CARRIZO OIL & GAS INC
Form 10-Q
August 09, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

[ ] 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	**76-0415919**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1000 Louisiana Street, Suite 1500, Houston, Texas	**77002**
(Address of principal executive offices)	(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 [] 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 [ ] Accelerated filer [X]

Non-accelerated filer [ ] Smaller reporting company [ ]

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

YES [ ] NO [X]

The number of shares outstanding of the registrant s common stock, par value $0.01 per share, as of July 29, 2011 was 39,297,781.

Table of Contents

CARRIZO OIL & GAS, INC.

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2011

INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

	000000000	000000000
	June 30, 2011 (Unaudited)	**December 31, 2010**
	(In thousands, except per share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 24,102	$ 4,128
Accounts receivable, net		
Oil and gas sales	16,063	16,027
Joint interest billing	15,978	14,309
Related party	1,478	-
Other	345	560
Advances to operators	625	487
Fair value of derivative instruments	17,754	17,698
Prepaids and other current assets	10,460	7,123
Total current assets	86,805	60,332
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full cost method of accounting:		
Proved oil and gas properties, net	622,548	626,665
Costs not subject to amortization	439,750	352,479
Other property and equipment, net	4,198	3,913
TOTAL PROPERTY AND EQUIPMENT, NET	1,066,496	983,057
DEFERRED FINANCING COSTS, NET	20,539	14,670
INVESTMENTS	2,523	3,392
FAIR VALUE OF DERIVATIVE INSTRUMENTS	4,717	7,257
DEFERRED INCOME TAXES	67,979	72,587
INVENTORY	-	1,646
OTHER ASSETS	1,566	1,193
TOTAL ASSETS	$ 1,250,625	$ 1,144,134
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 24,731	$ 33,653
Revenue and royalties payable	32,896	23,864
Current state tax payable	-	4,052
Accrued drilling costs	51,415	26,884
Accrued interest	7,908	5,953
Other accrued liabilities	20,935	11,838
Advances for joint operations	15,775	3,407
Current maturities of long-term debt	-	160
Deferred income taxes	5,418	5,286
Other current liabilities	2,082	3,907

Total current liabilities		161,160		119,004
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT		607,009		558,094
ASSET RETIREMENT OBLIGATIONS		6,133		6,369
FAIR VALUE OF DERIVATIVE INSTRUMENTS		87		715
OTHER LIABILITIES		3,371		3,316
COMMITMENTS AND CONTINGENCIES				
SHAREHOLDERS EQUITY				
Common stock, $0.01 par value (90,000 shares authorized, 39,280 and 38,906 shares issued and outstanding at June 30, 2011 and December 31, 2010, respectively)		393		389
Additional paid-in capital		638,593		630,845
Accumulated deficit		(166,121)		(174,598)
Total shareholders equity		472,865		456,636
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$	1,250,625	$	1,144,134

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

Table of Contents

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	00000000000	00000000000	00000000000	00000000000
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands except per share amounts)			
OIL AND GAS REVENUES	$ 50,672	$ 32,922	$ 94,730	$ 71,878
COSTS AND EXPENSES				
Lease operating	7,427	6,166	14,093	11,243
Production tax	1,466	885	2,407	1,790
Ad valorem tax	981	468	1,672	1,672
Depreciation, depletion and amortization	20,595	11,079	37,271	20,920
Impairment of oil and gas properties	-	2,731	-	2,731
General and administrative (inclusive of stock-based compensation expense of $6,805 and $3,156 for the three months ended June 30, 2011 and 2010, respectively, and $10,655 and $5,320 for the six months ended June 30, 2011 and 2010, respectively)	14,094	7,750	23,339	14,686
Accretion related to asset retirement obligations	71	53	145	104
TOTAL COSTS AND EXPENSES	44,634	29,132	78,927	53,146
OPERATING INCOME	6,038	3,790	15,803	18,732
OTHER INCOME AND EXPENSES				
Gain (loss) on derivative instruments, net	12,065	3,214	11,878	26,016
Loss on extinguishment of debt	-	-	(897)	-
Interest expense	(12,407)	(9,845)	(24,615)	(19,655)
Capitalized interest	5,649	4,992	10,909	9,461
Other income (expense), net	(1)	(51)	61	(21)
INCOME BEFORE INCOME TAXES	11,344	2,100	13,139	34,533
INCOME TAX EXPENSE	(3,602)	(315)	(4,662)	(13,012)
NET INCOME	$ 7,742	$ 1,785	$ 8,477	$ 21,521
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAXES				
Increase in market value of investment in Pinnacle Gas Resources, Inc., net of income taxes	-	15	-	-
COMPREHENSIVE INCOME	$ 7,742	$ 1,800	$ 8,477	$ 21,521
NET INCOME PER COMMON SHARE				
BASIC	$ 0.20	$ 0.05	$ 0.22	$ 0.66
DILUTED	$ 0.20	$ 0.05	$ 0.21	$ 0.65
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	38,898	34,060	38,841	32,574
DILUTED	39,497	34,464	39,450	33,022

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

Table of Contents

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	000000000	000000000
	For the Six Months Ended June 30	
	2011	**2010**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 8,477	$ 21,521
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	37,271	20,920
Unrealized (gain) loss on derivative instruments	3,032	(12,269)
Impairment of oil and gas properties	-	2,731
Accretion related to asset retirement obligations	145	104
Loss on extinguishment of debt	897	-
Stock-based compensation	10,655	5,320
Allowance for doubtful accounts	(54)	345
Deferred income taxes	4,739	12,995
Amortization of discount and deferred financing costs, net of amounts capitalized	1,570	4,066
Other, net	4,058	813
Changes in operating assets and liabilities-		
Accounts receivable	(2,912)	(9,327)
Accounts payable	8,381	(5,295)
Accrued liabilities	3,876	(2,562)
Other, net	(6,013)	816
Net cash provided by operating activities	74,122	40,178
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(219,179)	(164,949)
Change in capital expenditure payables and accruals	12,464	(2,662)
Proceeds from sales of oil and gas properties	101,590	1,977
Advances to operators	(138)	116
Advances for joint operations	12,368	(412)
Other, net	(221)	(287)
Net cash used in investing activities	(93,116)	(166,217)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings	346,000	163,600
Debt repayments	(298,660)	(113,000)
Proceeds from common stock offering, net of offering costs	-	74,042
Proceeds from stock options exercised	47	667
Payments of debt issuance costs	(8,419)	(355)
Net cash provided by financing activities	38,968	124,954
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	19,974	(1,085)

CASH AND CASH EQUIVALENTS, beginning of period		4,128		3,837
CASH AND CASH EQUIVALENTS, end of period	$	24,102	$	2,752

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

Table of Contents

CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc. is an independent energy company which, together with its subsidiaries (collectively referred to herein as the Company), is engaged in the exploration, development and production of oil and gas in the United States and the U.K. North Sea. The Company s current operations are principally focused in proven, producing oil and gas plays in the Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania, New York and West Virginia, the Eagle Ford Shale in South Texas, the Niobrara Formation in Colorado and the Huntington Field located in the U.K. North Sea.

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. The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and LLCs 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 U.S. generally accepted accounting principles (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 six months ended June 30, 2011 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, 2010.

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, comprehensive 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 test, 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 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.

Table of Contents

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 on a quarterly basis and adjusts the allowance as necessary using the specific identification method. At June 30, 2011 and December 31, 2010, the Company s allowance for doubtful accounts was $2.3 million and $2.5 million, respectively.

Concentration of Credit Risk

Substantially all of the Company s accounts receivable result from oil and gas sales, joint interest billings to third parties 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 9. 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 directly associated with acquisition, exploration and development activities are capitalized and totaled $ 3.1 million and $1.6 million for the three months ended June 30, 2011 and 2010, respectively, and $5.5 million and $2.8 million for the six months ended June 30, 2011 and 2010, respectively. 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 Mcfe on oil and gas properties was $1.82 and $1.16 for the three months ended June 30, 2011 and 2010, respectively, and $1.68 and $1.16 for the six months ended June 30, 2011 and 2010, respectively.

Costs not subject to amortization include unevaluated leasehold costs, seismic costs associated with specific unevaluated properties, related capitalized interest and the cost of exploratory wells in progress. Significant costs 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, and the terms of oil and gas leases not held by production and drilling capital expenditure plans. The Company expects to complete its evaluation of the majority of its unproved properties within the next two to five years. Insignificant costs 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 of $5.6 million and $5.0 million for the three months ended June 30, 2011 and 2010, and $10.9 million and $9.5 million for the six months ended June 30, 2011 and 2010, respectively. Interest is capitalized on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of oil and gas properties are recognized as a reduction of capitalized oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company has not had any sales of oil and gas properties that significantly alter that relationship.

Table of Contents

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 provided using the straight-line method based on estimated useful lives ranging from five to ten years.

Deferred Financing Costs

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

Investments

Prior to the sale in January 2011 (see Note 3. Investments), the Company accounted for its investment in Pinnacle Gas Resources, Inc. (Pinnacle) as available-for-sale and adjusted the book value to fair value through other comprehensive income (loss), net of income taxes. This fair value was assessed quarterly for other than temporary impairment based on publicly available information. If the impairment was deemed other than temporary, it was recognized in earnings. Subsequent recoveries in fair value were reflected as increases to investments and other comprehensive income (loss), net of income taxes.

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 current and long-term debt. The carrying amounts of cash and cash equivalents, receivables, payables and short-term debt approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amounts of long-term debt under the Prior Credit Facility and the Revolving Credit Facility (each as defined in Note 6. Debt) approximate fair value as these borrowings bear interest at variable rates of interest. The carrying amounts of the Company s 8.625% Senior Notes due 2018 (Senior Notes)and the Company s 4.375% convertible senior notes due 2028 (Convertible Senior Notes) do not approximate fair value because the notes bear interest at fixed rates of interest. See Note 10. 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 when the well is drilled with an associated increase in oil and gas property costs. The asset retirement obligation is recorded at fair value and requires 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 obligation is discounted using a credit-adjusted risk-free interest rate which is accreted over time to its expected settlement value. Estimated costs consider historical experience, third party estimates and state regulatory requirements and do not consider salvage values. At least annually, the Company reassesses its asset retirement obligations to determine whether a change in the estimated obligation is necessary. On a quarterly basis, the Company evaluates whether there are indicators that 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 it is both probable that an asset has been impaired or that a liability has been incurred and the amount of such loss is reasonably estimable.

Table of Contents

Revenue Recognition

Oil and gas sales 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 June 30, 2011 and December 31, 2010, 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 current 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 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.

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 9. 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 (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 expenses for the periods indicated which is reflected as general and administrative expense in the consolidated statements of operations:

	00000000	00000000	00000000	00000000
	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(In thousands)			
Stock Options and SARs	$ 3,794	$ 100	$ 6,914	$ 521
Restricted Stock Awards and Units	4,450	3,056	6,450	4,799
	8,244	3,156	13,364	5,320
Less: amounts capitalized	(1,439)	-	(2,709)	-
Total Stock-Based Compensation Expense	$ 6,805	$ 3,156	$ 10,655	$ 5,320

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. 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 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.

Table of Contents

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 awards or units with performance conditions, in which case the Company uses the graded vesting method. The fair value of restricted stock awards and units is based on the average of the high and low 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. 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 Per Common Share

Supplemental net income per common share information is provided below:

	$00001,785	$00001,785	$00001,785	$00001,785
	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(In thousands, except per share amounts)			
Net income	$ 7,742	$ 1,785	$ 8,477	$ 21,521
Weighted average common shares outstanding				
Basic weighted average common shares outstanding	38,898	34,060	38,841	32,574
Restricted stock, stock options and warrants	599	404	609	448
Diluted weighted average common shares outstanding	39,497	34,464	39,450	33,022
Net income (loss) per common share				
Basic	$ 0.20	$ 0.05	$ 0.22	$ 0.66
Diluted	$ 0.20	$ 0.05	$ 0.21	$ 0.65

Basic income per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted income 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 units, stock options, Stock SARs expected to be settled in common stock, warrants and convertible debt. The Company excluded 1,369 and 263,230 shares related to restricted stock units, stock options and warrants from the calculation of dilutive shares for the three months ended June 30, 2011 and 2010, and 688 and 263,230 shares for the six months ended June 30, 2011 and 2010, respectively, because the grant prices were greater than the average market prices of the common shares for the period and would be antidilutive to the computation. Shares of common stock subject to issuance upon the conversion of the Convertible Senior Notes did not have an effect on the calculation of dilutive shares for the three and six months ended June 30, 2011 or 2010, because the conversion price was in excess of the market price of the common stock for those periods.

Table of Contents

3. INVESTMENTS

Investments consisted of the following at June 30, 2011 and December 31, 2010:

	0000000000000 June 30, 2011	0000000000000 December 31, 2010
	(In thousands)	
Pinnacle Gas Resources, Inc.	$ -	$ 869
Oxane Materials, Inc.	2,523	2,523
	$ 2,523	$ 3,392

Pinnacle Gas Resources, Inc.

On January 25, 2011, Pinnacle announced that it had been acquired by Powder Holdings, LLC, an entity controlled by SW Energy Capital LP. Under the terms of the merger agreement, the Company received $0.9 million, or $0.34 per share, for its 2,555,825 shares of Pinnacle common stock during the second quarter of 2011.

4. PROPERTY AND EQUIPMENT

At June 30, 2011 and December 31, 2010, property and equipment consisted of the following:

	June 30, 2011	December 31, 2010
	(In thousands)	
Proved oil and natural gas properties	$ 973,778	$ 941,267
Costs not subject to amortization	439,750	352,479
Land, building and other equipment	7,697	7,314
Total property and equipment	1,421,225	1,301,060
Accumulated depreciation, depletion and amortization	(354,729)	(318,003)
Property and equipment, net	$ 1,066,496	$ 983,057

During the second quarter of 2011, the Company sold a substantial portion of its non-core area Barnett Shale properties to KKR Natural Resources, a partnership formed between an affiliate of Kohlberg Kravis Roberts & Co. L.P. (KKR) and Premier Natural Resources. Net proceeds received from the sale were approximately $98 million, which represent an agreed upon purchase price of approximately $104 million less net purchase price 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, 2011 and the closing date of May 17, 2011. The proceeds from such sale were recognized as a reduction of proved oil and gas properties, net.

On August 4, 2010, the Company entered into a purchase and sale agreement with Reliance Marcellus II, LLC (Reliance), a wholly-owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited pursuant to which Reliance purchased 20% of our interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale for a combination of cash and a commitment to pay certain of our future development costs. Simultaneous with such transaction, our joint venture partner, ACP II Marcellus, LLC (ACP II), an affiliate of Avista Capital Holdings LP, entered into a purchase and sale agreement with Reliance under which it agreed to sell its entire interest in the same properties to Reliance. In June 2011, in accordance with the title and post-closing adjustment provisions of the purchase and sale agreements described above, the Company provided additional interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale to Reliance in substitution of properties included in the sale that were affected by certain alleged title defects. In exchange for such substitute properties, the

Company received $0.3 million in cash from Reliance relating to the sale of 20% of its interest. Additionally, during the second quarter of 2011, the Company received cash distributions of $3.3 million on its B Unit investment in ACP II as a result of ACP II s distribution to Avista of remaining proceeds from its sale of oil and gas properties to an affiliate of Reliance. These distributions are recognized as a reduction of capitalized oil and gas property costs.

Table of Contents

5. INCOME TAXES

For the three and six months ended June 30, 2011 and 2010, all of the Company s income before income taxes is derived primarily from activities within the United States as well as the Company s activities in the United Kingdom. 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 is 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. Actual income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate rate of 35% to income before income taxes as follows:

	0000000	0000000	0000000	0000000
	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(In thousands)			
Income tax expense at the statutory rate	$ 3,971	$ 735	$ 4,599	$ 12,087
State income taxes, net of federal benefit	127	14	1,702	1,348
Foreign income taxes	(175)		(175)	
Capital loss associated with investment in Pinnacle for which no income tax benefit was recognized in prior years	-		(1,135)	-
Other, net	(321)	(434)	(329)	(423)
Income tax expense	$ 3,602	$ 315	$ 4,662	$ 13,012

As of June 30, 2011, the Company had income tax net operating loss (NOL) carryforwards of approximately $181.8 million which expire between 2019 and 2031 if not utilized in earlier periods. The realization of the deferred tax assets related to NOL carryforwards is dependent on the Company s ability to generate taxable income in the future. The Company believes it will be able to generate sufficient taxable income in the NOL carry forward period. As such, the Company believes that it is more likely than not that its deferred tax assets will be fully realized.

At June 30, 2011, the Company had no material uncertain tax positions and the tax years since 1999 remain open to review by federal and various state tax jurisdictions.

6. DEBT

Debt consisted of the following at June 30, 2011 and December 31, 2010:

	0000000000000	0000000000000
	June 30, 2011	**December 31, 2010**
	(In thousands)	
Senior Notes	$ 400,000	$ 400,000
Unamortized discount for Senior Notes	(2,627)	(2,751)
Convertible Senior Notes	73,750	73,750
Unamortized discount for Convertible Senior Notes	(5,114)	(6,405)
Senior Secured Revolving Credit Facilities	141,000	93,500
Senior Secured Multicurrency Credit Facility	-	-
Other	-	160

		607,009		558,254
Less: Current maturities		-		(160)
	$	607,009	$	558,094

Prior Senior Secured Revolving Credit Facility

Prior to January 27, 2011, the Company had a senior secured revolving credit facility (the Prior Credit Facility) with Wells Fargo Bank, N.A., as administrative agent. In connection with the Company s entrance into a new senior secured revolving credit facility with an increased borrowing capacity and extended maturity as discussed below, on January 27, 2011, the Company repaid its full indebtedness outstanding under the senior credit agreement governing the Prior Credit Facility and terminated such senior credit agreement. As a result, the Company recognized a $0.9 million non-cash pre-tax loss on extinguishment of debt, related to the deferred financing costs attributable to the commitments of two banks in the Prior Credit Facility who are not participating in the new credit facility.

Senior Secured Revolving Credit Facility

On January 27, 2011, the Company entered into a new $750 million secured revolving credit facility with a five-year term (Revolving Credit Facility) with BNP Paribas as the administrative agent, sole book runner and lead arranger. 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 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of the Company s assets and is guaranteed by certain of the Company s subsidiaries. The initial Borrowing Base under the Revolving Credit Facility was $350 million. Subsequent to the sale of certain of the Company s non-core Barnett Shale properties in the second quarter of 2011 described in Note 4. Property Plant and Equipment, the Borrowing Base availability under the Revolving Credit Facility was reduced from $350 million to $300 million. On June 10, 2011, the Borrowing Base availability was raised to $340 million after completing the regular semi-annual Borrowing Base redetermination. The next Borrowing Base redetermination is currently expected to occur on or before November 1, 2011.

The annual interest rate on each base rate borrowing is (a) the greatest of the Prime Rate, the Federal Funds Effective Rate plus 0.5% and the adjusted LIBO rate for a three-month interest period on such day plus 1.00%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBO rate for the applicable interest period plus a margin between 2.00% to 3.00% (depending on the then-current level of borrowing base usage).

The Company is subject to certain covenants under the terms of the Revolving Credit Facility which include, but are not limited to, the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for fiscal quarters ending June 30, 2011 through December 31, 2011, (b) 4.25 to 1.00 for fiscal quarters ending March 31, 2012 through June 30, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending September 30, 2012 and thereafter; (2) a current ratio of not less than 1.0 to 1.0; (3) a Senior Debt to EBITDA ratio of not more than 2.50 to 1.00; and (4) an EBITDA to Interest Expense ratio of not less than 2.50 to 1.00. At June 30, 2011, the ratio of Total Debt to EBITDA was 3.30 to 1.00, the current ratio was 1.81 to 1.0, the Senior Debt to EBITDA ratio was 0.79 to 1.00 and the EBITDA to Interest Expense ratio was 4.73 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 June 30, 2011, the Company had $141 million of borrowings outstanding under the Revolving Credit Facility with a weighted average interest rate of 2.81%. At June 30, 2011, the Company also had $0.4 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the $340 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 only to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

Table of Contents

UK Huntington Limited Recourse Credit Facility

From issuance through June 30, 2011, no amounts were outstanding under the Company s Senior Secured Multicurrency Credit Facility (the Huntington Facility) and no letters of credit had been issued.

During the first quarter of 2011, the Company made an equity contribution of approximately $22 million to Carrizo UK Huntington Ltd. (Carrizo UK). At June 30, 2011, Carrizo UK has a cash balance of $9.5 million which represents the remaining portion of the equity contribution. Initial borrowings under the Huntington Facility are conditioned on, among other things, the Company s prior utilization of the equity contribution on normal business operations in the UK North Sea.

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 revolving credit facility or (ii) 4.75% for the cost overrun facility.

7. COMMITMENTS AND CONTINGENCIES

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

The 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.

8. SHAREHOLDERS EQUITY

On November 24, 2009, the Company entered into a Land Agreement, as amended (the Land Agreement), with an unrelated third party and its affiliate. The Land Agreement expired pursuant to its terms on May 31, 2011. Under the Land Agreement, the Company was able to acquire up to $20 million of oil, gas and mineral interests/leases in certain specified areas in the Barnett Shale from such third party. In consideration for the Company s receipt of an option to purchase the leases acquired by the third party, each time the third party purchased a lease group under the Land Agreement the Company agreed to issue to the third party s affiliate warrants to purchase a number of shares of the Company s common stock with an exercise price of $22.09 and an expiration date of August 21, 2017. In addition, under certain circumstances where the Company reached surface casing point on an initial well in one of the areas covered by the Land Agreement but has not achieved a specified lease up threshold for acreage in such area, the Company agreed to issue additional warrants. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis.

Under the Land Agreement, the Company issued warrants to purchase 57,461 shares of common stock in 2010 and warrants to purchase 18,608 shares of common stock onduring the first quarter of 2011. No Warrants were issued in the second quarter of 2011. During the third quarter of 2011, we expect to issue approximately 5,000 additional warrants to the third party s affiliate for leases acquired prior to the expiration of the Land Agreement.

During the second quarter of 2011, we contributed $1.0 million in common stock to the Carrizo Oil & Gas, Inc endowed scholarship fund at the University of Texas at Arlington (UTA) where we are producing natural gas from a number of wells in the Barnett Shale play.

9. 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 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 or as required by the terms of our credit facilities.

Table of Contents

The fair value of derivative instruments at June 30, 2011, and December 31, 2010 was a net asset of $22.4 million and $24.1 million, respectively. At June 30, 2011, approximately 63% of the fair value of the Company s derivative instruments were with Credit Suisse, 18% were with BNP Paribas, 12% were with Shell Energy North America (US) LP, 6% were with Credit Agricole, and the remaining less than 1% were with Societe Generale and 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, 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, BNP Paribas, Credit Agricole, 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.

The following sets forth a summary of the Company s natural gas derivative positions at average delivery location (Waha and Houston Ship Channel) prices as of June 30, 2011. Our crude oil derivative positions at June 30, 2011 were not significant.

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2011	15,180,000	$ 5.54	$ 5.61
2012	18,943,000	$ 5.50	$ 5.60
2013	7,300,000	$ 5.21	$ 5.21

In connection with the derivative instruments above, the Company has entered into protective put spreads. When the market price declines below the short put price as reflected below, the Company will effectively receive the market price plus a put spread. For example, for the remainder of 2011, if market prices fall below the short put price of $4.92, the floor price becomes the market price plus the put spread of $1.15 on 5,849,000 of the 15,180,000 MMBtus and the remaining 9,331,000 MMBtus would have a floor price of $5.54.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2011	5,849,000	$ 4.92	$ 1.15
2012	6,404,000	$ 5.05	$ 1.22

For the three and six months ended June 30, 2011 and 2010, the Company recorded the following related to its derivative instruments:

	0000000	0000000	0000000	0000000
	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Realized gain	$ 4,904	$ 8,792	$ 14,910	$ 13,747
Unrealized gain (loss)	7,161	(5,578)	(3,032)	12,269
Gain (loss) on derivative instruments, net	$ 12,065	$ 3,214	$ 11,878	$ 26,016

The Company deferred the payment of premiums associated with certain of its oil and gas derivative instruments totaling $3.2 million and $3.9 million at June 30, 2011 and December 31, 2010, respectively. The Company classified $2.1 million and $3.9 million as other current liabilities at June 30, 2011 and December 31, 2010, respectively, and $1.1 million as other non-current liabilities at June 30, 2011. These deferred premiums will be paid to the counterparty with each monthly settlement (July 2011 March 2014) and recognized as a reduction of realized gain on derivative instruments.

Table of Contents

10. 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 June 30, 2011 and December 31, 2010, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	000000	000000	000000	000000	000000	000000	000000	000000
	June 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in thousands)				
Assets:								
Investment in Pinnacle Gas Resources, Inc.	$ -	$ -	$ -	$ -	$ 869	$ -	$ -	$ 869
Derivative instruments	-	39,297	-	39,297	-	48,140	-	48,140
Liabilities:								
Derivative instruments	-	(16,934)	-	(16,934)	-	(24,062)	-	(24,062)
Total	$ -	$ 22,363	$ -	$ 22,363	$ 869	$ 24,078	$ -	$ 24,947

The fair values of derivative instruments are based on a third-party pricing model which utilizes inputs that include (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 compared to the values provided by the counterparty for reasonableness. Derivative instruments are subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company s derivative instruments, but to date has not had a material impact on estimates of 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 fair value of the investment in Pinnacle was based on the closing price of Pinnacle s common stock on December 31, 2010. The Company had no transfers in or out of Levels 1 or 2 for the six months ended June 30, 2011.

Fair Value of Other Financial Instruments

The Company s other financial instruments consist of cash and cash equivalents, receivables, payables and current and long-term debt. The carrying amounts of cash and cash equivalents, receivables, payables and short-term debt approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the borrowings under the Revolving Credit Facility as of June 30, 2011 and the Prior Credit Facility as of December 31, 2010, approximate the carrying amounts and were based upon interest rates currently available to the Company for borrowings with similar terms. The fair values of the Convertible Senior Notes and Senior Notes at June 30, 2011, were estimated at approximately $73.4 million and $414.0 million based on quoted market prices.

-15-

Table of Contents

Other Fair Value Measurements

The initial measurement of asset retirement obligations at fair value is calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, surface restoration and reserve lives.

11. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 28, 2010, the Company and certain of its wholly owned subsidiaries (collectively, the Subsidiary Guarantors) entered into a purchase agreement pursuant to which the Company agreed to sell $400 million aggregate principal amount of the Company s Senior Notes. Certain, but not all, of the Company s wholly owned subsidiaries have issued full, unconditional and joint and several guarantees of the Senior Notes and may guarantee future issuances of debt securities. On May 4, 2011, two of the Subsidiary Guarantors, CCBM, Inc. and Chama Pipeline Holding LLC, were released from their respective guarantees of the Senior Notes and the Convertible Senior Notes. These entities were subsequently dissolved.

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information as of June 30, 2011 and December 31, 2010, and for the three and six months ended June 30, 2011 and 2010 on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries, eliminating entries, 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.

Table of Contents

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	00000000000	00000000000	00000000000	00000000000	00000000000
			June 30, 2011		
ASSETS	**Parent Company**	**Combined Guarantor Subsidiaries**	**Combined Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
			(In thousands)		
Current assets	$ 1,136,869	$ 45,679	$ 9,793	$ (1,105,536)	$ 86,805
Property and equipment, net	132,330	888,521	38,789	6,856	1,066,496
Investments in subsidiaries	(127,494)	-	-	127,494	-
Other assets	94,028	69,802	4,190	(70,696)	97,324
Total assets	$ 1,235,733	$ 1,004,002	$ 52,772	$ (1,041,882)	$ 1,250,625
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 85,636	$ 1,129,779	$ 51,281	$ (1,105,536)	$ 161,160
Long-term liabilities	682,468	870	2,338	(69,076)	616,600
Shareholders equity	467,629	(126,647)	(847)	132,730	472,865
Total liabilities and shareholders equity	$ 1,235,733	$ 1,004,002	$ 52,772	$ (1,041,882)	$ 1,250,625

			December 31, 2010		
ASSETS	**Parent Company**	**Combined Guarantor Subsidiaries**	**Combined Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
			(In thousands)		
Current assets	$ 1,029,000	$ 22,733	$ -	$ (991,401)	$ 60,332
Property and equipment, net	194,243	784,790	-	4,024	983,057
Investments in subsidiaries	(139,829)	-	-	139,829	-
Other assets	99,876	78,288	-	(77,419)	100,745
Total assets	$ 1,183,290	$ 885,811	$ -	$ (924,967)	$ 1,144,134
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 85,783	$ 1,024,622	$ -	$ (991,401)	$ 119,004
Long-term liabilities	644,315	1,018	-	(76,839)	568,494
Shareholders equity	453,192	(139,829)	-	143,273	456,636
Total liabilities and shareholders equity	$ 1,183,290	$ 885,811	$ -	$ (924,967)	$ 1,144,134

Table of Contents

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	00000000000	00000000000	00000000000	00000000000	00000000000
	For the Three Months Ended June 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and Gas revenues	$ 9,389	$ 41,283	$ -	$ -	$ 50,672
Cost and expenses	21,788	24,237	143	(1,534)	44,634
Operating income (loss)	(12,399)	17,046	(143)	1,534	6,038
Other income and (expense), net	15,242	(8,255)	(1,681)	-	5,306
Income (loss) before income taxes	2,843	8,791	(1,824)	1,534	11,344
Income tax (expense) benefit	(784)	(3,230)	976	(564)	(3,602)
Equity in income (loss) of subsidiaries	4,713	-	-	(4,713)	-
Net income (loss)	$ 6,772	$ 5,561	$ (848)	$ (3,743)	$ 7,742

	For the Three Months Ended June 30, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and Gas revenues	$ 8,371	$ 24,551	$ -	$ -	$ 32,922
Cost and expenses	17,387	12,818	-	(1,073)	29,132
Operating income (loss)	(9,016)	11,733	-	1,073	3,790
Other income and (expense), net	553	(2,243)	-	-	(1,690)
Income before income taxes	(8,463)	9,490	-	1,073	2,100
Income tax (expense) benefit	2,697	(2,629)	-	(383)	(315)
Equity in income (loss) of subsidiaries	6,861	-	-	(6,861)	-
Net income (loss)	$ 1,095	$ 6,861	$ -	$ (6,171)	$ 1,785

Table of Contents

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	00000000000	00000000000	00000000000	00000000000	00000000000
	For the Six Months Ended June 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and Gas revenues	$ 18,164	$ 76,566	$ -	$ -	$ 94,730
Cost and expenses	37,969	43,647	143	(2,832)	78,927
Operating income (loss)	(19,805)	32,919	(143)	2,832	15,803
Other income and (expense), net	11,098	(12,081)	(1,681)	-	(2,664)
Income (loss) before income taxes	(8,707)	20,838	(1,824)	2,832	13,139
Income tax (expense) benefit	3,059	(7,656)	976	(1,041)	(4,662)
Equity in income (loss) of subsidiaries	12,334	-	-	(12,334)	-
Net income (loss)	$ 6,686	$ 13,182	$ (848)	$ (10,543)	$ 8,477

	For the Six Months Ended June 30, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and Gas revenues	$ 19,599	$ 52,279	$ -	$ -	$ 71,878
Cost and expenses	31,177	24,338	-	(2,369)	53,146
Operating income (loss)	(11,578)	27,941	-	2,369	18,732
Other income and (expense), net	20,459	(4,658)	-	-	15,801
Income (loss) before income taxes	8,881	23,283	-	2,369	34,533
Income tax (expense) benefit	(3,831)	(8,336)	-	(845)	(13,012)
Equity in income (loss) of subsidiaries	14,947	-	-	(14,947)	-
Net income (loss)	$ 19,997	$ 14,947	$ -	$ (13,423)	$ 21,521

Table of Contents

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Six Months Ended June 30, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$ 18,563	$ 56,042	$ (483)	$ -	$ 74,122
Net cash used in investing activities	(57,759)	(114,348)	(35,130)	114,121	(93,116)
Net cash provided by financing activities	42,199	65,766	45,124	(114,121)	38,968
Net increase (decrease) in cash and cash equivalents	3,003	7,460	9,511	-	19,974
Cash and cash equivalents, beginning of period	1,418	2,710	-	-	4,128
Cash and cash equivalents, end of period	$ 4,421	$ 10,170	$ 9,511	$ -	$ 24,102

	For the Six Months Ended June 30, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$ 4,042	$ 36,136	$ -	$ -	$ 40,178
Net cash used in investing activities	(127,570)	(163,310)	-	124,663	(166,217)
Net cash provided by financing activities	124,954	124,663	-	(124,663)	124,954
Net increase (decrease) in cash and cash equivalents	1,426	(2,511)	-	-	(1,085)
Cash and cash equivalents, beginning of period	1,337	2,500		-	3,837
Cash and cash equivalents, end of period	$ 2,763	$ (11)	$ -	$ -	$ 2,752

12. SUBSEQUENT EVENTS

On August 5, 2011, the Company, its two recently formed wholly owned subsidiaries, Carrizo (Eagle Ford) LLC and Carrizo (Niobrara) LLC, and Wells Fargo Bank, National Association, as Trustee, entered into the Eighth Supplemental Indenture and Ninth Supplemental Indenture, pursuant to which such wholly owned subsidiaries have issued full, unconditional and joint and several guarantees of the Senior Notes and the Convertible Senior Notes, respectively, and may guarantee future issuances of debt securities. These subsidiaries also guarantee borrowings under the Revolving Credit Facility.

Table of Contents

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 fiscal year ended December 31, 2010, and the unaudited consolidated financial statements included in this quarterly report.

General Overview

Our second quarter 2011 included oil and gas revenues of $50.7 million and production of 11.2 Bcfe. The key drivers to our results for the three months ended June 30, 2011 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the three months ended June 30, 2011, we drilled (a) 10 gross wells (3.2 net) in the Barnett Shale, (b) 12 gross wells (2.6 net) in the Marcellus Shale, (c) 6 gross wells (6.0 net) in the Eagle Ford Shale, (d) 1 gross well (1.0 net) in the Niobrara Formation, and (e) 2 gross (0.1 net) wells in the other project areas.

Production. Our second quarter 2011 production of 11.2 Bcfe, or 122.8 MMcfe/d, increased 20% from the second quarter 2010 production of 9.3 Bcfe, or 102.1 MMcfe/d, and increased 5% from the first quarter 2011 production of 10.7 Bcfe, or 118.8 MMcfe/d. The increase from the second quarter of 2010 and the first quarter of 2011 to the second quarter of 2011 was primarily a result of production from new wells in the Barnett Shale, Eagle Ford Shale and the Niobrara Formation, partially offset by normal production decline and the sale of substantially all of our non-core area Barnett Shale properties to KKR in May 2011.

Commodity prices. Our average natural gas price during the second quarter of 2011 was $3.25 per Mcf (excluding the impact of our derivative instruments), $0.05 per Mcf, or 2% higher than the price during the second quarter of 2010 and $0.19 per Mcf, or 6% higher than the price during the first quarter of 2011. Excluded from these prices are realized gains on derivative instruments of $5.3 million ($0.48 per Mcf) for the second quarter of 2011, $9.9 million ($0.92 per Mcf) for the first quarter of 2011 and $8.8 million ($0.95 per Mcf) for the second quarter of 2010. Our average oil price during the second quarter of 2011 was $98.02 per barrel, $22.30 per barrel, or 30% higher than the price during the second quarter of 2010 and $9.37 per barrel, or 11% higher than the price during the first quarter of 2011. Realized gains attributable to oil were not significant.

Sale of Non-Core Properties. In May 2011, we completed the sale of certain non-core Barnett Shale properties. Net proceeds received from the sale were approximately $98 million, which represent an agreed upon purchase price of approximately $104 million less net purchase price 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, 2011 and the closing date of May 17, 2011. The sale included approximately 13,000 leased acres, including 75 gross (58.5 net) wells that produced at an approximate gross rate of 15.7 MMcfe per day (8.3 MMcfe/d net). Estimated proved reserves associated with the divested properties amount to 122.4 Bcfe, 55% of which were proved undeveloped, as determined by our third party engineers at year-end 2010. As a consequence of the sale, the Borrowing Base (as defined in the senior credit agreement governing the Revolving Credit Facility) availability under the Revolving Credit Facility was reduced from $350 million to $300 million. We used the net proceeds from this sale to repay borrowings under our Revolving Credit Facility. On June 10, 2011, the Borrowing Base availability was raised to $340 million after completing the regular semi-annual Borrowing Base redetermination.

Outlook

Our outlook for 2011 remains positive but challenging, primarily due to the low futures prices of natural gas. Production growth and commodity prices that permit us to drill, develop and produce at a profit are key to our future success, and we believe the following measures will continue to have a positive impact on our results in 2011:

Eagle Ford and Niobrara. Based upon the success of our drilling results in late 2010 and early 2011, we continue to focus on developing our liquid rich resource plays in the Eagle Ford Shale and the Niobrara Formation. In the second quarter, we reached agreements on several Eagle Ford lease purchases, and a significant portion of our development costs is expected to be funded through drilling carries. We also relocated a rig from the Barnett Shale to the Eagle Ford Shale and extended a one year contract on a rig previously moved to the Eagle Ford Shale during the first quarter of this year. We currently have three rigs on our Eagle Ford properties and await delivery of a fourth drilling rig in the fourth quarter of this year. We continue to obtain and evaluate seismic data in the Niobrara Formation to enhance our drilling opportunities and we recently brought on production from a fourth well. We

Table of Contents

currently have one rig drilling on our Niobrara properties. We continue to focus on land acquisition efforts in the Niobrara Formation.

Marcellus Shale. We currently have four rigs drilling in the Marcellus Shale, all of which we operate as part of our Reliance joint venture. Stimulation and completion of the back-log of drilled wells and first sales from Susquehanna County are expected to begin in September following the construction by third parties of certain gas gathering lines in the vicinity of our operated wells.

Barnett Shale. During the second quarter of 2011, we relocated a rig from the Barnett Shale to South Texas in order to accelerate our Eagle Ford Shale activity. Current plans call for this rig to remain in South Texas until it is replaced by a rig currently scheduled for arrival in December 2011, at which time it will return to the Barnett Shale. Given the current backlog of wells waiting on completion in the Barnett Shale, we do not expect this rig move to have a significant impact on estimated 2011 production.

U.K. North Sea. During the second quarter of 2011, we continued development of the Huntington Field, and we currently expect production from this field to begin mid-year 2012.

Results of Operations

Three Months Ended June 30, 2011, Compared to the Three Months Ended June 30, 2010

Revenues from oil and gas production for the three months ended June 30, 2011 increased 54% to $50.7 million from $32.9 million for the same period in 2010 primarily due to increased production, particularly higher oil and condensate production in the Eagle Ford Shale, and higher oil prices. The increase in production from the second quarter of 2010 to the second quarter of 2011 was primarily due to increased production from new wells in the Barnett Shale, Eagle Ford Shale and Niobrara Formation, partially offset by normal production decline and the sale of substantially all of our non-core area Barnett Shale properties to KKR in May 2011. Average natural gas prices, excluding the impact attributable to a $5.3 million and an $8.8 million realized gain on derivative instruments for the quarters ended June 30, 2011 and 2010, respectively, increased 2% to $3.25 per Mcf in the second quarter of 2011 from $3.20 per Mcf in the same period in 2010. Average oil prices, excluding the impact attributable to a $0.4 million realized loss on derivative instruments for the quarter ended June 30, 2011, increased 30% to $98.02 per barrel from $75.72 per barrel in the same period in 2010.

The following table summarizes production volumes, average sales prices (excluding the impact of derivative instruments) and oil and gas revenues for the three months ended June 30, 2011 and 2010:

	000000	000000	000000	000000
	Three Months Ended June 30		**2011 Period Compared to 2010 Period**	
			Increase	**% Increase**
	2011	**2010**	**(Decrease)**	**(Decrease)**
Production volumes				
Oil and condensate (MBbls)	158	38	120	316%
Natural gas and NGLs (MMcfe)	10,223	9,067	1,156	13%
Average sales prices				
Oil and condensate ($ per Bbl)	$ 98.02	$ 75.72	$ 22.30	29%
Natural gas ($ per Mcf)	3.25	3.20	0.05	2%
NGLs ($ per Mcfe)	7.86	6.19	1.67	27%
Oil and gas revenues (In thousands of $)				
Oil and condensate	$ 15,530	$ 2,884	$ 12,646	438%
Natural gas and NGLs	35,142	30,038	5,104	17%
Total oil and gas revenues	$ 50,672	$ 32,922	$ 17,750	54%

Lease operating expenses (including transportation costs of $1.6 million) were $7.4 million (or $0.66 per Mcfe) for the three months ended June 30, 2011 as compared to lease operating expenses (including transportation costs of $1.5 million) of $6.2 million (or $0.66 per Mcfe) for the second quarter of 2010. Lease operating expenses increased due to increased production primarily attributable to new wells in the Barnett Shale, Eagle Ford Shale and Niobrara Formation. Although we continued to experience a decrease in the operating cost per Mcfe of our Barnett

Shale production, driven by comparatively less salt water disposal costs in the core area of the Barnett Shale as compared to production from other areas of the Barnett Shale, this decrease was offset by increased operating cost per Mcfe associated with higher cost oil production.

Production taxes were $1.5 million (or 2.89% of revenues) for the three months ended June 30, 2011 compared to $0.9 million (or 2.69% of revenues) for the three months ended June 30, 2010. The increases in production taxes and the percentage of revenues are due to increased oil production, which has a higher effective production tax rate as compared to natural gas.

Ad valorem taxes increased to $1.0 million (or $0.05 per Mcfe) for the three months ended June 30, 2011 from $0.5 million ($0.09 per Mcfe) for the same period in 2010. The increase in ad valorem taxes is due to new oil and gas wells drilled in 2010 as well as a reduction in ad valorem taxes recorded in the second quarter of 2010 reflecting a true up of our first quarter 2010 estimate. The decrease in Mcfe amounts is due primarily to this true up of the first quarter estimate.

Depreciation, depletion and amortization (DD&A) expense for the three months ended June 30, 2011 increased to $20.6 million (or $1.84 per Mcfe) from $11.1 million (or $1.19 per Mcfe) for the same period in 2010. The increases in DD&A and the related per Mcfe amounts were primarily due to increased production during the second quarter of 2011 as compared to the same period in 2010 and increased future development costs associated with crude oil and natural gas liquids reserves in the Eagle Ford which were added during the fourth quarter of 2010 and have a higher future development cost per equivalent unit than the Company s proved gas reserves.

In June 2010, we concluded that it was uneconomical to pursue development on the license covering the Monterey field in the U.K. North Sea and terminated further development efforts, resulting in a full-cost ceiling test impairment of $2.7 million ($1.8 million after-tax) for the three months ended June 30, 2010 with respect to the U.K. cost center.

General and administrative expense increased to $14.1 million for the three months ended June 30, 2011 from $7.8 million for the corresponding period in 2010. The increase was primarily due to (a) increased stock-based compensation largely attributable to additional stock appreciation rights as well as stock appreciation rights that increased in fair value, and (b) increased compensation costs largely due to an increase in the number of employees in the second quarter of 2011.

During the second quarter of 2011, we contributed $1.0 million in common stock to the Carrizo Oil & Gas, Inc. endowed scholarship fund at UTA where we are producing natural gas from a number of wells in the Barnett Shale play.

The net gain on derivative instruments of $12.1 million in the second quarter of 2011 consisted of a $7.2 million unrealized gain on derivatives and a $4.9 million realized gain on derivatives. The net gain on derivative instruments of $3.2 million in the second quarter of 2010 was comprised of a $5.6 million unrealized loss on derivatives and an $8.8 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended June 30, 2011 were $12.4 million and $5.6 million, respectively, as compared to $9.8 million and $5.0 million, respectively, for the same period in 2010. The net increase was primarily due to interest on the $400 million aggregate principal amount of Senior Notes that were issued in the fourth quarter of 2010, partially offset by decreased interest and discount amortization attributable to the $300 million aggregate principal amount of the Convertible Senior Notes repurchased in a tender offer during the fourth quarter of 2010, and higher capitalized interest due to higher levels of unproved properties and a higher weighted average interest rate in 2011.

The effective income tax rate was 31.8% for the second quarter of 2011 and 15.0% for the second quarter of 2010. Our estimated annual effective income tax rate for 2011 is approximately 37%, substantially all of which we expect to be deferred. The effective income tax rate for the second quarter of 2011 was lower than 37% primarily due to the true up of prior estimates of the foreign tax benefit associated with the Company s UK Huntington field development. The lower rate in the second quarter of 2010 was due to a true up of prior estimates of state income tax.

Six Months Ended June 30, 2011, Compared to the Six Months Ended June 30, 2010

Revenues from oil and gas production for the six months ended June 30, 2011 increased 32% to $94.7 million from $71.9 million for the same period in 2010 primarily due to increased production, particularly higher oil and condensate production in the Eagle Ford Shale, and higher oil prices, partially offset by lower gas prices. Production volumes for the six months ended June 30, 2011 and 2010 were 21.9 Bcfe and 17.6 Bcfe, respectively. The increase in production for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 was primarily due to increased production from new wells in the Barnett Shale, Eagle Ford Shale and Niobrara Formation, partially offset by normal production decline and the sale of substantially all of our non-core area Barnett Shale properties to KKR in May 2011. Average natural gas prices, excluding the impact attributable to a $15.2 million and a $13.7 million realized gain on derivative instruments for the six months ended June 30, 2011 and 2010, respectively, decreased to $3.16 per Mcf for the first six months of 2011 from $3.73 per Mcf in the same period in 2010. Average oil prices, excluding the impact of a realized loss on derivative instruments of $0.3 million and $0 for the six months ended June 30, 2011 and 2010, respectively, increased 24% to $93.74 per barrel from $75.92 per barrel in the same period in 2010.

-23-

Table of Contents

The following table summarizes production volumes, average sales prices (excluding the impact of derivative instruments) and oil and gas revenues for the six months ended June 30, 2011 and 2010:

	Increase000		Increase000		Increase000	Increase000
	Six Months Ended June 30				2011 Period Compared to 2010 Period	
	2011		2010		Increase (Decrease)	% Increase (Decrease)
Production volumes						
Oil and condensate (MBbls)		292		76	216	284%
Natural gas and NGLs (MMcfe)		20,114		17,107	3,007	18%
Average sales prices						
Oil and condensate ($ per Bbl)	$	93.74	$	75.92	$ 17.82	24%
Natural gas($ per Mcf)		3.16		3.73	(0.57)	(15)%
NGLs ($ per Mcfe)		7.83		6.76	1.07	16%
Oil and gas revenues (In thousands of $)						
Oil and condensate	$	27,360	$	5,758	$ 21,602	375%
Natural gas and NGLs		67,370		66,120	1,250	2%
Total oil and gas revenues	$	94,730	$	71,878	$ 22,852	32%

Lease operating expenses (including transportation costs of $2.9 million) were $14.1 million (or $0.64 per Mcfe) for the six months ended June 30, 2011 as compared to lease operating expenses (including transportation costs of $2.8 million) of $11.2 million (or $0.64 per Mcfe) for the six months ended June 30, 2010. Lease operating expenses increased due to increased production primarily attributable to new wells in the Barnett Shale, Eagle Ford Shale and Niobrara Formation. Although we continued to experience a decrease in the operating cost per Mcfe of our Barnett Shale production, driven by comparatively less salt water disposal costs in the core area of the Barnett Shale as compared to production from other areas of the Barnett Shale, this decrease was largely offset by increased operating cost per Mcfe associated with higher cost oil production.

Production taxes increased to $2.4 million (or 2.54% of revenues) for the six months ended June 30, 2011 from $1.8 million (or 2.49% of revenues) for the same period in 2010. The increases in production taxes and the percentage of revenues are due to increased oil production, which has a higher effective production tax rate as compared to natural gas.

Ad valorem taxes remained unchanged at $1.7 million for the six months ended June 30, 2011 and 2010. Ad valorem taxes for the first six months of 2011 includes a reduction to ad valorem taxes reflecting a true up of our estimated amounts to actual for 2010. This reduction was offset by increased ad valorem taxes associated with new oil and gas wells drilled in 2010. Ad valorem taxes per Mcfe decreased from $0.10 for the first six months of 2010 to $0.08 for the first six months of 2011 due primarily to this true up of the 2010 estimate.

DD&A expense for the six months ended June 30, 2011 increased to $37.3 million (or $1.70 per Mcfe) from $20.9 million (or $1.19 per Mcfe) for the same period in 2010. The increases in DD&A and the related per Mcfe amounts were primarily due to increased production during the first six months of 2011 as compared to the same period in 2010 and increased future development costs associated with crude oil and natural gas liquids reserves in the Eagle Ford which were added during the fourth quarter of 2010, and have a higher future development cost per equivalent unit than the Company s proved gas reserves.

In June 2010, we concluded that it was uneconomical to pursue development on the license covering the Monterey field in the U.K. North Sea and terminated further development efforts, resulting in a full-cost ceiling test impairment of $2.7 million for the six months ended June 30, 2010 with respect to the U.K. cost center.

General and administrative expense increased to $23.3 million for the six months ended June 30, 2011 from $14.7 million for the corresponding period in 2010. The increase was primarily due to (a) increased stock-based compensation largely to additional stock appreciation rights as well as stock appreciation rights that increased in fair value, and (b) increased compensation costs largely due to an increase in the number of employees in the first half of 2011.

During the six months ended June 30, 2011, we contributed $1.0 million in common stock to the Carrizo Oil & Gas, Inc. endowed scholarship fund at UTA where we are producing natural gas from a number of wells in the Barnett Shale play.

Table of Contents

The net gain on derivative instruments of $11.9 million in the first six months of 2011 consisted of a $3.0 million unrealized loss on derivatives and a $14.9 million realized gain on derivatives. The net gain on derivative instruments of $26.0 million in the first six months of 2010 was comprised of a $12.3 million realized gain on derivatives and a $13.7 million unrealized gain on derivatives.

In January 2011, in connection with our entrance into a new senior secured revolving credit facility, we terminated our prior credit facility. As a result, we recognized a non-cash, pre-tax loss on extinguishment of debt of $0.9 million representing the deferred financing costs attributable to the commitments of two banks in the prior credit facility who are not participating in the new credit facility.

Interest expense and capitalized interest for the six months ended June 30, 2011 were $24.6 million and $10.9 million, respectively, as compared to $19.7 million and $9.5 million, respectively, for the same period in 2010. The net increase was primarily due to interest on the $400 million aggregate principal amount of Senior Notes that were issued in the fourth quarter of 2010, partially offset by decreased interest and discount amortization attributable to the $300 million aggregate principal amount of the Convertible Senior Notes repurchased in a tender offer during the fourth quarter of 2010.

Our overall effective tax rate was 35.5% for the first six months of 2011 and 37.7% for the first six months of 2010. Our estimated annual effective income tax rate for 2011 is approximately 37%, substantially all of which we expect to be deferred. The effective income tax rate for the six months ended June 30, 2011 was lower than 37% due to the true up of prior estimates of the foreign tax benefit associated with the Company s UK Huntington field development.

Liquidity and Capital Resources

2011 Capital Expenditure Plan and Funding Strategy. For 2011, our Board has established a capital expenditure plan of $340 million which includes approximately $253 million for drilling (including $129 million in the Eagle Ford Shale, $75 million for the Barnett Shale, $25 million for the Niobrara Formation, $21 million in the Marcellus Shale and $3 million for other project areas all net of carry), $34 million for leasehold and seismic costs and $53 million for the Huntington field development in the U.K. North Sea of which $31 million will be funded by our Huntington Facility (described below) with the remaining $22 million funded by the equity investment we made in our U.K. North Sea subsidiary during the first quarter of 2011. We intend to finance the remainder of our 2011 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.

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 six months ended June 30, 2011, capital expenditures, net of proceeds from asset sales, exceeded our net cash provided by operations. During the first half of 2011, we funded our capital expenditures with cash provided by operations, proceeds from the sale of non-core assets, payments or carried interest from our joint ventures with Reliance and Avista, and borrowings under our Prior Credit Facility and the Revolving Credit 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. At July 29, 2011, $148.0 million of borrowings were outstanding under the Revolving Credit Facility. At July 29, 2011, we also had $0.4 million in letters of credit outstanding, which reduce the amounts available under the Revolving Credit Facility. The amount we are able to borrow with respect to the Borrowing Base, which is currently $340 million, is subject to compliance with the financial covenants and other provisions of the credit agreement governing the Revolving Credit Facility.

- Borrowings under project financing arrangements in certain limited circumstances. As described above, we plan to fund a substantial portion of our costs relating to the Huntington Field from our recently established Huntington Facility.

Asset sales. In the second quarter of 2011, we sold certain non-core area Barnett Shale properties to KKR. Net proceeds received from the sale were approximately $98 million, which represent an agreed upon purchase price of approximately $104 million less net purchase price 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, 2011 and the closing date of May 17, 2011. We used the net proceeds from this sale to repay borrowings under our Revolving Credit Facility and then used the resulting additional capacity under our Revolving Credit Facility to fund, in part, our 2011 capital expenditure plan, and for general corporate purposes. As a consequence of the sale, the Borrowing Base availability under the Revolving Credit Facility was reduced from $350 million to $300 million, followed by an increase to $340 million after completing the regular semi-annual Borrowing Base redetermination on June 10, 2011. 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 need 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 Marcellus Shale, the Barnett Shale and other plays. Please read Lease Option Arrangements from our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage and/or purchase a portion of interests, such as our joint ventures with Avista and Reliance in the Marcellus Shale play and our joint venture with Sumitomo in the Barnett Shale.

We may consider sale/leaseback transactions of certain capital assets, such as our remaining pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Overview of Cash Flow Activities. Net cash provided by operating activities was $74.1 million and $40.2 million for the six months ended June 30, 2011 and 2010, respectively. The increase was primarily due to increased production, particularly higher crude oil and condensate production in the Eagle Ford Shale and increased oil prices, partially offset by lower gas prices in the first six months of 2011 as compared to the same period in 2010.

Net cash used in investing activities was $93.1 million and $166.2 million for the six months ended June 30, 2011 and 2010, respectively, and decreased primarily due to higher proceeds from the sales of oil and gas properties, partially offset by increased capital expenditures during 2011.

Net cash provided by financing activities for the six months ended June 30, 2011 and 2010 was $39.0 million and $125.0 million, respectively. The decrease related primarily to the absence of common stock offerings during the first half of 2011 as compared to the first half of 2010.

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 non-core assets and borrowings under the Revolving Credit Facility and the Huntington Facility 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 continue to 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 July 29, 2011, we had hedged approximately 12,607,000 MMBtu (82,000 MMBtu per day for the remainder of 2011) of our 2011 natural gas production at a weighted average floor or swap price of $5.54 per MMBtu relative to Waha and Houston Ship Channel prices. As of July 29, 2011, we had borrowings outstanding of $148.0 million under our Revolving Credit Facility with a borrowing availability of $340 million. At July 29, 2011, we also had $0.4 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 banks assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our banks reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base.

If cash provided by operating activities, 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 our 2011 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing 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 our planned 2011 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties.

Contractual Obligations

During the three months ended June 30, 2011, we entered into and extended long-term drilling contracts that require payments of $8.2 million for the remainder of 2011, $12.2 million for 2012, $9.9 million for 2013 and $9.4 million for 2014.

Financing Arrangements

Senior Secured Revolving Credit Facility

On January 27, 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 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of the Company s domestic assets and is guaranteed by certain of the Company s domestic subsidiaries. The current Borrowing Base under the Revolving Credit Facility is $340 million. The Borrowing Base will be redetermined by the lenders at least semi-annually on May 1 and November 1.

The annual interest rate on each base rate borrowing is (a) the greatest of the Prime Rate, the Federal Funds Effective Rate plus 0.5% and the adjusted LIBO rate for a three-month interest period on such day plus 1.00%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBO rate for the applicable interest period plus a margin between 2.00% to 3.00% (depending on the then-current level of borrowing base usage).

We are subject to certain covenants under the terms of the Revolving Credit Facility which include, but are not limited to, the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for fiscal quarters ending June 30, 2011 through December 31, 2011, (b) 4.25 to 1.00 for fiscal quarters ending March 31, 2012 through June 30, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending September 30, 2012 and thereafter; (2) a current ratio of not less than 1.0 to 1.0; (3) a Senior Debt to EBITDA ratio of not more than 2.50 to 1.00; and (4) an EBITDA to Interest Expense ratio of not less than 2.50 to 1.00. At June 30, 2011, the ratio of Total Debt to EBITDA was 3.30 to 1.00, the current ratio was 1.81 to 1.0, the Senior Debt to EBITDA ratio was 0.79 to 1.00 and the EBITDA to Interest Expense ratio was 4.73 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 the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s 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 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).

On January 27, 2011, we borrowed $112 million under the Revolving Credit Facility, which was used to repay in full indebtedness outstanding under the Prior Credit Facility, to pay transaction costs associated with the entrance into the Revolving Credit Facility and for other general corporate purposes.

At June 30, 2011, we had $141 million of borrowings outstanding under the Revolving Credit Facility with a weighted average interest rate of 2.81%. At June 30, 2011, we also had $0.4 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the $340 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 only to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

UK Huntington Limited Recourse Credit Facility

On January 28, 2011, the Company 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 the Company. 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 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 loans and letters of credit to be used to fund certain abandonment and decommissioning costs 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, except that the first such redetermination and recalculation took place in the second quarter 2011 and resulted in reduction to the availability of the term loan facility to $53 million.

Initial borrowings under the term loan facility and cost overrun facility are conditioned on, among other things, the Company s having made and spent an approximately $22 million equity contribution to Carrizo UK, which was completed in February 2011. At June 30, 2011, Carrizo UK had an outstanding cash balance of $9.5 million which represents the remaining portion of the equity contribution. Initial borrowings under the Huntington Facility are conditioned on, among other things, us utilizing the equity contribution on normal business operations in the UK North Sea. We currently expect to utilize the remaining portion of the equity contribution in the third quarter of 2011.

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 revolving 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 December 31, 2012 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 revolving credit facility mature on December 31, 2016. Amounts outstanding under the term loan or cost overrun facility must currently be repaid according to the following schedule: (i) 45% will be due on December 31, 2012, (ii) 20% will be due on June 30, 2013, (iii) 20% will be due on December 31, 2013, (iv) 10% will be due on June 30, 2014 and (iv) the remaining 5% 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 the Company or its 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.

From issuance to June 30, 2011, no amounts were outstanding under the Huntington Facility and no letters of credit had been issued.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and gas prices. The significant decline in gas prices since mid-2008 and the continued depressed price of gas has resulted in a significant decline in revenue per unit of production. Although operating costs have also declined, the rate of decline in gas prices has been substantially greater. Historically, inflation has had a minimal effect on us. However, with interest rates at historic lows and the government attempting to stimulate the economy through rapid expansion of the money supply in recent months, inflation could become a significant issue in the future.

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 fiscal year ended December 31, 2010. 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 cost center ceiling exceeded our net capitalized costs for the U.S. cost center at June 30, 2011 by approximately $73.0 million and was based on crude oil and condensate prices of $82.59 per barrel, natural gas liquids prices of $42.48 per barrel and natural gas prices of $3.39 per Mcf (or a volume weighted average price of $4.55 per Mcfe), representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended June 30, 2011. A ten percent increase in the unweighted average market prices for the 12-month period ended June 30, 2011 would have increased the cost center ceiling by approximately $209.6 million and a ten percent decrease in the unweighted average market prices would have resulted in a ceiling test impairment of approximately $82.4 million. This sensitivity analysis is as of June 30, 2011 and, accordingly, does not consider drilling results, production and prices subsequent to June 30, 2011 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 natural gas properties quarterly using the full cost method of accounting rules. See Summary of Critical Accounting Policies Oil and Natural Gas Properties, in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

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 or as required by terms of the Revolving Credit Facility. 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 June 30, 2011, and December 31, 2010 was a net asset of $22.4 million and $24.1 million, respectively. At June 30, 2011, approximately 63% of the fair value of our derivative instruments were with Credit Suisse, 18% were with BNP Paribas, 12% were with Shell Energy North America (US) LP, 6% were with Credit Agricole, and the remaining less than 1% were with Societe Generale and 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, BNP Paribas, Credit Agricole, and Societe Generale are lenders in our Revolving Credit Facility, and BNP Paribas and Societe Generale are lenders in 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.

The following sets forth a summary of the Company s natural gas derivative positions at average delivery location (Waha and Houston Ship Channel) prices as of June 30, 2011. Our crude oil derivative positions at June 30, 2011 were not significant.

	Ceiling Price	Ceiling Price	Ceiling Price
Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2011	15,180,000	$ 5.54	$ 5.61
2012	18,943,000	$ 5.50	$ 5.60
2013	7,300,000	$ 5.21	$ 5.21

In connection with the derivative instruments above, we have entered into protective put spreads. When the market price declines below the short put price as reflected below, we will effectively receive the market price plus a put spread. For example, for the

Table of Contents

remainder of 2011, if market prices fall below the short put price of $4.92, the floor price becomes the market price plus the put spread of $1.15 on 5,849,000 of the 15,180,000 MMBtus and the remaining 9,331,000 MMBtus would have a floor price of $5.54.

Period	Put Spread Volume (in MMbtu)	Put Spread Weighted Average Short Put Price ($/MMbtu)	Put Spread Weighted Average Put Spread ($/MMbtu)
2011	5,849,000	$ 4.92	$ 1.15
2012	6,404,000	$ 5.05	$ 1.22

For the three and six months ended June 30, 2011 and 2010, we recorded the following related toour derivative instruments:

	Put Sprea	Put Sprea	Put Sprea	Put Sprea
	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Realized gain	$ 4,904	$ 8,792	$ 14,910	$ 13,747
Unrealized gain (loss)	7,161	(5,578)	(3,032)	12,269
Gain (loss) on derivative instruments, net	$ 12,065	$ 3,214	$ 11,878	$ 26,016

We deferred the payment of premiums associated with certain of our oil and gas derivative instruments totaling $3.2 million and $3.9 million at June 30, 2011 and December 31, 2010, respectively. We classified $2.1 million and $3.9 million as other current liabilities at June 30, 2011 and December 31, 2010, respectively, and $1.1 million as other non-current liabilities at June 30, 2011. These deferred premiums will be paid to the counterparty with each monthly settlement (July 2011 June 2014) and recognized as a reduction of realized gain on derivative instruments.

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, 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, 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, believe and similar expressions are intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities 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, 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, 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 fiscal year ended December 31, 2010 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 Quantitative and Qualitative Disclosures about Market Risk in Item 7A. of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. 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 fiscal year ended December 31, 2010.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company s management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of June 30, 2011 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended June 30, 2011 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.

Other than the risk factors set forth below, 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, 2010. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions and hydraulic fracturing, and future regulations may be more stringent.

Oil and gas operations are subject to various federal, state, local and foreign laws and government regulations that may change from time to time. Matters subject to regulation include discharge permits for drilling operations, plug and abandonment bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. Other federal, state, local and foreign laws and regulations relating primarily to the protection of human health and the environment apply to the development, production, handling, storage, transportation and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and gas operations, including drilling fluids and wastewater. In addition, we may incur costs arising out of property damage, including environmental damage caused by previous owners or operators of property we purchase or lease or relating to third party sites, or injuries to employees and other persons. As a result, we may incur substantial liabilities to third parties or governmental entities and

Table of Contents

may be required to incur substantial remediation costs. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted. Compliance with existing, new or modified laws and regulations could result in substantial costs, delay our operations or otherwise have a material adverse effect on our business, financial position and results of operations.

Moreover, changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Stricter laws, regulations or enforcement policies could significantly increase our compliance costs and negatively impact our production and operations. For example, the Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in the Barnett Shale area, in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. These initiatives, or other similar initiatives, could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state, and federal levels. Additionally, the Environmental Protection Agency (the EPA) is currently evaluating, pursuant to a court-mandated settlement, measures to strengthen and to expand certain regulations under the Clean Air Act, including the New Source Performance Standards (NSPS), maximum achievable control technology standards (MACT) and residual risk standards, affecting a wide array of air emission sources in the oil and gas industry. If these or other initiatives result in an increase in regulation, it could increase our costs or reduce our production, which could have a material adverse effect on our results of operations and cash flows.

Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional resource plays like the Barnett Shale, the Marcellus Shale, the Eagle Ford Shale and the Niobrara Formation. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing, delaying the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse environmental impacts of hydraulic fracturing, including on water quality and public health. The initial EPA study results are expected to be available in late 2012. In addition, committees of the U.S. House of Representatives and Senate continue to hold hearings to investigate issues related to hydraulic fracturing. The Department of Energy, at the direction of the President, is also studying hydraulic fracturing in order to provide recommendations and identify best practices and other steps to enhance companies safety and environmental performance of hydraulic fracturing. Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as recent incidents involving the release of natural gas and fluids as a result of drilling activities in the Marcellus Shale, there have been a variety of regulatory initiatives at both the federal and state levels to restrict oil and gas drilling operations in certain locations. For example, the New York legislature recently approved a temporary moratorium on drilling involving hydraulic fracturing and the Governor of Pennsylvania has instituted a moratorium on leasing state forest land for gas drilling. Additionally, the New York State Department of Environmental Conservation has ceased issuing exploration and production drilling permits, pending completion of an environmental impact statement regarding hydraulic fracturing. At the international level, the U.K. and EU Parliaments have each discussed implementing a drilling moratorium in the U.K. North Sea. We use hydraulic fracturing extensively and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states of New York and Pennsylvania, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

President Obama s 2012 Fiscal Year Budget proposals, and certain legislation introduced in the United States Congress, if enacted into law, would make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial position and results of operations.

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

Issuance of Common Stock to the University of Texas at Arlington. On May 24, 2011, the Company issued 27,640 shares of the Company s common stock to the University of Texas at Arlington at par value ($0.01 per share), for proceeds of $276. This issuance was related to our second quarter 2011 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.

Table of Contents

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved).

Item 5. Other Information.

None.

Item 6. Exhibits.

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

Exhibit Number	Exhibit Description
*4.3	Eighth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
*4.4	Ninth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee.
*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.

* Filed herewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Carrizo Oil & Gas, Inc. (Registrant)
Date: August 9, 2011	By: /s/ Paul F. Boling Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)
Date: August 9 , 2011	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)