

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. The Company has not had any sales of oil and gas properties that significantly alter that relationship.

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In connection with the formation of ACP II Marcellus LLC (“ACP II”), the Company’s partner in one of its joint ventures in the Marcellus Shale, the Company was issued a class of interests (“B Units”) in ACP II. The B Units entitle the Company to certain percentages of cash distributions to affiliates of Avista Capital Partners, LP, (together with its affiliates, “Avista”), if, when and only to the extent that those cash distributions exceed certain internal rates-of-return and return-on-investment thresholds with respect to Avista’s investment in ACP II as set forth in the limited liability company agreement of ACP II, as amended, unless and until we increase our interest in certain oil and gas properties of ACP II located in Pennsylvania and Ohio or sell substantially all of our interest in such properties. Because the B Units do not provide the Company with an ownership interest in the oil and gas properties of ACP II, the Company is not required to pay for property acquisition, exploration or development costs associated with ACP II’s ownership interest in oil and gas properties, nor do the B Units entitle the Company to recognize oil and gas production and therefore, proved reserves associated with ACP II’s ownership interest in oil and gas properties. However, under the full cost method of accounting, cash distributions received on the B Units are considered proceeds from the sale of oil and gas properties which are recognized as a reduction of capitalized oil and gas property costs.

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 properties not subject to amortization, 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 average quoted 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 revolving credit facilities or the issuance of debt securities. 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 revolving credit facilities.

Investment

The Company accounts for its investment in Oxane Materials, Inc. (“Oxane”) using the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from Oxane.

Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, receivables, payables, derivative instruments and 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 derivative instruments are based on a pricing model that uses market data obtained from reputable independent sources, including (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The carrying amounts of debt under the Company's credit facilities approximate fair value as these 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 5. Debt and Note 8. Fair Value Measurements.

Asset Retirement Obligations

The Company's oil and gas properties require expenditures to plug and abandon wells 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 over the estimated productive lives of the oil and gas properties to their expected settlement values. 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

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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 changes in estimated timing of oil and gas property retirement. 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 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 of the revenue 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, 2012 and December 31, 2011, 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 7. 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 (“Stock SARs”), SARs that may only be settled in cash (“Cash SARs”), restricted stock awards and restricted stock units to directors, employees and independent contractors. The Company recognized the following stock-based compensation expense (benefit) 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,	
	2012	2011	2012	2011
	(In thousands)			
Stock Options and SARs	$1,536	$(8,035)	$226	$(1,121)
Restricted Stock Awards and Units	4,598	3,777	13,179	10,227

	6,134	(4,258)	13,405	9,106
Less: Amounts Capitalized	(1,043)	198	(2,783)	(2,511)
Total Stock-Based Compensation Expense (Benefit)	$5,091	$(4,060)	$10,622	$6,595
Income Tax (Expense) Benefit	$(1,937)	$1,531	$(4,042)	$(2,486)

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Stock Options and SARs. For stock options and Stock 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 Cash SARs and any Stock 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 any 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 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.

Foreign Currency

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

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) Per Common Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
Net income (loss)	$(930)	$21,643	$36,997	$30,119
Basic weighted average common shares outstanding	39,634	38,914	39,559	38,927
Effect of dilutive instruments	—	454	433	556
Diluted weighted average common shares outstanding	39,634	39,368	39,992	39,483
Net income (loss) per common share				
Basic	$(0.02)	$0.56	$0.94	$0.77
Diluted	$(0.02)	$0.55	$0.93	$0.76

Basic net income (loss) per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) 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, warrants and convertible debt. 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, 2012 or 2011, because the conversion price was in excess of the market price of the common stock for those periods.

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3. PROPERTY AND EQUIPMENT, NET

At September 30, 2012 and December 31, 2011, property and equipment, net consisted of the following:

	September 30, 2012	December 31, 2011
	(In thousands)	
Proved oil and gas properties	$1,629,336	$1,239,778
Accumulated depreciation, depletion and amortization	(517,704)	(397,737)
Proved oil and gas properties, net	1,111,632	842,041
Unproved properties and significant development projects, not being amortized		
Unevaluated leasehold and seismic costs	285,242	277,425
Significant development projects	99,563	65,306
Exploratory wells in progress	47,263	70,533
Capitalized interest	48,990	46,471
Total costs not subject to amortization	481,058	459,735
Other property and equipment	16,543	12,835
Accumulated depreciation	(5,218)	(4,097)
Other property and equipment, net	11,325	8,738
Total property and equipment, net	$1,604,015	$1,310,514

Sale of Barnett Shale Properties

During the second quarter of 2012, the Company sold a significant portion of its Barnett Shale properties to an affiliate of Atlas Resource Partners, L.P. ("Atlas") for an agreed upon price of $190.0 million. Net proceeds received from the sale were approximately $186.7 million, subject to final post-closing adjustments. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2012 and the closing date of April 30, 2012. The proceeds from such sale were recognized as a reduction of proved oil and gas properties.

Sale of Gulf Coast Properties

During the third quarter of 2012, the Company completed the divestiture of substantially all of its legacy producing properties along the onshore Gulf of Mexico located primarily in Texas and Louisiana for an agreed upon price of $19.3 million, subject to final post-closing adjustments. Net proceeds received from the sale were approximately $14.3 million as of September 30, 2012 and we expect to receive up to an additional $3.5 million in the fourth quarter of 2012. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of July 1, 2012 and the closing date of September 27, 2012. The proceeds from such sale were recognized as a reduction of proved oil and gas properties.

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4. 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 (benefit) differs from income tax expense (benefit) computed by applying the U.S. federal statutory corporate income tax rate of 35% to income before income taxes as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Income tax expense (benefit) at the statutory rate	$(989)	$12,331	$18,875	$16,930
State income taxes, net of U.S. federal income tax benefit	334	754	1,421	2,456
U.K. income tax expense (benefit)	(1,202)	155	(3,738)	(19)
Capital loss associated with investment in Pinnacle Gas Resources, Inc. for which no income tax benefit was recognized in prior periods	—	—	—	(1,135)
Other, net	(41)	350	372	20
Income tax expense (benefit)	$(1,898)	$13,590	$16,930	$18,252

As of September 30, 2012, the Company had U.S. and U.K. income tax loss carryforwards of approximately $194.5 million and $117.0 million, respectively. The U.S. loss carryforwards expire between 2019 and 2032 if not utilized in earlier periods. The U.K. loss carryforwards are not subject to expiration as long as the Company maintains an activity trading status in the U.K. The realization of the deferred tax assets related to the 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 net deferred tax assets will be fully realized.

At September 30, 2012, the Company had no material uncertain tax positions and the tax years since 1999 in the U.S. remain open to review by federal and various state tax jurisdictions. In the U.K., the tax years since 2010 remain open to review by Her Majesty's Revenue and Customs.

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5. DEBT

Debt consisted of the following at September 30, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
	(In thousands)	
8.625% Senior Notes	$600,000	$600,000
Unamortized discount for 8.625% Senior Notes	(5,008)	(5,464)
7.50% Senior Notes	300,000	—
Convertible Senior Notes	73,750	73,750
Unamortized discount for Convertible Senior Notes	(1,779)	(3,799)
Senior Secured Revolving Credit Facility	—	47,000
U.K. Huntington Field Development Project Credit Facility	47,000	17,813
	1,013,963	729,300
Less: Current maturities of Huntington Facility due June 30, 2013	(21,150)	—
	$992,813	$729,300

Senior Notes

On November 2, 2010, the Company issued $400.0 million aggregate principal amount of 8.625% Senior Notes due 2018 in a private placement. On November 17, 2011, the Company issued an additional $200.0 million aggregate principal amount of 8.625% Senior Notes in a private placement. In June 2011 and February 2012, the Company completed the exchange of registered 8.625% Senior Notes due 2018 for any and all of its then unregistered $400.0 million and $200.0 million aggregate principal amount of 8.625% Senior Notes due 2018, respectively.

On September 10, 2012, the Company issued in a public offering $300.0 million aggregate principal amount of 7.50% Senior Notes due 2020 at a price to the public of 100% of the principal amount. The net proceeds of $294.2 million (after deducting the underwriters discount and the Company's expenses) were used to repay borrowings outstanding under the Revolving Credit Facility (defined below) and for general corporate purposes.

The 7.50% Senior Notes bear interest at 7.50% per annum which is payable semi-annually on each March 15 and September 15 and mature on September 15, 2020. Except in certain circumstances described below, the Company may not redeem the 7.50% Senior Notes prior to September 15, 2016. On and after September 15, 2016, the Company may redeem all or a part of the 7.50% Senior Notes, at redemption prices decreasing from 103.750% of the principal amount to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest. In connection with certain equity offerings by the Company, the Company may at any time prior to September 15, 2015, subject to certain conditions, on one or more occasions, redeem up to 35% of the aggregate principal amount of the 7.50% Senior Notes at a redemption price of 107.500%, of the principal amount, plus accrued and unpaid interest, if any, to the redemption date using the net cash proceeds of such equity offerings. Prior to September 15, 2016, the Company may redeem all or part of the 7.50% Senior Notes at 100% of the principal amount thereof, plus accrued and unpaid interest and a make whole premium (as defined in the Indenture governing the 7.50% Senior Notes). If a Change of Control (as defined in the Indenture governing the 7.50% Senior Notes) occurs, the Company may be required by holders to repurchase the 7.50% Senior Notes for cash at a price equal to 101% of the aggregate principal amount, plus any accrued but unpaid interest.

The Indentures governing the 8.625% Senior Notes and the 7.50% Senior Notes contains covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company's common stock or other capital stock or redeem the Company's subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company's assets; enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries. At September 30, 2012, the 8.625% Senior Notes and the 7.50% Senior Notes were guaranteed by all of the Company's existing subsidiaries (other than Carrizo UK Huntington Ltd, Carrizo (Utica) LLC, Monument Exploration LLC, and Carrizo UK Bardolph Ltd).

The 8.625% Senior Notes and the 7.50% Senior Notes and the Indenture governing the notes are subject to customary events of default, including those relating to failures to comply with the terms of the notes and indenture, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

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Convertible Senior Notes

At September 30, 2012, the Company had issued and outstanding $73.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 ("Convertible Senior Notes"). The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem the notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

While the holders of the Convertible Senior Notes may require the Company to repurchase the Convertible Senior Notes in June 2013, the Company has the intent and ability to refinance the Convertible Senior Notes on a long-term basis with the available capacity of its senior secured revolving credit facility, and accordingly, the Convertible Senior Notes have been classified as long-term debt in the consolidated balance sheet.

Senior Secured Revolving Credit Facility

The Company is party to a senior secured revolving credit facility ("Revolving Credit Facility") with Wells Fargo Bank, National Association as the administrative agent. The Revolving Credit Facility provides for a borrowing capacity up to the lesser of (i) the borrowing base (as defined in the senior credit agreement governing the Revolving Credit Facility) and (ii) $750.0 million. The Revolving Credit Facility matures on January 27, 2016. The Revolving Credit Facility is secured by substantially all of the Company’s U.S. assets and, at September 30, 2012, was guaranteed by all of the Company's existing subsidiaries (other than Carrizo UK Huntington Ltd, Carrizo (Utica) LLC, Monument Exploration LLC, and Carrizo UK Bardolph Ltd). The initial borrowing base under the Revolving Credit Facility was $350.0 million and as of June 30, 2012, the borrowing base was $325.0 million. As a result of the Fall 2012 borrowing base redetermination, effective September 27, 2012, the borrowing base was increased to $365.0 million after considering the addition of proved reserves as a result of the Company's successful ongoing drilling program, the removal of properties in connection with the recent sale of Gulf Coast properties, and the Niobrara Formation transaction with OIL India Ltd. and Indian Oil Corporation Ltd.

On March 26, 2012, the Revolving Credit Facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the Revolving Credit Facility) steps down and (2) increase the basket available for redemptions of the Company's Convertible Senior Notes. On September 4, 2012 the Revolving Credit Facility was amended to increase the basket available for issuances of additional senior notes, including those issued in the September 2012 notes offering. On September 27, 2012, the Revolving Credit Facility was amended to, among other things, extend the maximum permitted duration of hedge agreements entered into by the Company and its restricted subsidiaries and to reflect the Fall 2012 borrowing base redetermination.

The Company is 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 (a) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012 and (b) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (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). At September 30, 2012, the ratio of Total Debt to EBITDA was 3.61 to 1.00, the Current Ratio was 2.08 to 1.00, the ratio of Senior Debt to EBITDA was 0.00 to 1.00 and the ratio of EBITDA to Interest Expense was 5.31 to 1.00. 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, 2012, the Company had no borrowings outstanding under the Revolving Credit Facility. At September 30, 2012, the Company had $1.0 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the $365.0 million 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 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. The Revolving Credit Facility may also be used to repurchase the Convertible Senior Notes.

U.K. Huntington Field Development Project Credit Facility

The Company and Carrizo U.K. Huntington Ltd. ("Carrizo UK"), as borrower, are parties to a Senior Secured Multicurrency Credit Facility (the "Huntington Facility"). The Huntington Facility provides for a multicurrency credit facility consisting of (1) a $55.0 million term loan facility to be used to fund Carrizo UK's share of project development costs, (2) a $6.5 million contingent cost overrun term loan facility and (3) a $22.5 million post-completion credit facility providing for letters of credit to be used to secure certain abandonment and decommissioning obligations following project completion. The availability under

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the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014. The Company expects the semi-annual redetermination to take place during the fourth quarter of 2012.

As of September 30, 2012, borrowings outstanding under the Huntington Facility were $47.0 million, of which $21.2 million was classified as current, with a weighted average interest rate of 3.93% and no letters of credit had been issued.

6. 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 material adverse effect on the financial position or results of operations of the Company.

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

7. DERIVATIVE INSTRUMENTS

The Company relies on 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 program. 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, expiration or exchanged for physical delivery contracts. The Company’s current long-term 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, 2012, and December 31, 2011 was a net asset of $34.4 million and $37.3 million, respectively. The following sets forth a summary of the distribution of net fair value of the Company's derivative instruments:

Counterparty	September 30, 2012		December 31, 2011	
Credit Suisse	54	%	68	%
BNP Paribas	24	%	19	%
Societe Generale	15	%	2	%
BBVA Compass	4	%	—	%
Shell Energy North America (US) LP	2	%	6	%
Wells Fargo	1	%	—	%
Credit Agricole	—	%	5	%
Total	100	%	100	%

Master netting agreements are in place with each of these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, the Company believes it has minimal credit risk and accordingly does not currently require its counterparties to post collateral to support the 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, Credit Agricole, BBVA Compass, Wells Fargo, and Societe Generale are lenders in the Company's Revolving Credit Facility, and BNP Paribas and Societe Generale are lenders in the Company's Huntington Facility, the Company is not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties as the contracts are secured by the Revolving Credit Facility or the Huntington Facility, respectively.

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The following sets forth a summary of the Company's U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of September 30, 2012:

Period	Volumes (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2012	4,876,000	$5.32	$5.50
2013	10,950,000	$5.07	$5.07
2014	3,650,000	$—	$5.50

In connection with the natural gas derivative instruments above, the Company has entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of $4.43, the floor price becomes the market price plus the put spread of $1.28 on 2,134,400 of the 4,876,000 MMBtus and the remaining 2,741,600 MMBtus would have a floor price of $5.32.

The following sets forth a summary of the Company's U.S. crude oil derivative positions at average NYMEX prices as of September 30, 2012:

Period	Volumes (in Bbls)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
2012	671,600	$89.95	$102.95
2013	2,591,500	$88.85	$103.32
2014	1,642,500	$89.50	$102.64
2015	985,500	$89.91	$100.08
2016	244,000	$85.00	$104.00

In connection with the crude oil derivative instruments above, the Company has entered into protective put spreads. For 2014, at market prices below the short put price of $65.00, the floor price becomes the market price plus the put spread of $20.00 on 182,500 of the 1,642,500 Bbls and the remaining 1,460,000 Bbls would have a floor price of $89.50.

Period	Volumes (in Bbls)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
2014	182,500	$65.00	$20.00
2015	365,000	$65.00	$20.00
2016	244,000	$65.00	$20.00

For the three and nine months ended September 30, 2012 and 2011, the Company recorded the following related to its oil and gas derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Realized gain (loss) on derivative instruments, net	$9,310	$8,626	$30,330	$23,536
Unrealized gain (loss) on derivative instruments, net	(24,163)	17,030	(3,898)	13,998
Gain (loss) on derivative instruments, net	$(14,853)	$25,656	$26,432	$37,534

8. 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, 2012 and December 31, 2011, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(In thousands)							
Assets:								
Derivative instruments	$—	$44,598	$—	$44,598	$—	$61,073	$—	$61,073
Liabilities:								
Derivative instruments	—	(10,193)	—	(10,193)	—	(23,792)	—	(23,792)
Total	$—	$34,405	$—	$34,405	$—	$37,281	$—	$37,281

The fair values of the Company's derivative instruments are based on a pricing model that uses market data obtained from reputable independent sources and are considered Level 2 inputs, including (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. 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 tables above are presented on a gross basis. 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 Company had no transfers in or out of Levels 1 or 2 for the nine months ended September 30, 2012 or 2011.

Fair Value of Other Financial Instruments

The Company’s other financial instruments consist of cash and cash equivalents, receivables, payables and debt which are all 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 carrying amounts of debt under the Revolving Credit Facility and the Huntington Facility approximate fair value as these borrowings bear interest at variable rates of interest. 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, 2012 and December 31, 2011.

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
8.625% Senior Notes	$600.0	$640.5	$600.0	$606.0
7.50% Senior Notes	$300.0	$304.5	$—	$—
4.375% Convertible Senior Notes	$73.8	$74.3	$73.8	$73.0

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9. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In November 2010 and November 2011, the Company and certain of the Company's wholly-owned subsidiaries (such subsidiaries collectively, the "Subsidiary Guarantors") issued in private placements $400.0 million and $200.0 million, respectively, aggregate principal amount of the Company's 8.625% Senior Notes. Certain, but not all, of the Company's wholly-owned subsidiaries have issued full, unconditional and joint and several guarantees of the 8.625% Senior Notes and may guarantee future issuances of debt securities. In June 2011 and February 2012, the Company completed the exchange of registered 8.625% Senior Notes due 2018 for any and all of its unregistered $400.0 million and $200.0 million aggregate principal amount of 8.625% Senior Notes , respectively. In September 2012, the Company and certain of the Company's wholly-owned subsidiaries issued in a public offering, $300.0 million aggregate principal amount of the Company's 7.50% Senior Notes.

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, 2012 and December 31, 2011, and for the three and nine months ended September 30, 2012 and 2011 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 the Subsidiary Guarantors 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.

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CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS

	September 30, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	$1,568,470	$111,155	$45,092	$(1,553,671)	$171,046
Property and equipment, net	93,543	1,370,782	117,150	22,540	1,604,015
Investments in subsidiaries	(11,509)	—	—	11,509	—
Other assets	49,156	29,694	11,219	(8,434)	81,635
Total assets	$1,699,660	$1,511,631	$173,461	$(1,528,056)	$1,856,696
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	$126,495	$1,577,747	$84,988	$(1,501,939)	$287,291
Long-term liabilities	973,915	2,514	31,352	—	1,007,781
Shareholders' equity	599,250	(68,630)	57,121	(26,117)	561,624
Total liabilities and shareholders' equity	$1,699,660	$1,511,631	$173,461	$(1,528,056)	$1,856,696

	December 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	$1,349,841	$71,018	$3,874	$(1,304,336)	$120,397
Property and equipment, net	101,015	1,131,672	68,911	8,916	1,310,514
Investments in subsidiaries	(58,764)	—	—	58,764	—
Other assets	38,853	54,062	9,133	(5,279)	96,769
Total assets	$1,430,945	$1,256,752	$81,918	$(1,241,935)	$1,527,680
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	$150,793	$1,368,456	$4,366	$(1,252,295)	$271,320
Long-term liabilities	724,801	2,183	22,429	(2,908)	746,505
Shareholders' equity	555,351	(113,887)	55,123	13,268	509,855
Total liabilities and shareholders' equity	$1,430,945	$1,256,752	$81,918	$(1,241,935)	$1,527,680

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

	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	15,267	56,135	151	488	72,041
Operating income (loss)	(10,808)	35,603	(151)	(488)	24,156
Other income and (expense), net	(16,422)	(10,448)	(114)	—	(26,984)
Income (loss) before income taxes	(27,230)	25,155	(265)	(488)	(2,828)
Income tax (expense) benefit	9,531	(8,796)	1,197	(34)	1,898
Equity in income (loss) of subsidiaries	17,291	—	—	(17,291)	—
Net income (loss)	$(408)	$16,359	$932	$(17,813)	$(930)

	For The Three Months Ended September 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$7,607	$44,061	$—	$—	$51,668
Cost and expenses	14,160	23,685	24	(3,118)	34,751
Operating income (loss)	(6,553)	20,376	(24)	3,118	16,917
Other income and (expense), net	22,966	(4,789)	139	—	18,316
Income (loss) before income taxes	16,413	15,587	115	3,118	35,233
Income tax (expense) benefit	(5,863)	(5,603)	(957)	(1,167)	(13,590)
Equity in income (loss) of subsidiaries	9,142	—	—	(9,142)	—
Net income (loss)	$19,692	$9,984	$(842)	$(7,191)	$21,643

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

	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	62,632	150,242	304	(13,624)	199,554
Operating income (loss)	(46,776)	94,632	(304)	13,624	61,176
Other income and (expense), net	18,892	(25,008)	(1,133)	—	(7,249)
Income (loss) before income taxes	(27,884)	69,624	(1,437)	13,624	53,927
Income tax (expense) benefit	9,760	(24,360)	3,733	(6,063)	(16,930)
Equity in income (loss) of subsidiaries	47,560	—	—	(47,560)	—
Net income (loss)	$29,436	$45,264	$2,296	$(39,999)	$36,997

	For The Nine Months Ended September 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	$25,771	$120,627	$—	$—	$146,398
Cost and expenses	52,129	67,332	167	(5,950)	113,678
Operating income (loss)	(26,358)	53,295	(167)	5,950	32,720
Other income and (expense), net	34,063	(16,870)	(1,542)	—	15,651
Income (loss) before income taxes	7,705	36,425	(1,709)	5,950	48,371
Income tax (expense) benefit	(2,804)	(13,259)	19	(2,208)	(18,252)
Equity in income (loss) of subsidiaries	21,476	—	—	(21,476)	—
Net income (loss)	$26,377	$23,166	$(1,690)	$(17,734)	$30,119

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

	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	$(11,086)	$144,665	$42,658	$—	$176,237
Net cash used in investing activities	(246,346)	(379,182)	(89,778)	249,644	(465,662)
Net cash provided by financing activities	247,068	232,369	45,808	(249,644)	275,601
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

	For The Nine Months Ended September 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$59,668	$71,777	$(1,139)	$—	$130,306
Net cash used in investing activities	(122,718)	(214,217)	(23,180)	174,363	(185,752)
Net cash provided by financing activities	53,143	151,646	24,710	(174,363)	55,136
Net increase (decrease) in cash and cash equivalents	(9,907)	9,206	391	—	(310)
Cash and cash equivalents, beginning of period	1,418	2,710	—	—	4,128
Cash and cash equivalents, end of period	$(8,489)	$11,916	$391	$—	$3,818

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10. SUBSEQUENT EVENTS

Utica Shale Joint Venture. In October 2012, the Company sold substantially all of its interests in oil and gas properties dedicated to its Utica joint venture in the northern portion of the Utica Shale play to an unrelated third party and received net cash proceeds of $42.7 million, subject to final post-closing adjustments. The proceeds from such sale will be recognized as a reduction of proved oil and gas properties. Simultaneously with the closing of the Utica Shale transaction discussed above, one of the Company's existing joint venture partners in the Utica Shale, ACP II Marcellus LLC (“ACP II”), an affiliate of Avista Capital Holdings, LP, a private equity firm (collectively with ACP II, “Avista”), sold substantially all of its interests in the same oil and gas properties. Other assets included in the sale were an existing drilling pad and approved well drilling permits associated with the properties. The properties sold are located in Mercer and Crawford Counties in Pennsylvania and Trumbull County in Ohio.

In connection with the sale transactions described above, 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% for which it held record title. Subsequently, on October 24, 2012, the Company and Avista amended their Utica Shale joint venture agreement to provide that the expiration date of the Company's remaining option to increase its participating interest in the Utica joint venture properties is accelerated from March 2013 to January 15, 2013. The Company and Avista also agreed that if the option is exercised prior to such date, the Company's participating interest in subsequently acquired properties within an area of mutual interest will continue to be 10%, and Avista's participating interest will be 90%, and the Company will be 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 after the exercise date. This additional option would expire May 31, 2013.

Additionally during the fourth quarter 2012, the Company received from Avista substantially all of the $43.4 million related party accounts receivable shown in the accompanying consolidated balance sheet.

Niobrara Joint Venture with OIL India Ltd. and Indian Oil Corporation Ltd. In October 2012, the Company completed the sale of an undivided 30% of substantially all of its interests in oil and gas properties in the Niobrara Formation to subsidiaries of OIL India Ltd. (OIL) and Indian Oil Corporation Ltd. (IOCL), both international energy companies based in Delhi, India, effective October 1, 2012. Under the purchase and participation agreement for this transaction, the Company received approximately $41.25 million in cash subject to final post-closing adjustments. The proceeds from such sale will be recognized as a reduction of proved oil and gas properties. As part of the consideration for the purchase, OIL and IOCL have committed to pay a “development carry” of 50% of certain of the Company's future development costs up to an aggregate of approximately $41.25 million, as further described below. The Niobrara Formation assets conveyed to OIL and IOCL under the terms of the agreement are located primarily in Weld and Adams Counties, Colorado. The amounts to be received by the Company are subject to final post-closing adjustments, pending completion of land and title matters.

The agreement also provides for an ongoing joint venture between the Company, OIL and IOCL with respect to the interests purchased. The development carry obligation extends until the full utilization of the approximately $41.25 million development carry. The Company will continue to operate the joint venture properties that it currently operates, and currently expects the development carry to be utilized by early 2014. The joint venture provides for an area of mutual interest including the purchased interests and specified areas adjacent to such interests. OIL and IOCL will have the right to purchase certain interests acquired by the Company in the area of mutual interest at a specified premium to the price paid by the Company.

Niobrara Joint Venture with Haimo Oil & Gas LLC. In October 2012, the Company also agreed to sell a portion of its remaining interest in the same oil and gas properties sold to OIL and IOCL in the transaction described above to Haimo Oil & Gas LLC (Haimo), a subsidiary of Lanzhou Haimo Technologies Co. Ltd., a company formed under the laws of the People's Republic of China, for a cash payment of $27.5 million. The purchase and participation agreement for this transaction provides for an ongoing joint venture between the Company, OIL and IOCL, and Haimo, with respect to the interests purchased. The Company will continue to operate the joint venture properties that it currently operates. Following the closing of the Haimo transaction late in the fourth quarter of 2012, the Company, OIL and IOCL, collectively, and Haimo will own 60%, 30% and 10% of the joint venture acreage, respectively. This transaction will also have an effective date of October 1, 2012 and is subject to adjustment, pending completion of land and title matters, and governmental approval. The proceeds from such sale will be recognized as a reduction of proved oil and gas properties.

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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, 2011, and the unaudited consolidated financial statements included in this quarterly report.

General Overview

Our third quarter 2012 included oil and gas revenues of $96.2 million and production of 2,354 Mboe. The key drivers to our results for the three months ended September 30, 2012 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the three months ended September 30, 2012, we drilled (a) 16 gross wells (12.3 net) in the Eagle Ford Shale, (b) 6 gross wells (3.4 net) in the Niobrara Formation and (c) 3 gross wells (0.8 net) in the Marcellus Shale.

Production. Our third quarter 2012 production of 2,354 Mboe increased 26% from the third quarter 2011 production of 1,875 Mboe. The increase in production from the third quarter of 2011 to the third quarter of 2012 was primarily due to increased production from new wells primarily in the Eagle Ford Shale and the Niobrara Formation, partially offset by normal production decline and the sale of a significant portion of our remaining Barnett Shale properties to Atlas Resource Partners, L.P. ("Atlas") in April 2012.

Commodity prices. Our average realized oil price during the third quarter of 2012 was $96.66 per barrel, or 8% higher than the price during the third quarter of 2011. Our average realized gas price during the third quarter of 2012 was $1.92 per Mcf, or 37% lower than the price during the third quarter of 2011.

Sale of Gulf Coast Properties. During the third quarter of 2012, we completed the divestiture of substantially all of our legacy producing properties along the onshore Gulf of Mexico located primarily in Texas and Louisiana for an agreed upon price of $19.3 million, subject to final post-closing adjustments. Net proceeds received from the sale were approximately $14.3 million as of September 30, 2012 and we expect to receive up to an additional $3.5 million in the fourth quarter of 2012. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of July 1, 2012 and the closing date of September 27, 2012. The proceeds from such sale were recognized as a reduction of proved oil and gas properties.

Outlook

While the market for natural gas remains challenging due to low spot and future prices, we are insulated from a portion of their effect by our hedging of 4,876,000 MMbtus of natural gas (approximately 66% of expected fourth quarter 2012 production) at September 30, 2012 for the remainder of 2012 and 10,950,000 MMbtus of natural gas (approximately 38% of expected 2013 production) hedged for 2013. The Atlas sale and our rapidly growing oil production, further serve to reduce our exposure to the natural gas market. The current market and outlook for crude oil is much more attractive and we are aggressively locking in these prices by increasing our hedge positions as our oil production grows. At September 30, 2012, we had hedges in place for 671,600 bbls of oil (approximately 84% of expected fourth quarter 2012 production) for the remainder of 2012 and 2,591,500 bbls of oil (approximately 86% of expected 2013 production) hedged for 2013. Production growth and commodity prices that permit us to drill, develop and produce at a profit are key to our future success.

Based upon the success of our drilling results since late 2010, we continue to focus on developing our oil rich resource plays in the Eagle Ford Shale and the Niobrara Formation and have reallocated capital from development of Barnett Shale and Marcellus Shale gas to Eagle Ford and Niobrara oil.

Eagle Ford Shale. During the third quarter of 2012, we brought on production 13 gross (10.1 net) wells. As of September 30, 2012, we had 58 wells producing in the Eagle Ford Shale and were operating three rigs on our Eagle Ford properties.

Niobrara Formation. During the third quarter of 2012, we brought on production 4 gross (2.4 net) wells. As of September 30, 2012, we had 24 wells producing in the Niobrara Formation and were operating one rig on our

Niobrara properties. In October 2012, we entered into a joint venture agreement with subsidiaries of OIL India Ltd. and Indian Oil Corporation Ltd., both international energy companies based in Delhi, India. Under the terms of the joint venture, we sold an undivided 30% non-operated interest in substantially all of our assets and operations prospective for Niobrara Formation oil development located primarily in Weld and Adams Counties, Colorado for total consideration of approximately $82.5 million, comprised of $41.25 million in cash and the assumption of an additional $41.25 million of our future drilling and development costs, subject to final post-closing adjustments.. The joint venture agreements are effective October 1, 2012 and contemplate an area of mutual interest agreement among the parties. The properties sold to OIL and IOCL accounted for approximately 555 Boe/d of production including 414 Bbls/d of oil production as of September 27, 2012.

Later in October 2012, the Company also agreed to sell a portion of its remaining interest in the same oil and gas properties sold to OIL and IOCL in the transaction described above to Haimo Oil & Gas LLC (Haimo), a subsidiary of Lanzhou Haimo Technologies Co. Ltd., a company formed under the laws of the People's Republic of China, for a cash payment of $27.5 million. The purchase and participation agreement for this transaction provides for an ongoing joint venture between the Company, OIL and IOCL, and Haimo, with respect to the interests purchased. Following the closing of the Haimo transaction late in the fourth quarter of 2012, the Company, OIL and IOCL, collectively, and Haimo will own 60%, 30% and 10% of the joint venture acreage, respectively. This transaction will also have an effective date of October 1, 2012 and is subject to adjustment, pending completion of land and title matters, and governmental approval.

Marcellus Shale. As a result of the material decline in natural gas prices, we and our joint venture partners are carefully reviewing our drilling program and have significantly reduced our planned spending in the Marcellus Shale during 2012. We will continue to monitor prices and, consistent with our existing contractual commitments, may decrease our activity level and capital expenditures further, or may increase such activity, if natural gas prices so warrant. As of September 30, 2012, we had 14 gross (4.5 net) wells completed and waiting on pipeline connection and 17 gross (4.3 net) wells drilled and waiting on completion. As of September 30, 2012, we had 21 wells producing in the Marcellus Shale. As of October 31, 2012 we were operating one rig on our Marcellus properties.

U.K. North Sea. In the third quarter of 2012, all producer and injector wells had been completed. As of October 31, 2012, the FPSO Teekay Spirit has left the shipyard and arrived in the field. Offshore installation work has commenced and is ongoing. Weather has delayed the project and first oil is currently expected in the first quarter of 2013.

Utica Shale Joint Venture. In October 2012, we sold substantially all of our interests in oil and gas properties in the northern portion of the Utica Shale play to an unrelated third party and received net cash proceeds of $42.7 million, subject to final post-closing adjustments. Simultaneous with the closing of the Utica Shale transaction discussed above, one of the our existing joint venture partners in the Utica Shale, ACP II, an affiliate of Avista Capital Holdings, LP, sold substantially all of its interests in the same oil and gas properties. In connection with the sale transactions described above, 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 rather than the 10% for which it held record title. Other assets included in the sale are an existing drilling pad and approved well drilling permits associated with the properties. The properties sold are located in Mercer and Crawford Counties in Pennsylvania and Trumbull County in Ohio. The proceeds from such sale will be recognized as a reduction of proved oil and gas properties. On October 24, 2012, we and Avista amended our Utica Shale joint venture agreement to provide that the expiration date of our remaining option to increase our participating interest in the Utica joint venture properties to January 15, 2013. We and Avista also agreed that if the option is exercised prior to such date, our participating interest in subsequently acquired properties within an area of mutual interest will continue to be 10%, and Avista's participating interest will be 90%, and we will be granted an additional option to increase our 10% ownership in such subsequently acquired properties to 50% at 8.625% above acreage cost and associated improvements after the exercise date. This additional option would expire May 31, 2013.

Results of Operations

Three Months Ended September 30, 2012, Compared to the Three Months Ended September 30, 2011

Revenues from oil and gas production for the three months ended September 30, 2012 increased 86% to $96.2 million from $51.7 million for the same period in 2011 primarily due to increased oil production and higher oil prices partially offset by lower gas production and prices. Production volumes for the three months ended September 30, 2012 and 2011 were 2,354 Mboe and 1,875 Mboe, respectively. The increase in production from the third quarter of 2011 to the third quarter of 2012 was primarily due to increased production from new wells, partially offset by normal production decline and the sale of Barnett Shale production to Atlas. Average realized oil prices increased 8% to $96.66 per barrel from $89.17 per barrel in the same period in 2011Average realized gas prices decreased 37% to $1.92 per Mcf in the third quarter of 2012 from $3.06 per Mcf in the same period in 2011.

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The following table summarizes production volumes, average realized sales prices and oil and gas revenues for the three months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		2012 Period Compared to 2011 Period			
	2012	2011	Increase (Decrease)		% Increase (Decrease)	
Production volumes-						
Oil and condensate (MBbls)	796	223	573		257	%
NGLs (Mboe)	78	36	42		117	%
Natural gas (MMcf)	8,877	9,695	(818	)	(8	)%
Total Natural gas and NGLs (MMcfe)	9,345	9,911	(566	)	(6	)%
Total barrels equivalent (Mboe)	2,354	1,875	479		26	%
Production Volumes per day-						
Oil and condensate per day (Bbls/d)	8,652	2,424	6,228		257	%
NGLs per day (Boe/d)	848	391	457		117	%
Natural gas (Mcfe/d)	96,489	105,380	(8,891	)	(8	)%
Total Natural gas and NGLs per day (Mcfe/d)	101,576	107,728	(6,152	)	(6	)%
Total barrels equivalent per day (Boe/d)	25,587	20,380	5,207		26	%
Average sales prices-						
Oil and condensate ($ per Bbl)	$96.66	$89.17	$7.49		8	%
NGLs ($ per Boe)	28.53	57.06	(28.53	)	(50	)%
Natural gas ($ per Mcf)	1.92	3.06	(1.14	)	(37	)%
Total average realized sales price (per Boe)	$40.87	$27.56	$13.31		48	%
Oil and gas revenues (In thousands)						
Oil and condensate	$76,945	$19,924	$57,021		286	%
NGLs	2,225	2,057	168		8	%
Natural gas	17,027	29,687	(12,660	)	(43	)%
Total oil and gas revenues	$96,197	$51,668	$44,529		86	%

Lease operating expenses were $7.1 million ($3.04 per Boe) for the three months ended September 30, 2012 as compared to lease operating expenses of $7.3 million ($3.89 per Boe) for the third quarter of 2011. The $0.2 million decrease in lease operating expenses is primarily due to the Atlas sale partially offset by increased production. The decrease in operating cost per Boe is primarily due to the Atlas sale (which were higher operating cost per Boe properties compared to our remaining Barnett Shale properties) partially offset by the higher operating cost per Boe associated with oil production.

Production taxes were $3.4 million (or 3.6% of oil and gas revenues) for the three months ended September 30, 2012 as compared to $1.3 million (or 2.6% of oil and gas revenues) for the three months ended September 30, 2011. 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 increased to $2.3 million ($0.99 per Boe) for the three months ended September 30, 2012 from $1.0 million ($0.55 per Boe) for the same period in 2011. The increase in ad valorem taxes is due primarily to new oil wells drilled in 2011. The increase in ad valorem taxes per Boe is due primarily to new oil wells drilled in 2011, which have higher property tax valuations as compared to our natural gas wells.

Depreciation, depletion and amortization (“DD&A”) expense for the third quarter of 2012 increased $26.2 million to $46.5 million ($19.76 per Boe) from the DD&A expense for the third quarter of 2011 of $20.3 million ($10.84 per

Boe). The $26.2 million 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 Shale as result

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of the Atlas sale as well as the significant increase in crude oil reserves in the Eagle Ford that were added in 2011 and 2012, which have a higher finding cost per Boe than our natural gas reserves.

General and administrative expense increased to $12.4 million for the three months ended September 30, 2012 from $4.7 million for the corresponding period in 2011. The increase was primarily due to increased stock-based compensation expense which was primarily driven by an increase in the fair value of cash-settled stock appreciation rights as well as an increase in the number of cash-settled stock appreciation rights outstanding during the third quarter of 2012 as compared to the same period of 2011, partially offset by decreased compensation costs attributable to the 2011 annual bonuses to senior management, which were paid during the second quarter of 2012, while the 2010 annual bonuses to senior management were paid during the third quarter of 2011.

The net loss on derivative instruments of $14.9 million in the third quarter of 2012 consisted of a $24.2 million unrealized loss on derivatives and a $9.3 million realized gain on derivatives. The net gain on derivative instruments of $25.6 million in the third quarter of 2011 was comprised of a $17.0 million unrealized gain on derivatives and an $8.6 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended September 30, 2012 were $18.9 million and $6.8 million, respectively, as compared to $13.4 million and $6.0 million, respectively, for the same period in 2011. The increase in interest expense was primarily due to interest on the $200 million aggregate principal amount of our 8.625% Senior Notes that were issued in the fourth quarter of 2011. The increase in capitalized interest was primarily related the U.K. Huntington field development project.

The estimated annual effective income tax rates for 2012 and 2011 were 38.1% and 36.4%, respectively. The benefit recognized during the third quarter of 2012 was due to the pre-tax loss incurred and the foreign tax benefit of our U.K. Huntington field development project. The actual effective income tax rate for the third quarter of 2011 was 38.6% which was higher than the estimated annual effective income tax rate due to revisions of prior period estimates of state income taxes.

Nine Months Ended September 30, 2012, Compared to the Nine Months Ended September 30, 2011

Revenues from oil and gas production for the nine months ended September 30, 2012 increased 78% to $260.7 million from $146.4 million for the same period in 2011 primarily due to increased production and higher oil prices, partially offset by lower gas prices. Production volumes for the nine months ended September 30, 2012 and 2011 were 7,056 Mboe and 5,520 Mboe, respectively. The increase in production for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 was primarily due to increased production from new wells, partially offset by normal production decline and the sales of Barnett Shale production to KKR Natural Resources ("KKR") and Atlas. Average realized oil prices increased 10% to $100.93 per barrel from $91.76 per barrel in the same period in 2011. Average realized gas prices decreased 46% to $1.70 per Mcf for the first nine months of 2012 from $3.12 per Mcf in the same period in 2011.

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The following table summarizes production volumes, average realized sales prices and oil and gas revenues for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30,		2012 Period Compared to 2011 Period	
	2012	2011	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (MBbls)	2,030	515	1,515	294 %
NGLs (Mboe)	191	175	16	9 %
Natural gas (MMcf)	29,011	28,977	34	— %
Total Natural gas and NGLs (MMcfe)	30,157	30,027	130	— %
Total barrels equivalent (Mboe)	7,056	5,520	1,536	28 %
Production volumes per day-				
Oil and condensate per day (Bbls/d)	7,409	1,886	5,523	293 %
NGLs per day (Boe/d)	697	641	56	9 %
Natural gas and NGLs per day (Mcfe/d)	105,880	106,143	(263)	— %
Total Natural gas and NGLs (Mcfe/d)	110,062	109,989	73	— %
Total barrels equivalent (Boe/d)	25,752	20,220	5,532	27 %
Average sales prices-				
Oil and condensate ($ per Bbl)	$ 100.93	$ 91.76	$ 9.17	10 %
NGLs ($ per Boe)	34.88	49.08	(14.20)	(29)%
Natural gas ($ per Mcf)	1.70	3.12	(1.42)	(46)%
Total average realized sales prices (per Boe)	$ 36.95	$ 26.52	$ 10.43	39 %
Oil and gas revenues (In thousands)				
Oil and condensate	$ 204,890	$ 47,284	$ 157,606	333 %
NGLs	6,662	8,576	(1,914)	(22)%
Natural gas	49,178	90,538	(41,360)	(46)%
Total oil and gas revenues	$ 260,730	$ 146,398	$ 114,332	78 %

Lease operating expenses were $22.6 million ($3.20 per Boe) for the nine months ended September 30, 2012 as compared to lease operating expenses of $21.4 million ($3.87 per Boe) for the nine months ended September 30, 2011. Lease operating expenses increased $1.2 million primarily due to increased production from new wells partially offset by the Atlas and KKR sales. The decrease in operating cost per Boe is due to the Atlas and KKR sales (which were higher operating cost per Boe properties as compared to our remaining Barnett Shale properties) partially offset by the higher operating cost per Boe associated with oil production.

Production taxes increased to $9.7 million (3.7% of oil and gas revenues) for the nine months ended September 30, 2012 from $3.7 million (2.5% of oil and gas revenues) for the nine months ended September 30, 2011. 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 increased to $8.2 million ($1.17 per Boe) for the nine months ended September 30, 2012 from $2.7 million ($0.49 per Boe) for the same period in 2011. The increase in ad valorem taxes is due primarily to new oil wells drilled in 2011 and the Commonwealth of Pennsylvania's February 2012 enactment of an "impact fee" on the drilling of unconventional natural gas wells. Because of the retroactive nature of the impact fee, approximately $1.2 million of ad valorem taxes recognized during the first nine months of 2012 is attributable to wells drilled prior to 2012. The increase in ad valorem taxes per unit is due primarily to new oil wells drilled in 2011, which have higher property tax valuations as compared to our natural gas wells, as well as the recognition of the impact fee in 2012.

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DD&A expense for the nine months ended September 30, 2012 increased $63.9 million to $121.5 million ($17.21 per Boe) from $57.6 million ($10.43 per Boe) for the same period in 2011. The $63.9 million 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 Shale as a result of the Atlas and KKR sales as well as the increase in crude oil reserves in the Eagle Ford that were added in 2011 and 2012, which have a higher finding cost per Boe than our natural gas reserves.

General and administrative expense increased to $37.0 million for the nine months ended September 30, 2012 from $28.1 million for the corresponding period in 2011. The increase was primarily due to increased compensation costs related to an increase in personnel in the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 and higher stock-based compensation expense due to a higher number of restricted stock awards outstanding at higher prices during 2012 as compared to the same period of 2011.

The net gain on derivative instruments of $26.4 million in the first nine months of 2012 consisted of a $3.9 million unrealized loss on derivatives and a $30.3 million realized gain on derivatives. The net gain on derivative instruments of $37.5 million in the first nine months of 2011 was comprised of a $23.5 million realized gain on derivatives and a $14.0 million unrealized gain on derivatives.

Interest expense and capitalized interest for the nine months ended September 30, 2012 were $54.0 million and $20.6 million, respectively, as compared to $38.0 million and $16.9 million, respectively, for the same period in 2011. The increase in interest expense was primarily due to interest on the $200 million aggregate principal amount of our 8.625% Senior Notes that were issued in the fourth quarter of 2011. The increase in capitalized interest was primarily related the U.K. Huntington field development project.

The estimated annual effective income tax rates for 2012 and 2011 were 38.1% and 36.4%, respectively. The actual effective income tax rate for the nine months ended September 30, 2012 was 31.4%, which was lower than the estimated annual effective income tax rates due to the foreign tax benefit of our U.K. Huntington field development project. The actual effective income tax rate for the nine months ended September 30, 2011 was 37.7%, which was higher than the estimated annual effective income tax rate due to revisions of prior period estimates of state income taxes.

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Liquidity and Capital Resources

2012 Capital Expenditure Plan and Funding Strategy. In August 2012, our Board approved a revised U.S. capital expenditure plan of $600.0 million which includes approximately $378.0 million for the Eagle Ford Shale, $61.0 million for the Niobrara Formation, $54.0 million for the Marcellus Shale, $29.0 million for the Barnett Shale, and $78.0 million for land, seismic and other activities, inclusive of carries. Planned capital expenditures for the Huntington Field development project in the U.K. North Sea are $35.0 million, all of which is expected to be funded by our Huntington Facility. We intend to finance the remainder of our 2012 capital expenditure plan primarily from the sources described below under " – Sources and Uses of Cash." Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. We are currently updating our U.S. capital expenditure plan to reflect the impact of the recently announced transactions on fourth quarter activity. Below is a summary of year to date U.S. capital expenditures through September 30, 2012.

	Year-to-date Capital Expenditures			
	March 31, 2012	June 30, 2012		September 30, 2012
U.S. Drilling	(In thousands)			
Eagle Ford	$102,080	$202,591		$296,577
Niobrara	15,660	41,888		57,890
Marcellus	24,444	53,372		73,921
Barnett, Gulf Coast, Other, etc.	20,239	32,016		35,897
Total U.S. Drilling	162,423	329,867	(a)	464,285
Total U.S. Leasehold & Seismic	21,273	68,163		92,415
Total U.S.	$183,696	$398,030		$556,700

(a) Includes approximately $25 million of retroactive increases in ownership interests and capital expenditures that were previously underestimated for work incurred during the quarter.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic data acquisition programs. The actual amount of investment could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. For the nine months ended September 30, 2012, we funded our capital expenditures with cash provided by operations, payments or carried interest relating to our joint ventures with Reliance and GAIL, net proceeds from the Atlas and Gulf Coast sales, proceeds from the offering of our 7.50% Senior Notes, and borrowings under our Revolving Credit Facility and the Huntington Facility. Potential sources of future liquidity include the following:

- Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oilfield services. We hedge a portion of our production to mitigate the risk of a decline in oil and gas prices. .
- Borrowings under the Revolving Credit Facility and the Huntington Facility. At October 31, 2012, no borrowings were outstanding under the Revolving Credit Facility and$48.0 million of borrowings were outstanding under the Huntington Facility. At October 31, 2012, we had $1.0 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, which borrowing base is currently $365.0 million, is subject to compliance with the financial covenants and other provisions of the credit agreement governing the Revolving Credit Facility.
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Borrowings under project financing arrangements in certain limited circumstances. As described above, we plan to fund a substantial portion of our remaining costs relating to development of the Huntington Field from our Huntington Facility.

• Asset sales. On April 30, 2012, we completed the sale of a significant portion of our Barnett Shale properties to Atlas for an agreed upon price of $190.0 million. Net proceeds received from the sale were approximately $186.7 million, subject to final post-closing adjustments. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2012 and the closing date of April 30,

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2012. We used substantially all of the net proceeds from this sale to reduce the outstanding borrowings under the Revolving Credit Facility. During the third quarter of 2012, we completed the sale of substantially all of our legacy producing properties along the onshore Gulf of Mexico located primarily in Texas and Louisiana for an agreed upon price of $19.3 million, subject to final post-closing adjustments. Net proceeds received from the sale were approximately $14.3 million as of September 30, 2012 and we expect to receive up to an additional $3.5 million in the fourth quarter of 2012. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of July 1, 2012 and the closing date of September 27, 2012. The proceeds from such sale were recognized as a reduction of proved oil and gas properties. In order to further fund our capital expenditure plan, we may consider additional sales of certain properties or assets, including our interest in the Huntington field development project in the U.K. North Sea that are not part of our core business, or are no longer deemed essential to our future growth, and provided that we are able to sell such assets on terms that are acceptable to us.

- Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.
- Lease option agreements and land banking arrangements, such as those we have entered into in the Barnett Shale and other plays.
- 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 and/or purchase a portion of interests, such as our joint ventures with Reliance in the Marcellus Shale, with GAIL in the Eagle Ford Shale, and the recently announced joint ventures in the Niobrara Formation.

Overview of Cash Flow Activities. Net cash provided by operating activities was $176.2 million and $130.3 million for the nine months ended September 30, 2012 and 2011, respectively. The increase was primarily due to increased crude oil production and prices, partially offset by lower gas prices in the first nine months of 2012 as compared to the same period in 2011.

Net cash used in investing activities was $465.7 million and $185.8 million for the nine months ended September 30, 2012 and 2011, respectively, and increased primarily due to increased capital expenditures particularly related to our increased Eagle Ford drilling program as well as increased advances for joint operations, partially offset by an increase in proceeds from sales of oil and gas properties.

Net cash provided by financing activities for the nine months ended September 30, 2012 and 2011 was $275.6 million and $55.1 million, respectively. The increase related primarily to the proceeds from the issuance of $300.0 million of our 7.50% Senior Notes in September 2012 as well as increased net borrowings under the Huntington Facility during the first nine months of 2012 as compared to the first nine months of 2011, partially offset by a decrease in net borrowings under the Revolving Credit Facility during the first nine months of 2012 as compared to the first nine months of 2011.

Liquidity/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, the sale of assets (including our sale of Barnett Shale properties to Atlas and our sale of Gulf Coast properties), our Utica and Niobrara joint venture transactions, borrowings under the Revolving Credit Facility and the Huntington Facility and cash on hand will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities is primarily driven by production and commodity prices. While we have steadily increased production over the last few years, spot and futures prices of natural gas remain depressed. 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 program, we hedge a portion of our production and, as of October 31, 2012, we had hedged approximately 4,876,000 MMBtu (53,000 MMBtu per day for the remainder of 2012) of our estimated November and December 2012 natural gas production at a weighted average floor or swap price of $5.32 per MMBtu relative to WAHA and Houston Ship Channel prices. Additionally, we had hedged approximately 671,600 Bbls (7,300 Bbls per day for the remainder of 2012) of our estimated November and December 2012 crude oil production at a weighted average floor or swap price of $89.95 per Bbl relative to NYMEX prices. As of October 31, 2012, no borrowings were outstanding under the Revolving Credit Facility and we had borrowings outstanding of $48.0 million under our Huntington Facility. Our borrowing base under our Revolving Credit Facility is currently $365.0 million. At October 31, 2012, we had $1.0 million in letters of credit outstanding, which reduce the amounts available under the Revolving Credit Facility. Additionally, as noted 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 is affected by our lenders' assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base. The next borrowing base redetermination is scheduled to occur in the spring of 2013.

If cash provided by operating activities, proceeds from asset sales, funds available under the Revolving Credit Facility and the Huntington Facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund the remainder of our revised 2012 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing

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alternatives to fund it. 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 revised 2012 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 or cash on hand 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, 2012 (in thousands):

	2012	2013	2014	2015	2016	2017 and Beyond	Total
Debt (1)	$—	$30,550	$16,450	$—	$73,750	$900,000	$1,020,750
Interest on debt (2)	29,336	79,076	78,439	76,591	74,426	148,500	486,368
Operating leases	25	1,216	1,388	1,370	1,370	7,533	12,902
Drilling contracts	12,332	52,358	30,509	9,490	—	—	104,689
Pipeline volume commitments	3,072	16,223	17,210	15,224	7,858	1,411	60,998
Asset retirement obligations	1,100	128	150	7	—	9,903	11,288
Seismic obligations	1,907	—	—	—	—	—	1,907
Other	1,189	660	104	—	—	—	1,953
Total Contractual Obligations	$48,961	$180,211	$144,250	$102,682	$157,404	$1,067,347	$1,700,855

(1) Noteholders may require us to repurchase the Convertible Senior Notes in June 2013, June 2018 or June 2023. The Company has the intent and ability to refinance the Convertible Senior Notes on a long-term basis with the available capacity of its Senior Secured Revolving Credit Facility, which matures in 2016, and accordingly, the Convertible Senior Notes have been presented as a 2016 contractual obligation.

(2) Interest on long-term debt is based on the 8.625% Senior Notes, the 7.50% Senior Notes, the September 30, 2012 average interest rate of 3.93% for amounts outstanding under the Huntington Facility and the 4.375% rate on the Convertible Senior Notes until June 1, 2013 and the Revolving Credit Facility rate of 3.17% thereafter (reflecting our intent and ability to refinance the Convertible Senior Notes with the available capacity under our Revolving Credit Facility). There were no borrowings under our Revolving Credit Facility as of September 30, 2012, therefore no interest was computed for the Revolving Credit Facility as it relates to the table above.

Financing Arrangements

Senior Secured Revolving Credit Facility

In January 2011, we entered into the Revolving Credit Facility which provides for a borrowing capacity up to the lesser of (i) the Borrowing Base and (ii) $750.0 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of our assets (excluding our Carrizo UK assets described below under "—Huntington Field Development Project Credit Facility" and our Utica Shale assets) and is guaranteed by all of our existing subsidiaries (other than Carrizo UK Huntington, Monument Exploration LLC and Carrizo UK Bardolph Ltd). In November 2012, our wholly-owned subsidiary, Carrizo (Utica) LLC, guaranteed borrowings under 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. The initial borrowing base under the Revolving Credit Facility was $350.0 million and as of June 30, 2012, the borrowing base was $325.0 million. As a result of the Fall 2012 borrowing base redetermination, effective September 27, 2012, the borrowing base was increased to $365.0 million after considering the addition of proved reserves as a result of the Company's successful ongoing drilling program, the removal of properties in connection with the recent sale of Gulf Coast properties, and the transaction with OIL India Ltd. and Indian Oil Corporation Ltd.

On March 26, 2012, the Revolving Credit Facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the Revolving Credit Facility) steps down and (2) increase the basket available for redemptions of our Convertible Senior Notes from $30.0 million to $75.0 million. On September 4, 2012, we amended the Revolving Credit Facility to increase the basket available for issuances of

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additional senior notes, including our 7.50% Senior Notes issued in September 2012, from $200 million to $350 million. On September 27, 2012, the Revolving Credit Facility was amended to, among other things, extend the maximum permitted duration of hedge agreements entered into by the Company and its restricted subsidiaries from four years to five years and to reflect the Fall 2012 borrowing base redetermination.

We are 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 (a) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012 and (b) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (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). At September 30, 2012, the ratio of Total Debt to EBITDA was 3.61 to 1.00, the Current Ratio was 2.08 to 1.00, the ratio of Senior Debt to EBITDA was 0.00 to 1.00 and the ratio of EBITDA to Interest Expense was 5.31 to 1.00. 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.

The 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.

The Revolving Credit Facility is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing the 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, 2012, we had no borrowings outstanding under the Revolving Credit Facility. At September 30, 2012, we had $1.0 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the $365.0 million 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. The Revolving Credit Facility may also be used to repurchase the Convertible Senior Notes.

U.K. Huntington Field Development Project Credit Facility

On January 28, 2011, we and Carrizo UK, as borrower, entered into the Huntington Facility. The Huntington Facility is secured by substantially all of Carrizo UK’s assets and is limited recourse to us. The Huntington Facility provides financing for a substantial portion of Carrizo UK’s share of costs associated with the Huntington Field development project in the U.K. North Sea. The Huntington Facility provides for a multicurrency credit facility consisting of (1) a $55.0 million term loan facility to be used to fund Carrizo UK’s share of project development costs, (2) a $6.5 million contingent cost overrun term loan facility and (3) a $22.5 million post-completion credit facility providing for letters of credit to be used to secure certain abandonment and decommissioning obligations following project completion. Availability under each of the term loan facility and the cost overrun facility is subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK attributable to certain proved reserves in the Huntington Field project. The availability under the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. The Company expects the semi-annual redetermination to take place during the fourth quarter of 2012.

Initial borrowings under the term loan facility and cost overrun facility were conditioned on, among other things, our having made an approximate $22.5 million equity contribution to Carrizo UK, which was completed during the first quarter of 2011. Prior to project completion, we may be responsible under the Huntington Facility for making an additional equity contribution to Carrizo UK in the event the term loan borrowing base is reduced to a level at or above the amount of borrowings then outstanding. We may also be responsible under the Huntington Facility for making certain additional equity contributions to Carrizo UK in the event of certain specified projected Cost Overruns (as defined in the Huntington Facility). To the extent that the cost overrun facility and any required equity contributions are insufficient, we are responsible for funding any Cost Overruns on a 100% basis. If after project completion, the lenders reasonably determine that Carrizo UK is required to incur additional capital expenditures that were not contemplated by the Huntington Field development plan originally approved by the U.K. Department of Energy and Climate Change, we will be responsible for funding such additional expenditures. We are responsible for making certain other payments under the Huntington Facility, including funding certain projected working capital shortfalls, providing cash collateral for letters of credit issued under the post-completion credit facility and paying certain costs of the required hedging arrangements described below.

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The annual interest rate on each borrowing is (a) LIBOR (EURIBOR for euro-denominated loans) for the applicable interest period, plus (b) a margin of (i) 3.50% until the completion of the Huntington Field development project and 3.0% thereafter for the term loan credit facility and post-completion credit facility or (ii) 4.75% for the cost overrun facility.

Borrowings under the term loan and cost overrun facilities are available until the earlier of June 30, 2013 or the achievement of certain project development milestones. The term loan and cost overrun facilities mature on December 31, 2014, subject to acceleration in the event that future projection estimates of remaining reserves in the project area have declined to less than 25% of the level initially projected by Carrizo UK and the lenders. Letters of credit under the post-completion credit facility mature on December 31, 2016. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014.

The Huntington Facility requires Carrizo UK to enter into certain hedging arrangements in order to hedge a specified portion of the Huntington Field project's exposure to fluctuating petroleum prices as well as changes in interest rates or exchange rates, and permits Carrizo UK to enter into additional hedging arrangements. The Huntington Facility places restrictions on Carrizo UK with respect to additional indebtedness, liens, the extension of credit, dividends or other payments to us or our other subsidiaries, investments, acquisitions, mergers, asset dispositions, commodity transactions outside of the mandatory hedging program, transactions with affiliates and other matters.

The Huntington Facility is subject to customary events of default. If an event of default occurs and is continuing, the Majority Lenders may accelerate amounts due under the Huntington Facility.

As of September 30, 2012, borrowings outstanding under the Huntington Facility were $47.0 million, of which $21.2 million was classified as current, with a weighted average interest rate of 3.93% and no letters of credit had been issued.

Critical Accounting Policies

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in our Annual Report on Form 10-K for the year ended December 31, 2011. 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 the 12 month average oil and gas prices used in our September 30, 2012 U.S. full cost ceiling test and related cushion along with various pricing scenarios to demonstrate the sensitivity of our U.S. cost center ceiling to changes in 12 month average oil and/or gas prices. This sensitivity analysis is as of September 30, 2012 and, accordingly, does not consider drilling results, production and prices subsequent to September 30, 2012 that may require revisions to our proved reserve estimates.

	12 Month Average Price		Cushion/(Impairment)
US Full Cost Pool Scenarios	Oil Price ($/Bbl)	Gas Price ($/MMbtu)	(in millions)
September 30, 2012 Actual	$100.13	$1.97	$59
Oil and Gas Price Sensitivity			
Oil and Gas +10%	$110.14	$2.17	$216
Oil and Gas -10%	$90.12	$1.77	$(133)
Oil Price Sensitivity			
Oil +10%	$110.14	$1.97	$184

Oil -10%	$90.12	$1.97	$(80)
Gas Price Sensitivity			
Gas +10%	$100.13	$2.17	$110
Gas -10%	$100.13	$1.77	$6

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The cost center ceiling exceeded our net capitalized costs for the U.K. cost center at September 30, 2012 by approximately $132.9 million and was based on 12 month average oil prices of $106.17 per barrel. A ten percent increase in average market prices at September 30, 2012 would have increased the cost center ceiling by approximately $20.9 million and a ten percent decrease in average market prices would have decreased the cost center ceiling by approximately $19.0 million. This sensitivity analysis is as of September 30, 2012 and, accordingly, does not consider drilling results and prices subsequent to September 30, 2012 that may require revisions to our proved reserve estimates.

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, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and gas.

We review the carrying value of our oil and gas properties quarterly 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, 2011.

We rely on 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 program. 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, expiration or exchanged for physical delivery contracts. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production for up to 36 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, 2012, and December 31, 2011 was a net asset of $34.4 million and $37.3 million, respectively. The following sets forth a summary of the net fair value of our derivative instruments by counterparty:

Counterparty	September 30, 2012		December 31, 2011	
Credit Suisse	54	%	68	%
BNP Paribas	24	%	19	%
Societe Generale	15	%	2	%
BBVA Compass	4	%	—	%
Shell Energy North America (US) LP	2	%	6	%
Wells Fargo	1	%	—	%
Credit Agricole	—	%	5	%
Total	100	%	100	%

Master netting agreements are in place with these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the 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, Credit Agricole, BBVA Compass, and Societe Generale are lenders under our Revolving Credit Facility, and BNP Paribas and Societe Generale are lenders under our Huntington 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 the Revolving Credit Facility or the Huntington Facility, respectively.

The following sets forth a summary of our U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of September 30, 2012:

Period	Volumes	Weighted	Weighted

	(in MMbtu)	Average Floor Price ($/MMbtu)	Average Ceiling Price ($/MMbtu)
2012	4,876,000	$5.32	$5.50
2013	10,950,000	$5.07	$5.07
2014	3,650,000	$—	$5.50

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In connection with the natural gas derivative instruments above, we entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of $4.43, the floor price becomes the market price plus the put spread of $1.28 on 2,134,400 of the 4,876,000 MMBtus and the remaining 2,741,600 MMBtus would have a floor price of $5.32.

The following sets forth a summary of our U.S. crude oil derivative positions at average NYMEX prices as of September 30, 2012:

Period	Volumes (in Bbls)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
2012	671,600	$ 89.95	$ 102.95
2013	2,591,500	$ 88.85	$ 103.32
2014	1,642,500	$ 89.50	$ 102.64
2015	985,500	$ 89.91	$ 100.08
2016	244,000	$ 85.00	$ 104.00

In connection with the crude oil derivative instruments above, we entered into protective put spreads. For 2014, at market prices below the short put price of $65.00, the floor price becomes the market price plus the put spread of $20.00 on 182,500 of the 1,642,500 Bbls and the remaining 1,460,000 Bbls would have a floor price of $89.50.

Period	Volumes (in Bbls)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
2014	182,500	$ 65.00	$ 20.00
2015	365,000	$ 65.00	$ 20.00
2016	244,000	$ 65.00	$ 20.00

For the three and nine months ended September 30, 2012 and 2011, we recorded the following related to our oil and gas derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Realized gain (loss) on derivative instruments, net	$ 9,310	$ 8,626	$ 30,330	$ 23,536
Unrealized gain (loss) on derivative instruments, net	(24,163)	17,030	(3,898)	13,998
Gain (loss) on derivative instruments, net	$ (14,853)	$ 25,656	$ 26,432	$ 37,534

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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, acquisition of 3-D seismic data (including number, timing and size of projects), 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 facilities, 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 expression 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 facilities, evaluations of the Company by lenders under our credit facilities, 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, 2011 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, 2011. 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, 2011.

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, 2012 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

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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, 2012 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 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, 2011.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
Issuance of Common Stock to the University of Texas at Arlington. On July 25, 2012, the company issued 45,327 shares of the Company's common stock to the University of Texas at Arlington at par value ($0.01 per share), for proceeds of $453. This issuance was related to our third quarter 2012 pledge of $1.0 million to the University of Texas at Arlington. The shares were issued pursuant to an exemption from registration under §4(2) of the Securities Act of 1933, as amended.

Item 3. Defaults Upon Senior Securities
None.

Item 4. Mine Safety Disclosures
None.

Item 5. Other Information
Additional Subsidiary Guarantor. On November 6, 2012, the Company, its guaranteeing subsidiaries under its public debt indentures, and Wells Fargo Bank, National Association, as Trustee, entered into the Eleventh Supplemental Indenture, Twelfth Supplemental Indenture, Thirteenth Supplemental Indenture, and Fourteenth Supplemental Indenture. As a result of the Eleventh, Twelfth and Thirteenth Supplemental Indentures, the Company's wholly-owned subsidiary, Carrizo (Utica) LLC, has issued a full, unconditional and joint and several guarantee of the 8.625% Senior Notes, the 7.50% Senior Notes, and the Convertible Senior Notes, respectively, and may guarantee future issuances of debt securities. Carrizo (Utica) LLC also guarantees borrowings under the Revolving Credit Facility. As a result of the Fourteenth Supplemental Indenture, certain definitions in the Indenture governing the 8.625% Senior Notes are conformed to those used in the offering memorandum and prospectus for such senior notes.

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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
*4.1	–	Eleventh Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
*4.2	–	Twelfth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
*4.3	–	Thirteenth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
*4.4	–	Fourteenth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
10.1	–	Second Amendment to Credit Agreement, dated as of September 4, 2012, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 4, 2012).
*10.2	–	Third Amendment to Credit Agreement, dated as of September 27, 2012, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto.
*31.1	–	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	–	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	–	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	–	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	–	Interactive Data Files

* Filed herewith.

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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 7, 2012	By: /s/ Paul F. Boling Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)
Date: November 7, 2012	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)