CARRIZO OIL & GAS INC
Form 10-Q
August 09, 2010

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, 2010

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

For the transition period from ________ to _________

Commission File Number 000-29187-87

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

Texas (State or other jurisdiction of incorporation or organization)	76-0415919 (IRS Employer Identification No.)
1000 Louisiana Street, Suite 1500, Houston, TX (Address of principal executive offices)	77002 (Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

YES [ ]   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 [ ]
(Do not check if a smaller reporting company)

Smaller reporting company [ ]

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

YES [ ]   NO [X]

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, as of July 30, 2010 was 34,836,898.

CARRIZO OIL & GAS, INC.

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2010
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PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

ASSETS	June 30, 2010 (Unaudited)	December 31, 2009
	(In thousands, except per share amount)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,752	$ 3,837
Accounts receivable, net		
Oil and gas sales	11,858	13,202
Joint interest billing	7,563	4,901
Related party	9,427	445
Other	1,476	2,793
Advances to operators	424	540
Fair value of derivative instruments	17,617	8,404
Other current assets	3,674	1,278
Total current assets	54,791	35,400
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full-cost method of accounting:		
Proved oil and gas properties, net	470,330	399,182
Costs not subject to amortization	399,932	330,607
Land, building and other equipment, net	3,735	3,911
TOTAL PROPERTY AND EQUIPMENT, NET	873,997	733,700
DEFERRED FINANCING COSTS, NET	8,501	9,738
INVESTMENTS	3,366	3,358
FAIR VALUE OF DERIVATIVE INSTRUMENTS	6,327	6,477
DEFERRED INCOME TAX	59,453	70,217
INVENTORY	3,292	3,292
OTHER ASSETS	1,057	925
TOTAL ASSETS	$ 1,010,784	$ 863,107
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 18,284	$ 19,907
Revenue and royalties payable	24,073	27,390
Accrued drilling costs	14,746	17,251
Accrued interest	1,879	1,922
Other accrued liabilities	8,410	11,120
Advances for joint operations	1,327	1,739
Current maturities of long-term debt	160	148
Deferred income tax	3,705	1,474
Other current liabilities	4,307	1,777
Total current liabilities	76,891	82,728

LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT		576,876		520,188
ASSET RETIREMENT OBLIGATION		4,534		5,410
FAIR VALUE OF DERIVATIVE INSTRUMENTS		2		2,818
OTHER LIABILITIES		3,223		4,354
COMMITMENTS AND CONTINGENCIES				
SHAREHOLDERS' EQUITY:				
Common stock, par value $0.01 per share (90,000 shares authorized; 34,835 and 31,100 issued and outstanding at June 30, 2010 and December 31, 2009, respectively)		348		311
Additional paid-in capital		511,847		431,757
Accumulated deficit		(163,027)		(184,548)
Accumulated other comprehensive income, net of taxes		90		89
Total shareholders' equity		349,258		247,609
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$	1,010,784	$	863,107

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands, except per share amounts)			
REVENUES:				
Oil and gas revenues	$32,922	$25,869	$71,878	$56,602
Other revenues	269	302	737	772
TOTAL REVENUES	33,191	26,171	72,615	57,374
COSTS AND EXPENSES:				
Lease operating	4,703	4,776	8,454	9,959
Production tax	885	300	1,790	(1,022)
Ad valorem tax	468	1,490	1,672	2,387
Transportation, gathering and processing	1,461	3,021	2,794	6,300
Gas purchases	271	317	732	867
Depreciation, depletion and amortization	11,079	12,249	20,920	27,525
Impairment of oil and gas properties	2,731	-	2,731	216,391
General and administrative (inclusive of stock-based compensation expense of $3,156 and $2,308 for the three months ended June 30, 2010 and 2009, respectively, and $5,320 and $5,734 for the six months ended June 30, 2010 and 2009, respectively)	7,750	6,361	14,686	14,261
Accretion expense related to asset retirement obligation	53	75	104	146
TOTAL COSTS AND EXPENSES	29,401	28,589	53,883	276,814
OPERATING INCOME (LOSS)	3,790	(2,418)	18,732	(219,440)
OTHER INCOME AND EXPENSES:				
Gain (loss) on derivative instruments, net	3,214	(2,302)	26,016	27,788
Interest expense	(9,845)	(9,654)	(19,655)	(18,714)
Capitalized interest	4,992	5,118	9,461	10,069
Impairment of investment in Pinnacle Gas Resources, Inc.	-	-	-	(2,091)
Other income (expense), net	(51)	1	(21)	52
INCOME (LOSS) BEFORE INCOME TAXES	2,100	(9,255)	34,533	(202,336)
INCOME TAX (EXPENSE) BENEFIT	(315)	3,239	(13,012)	70,775
NET INCOME (LOSS)	$1,785	$(6,016)	$21,521	$(131,561)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES:				
Increase in market value of investment in Pinnacle Gas Resources, Inc., net of taxes	15	175	-	115
Reclassification of cumulative decrease in market value of investment in				

Pinnacle Gas Resources, Inc., net of taxes	-	-	-	1,359
COMPREHENSIVE INCOME (LOSS)	$1,800	$(5,841)	$21,521	$(130,087)
BASIC INCOME (LOSS) PER COMMON SHARE	$0.05	$(0.19)	$0.66	$(4.25)
DILUTED INCOME (LOSS) PER COMMON SHARE	$0.05	$(0.19)	$0.65	$(4.25)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	34,060	31,002	32,574	30,943
DILUTED	34,464	31,002	33,022	30,943

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

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

	For the Six Months Ended June 30, 2010	2009
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$21,521	$(131,561)
Adjustments to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation, depletion and amortization	20,920	27,525
Impairment of oil and gas properties	2,731	216,391
Unrealized (gain) loss on derivative instruments	(12,269)	18,237
Accretion of discount on asset retirement obligation	104	146
Stock-based compensation	5,320	5,734
Allowance for doutbful accounts	345	288
Deferred income taxes	12,995	(70,841)
Amortization of deferred financing costs and equity premium associated with		
Convertible Senior Notes	4,066	3,938
Impairment of investment in Pinnacle Gas Resources, Inc.	-	2,091
Other	813	979
Changes in operating assets and liabilities-		
Accounts receivable	(9,327)	(807)
Accounts payable	(5,295)	9,173
Accrued liabilities	(2,562)	95
Other, net	816	(515)
Net cash provided by operating activities	40,178	80,873
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(164,949)	(99,477)
Change in capital expenditure accruals	(2,662)	(22,508)
Proceeds from the sale of oil and gas properties	1,977	6
Advances to operators	116	66
Advances for joint operations	(412)	4,123
Other	(287)	(69)
Net cash used in investing activities	(166,217)	(117,859)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	163,600	64,000
Debt repayments	(113,000)	(24,462)
Proceeds from common stock offering, net of offering costs	74,042	-
Proceeds from stock options exercised	667	9
Payments of financing costs and other	(355)	(2,959)
Net cash provided by financing activities	124,954	36,588
DECREASE IN CASH AND CASH EQUIVALENTS	(1,085)	(398)

CASH AND CASH EQUIVALENTS, beginning of period	3,837	5,184
CASH AND CASH EQUIVALENTS, end of period	$2,752	$4,786

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

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CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Carrizo Oil & Gas, Inc., a Texas corporation (the "Company"), is an independent energy company engaged in the exploration, development and production of oil and gas, primarily in the Barnett Shale area in North Texas, the Marcellus Shale area in Appalachia, the Eagle Ford Shale in South Texas, the Niobrara formation in Colorado and in other proved onshore trends along the Texas and Louisiana Gulf Coast regions. The Company's other interests include properties in the U.K. North Sea.

Principles of Consolidation

The consolidated financial statements are presented in accordance with U.S. generally accepted accounting principles. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances. The financial statements reflect necessary adjustments, all of which were of a recurring nature and are in the opinion of management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). The Company believes that the disclosures presented are adequate to allow the information presented not to be misleading. The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2009.

Unconsolidated Investments

The Company accounts for its investment in Pinnacle Gas Resources, Inc. as available-for-sale and adjusts the book value to fair value through other comprehensive income (loss), net of taxes. This fair value is assessed quarterly for other than temporary impairment based on publicly available information. If the impairment is deemed other than temporary, it is recognized in earnings. Subsequent recoveries in fair value are reflected as increases to investments and other comprehensive income (loss), net of taxes.

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

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 (loss), comprehensive income (loss) or net cash provided by/used in operating, investing or financing activities.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and gas reserves used in calculating depletion of proved oil and gas properties, future net revenues and abandonment obligations, impairment of unproved properties, future taxable income and related income tax assets and liabilities, the collectability of outstanding accounts receivable, fair values of derivative instruments, stock-based compensation, contingencies and the results of current and future litigation. Oil and gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, 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 revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of oil and gas, the credit worthiness of counterparties, interest rates, the market value and volatility of the Company's common stock and the Company's ability to generate future taxable income. Future changes in these assumptions may affect these significant estimates materially in the near term. The Company has evaluated subsequent events for recording and disclosures, including assumptions used in its estimates.

Oil and Gas Properties

Investments in oil and gas properties are accounted for using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of oil and gas properties are capitalized. Such costs include lease acquisitions, seismic surveys, and drilling and completion equipment. The Company proportionately consolidates its interests in unincorporated joint ventures and oil and gas properties. The Company capitalized employee-related costs for employees working directly on acquisition, exploration and development activities of $1.6 million and $1.5 million for the three months ended June 30, 2010 and 2009, respectively, and $2.8 million and $3.0 million for the six months ended June 30, 2010 and 2009, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization ("DD&A") of proved oil and gas properties is based on the unit-of-production method using estimates of proved reserve quantities. The depletable base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the three months ended June 30, 2010 and 2009 was $1.16 and $1.52, respectively, and for the six months ended June 30, 2010 and 2009 was $1.16 and $1.68, respectively. Under the full-cost method of accounting, the depletion rate is the current period production as a percentage of the total proved oil and gas reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value of the oil and gas properties (excluding unproved properties, capitalized interest and exploratory wells in progress) and estimated future development costs less salvage value to calculate the depletion expense.

Costs not subject to amortization include costs of unproved properties (which consists of unevaluated leaseholds and seismic costs associated with specific unevaluated properties), capitalized interest and exploratory wells in progress. These costs are evaluated periodically for impairment on a property-by-property basis. If the results of an assessment indicate that the properties have been impaired, the amount of such impairment is added to the proved oil and gas property costs subject to DD&A and the full-cost ceiling test. Factors considered by management in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production, production response to secondary activities and available funds for exploration and development. The Company expects it will complete its evaluation of the properties representing the majority of its unproved property costs within the next two to five years. The Company capitalized interest costs associated with its unproved properties of $5.0 million and $5.1 million for the three months ended June 30, 2010 and 2009, respectively, and $9.5 million and $10.1 million for the six months ended June 30, 2010 and 2009, respectively.

Dispositions of oil and gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments significantly alter the relationship between capitalized costs and proved reserves. We have not had any transactions that significantly alter that relationship.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to a "ceiling-test" based on the estimated future net revenues based on average market prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period, discounted at 10% per annum, from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. If net capitalized costs exceed this limit, the excess is charged to earnings. Prices used in the ceiling test computation do not include the impact of derivative instruments as the Company's derivative instruments are treated as non-designated derivatives.

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

Stock-Based Compensation

The Company grants stock options, stock appreciation rights ("SARs") and restricted stock to directors, employees and independent contractors.

For stock options, including SARs that settle in common stock, compensation expense is based on the grant-date fair value and expensed over the vesting period (generally three years) using the straight-line method, except for awards with performance conditions, in which case the graded vesting method is used. Stock options typically expire ten years after the date of grant. SARs

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expire seven years after the date of grant. For SARs that settle in cash, the liability is adjusted to fair value at each reporting period date and amortized to expense over the vesting period.

For restricted stock, the Company measures deferred compensation based on the average of the high and low price of the Company's stock on the grant date. The deferred compensation is amortized to expense over the vesting period of the restricted stock (generally one to three years), using the straight-line method, except for awards with performance conditions, in which case the Company uses the graded vesting method. Restricted stock issued to independent contractors is adjusted to fair value at each reporting period date and amortized to expense over the vesting period.

The Company recognized the following stock-based compensation expense for the periods indicated, which are reflected as general and administrative expense in the accompanying consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Stock Options and SARs	$ 100	$ 71	$ 521	$ 71
Restricted Stock	3,056	2,237	4,799	5,663
Total Stock-Based Compensation	$ 3,156	$ 2,308	$ 5,320	$ 5,734

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis swaps, to manage price risk underlying its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its derivative instruments as a cash flow hedge, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, the Company recognizes all unrealized and realized gains and losses related to these contracts currently in earnings and are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

The Company's Board of Directors sets all risk management policies and reviews the status and results of derivative activities, 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 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.

Accounts Receivable and Allowance for Doubtful Accounts

At June 30, 2010 and December 31, 2009, the Company had related party receivables of $9.4 million and $0.4 million, respectively, with ACP II Marcellus, LLC, a private equity fund, related to the Company's operations in the Marcellus Shale.

The Company establishes provisions for losses on accounts receivable when it determines that it will not collect all or a part of the outstanding balance. The Company reviews collectability quarterly and adjusts the allowance as necessary using the specific identification method. At June 30, 2010 and December 31, 2009, the Company’s allowance for doubtful accounts was $2.3 million and $2.0 million, respectively.

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Earnings Per Share

Supplemental earnings per share information is provided below:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In thousands, except per share amounts)			
Net income (loss)	$ 1,785	$ (6,016)	$ 21,521	$ (131,561)
Average common shares outstanding				
Weighted average common shares outstanding	34,060	31,002	32,574	30,943
Restricted stock, stock options and SARs	404	-	448	-
Diluted weighted average common shares outstanding	34,464	31,002	33,022	30,943
Net income (loss) per common share				
Basic	$ 0.05	$ (0.19)	$ 0.66	$ (4.25)
Diluted	$ 0.05	$ (0.19)	$ 0.65	$ (4.25)

Basic earnings per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings per common share is based on the weighted average number of common shares outstanding and all dilutive potential common shares outstanding during the periods. The Company excluded 263,230 and 47,772 shares related to restricted stock, stock options and SARs from the calculation of dilutive shares for the three months and six months ended June 30, 2010, respectively, because the grant prices were greater than the average market prices of the common shares for the periods and would be antidilutive to the computations. The Company excluded 893,837 shares related to stock options and SARs from the calculation of dilutive shares for the three months and six months ended June 30, 2009 due to the net loss reported in the periods. Shares of common stock subject to issuance pursuant to the conversion features of the 4.375% convertible senior notes due 2028 did not have an effect on the calculation of dilutive shares for the three months and six months ended June 30, 2010 and 2009.

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 future taxable income based upon the Company's estimated 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.

Recently Adopted Accounting Pronouncements

A standard to improve disclosures about fair value measurements was issued by the Financial Accounting Standards Board (the "FASB") in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity and (4) the transfers in and out of Levels 1 and 2. The Company adopted the new disclosures in the first quarter of 2010.

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2. INVESTMENTS

Investments consisted of the following at June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	(In thousands)	
Pinnacle Gas Resources, Inc.	$ 843	$ 835
Oxane Materials, Inc.	2,523	2,523
	$ 3,366	$ 3,358

Pinnacle Gas Resources, Inc.

In 2003, the Company and its wholly-owned subsidiary CCBM, Inc. contributed their interests in certain oil and gas leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle Gas Resources, Inc. ("Pinnacle").

At March 31, 2009, the market value of the Company's investment in Pinnacle had consistently remained below its original book basis since October 2008. The Company determined that the impairment was other than temporary and, accordingly, recorded an impairment expense of $2.1 million at March 31, 2009. At June 30, 2010, the Company owned 2,555,825 shares of Pinnacle common stock and reported the fair value of the stock at $0.8 million (based on $0.33 per share, the closing price of Pinnacle's common stock on June 30, 2010).

On February 23, 2010, Pinnacle entered into an Agreement and Plan of Merger (the "Merger Agreement") with affiliates of Scotia Waterous (USA), Inc. At the closing of the transactions contemplated by the Merger Agreement, Pinnacle is expected to be owned by an investor group led by Scotia Waterous (USA), Inc., which includes DLJ Merchant Banking Partners III, L.P. and affiliated investment funds and certain members of Pinnacle's management team. Subject to the terms and conditions of the Merger Agreement, at the effective time and as a result of the Merger, each outstanding share of Pinnacle common stock, (other than dissenting shares and those owned by the buyers and affiliates) will be converted into the right to receive a cash amount of $0.34 per share. The merger is expected to be completed during the third quarter of 2010.

Oxane Materials, Inc.

In May 2008, the Company entered into a strategic alliance agreement with Oxane Materials, Inc. ("Oxane") in connection with the development of a proppant product to be used in the Company's exploration and production program. The Company contributed approximately $2.0 million to Oxane in exchange for warrants to purchase Oxane common stock and for certain exclusive use and preferential purchase rights with respect to the proppant. The Company simultaneously invested an additional $500,000 in a convertible promissory note from Oxane. The convertible promissory note accrued interest at a rate of 6% per annum. During the fourth quarter of 2008, the Company converted the promissory note into 630,371 shares of Oxane preferred stock.

3. PROPERTY AND EQUIPMENT, NET

At June 30, 2010 and December 31, 2009, property and equipment, net consisted of the following:

	June 30, 2010	December 31, 2009
	(In thousands)	
Proved oil and gas properties	$ 759,460	$ 667,907
Costs not subject to amortization:		
Unevaluated leaseholds and seismic costs	315,507	258,300
Capitalized interest	40,858	34,563
Exploratory wells in progress	43,567	37,744
Land, building and other equipment	6,670	6,475
Total property and equipment	1,166,062	1,004,989
Accumulated depreciation, depletion and amortization	(292,065)	(271,289)
Total property and equipment, net	$ 873,997	$ 733,700

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In June 2010, the Company 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 and six months ended June 30, 2010 with respect to the U.K. cost center. For the six months ended June 30, 2009, the Company incurred a full cost-ceiling test impairment of $216.4 million ($140.6 million net of tax) with respect to the U.S. cost center. To measure the full-cost ceiling test impairment for the first quarter of 2009, the Company elected to use a pricing date subsequent to the balance sheet date, as allowed by SEC guidelines in effect at the time. Using prices as of May 6, 2009, the Company incurred a full-cost ceiling test impairment of $216.4 million ($140.6 million net of tax). Had the Company used prices in effect as of March 31, 2009, a full cost ceiling test impairment of $323.2 million ($210.1 million net of tax) would have been recorded for the first quarter of 2009. The option to use a pricing date subsequent to the balance sheet date is no longer available to the Company due to the adoption of the new oil and gas reporting requirements effective December 31, 2009.

4. INCOME TAXES

The Company computes quarterly income taxes under the effective tax rate method based on applying an anticipated annual effective income tax rate to the year-to-date income (loss), except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. Actual income tax (expense) benefit differs from income tax (expense) benefit computed by applying the U.S. federal statutory corporate rate of 35% to pretax income (loss) as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
(Expense) benefit at the statutory rate	$ (735)	$ 3,239	$ (12,087)	$ 70,817
State and local income tax expense, net of federal benefit	(14)	-	(1,348)	(66)
Other	434	-	423	24
Total income tax (expense) benefit	$ (315)	$ 3,239	$ (13,012)	$ 70,775

At June 30, 2010, the Company had a net deferred tax asset of $55.7 million. The Company has determined it is more likely than not that its deferred tax assets are fully realizable based on projections of future taxable income which included estimated production of proved reserves at estimated future pricing. No valuation allowance for the net deferred tax asset is currently needed.

The Company classifies interest and penalties associated with income taxes as interest expense. At June 30, 2010, 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.

5. DEBT

Debt consisted of the following at June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	(In thousands)	
Convertible Senior Notes	$ 373,750	$ 373,750
Unamortized discount for Convertible Senior Notes	(38,874)	(45,122)
Senior Secured Revolving Credit Facility	242,000	191,400
Other	160	308
	577,036	520,336
Less: Current maturities	(160)	(148)
	$ 576,876	$ 520,188

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (the "Convertible Senior Notes"). Interest is payable on June 1 and December 1 each year. The notes are convertible, using a net share settlement process, into a combination of cash and Company common stock that entitles holders of the Convertible Senior Notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of the Company's conversion obligation in excess of such principal amount.

The notes are convertible into the Company's common stock at a ratio of 9.9936 shares per $1,000 principal amount of notes, equivalent to a conversion price of approximately $100.06. This conversion rate is subject to adjustment upon certain corporate events. In addition, if certain fundamental changes occur on or before June 1, 2013, the Company will in some cases increase the conversion rate for a holder electing to convert notes in connection with such fundamental change; provided, that in no event will the total number of shares issuable upon conversion of a note exceed 14.7406 per $1,000 principal amount of notes (subject to adjustment in the same manner as the conversion rate).

Holders may convert the notes only under the following conditions: (a) during any calendar quarter if the last reported sale price of the Company's common stock exceeds 130 percent of the conversion price for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter, (b) during the five business days after any five consecutive trading day period in which the trading price per $1,000 principal amount of the notes is equal to or less than 97% of the conversion value of such notes, (c) during specified periods if specified distributions to holders of the Company's common stock are made or specified corporate transactions occur, (d) prior to the close of business on the business day preceding the redemption date if the notes are called for redemption or (e) on or after March 31, 2028 and prior to the close of business on the business day prior to the maturity date of June 1, 2028.

The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

The Convertible Senior Notes are subject to customary non-financial covenants and events of default, including a cross default under the Senior Credit Facility (defined below), the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes.

The Convertible Senior Notes are unsecured obligations of the Company and rank equal to all future senior unsecured debt but rank second in priority to the Senior Credit Facility.

The Company valued the Convertible Senior Notes at May 21, 2008, as $309.6 million of debt and $64.2 million of equity representing the fair value of the conversion premium. The resulting debt discount is being amortized to interest expense through June 1, 2013, the first date on which the holders may require the Company to repurchase the Convertible Senior Notes, resulting in an effective interest rate of approximately 8% for the Convertible Senior Notes. Amortization of the debt discount amounted to $3.1 million and $3.0 million for the three months ended June 30, 2010 and 2009, respectively, and $6.2 million and $6.0 million for the six months ended June 30, 2010 and 2009, respectively.

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility (the "Senior Credit Facility") with Wells Fargo Bank, N.A., as administrative agent. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base or $375.0 million. It is secured by substantially all of the Company's proved oil and gas assets and is currently guaranteed by certain of the Company's subsidiaries: CCBM, Inc.; CLLR, Inc.; Carrizo (Marcellus), LLC; Carrizo Marcellus Holdings, Inc.; Hondo Pipeline Inc.; Bandelier Pipeline Holding, LLC and Mescalero Pipeline, LLC. The Senior Credit Facility matures on October 29, 2012, and is subject to semi-annual borrowing base redeterminations on March 31 and September 30.

In April 2009, the Company amended the Senior Credit Facility to, among other things, (1) adjust the maximum ratio of total net debt to Consolidated EBITDA; (2) modify the calculation of total net debt for purposes of determining the ratio of total net debt to Consolidated EBITDA to exclude the following amounts, which represent a portion of the Convertible Senior Notes deemed to be an equity component that may be settled in cash (including partial cash settlement) upon conversion: $51.3 million during 2009, $38.9 million during 2010, $26.0 million during 2011 and $12.7 million during 2012 until the maturity date; (3) add a new senior leverage ratio; (4) modify the interest rate margins applicable to Eurodollar loans; (5) modify the interest rate margins applicable to base rate loans; and (6) establish new procedures governing the modification of swap agreements.

In May 2009, the Company amended the Senior Credit Facility to, among other things, (1) provide that the aggregate notional volume of oil and gas subject to swap agreements may not exceed 80% of "forecasted production from proved producing reserves," (as that term is defined in the Senior Credit Facility), for any month, (2) remove a provision that limited the maximum duration of swap

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agreements permitted under the Senior Credit Facility to five years, and (3) provide that the aggregate notional amount under interest rate swap agreements may not exceed the amount of borrowings then outstanding under the Senior Credit Facility.

In May 2010, the Company amended the Senior Credit Facility to increase the borrowing base to $375 million from $350 million.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, the Company has the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest will be due at maturity.

The annual interest rate on each base rate borrowing is (a) the greatest of the agent's Prime Rate, the Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage), but such interest rate can never be lower than the adjusted Daily LIBO rate on such day plus a margin between 2.25% to 3.25% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted daily LIBO rate plus a margin between 2.25% to 3.25% (depending on the then-current level of borrowing base usage). At June 30, 2010, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.3%.

The Company is subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.00 to 1.00 (as defined in the Senior Credit Facility); and (2) a maximum total net debt to Consolidated EBITDA (as defined in the Senior Credit Facility) of (a) 4.75 to 1.00 for each quarter ending on or after December 31, 2009 and on or before September 30, 2010, (b) 4.25 to 1.00 for the quarter ending December 31, 2010, and (c) 4.00 to 1.00 for each quarter ending on or after March 31, 2011; and (3) a maximum ratio of senior debt (which excludes certain amounts attributable to the Convertible Senior Notes) to Consolidated EBITDA of 2.25 to 1.00. As defined in the Senior Credit Facility, the current ratio was 2.36 to 1, the total net debt to Consolidated EBITDA ratio was 4.47 to 1 and the ratio of senior debt to Consolidated EBITDA ratio was 1.88 to 1 as of June 30, 2010. 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 Senior Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and equity offerings.

The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

At June 30, 2010, the Company had $242.0 million of borrowings outstanding under the Senior Credit Facility. Future availability under our $375.0 million borrowing base is subject to the terms and covenants of the Senior Credit Facility. The Senior 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 equity offerings.

6. ASSET RETIREMENT OBLIGATION

The following is a rollforward of the asset retirement obligation:

	Six Months Ended June 30, 2010	Year Ended December 31, 2009
	(In thousands)	
Asset retirement obligation at beginning of period	$ 5,410	$ 6,503
Liabilities incurred	100	444
Liabilities settled	-	(36)
Accretion expense	104	308
Revisions of previous estimates	(1,080)	(1,809)
Asset retirement obligation at end of period	$ 4,534	$ 5,410

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The revisions of previous estimates relate primarily to increases in the estimated life of wells in the Barnett Shale and the reduction of estimated obligations in the U.K. North Sea.

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

The following is a rollforward of the Company's shares outstanding:

	Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Shares outstanding at January 1	31,100	30,860
Common stock offering	3,220	-
Restricted stock awards, net of forfeitures	253	162
Stock options exercised for cash	262	5
Other	-	10
Shares outstanding at June 30	34,835	31,037

In April 2010, the Company sold 3.22 million shares of its common stock in an underwritten public offering at a price of $23.00 per share. The Company received proceeds of approximately $74.1 million, which were used to repay a portion of the outstanding borrowings under the Senior Credit Facility.

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 investment program. The commodity derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis swaps. The Company's 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 the changes in fair value included in the consolidated statements of operations for the period in which the changes occur.

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 enters into the majority of its derivative transactions with three counterparties and netting agreements are in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price and credit risk.

The following sets forth a summary of our natural gas derivative positions at average delivery location (Waha and Houston Ship Channel) prices as of June 30, 2010. Our crude oil derivative positions at June 30, 2010, were not significant.

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Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2010	13,156,000	$ 5.72	$ 6.28
2011	21,340,000	$ 6.12	$ 6.58
2012	7,963,000	$ 6.53	$ 7.03

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 2010, if market prices fall below the short put price of $4.12, the floor price becomes the market price plus the put spread of $1.60 on 11,484,000 of the 13,156,000 MMBtus and the remaining 1,672,000 MMBtus have a floor price of $5.72.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2010	11,484,000	$ 4.12	$ 1.60
2011	14,049,000	$ 4.52	$ 1.60
2012	6,404,000	$ 4.47	$ 2.06

For the three months and six months ended June 30, 2010 and 2009, the Company recorded the following related to its derivative instruments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Realized gain	$ 8,792	$ 27,215	$ 13,747	$ 46,025
Unrealized gain (loss)	(5,578)	(29,517)	12,269	(18,237)
Gain (loss) on derivative instruments, net	$ 3,214	$ (2,302)	$ 26,016	$ 27,788

The Company deferred the payment of premiums associated with certain of its derivative instruments totaling $6.5 million and $4.8 million at June 30, 2010 and December 31, 2009, respectively. The Company classified $4.3 million and $1.8 million as other current liabilities at June 30, 2010 and December 31, 2009, respectively, and $2.2 million and $3.0 million as other non-current liabilities at June 30, 2010 and December 31, 2009, respectively. These deferred premiums will be paid to the counterparty with each monthly settlement (July 2010 – December 2011) and recognized as realized gain on derivative instruments.

The fair value of the outstanding derivatives at June 30, 2010 and December 31, 2009 was a net asset of $23.9 million and $12.1 million, respectively. At June 30, 2010, approximately 72% of the fair value of the Company's derivative instruments were with Credit Suisse, 15% were with Shell Energy North America (US) LP, and the remaining 13% were with Credit Agricole.

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.

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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.

The following presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of June 30, 2010 and December 31, 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	June 30, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in thousands)							
Assets:								
Investment in Pinnacle Gas Resources, Inc.	$ 843	$ -	$ -	$ 843	$ 835	$ -	$ -	$ 835
Derivative instruments	-	49,097	-	49,097	-	48,192	-	48,192
Liabilities:								
Derivative instruments	-	25,155	-	25,155	-	36,129	-	36,129
Total	$ 843	$ 23,942	$ -	$ 24,785	$ 835	$ 12,063	$ -	$ 12,898

The derivative assets and liabilities above are presented as gross assets and liabilities, without regard to master netting arrangements, which are considered in the presentation of derivative assets and liabilities in our consolidated balance sheets.

Derivatives instruments are valued by industry-standard valuation models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. We had no transfers in or out of Levels 1 or 2 for the six months ended June 30, 2010.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and debt. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature or short-term nature of these instruments. The fair values of the borrowings under the Senior Credit Facility approximate the carrying amounts as of June 30, 2010 and December 31, 2009, and were determined based upon interest rates currently available to the Company for borrowings with similar terms. The fair value of the Convertible Senior Notes at June 30, 2010 and December 31, 2009 was estimated at approximately $320.0 million and $321.7 million, respectively, based on a quote provided by an investment bank.

11. SUBSEQUENT EVENT

On August 4, 2010, the Company, entered into a purchase and sale agreement (the "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. The Purchase and Sale Agreement provides for Reliance's purchase of 20% of the Company's interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale for a combination of approximately $13 million in cash and a commitment to pay 75% of certain of the Company's future development costs up to approximately $52 million. Simultaneous with this transaction, the Company's current joint venture partner, ACP II Marcellus, LLC ("ACP II"), an affiliate of Avista Capital Holdings LP ("Avista"), entered into a purchase and sale agreement with Reliance under which it agreed to sell its entire interest in the same properties to Reliance. Because of the Company's interest in ACP II, the Company expects to receive up to approximately $44 million in cash distributions based on Avista's sale to Reliance. Upon closing of the sale transactions, the Company and Reliance will enter into agreements to form a new joint venture with respect to the interests being purchased by Reliance from the Company and Avista. Closing of the Company's sale to Reliance and entry into the joint venture is expected on or before September 17, 2010 and is subject to certain closing conditions. Proceeds expected to be received as a result of these transactions are subject to purchase price adjustments.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of the significant factors that affected the Company's financial position and results of operations during the periods included in the accompanying unaudited 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 financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2009 and the unaudited financial statements included in this quarterly report.

General Overview

Our second quarter 2010 included oil and gas revenues of $32.9 million and production of 9.3 Bcfe. The key drivers to our results for the three months ended June 30, 2010 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the three months ended June 30, 2010, we drilled (1) 22 gross wells (11.8 net) in the Barnett Shale area with a success rate of 100%, (2) one gross (one net) unsuccessful well in the Gulf Coast and (3) one gross (0.1 net) successful well in the Marcellus Shale area. At June 30, 2010 we had an inventory of 53 gross wells (28.7 net) in the Barnett Shale that have been drilled and are waiting on fracturing, completion or pipeline connection.

Production. Our second quarter 2010 production of 9.3 Bcfe, or 102.1 MMcfe/d, increased 18% from the second quarter 2009 production of 7.9 Bcfe, or 86.7 MMcfe/d, and increased 12% from the first quarter 2010 production of 8.3 Bcfe, or 91.9 MMcfe/d. The increases were primarily a result of production from new wells in the Barnett Shale, partially offset by normal production decline.

Commodity prices. Our average natural gas price during the second quarter of 2010 was $3.31 per Mcf (excluding the impact of our derivative instruments), $0.23 per Mcf, or seven percent higher than the price in the second quarter of 2009 and $1.18 per Mcf, or 26%, lower than the price in the first quarter of 2010. Excluded from these prices are realized hedge gains of $8.8 million ($0.95 per Mcf) for the second quarter of 2010, $27.2 million ($3.45 per Mcf) for the second quarter of 2009 and $5.0 million ($0.60 per Mcf) for the first quarter of 2010.

Financial flexibility. In April 2010, we sold 3.22 million shares of our common stock in an underwritten public offering at a price of $23.00 per share. We used the net proceeds of approximately $74.1 million to repay a portion of the outstanding borrowings under our Senior Credit Facility. We expect to fund, in part, our recently expanded capital expenditure plan for 2010 with the available capacity under the Senior Credit Facility. On May 5, 2010, the borrowing base of our Senior Credit Facility increased from $350 million to $375 million, representing a $25 million increase.

Recent Developments

New Marcellus Shale Joint Venture with Reliance Industries

On August 4, 2010, we entered into a purchase and sale agreement (the "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. The Purchase and Sale Agreement provides for Reliance's purchase of 20% of our interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale for a combination of approximately $13 million in cash and a commitment to pay 75% of certain of our future development costs up to approximately $52 million (the "Carry Commitment"). We have agreed to indemnify Reliance for breaches of the Purchase and Sale Agreement and specified retained liabilities.

Simultaneous with this transaction, our current joint venture partner, ACP II Marcellus, LLC (“ACP II”), an affiliate of Avista Capital Holdings LP (“Avista”), entered into a purchase and sale agreement with Reliance under which it agreed to sell its entire interest in the same properties to Reliance for approximately $327 million. We expect to receive up to $44 million in cash distributions from our interests in ACP II based on the sale of Avista’s approximately 52,200 net acres, subject to reserves that ACP II may establish. We expect that the Avista transaction will close concurrently with our transaction with Reliance on or before September 17, 2010. Following the closings, our joint venture with Avista would continue to cover approximately 140,000 gross acres in the Marcellus Shale region, primarily in West Virginia and New York.

The Purchase and Sale Agreement provides that, upon closing of the sale transactions, we will enter into agreements with Reliance to form a new joint venture with respect to the interests being purchased by Reliance from us and Avista and related interests being retained by us covering approximately 104,400 gross acres in northeastern and central Pennsylvania. We would retain a 40% working interest in the acreage and Reliance would own 60%. The period during which the Carry Commitment must be used would run for two years, subject to certain extensions. Following such period, there is a mutual right of first offer on direct and indirect property transfers for the remainder of a ten-year development period, subject to specified exceptions. We have granted an option in favor of Reliance to purchase a 60% (as adjusted over time) share of acreage purchased directly or indirectly by us after the closing. This option, which covers substantially all of Pennsylvania, is exercisable at our cost plus, in the case of direct property sales, a specified premium and is subject to specified exceptions. Reliance has the right to assume operatorship of 60% of undeveloped acreage in portions of central Pennsylvania and for a three-year period to purchase all of our 40% interest in such acreage at a specified price. Operations under the joint venture will generally be required to conform to a budget approved by an operating committee that includes representatives of both parties, subject to exceptions, including those for sole risk operations and in the event of defaults by the parties. The parties have also generally agreed until 2013 to forego the ability conduct sole risk operations and have agreed to certain other limits to such operations thereafter. Reliance has also agreed to certain limitations with respect to specified actions taken by us. At the closing of the sale transactions, we and Avista will release the properties being sold to Reliance or that are part of the joint venture with Reliance, from our existing joint venture.

In addition to customary conditions, closing of our sale to Reliance and entry into the joint venture are conditioned on the closing of Avista's sale to Reliance, obtaining consents from the lenders under our credit facility, and title defects, lease consents and unwaived preferential purchase rights not exceeding specified levels.

New Growth Strategy and Increased Capital Expenditure Plan

In connection with our public equity offering described above, our Board of Directors increased our 2010 capital expenditure plan from $170 million to $225 million and we announced an additional growth strategy in crude oil and liquids-rich plays. We are attempting to increase the level of our crude oil and liquids production and reserves by as early as the first quarter of 2011. As part of this effort, we have completed the acquisition of acreage and are pursuing additional land acquisitions in an unconventional play that is rich in condensate and natural gas liquids located in the Eagle Ford shale formation (the "Eagle Ford Shale"), principally in LaSalle County, Texas. In addition, we acquired land acquisitions in an unconventional oil play located in the Niobrara formation in the Denver-Julesberg basin (the "Niobrara") in Weld County, Colorado.

Eagle Ford Update. During the first quarter of 2010, we commenced leasing in the condensate and liquids-rich portions of the Eagle Ford Shale. As of July 30, 2010, we have closed on approximately 17,000 net acres. We relocated a rig under a long-term contract in the Barnett Shale to the Eagle Ford Shale and are in the process of drilling the second of our initial two horizontal wells on this acreage.

Niobrara Update. We have acquired approximately 58,000 net leasehold acres through July 30, 2010 in an unconventional oil play located in the Niobrara. Our revised capital expenditure plan includes the drilling of two to three horizontal wells in the Niobrara during 2010 and we currently anticipate that our first Niobrara well should spud in the third quarter of 2010.

Outlook

Our outlook for 2010 remains challenging, primarily as a result of the decline in gas prices that began in mid 2008, but our outlook for the long-term future remains positive. 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 2010:

- As described above, we plan to increase the level of our crude oil and liquids production and reserves in our portfolio of drilling areas by as early as the first quarter of 2011. Since the beginning of the year, we acquired acreage positions and plan to drill in the Eagle Ford Shale and the Niobrara.

- We plan to continue the exploration and development activities in the Marcellus Shale in the Northeastern United States, primarily through joint ventures with ACP II for properties primarily located in West Virginia and New York and with Reliance for properties located in Pennsylvania assuming that our recently announced joint venture is consummated. Among other activities, we currently plan to drill one gross (0.5 net) vertical well and fracture stimulate four gross (2.0 net) previously drilled vertical wells in the West Virginia portion of the Marcellus Shale to test the prospectivity of that area. In the later part of 2009, we started drilling two wells in Pennsylvania and plan to drill a third well pending further seismic data interpretation.

- In connection with our recent equity offering and our new strategy to enter into crude oil and liquids-rich plays, we have increased our 2010 capital expenditure plan from $170 million to $225 million, which currently includes $147 million for drilling, $76 million for land and seismic acquisitions and $2 million for the pre-development work of our Huntington Field in the U.K. North Sea.

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- We expect to continue to hedge production to limit our exposure to reductions in natural gas prices. At June 30, 2010, we had hedged approximately 42,459,000 MMBtus of natural gas production through 2012.

Results of Operations

Three Months Ended June 30, 2010, Compared to the Three Months Ended June 30, 2009

Revenues from oil and gas production for the three months ended June 30, 2010 increased 27% to $32.9 million from $25.9 million for the same period in 2009 due to higher gas production and increased oil and gas prices. Production volumes for natural gas for the three months ended June 30 was 9.1 Bcf and 7.6 Bcf in 2010 and 2009, respectively. The increase in production was primarily attributable to new production from wells in the Barnett Shale partially offset by normal production decline. Average natural gas prices, excluding the impact attributable to an $8.8 million and a $27.2 million realized gain on derivative instruments for the quarters ended June 30, 2010 and 2009, respectively, increased to $3.31 per Mcf in the second quarter of 2010 from $3.08 per Mcf in the same period in 2009. Average oil prices increased 33% to $75.71 per barrel from $56.95 per barrel in the same period in 2009.

The following summarizes production volumes, average sales prices (excluding the impact of derivative instruments) and oil and gas revenues for the three months ended June 30, 2010 and 2009:

	Three Months Ended June 30,		2010 Period Compared to 2009 Period	
	2010	2009	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	38	41	(3)	(7)%
Natural gas and NGLs (MMcf)	9,067	7,648	1,419	19 %
Average sales prices				
Oil and condensate (per Bbl)	$ 75.71	$ 56.95	$ 18.76	33 %
Natural gas and NGLs (per Mcf)	3.31	3.08	0.23	7 %
Oil and gas revenues (In thousands)				
Oil and condensate	$ 2,884	$ 2,331	$ 553	24 %
Natural gas and and NGLs	30,038	23,538	6,500	28 %
Total oil and gas revenues	$ 32,922	$ 25,869	$ 7,053	27 %

Lease operating expenses were $4.7 million (or $0.51 per Mcfe) during the three months ended June 30, 2010 as compared to $4.8 million (or $0.61 per Mcfe) for the second quarter of 2009. Lease operating expenses remained essentially unchanged as a decrease in service costs was largely offset by increased operating expenses associated with higher production. The decline in service costs was primarily driven by a decrease in operating expenses related to the pipeline and gathering system that was sold during the fourth quarter of 2009 and the increase in production from our Tarrant County Barnett Shale area, which has comparatively less associated salt water production that must be disposed of than production from other areas.

Production taxes increased from $0.3 million in the second quarter of 2009 to $0.9 million for the same period in 2010 as a result of a severance tax refund of $0.2 million in the second quarter of 2009 and increased production and gas prices in 2010 as compared to 2009.

Ad valorem taxes decreased 69% to $0.5 million for the three months ended June 30, 2010 from $1.5 million for the same period in 2009 primarily due to lower estimated property valuations in 2010 as compared to 2009 and a true up of the first quarter 2010 estimate of ad valorem taxes.

Transportation, gathering and processing costs decreased 52% to $1.5 million for the second quarter of 2010 primarily as a result of a change in contractual pricing effective July 1, 2009 whereby natural gas production is now sold at the wellhead.

DD&A expense for the three months ended June 30, 2010 decreased 10% to $11.1 million ($1.19 per Mcfe) from $12.2 million ($1.55 per Mcfe) for the same period in 2009. This decrease in DD&A was primarily due to a lower depletion rate resulting from an impairment charge that reduced the depletable full-cost pool in the fourth quarter of 2009 and lower overall finding costs of new reserves added primarily in the fourth quarter of 2009, partially offset by increased production.

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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 $7.8 million for the three months ended June 30, 2010 from $6.4 million for the corresponding period in 2009. The increase was primarily due to increased stock based compensation as the 2009 annual bonuses to non-executive employees were approved during the second quarter of 2010 while the 2008 annual bonuses to non-executive employees were approved during the first quarter of 2009.

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. The net loss on derivative instruments of $2.3 million in the second quarter of 2009 was comprised of a $29.5 million unrealized loss on derivatives and a $27.2 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended June 30, 2010 were $9.8 million and $5.0 million, respectively, as compared to $9.7 million and $5.1 million, respectively, for the same period in 2009. The net increase was primarily due to higher amortization of deferred loan costs during the second quarter of 2010.

Six Months Ended June 30, 2010, Compared to the Six Months Ended June 30, 2009

Revenues from oil and gas production for the six months ended June 30, 2010 increased 27% to $71.9 million from $56.6 million for the same period in 2009 due to increased gas production and higher oil and gas prices. Production volumes for natural gas for the six months ended June 30, were 17.1 Bcf and 15.6 Bcf in 2010 and 2009, respectively. The increase in production was primarily due to new production from wells in the Barnett Shale partially offset by normal production decline. Average natural gas prices, excluding the impact attributable to a $13.8 million and a $43.2 million realized gain on derivative instruments for the six months ended June 30, 2010 and 2009, respectively, increased to $3.87 per Mcf for the first six months of 2010 from $3.36 per Mcf in the same period in 2009. Average oil prices, excluding the impact of a realized gain on derivative instruments of $2.8 million for the six months ended June 30, 2009, increased 59% to $75.92 per barrel from $47.84 per barrel in the same period in 2009.

The following summarizes production volumes, average sales prices (excluding the impact of derivative instruments) and oil and gas revenues for the six months ended June 30, 2010 and 2009:

	Six Months Ended June 30,		2010 Period Compared to 2009 Period	
	2010	2009	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	76	85	(9)	(11)%
Natural gas and NGLs (MMcf)	17,107	15,642	1,465	9%
Average sales prices				
Oil and condensate (per Bbl)	$ 75.92	$ 47.84	$ 28.08	59%

Natural gas and NGLs (MMcf)	3.87	3.36	0.51	15	%
Oil and gas revenues (In thousands)					
Oil and condensate	$ 5,758	$ 4,065	$ 1,693	42	%
Natural gas and NGLs	66,120	52,537	13,583	26	%
Total oil and gas revenues	$ 71,878	$ 56,602	$ 15,276	27	%

Lease operating expenses were $8.5 million (or $0.48 per Mcfe) during the six months ended June 30, 2010 as compared to $10.0 million (or $0.62 per Mcfe) for the six months ended 2009. The decrease in lease operating expenses was due to a decrease in service costs partially offset by increased operating expenses associated with higher production. The decline in service costs was driven primarily by a decrease in operating expenses related to the pipeline and gathering system that was sold during the fourth quarter of 2009 and the increase in production from our Tarrant County Barnett Shale area, which has comparatively less associated salt water production that must be disposed of than production from other areas.

Production taxes increased from a credit of $(1.0) million in the first six months of 2009 to $1.8 million for the same period in 2010 as a result of a severance tax refund of $2.0 million in 2009 and increased production and prices in 2010 as compared to 2009.

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Ad valorem taxes decreased 30% to $1.7 million for the six months ended June 30, 2010 from $2.4 million for the same period in 2009 primarily due to lower estimated property valuations in 2010 as compared to 2009.

Transportation, gathering and processing costs decreased 56% to $2.8 million for the first six months of 2010 primarily as a result of a change in contractual pricing effective July 1, 2009, whereby natural gas production is now sold at the wellhead.

DD&A expense for the six months ended June 30, 2010 decreased 24% to $20.9 million ($1.19 per Mcfe) from $27.5 million ($1.70 per Mcfe) for the same period in 2009. This decrease in DD&A was primarily due to a lower depletion rate resulting from impairment charges that reduced the depletable full-cost pool in the first and fourth quarters of 2009 and lower overall finding costs of new reserves added primarily in the fourth quarter of 2009, partially offset by increased production.

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 six months ended June 30, 2010 with respect to the U.K. cost center. Due to low oil and gas prices during 2009, indicated by average prices of $3.17 per Mcf for natural gas and $51.76 per Bbl for crude oil on May 6, 2009, the discounted present value (discounted at ten percent) of future net cash flows from our proved oil and gas reserves fell below our net book basis in the proved oil and gas properties. This resulted in a full-cost ceiling test impairment at March 31, 2009 of $216.4 million ($140.6 million after tax) with respect to the U.S. cost center.

General and administrative expense increased to $14.7 million for the six months ended June 30, 2010 from $14.3 million for the corresponding period in 2009. The increase was due primarily to higher legal, professional and audit fees. This increase was partially offset by (1) lower stock-based compensation as a result of higher levels of amortization in 2009 associated with higher priced restricted stock awards granted in prior years and (2) lower compensation expense as the 2008 annual bonuses to executives were approved during the second quarter of 2009 and the 2009 annual bonuses to executives were approved during the third quarter of 2010.

The net gain on derivative instruments of $26.0 million in the first six months of 2010 was comprised of a $12.2 million unrealized gain on derivatives and a $13.8 million realized gain on derivatives. The net gain on derivative instruments of $27.8 million in the first six months of 2009 was comprised of a $46.0 million realized gain on derivatives and a $18.2 million unrealized loss on derivatives.

Interest expense and capitalized interest for the six months ended June 30, 2010 were $19.7 million and $9.5 million, respectively, as compared to $18.7 million and $10.1 million, respectively, for the same period in 2009. The net increase was primarily due to higher debt levels under the Senior Credit Facility, lower levels of capitalized interest and higher amortization of deferred financing costs during 2010.

Our overall tax effective rate was 37.7% for the first six months of 2010 and 35.0% for the first six months of 2009. The increase in the effective tax rate was primarily due to a true up of prior year estimates of state income taxes during 2010.

Liquidity and Capital Resources

2010 Capital Budget and Funding Strategy. In connection with our recent equity offering and our new strategy to enter into crude oil and liquids-rich plays, we have increased our 2010 capital expenditure plan from $170 million to $225 million which currently includes $147 million for drilling, $76 million for land and seismic acquisitions and $2 million for the development of the U.K. North Sea. If our development plan for the Huntington Field in the U.K.

North Sea is approved by our joint venture during 2010, we may be required to invest up to an additional $20.0 million in facilities and drilling to develop this field in 2010. We currently intend to project finance all or a portion of the additional Huntington field development costs. We intend to finance our 2010 capital expenditure plan primarily from cash flows from operations, the possible selective sale or monetization of non-core assets and available borrowings under the Senior Credit Facility. We may be required to reduce or defer part of our 2010 capital expenditure plan if we are unable to obtain sufficient financing from these sources or if natural gas prices decline. In addition, the 2010 capital expenditure plan and our outlook for the balance of 2010 described in this quarterly report do not give effect to our recently announced new joint venture with Reliance or the related sale by Avista, assuming those transactions close as expected.

Sources and Uses of Cash. During the six months ended June 30, 2010, capital expenditures, net of proceeds from property sales, exceeded our net cash provided by operations. During 2010, we have funded our capital expenditures with cash generated from operations and net additional borrowings under the Senior Credit Facility, including borrowing capacity made available by the paydown of the facility, with proceeds of our common stock offering. 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 oil and gas field services. We hedge a portion of our production to reduce the downside risk of declining oil and gas prices.

- Borrowings under the Senior Credit Facility. On May 5, 2010, we amended our Senior Credit Facility to increase the borrowing base to $375 million from $350 million, representing an increase of $25 million. As of July 30, 2010, the outstanding balance under the Senior Credit Facility was approximately $263.0 million. We have also issued $4.1 million of letters of credit which reduce the amounts available under the Senior Credit Facility. Future availability under our $375 million borrowing base is subject to the terms and covenants of the Senior Credit Facility. The Senior Credit Facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan only to the extent that such amounts exceed cash flow from operations, proceeds from the sale of oil and gas properties and equity offerings. The next borrowing base redetermination is scheduled for the fourth quarter of 2010.

- Asset sales. In order to fund our capital expenditure plan, we may consider the sale of certain properties or assets that are not part of our core business, or are no longer deemed essential to our future growth, if we are able to sell such assets on terms that are acceptable to us. We may consider the sale of additional non-core assets, including the possible sale of our interest in the Huntington Field located in the U.K. North Sea, provided that we can obtain terms that are acceptable to us.

- Debt and equity offerings. In April 2010, we sold 3.22 million shares of our common stock in an underwritten public offering at a price of $23.00 per share. We used the net proceeds of approximately $74.1 million to repay a portion of the outstanding borrowings under the Senior Credit Facility.

- Project financing in certain limited circumstances, particularly to fund all or a portion of our future development costs for the Huntington Field in the U.K. North Sea.

- Lease option agreements and land banking arrangements, such as those we have entered into in the past regarding the Marcellus Shale, the Barnett Shale and other plays.

- Joint ventures through which parties fund a portion of our land acquisition exploration activities to earn an interest in our exploration acreage, such as our joint ventures with Avista and Reliance (if the joint venture is consummated) 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 pipelines and compressors, which are not part of our core oil and gas exploration and production business.

In 2010 we currently plan to drill 57 gross (38.1 net) wells in the Barnett Shale area, eleven gross (3.8 net) wells in the Marcellus shale area, two gross (2.0 net) wells in the Eagle Ford Shale, three gross (3.0 net) wells in the Niobrara and three gross (1.5 net) wells in our other areas. The actual number of wells drilled and capital expended depends on our available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors. Capital expenditures do not include operating costs such as the steam costs that will be required for the multi-year development of our Camp Hill project. In addition to our capital expenditure plan, we have contractual obligations as discussed below.

Overview of Cash Flow Activities. Net cash provided by operating activities were $40.2 million and $80.9 million for the six months ended June 30, 2010 and 2009, respectively. The decrease was primarily due to a higher amount of realized gains on our derivative instruments in 2009 as compared to 2010.

Net cash used in investing activities were $166.2 million and $117.9 million for the six months ended June 30, 2010 and 2009, respectively, and increased primarily due to increased oil and gas property expenditures during 2010 as compared to 2009.

Net cash provided by financing activities for the six months ended June 30, 2010 and 2009 was $125.0 million and $36.6 million, respectively. The increase related primarily to net borrowings under the Senior Credit Facility and proceeds from our equity offering in April 2010.

Liquidity/Cash Flow Outlook. We currently believe that cash generated from our April 2010 equity offering and from operations, supplemented by borrowings under the Senior Credit Facility, will be sufficient to fund our immediate needs. Cash generated from operations is primarily driven by production and commodity prices. While we have steadily increased production over the last few years, natural gas prices declined significantly since the third quarter of 2008. In an effort to mitigate declining prices, we hedge a portion of our production and, as of June 30, 2010, we had hedged approximately 13,156,000 MMBtu (71,500 MMBtu per day for the year, or 75% of our forecasted production from July through December 2010) of our 2010 natural gas production at a weighted average floor or swap price of $5.72 per MMBtu relative to WAHA and Houston Ship Channel prices. On May 5, 2010, we amended the Senior Credit Facility to increase the borrowing base to $375 million from $350 million, representing an increase of $25 million. As of July 30, 2010, the outstanding balance under our credit facility was approximately $263.0 million. We have also issued $4.1 million of letters of credit which reduce the amounts available under the Senior Credit Facility. Future availability under our $375 million borrowing base is subject to the terms and covenants of the Senior Credit Facility. The Senior Credit Facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan only to the extent that such amounts exceed cash flow from operations, proceeds from the sale of oil and gas properties and equity offerings.

We expect to receive approximately $13 million in proceeds from the sale of 20% of our interests in oil and gas properties to Reliance and up to $44 million in proceeds from our interests in ACP II based on the sale of Avista's interests in those same oil and gas properties to Reliance. Total expected proceeds from these transactions of up to $58 million will be used to pay down a portion of the outstanding borrowings under the Senior Credit Facility. The sale of 20% of our interest in oil and gas properties to Reliance will also include a commitment by Reliance to pay 75% of our share of certain of our future development costs up to approximately $52 million, primarily during the fourth quarter of 2010 and in 2011.

If cash from operations, funds available under the Senior Credit Facility and the other sources of cash described under "Sources and Uses of Cash" are insufficient to fund our 2010 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 2010 oil and gas exploration and development program, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties.

Contractual Obligations

Through June 30, 2010, we entered into long-term transportation agreements that require minimum volume commitments valued at $0.2 million for 2010, $1.2 million for 2011, $2.5 million for 2012, $4.1 million for 2013 and $9.8 million thereafter.

Financing Arrangements

In April 2010, we sold 3.22 million shares of our common stock in an underwritten public offering at a price of $23.00 per share. We used the net proceeds of approximately $74.1 million to repay a portion of the outstanding borrowings under our Senior Credit Facility. We expect to fund in part our recently expanded capital expenditure plan for 2010 with the available capacity under our Senior Credit Facility.

In May 2010, we amended the Senior Credit Facility to increase the borrowing base to $375 million from $350 million.

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 the third quarter of 2008 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.

Recently Adopted Accounting Pronouncements

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity and (4) the transfers in and out of Levels 1 and 2. We adopted the new disclosures in the first quarter of 2010.

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 the 2009 Form 10-K. 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 contingencies.

The full-cost ceiling test cushion for the U.S. cost center at June 30, 2010 was $176.9 million and was based upon average realized oil, natural gas liquids and natural gas prices of $70.63 per Bbl, $29.13 per Bbl and $3.93 per Mcf, respectively, or a volume weighted average price of $4.27 per Mcfe. In connection with our June 30, 2010 full-cost ceiling test computation for the U.S. cost center, a price sensitivity study indicated that a ten percent increase in the commodity prices used in the ceiling test at June 30, 2010 would have increased the full-cost ceiling test cushion by approximately $86.5 million and a ten percent decrease in such commodity prices would have decreased the full-cost ceiling test cushion by approximately $120.6 million. The aforementioned price sensitivity is as of June 30, 2010 and, accordingly, does not include any potential changes in reserve values due to subsequent performance or events, such as commodity prices, reserve revisions and drilling results.

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 under the full-cost method of accounting rules. See "—Critical Accounting Policies—Oil and Natural Gas Properties," in our 2009 Form 10-K.

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 investment program. The commodity derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis swaps. Our long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. Our derivative instruments are carried at fair value in the consolidated balance sheets, with the changes in fair value included in the consolidated statements of operations for the period in which the changes occur.

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. We enter into the majority of our derivative transactions with three counterparties and netting agreements are in place with those counterparties. We do not obtain collateral to support the agreements but monitor the financial viability of counterparties and believe our credit risk is minimal on these transactions. In the event of nonperformance, we would be exposed to price and credit risk.

The following sets forth a summary of our natural gas derivative positions at average delivery location (Waha and Houston Ship Channel) prices as of June 30, 2010. Our crude oil derivative positions at June 30, 2010, were not significant.

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2010	13,156,000	$ 5.72	$ 6.28
2011	21,340,000	$ 6.12	$ 6.58
2012	7,963,000	$ 6.53	$ 7.03

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 remainder of 2010, if market prices fall below the short put price of $4.12, the floor price becomes the market price plus the put spread of $1.60 on 11,484,000 of the 13,156,000 MMBtus and the remaining 1,672,000 MMBtus have a floor price of $5.72.

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Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2010	11,484,000	$ 4.12	$ 1.60
2011	14,049,000	$ 4.52	$ 1.60
2012	6,404,000	$ 4.47	$ 2.06

For the three months and six months ended June 30, 2010 and 2009, the Company recorded the following related to its derivative instruments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Realized gain	$ 8,792	$ 27,215	$ 13,747	$ 46,025
Unrealized gain (loss)	(5,578)	(29,517)	12,269	(18,237)
Gain (loss) on derivative instruments, net	$ 3,214	$ (2,302)	$ 26,016	$ 27,788

We deferred the payment of premiums associated with certain derivative instruments totaling $6.5 million and $4.8 million at June 30, 2010 and December 31, 2009, respectively. We classified $4.3 million and $1.8 million as other current liabilities at June 30, 2010 and December 31, 2009, respectively, and $2.2 million and $3.0 million as other non-current liabilities at June 30, 2010 and December 31, 2009, respectively. The deferred premiums will be paid to the counterparty with each monthly settlement (July 2010 – December 2011) and recognized as realized gain on derivative instruments.

The fair value of the outstanding derivatives at June 30, 2010 and December 31, 2009 was a net asset of $23.9 million and $12.1 million, respectively. At June 30, 2010, approximately 72% of the fair value of our derivative instruments were with Credit Suisse, 15% were with Shell Energy North America (US) LP, and the remaining 13% were with Credit Agricole.

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), spending plans, capital expenditure plans, planned evaluation of prospects, probability of prospects having oil and gas, expected production or reserves, increases in reserves, acreage, working capital requirements, hedging activities and the impact on our average prices, the ability of expected sources of liquidity to implement the Company's business strategies, accessibility of borrowings under our credit facility, future exploration activity, drilling, completion and fracturing of wells, land acquisitions, production rates, forecasted production, project financing, growth in production, development of new drilling programs, participation of our industry partners, funding for our Marcellus Shale operations, hedging of production, exploration and development expenditures, the impact of our business strategies, the benefits, results, effects, closing and timing of our new and existing joint ventures and sales transactions and all and any other statements regarding future operations, financial results, business plans and cash needs and other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words “anticipate,” “estimate,” “expect,” “may,” “project,” “plan,” “believe” and similar expressions are intended to be amo 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 new SEC rules regarding oil and gas reserves, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under the Senior Credit Facility, evaluations of the Company by potential lenders under the Senior Credit Facility, the potential impact of government regulations, including proposed

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legislation and regulations related to hydraulic fracturing, air emissions and climate change, and adverse regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, weather, availability of financing, actions by lenders, ability to obtain permits, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence of title defects, the closing of the Avista sale concurrently with the closing of the Reliance joint venture, failure to otherwise satisfy conditions to the closing of the Avista sale or the Reliance joint venture, delays, costs and difficulties relating to these transactions, actions by joint venture partners, results of exploration activities and other factors detailed in the "Risk Factors" and other sections of our Annual Report on Form 10-K for the year ended December 31, 2009 and in this and our other filings with the SEC. 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 year ended December 31, 2009. There have been no material changes to the disclosure regarding our exposure to certain market risks made in our Annual Report on Form 10-K for the year ended December 31, 2009.

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, 2010 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, 2010 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

In addition to the risk factors set forth below and the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2009, and in Part II, Item 1A., “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, which could materially affect our business, financial condition or future operating results. 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.

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Natural gas and oil operations are subject to various federal, state, local and foreign 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 natural gas and oil wells below actual production capacity in order to conserve supplies of natural gas and oil. Other federal, state and local 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 natural gas and oil, by-products thereof and other substances and materials produced or used in connection with natural gas and oil operations. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. As a result, we may incur substantial liabilities to third parties or governmental entities and 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 have a material adverse effect on our business, financial condition and results of operations.

Moreover, changes in environmental laws and regulations occur frequently, and stricter laws, regulations or enforcement policies could significantly increase our compliance costs. Further, stricter requirements could 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 could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state, and federal levels. Additionally, the EPA has recently entered into a settlement that requires it to consider strengthening regulations under the Clean Air Act (CAA), 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.

Similarly, 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. 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 and Marcellus Shale. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. 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 costs and additional regulatory burdens that could make it more difficult for us to perform 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. We use hydraulic fracturing extensively and any increased federal, state or local regulation, including proposed legislation in the states of New York and Pennsylvania, could reduce the volumes of natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

President Obama’s Proposed 2011 Fiscal Year Budget includes proposed legislation that would, if enacted into law, 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 natural gas exploration and production companies. The passage of any legislation as a result of these proposals 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 condition and results of operations.

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

None.

Item 3. Defaults Upon Senior Securities

None.

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Item 5. Other Information

None.

Item 6. Exhibits

Exhibits required by Item 601 of Regulation S-K are as follows:

Exhibit Number	Description
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.

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SIGNATURES

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

	Carrizo Oil & Gas, Inc. (Registrant)
Date: August 9, 2010	By: /s/ Paul F. Boling Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)
Date: August 9, 2010	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)