CARRIZO OIL & GAS INC
Form 10-Q
August 17, 2009

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, 2009

[ ] 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 [X]   Accelerated filer []

Non-accelerated filer [ ]
(Do not check if a smaller reporting company)

Smaller reporting company [ ]

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

YES [ ]   NO [X]

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, as of August 1, 2009, the latest practicable date, was 31,057,515.

EXPLANATORY NOTE

The consolidated financial information that is presented in this Form 10-Q supersedes and replaces the information presented in our Current Report on Form 8-K filed on August 10, 2009 and the press release furnished as an exhibit thereto.

CARRIZO OIL & GAS, INC.

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2009
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CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

ASSETS	June 30, 2009 (Unaudited)	December 31, 2008
	(In thousands, except par value amount)	
CURRENT ASSETS:		
Cash and cash equivalents	$4,786	$5,184
Accounts receivable, trade (net of allowance for doubtful accounts of $1,552 and $1,264 at June 30, 2009 and December 31, 2008, respectively)	25,193	24,675
Advances to operators	270	336
Fair value of derivative financial instruments	25,889	22,791
Other current assets	4,417	3,335
Total current assets	60,555	56,321
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including costs not subject to amortization of $392,515 and $378,634 at June 30, 2009 and December 31, 2008, respectively)	846,789	986,629
DEFERRED FINANCING COSTS, NET	10,218	8,430
INVESTMENTS	3,467	3,274
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	-	15,876
DEFERRED INCOME TAXES	35,281	-
OTHER ASSETS	1,051	1,172
TOTAL ASSETS	$957,361	$1,071,702
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$58,743	$46,683
Accrued liabilities	28,010	54,149
Advances for joint operations	7,938	3,815
Current maturities of long-term debt	148	173
Deferred tax liability	9,061	9,103
Total current liabilities	103,900	113,923
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT	522,657	475,788
ASSET RETIREMENT OBLIGATION	9,772	6,503
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	5,028	-
DEFERRED INCOME TAXES	-	34,778
DEFERRED CREDITS	534	625
COMMITMENTS AND CONTINGENCIES		-
SHAREHOLDERS' EQUITY:		
Common stock, par value $0.01 (90,000 shares authorized; 31,037 and 30,860 issued and outstanding at June 30, 2009 and		

December 31, 2008, respectively)	310	309
Additional paid-in capital	426,249	420,778
Retained earnings (deficit)	(111,264)	20,297
Accumulated other comprehensive income (loss), net of tax	175	(1,299)
Total shareholders' equity	315,470	440,085
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$957,361	$1,071,702

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)
(As Adjusted (See Note 2))

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands except per share amounts)			
OIL AND NATURAL GAS REVENUES	$26,171	$67,388	$57,374	$120,948
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	9,587	9,229	17,624	17,620
Third party gas purchases	317	2,596	867	2,596
Depreciation, depletion and amortization	12,249	13,865	27,525	27,952
Impairment of oil and gas properties	-	-	216,391	-
General and administrative (inclusive of stock-based compensation expense of $2,308 and $1,508 for the three months ended June 30, 2009 and 2008, respectively, and $5,734 and $2,988 for the six months ended June 30, 2009 and 2008, respectively)	6,361	5,580	14,261	12,099
Accretion expense related to asset retirement obligations	75	57	146	115
TOTAL COSTS AND EXPENSES	28,589	31,327	276,814	60,382
OPERATING INCOME (LOSS)	(2,418)	36,061	(219,440)	60,566
OTHER INCOME AND EXPENSES:				
Net gain (loss) on derivatives	(2,302)	(48,227)	27,788	(78,043)
Loss on early extinguishment of debt	-	(5,705)	-	(5,705)
Interest income	6	60	12	208
Interest expense	(9,654)	(6,004)	(18,714)	(12,459)
Capitalized interest	5,118	4,446	10,069	8,164
Impairment of investment in Pinnacle Gas Resources, Inc.	-	-	(2,091)	-
Other income (expenses), net	(5)	(20)	40	49
LOSS BEFORE INCOME TAXES	(9,255)	(19,389)	(202,336)	(27,220)
INCOME TAX BENEFIT	(3,239)	(6,609)	(70,775)	(9,144)
NET LOSS	$(6,016)	$(12,780)	$(131,561)	$(18,076)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES:				
Increase (decrease) in market value of investment in Pinnacle Gas Resources, Inc.	175	1,653	115	(1,544)

Reclassification of cumulative decrease in market value of investment in Pinnacle Gas Resources, Inc.	-	-	1,359	-
COMPREHENSIVE LOSS	$(5,841)	$(11,127)	$(130,087)	$(19,620)
BASIC LOSS PER COMMON SHARE	$(0.19)	$(0.42)	$(4.25)	$(0.61)
DILUTED LOSS PER COMMON SHARE	$(0.19)	$(0.42)	$(4.25)	$(0.61)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	31,002	30,662	30,943	29,727
DILUTED	31,002	30,662	30,943	29,727

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)
(As Adjusted (See Note 2))

	For the Six Months Ended June 30, 2009	2008
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(131,561)	$(18,076)
Adjustment to reconcile net loss to net cash provided by operating activities-		
Depreciation, depletion and amortization	27,525	27,952
Impairment of oil and gas properties	216,391	-
Fair value loss of derivative financial instruments	17,806	67,821
Accretion of discounts on asset retirement obligations and debt	146	115
Stock-based compensation	5,734	2,988
Provision for allowance for doutbful accounts	288	(166)
Deferred income taxes	(70,841)	(9,527)
Loss on extenguishment of debt	-	4,601
Amortization of equity premium associated with Convertible Senior Notes	2,779	243
Impairment of investment in Pinnacle Gas Resources, Inc.	2,091	-
Other	2,569	12
Changes in operating assets and liabilities		
Accounts receivable	(807)	(13,644)
Other assets	(515)	1,593
Accounts payable	9,173	2,776
Accrued liabilities	95	2,340
Net cash provided by operating activities	80,873	69,028
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(99,477)	(315,549)
Change in capital expenditure accrual	(22,508)	(8,794)
Proceeds from the sale of properties	6	19
Advances to operators	66	944
Advances for joint operations	4,123	(500)
Other	(69)	(2,712)
Net cash used in investing activities	(117,859)	(326,592)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from debt issuance and borrowings	64,000	515,750
Debt repayments	(24,462)	(380,501)
Proceeds from common stock offering, net of offering costs	-	135,158
Proceeds from stock options exercised	9	137
Deferred loan costs and other	(2,959)	(8,961)
Net cash provided by financing activities	36,588	261,583
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(398)	4,019

CASH AND CASH EQUIVALENTS, beginning of period	5,184	8,026
CASH AND CASH EQUIVALENTS, end of period	$4,786	$12,045
CASH PAID FOR INTEREST (NET OF AMOUNTS CAPITALIZED)	$4,055	$1,759

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. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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/A for the year ended December 31, 2008 (the "2008 Form 10-K/A").

Unconsolidated Investments

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.

The Company's investment in Pinnacle Gas Resources, Inc. is classified as available-for-sale. The Company adjusts the book value to fair market value through other comprehensive income (loss), net of taxes. If the impairment of the investment is considered other than temporary, the loss will be reclassified to the Statements of Operations from Other Comprehensive Income (Loss). Subsequent recoveries in fair value are reflected as increases to the Investments line item and Other Comprehensive Income (Loss).

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation. These reclassifications had no effect on total assets, total liabilities, shareholders' equity or net income (loss).

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 natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair values of derivatives, stock-based compensation expense, contingencies and the results of current and future litigation. Oil and natural 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, testing and production may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates may be affected by changes in wellhead prices of crude oil and natural 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 natural gas volumes, interest rates, the market value and volatility of the Company’s common stock and corresponding volatility and the Company’s ability to generate future taxable income. Future changes in these assumptions may materially affect these significant estimates in the near term.

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The Company evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which the Company believes to be reasonable under the circumstances. The Company adjusts such estimates and assumptions when facts and circumstances dictate. The Company has evaluated subsequent events for recording and disclosure through August 17, 2009.

Oil and Natural Gas Properties

Investments in oil and natural 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 natural gas properties, including the Company's gas gathering systems, are capitalized. Such costs include lease acquisitions, seismic surveys, and drilling and completion equipment. The Company proportionally consolidates its interests in oil and natural gas properties. The Company capitalized employee-related costs for employees working directly on exploration activities of $3.0 million and $3.4 million for the six months ended June 30, 2009 and 2008, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization ("DD&A") of proved oil and natural gas properties is based on the unit-of-production method using estimates of proved reserve quantities. Costs not subject to amortization include costs of unevaluated leaseholds, seismic costs associated with specific unevaluated properties 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 determined and added to the proved oil and natural gas property costs subject to DD&A. The depletable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the quarters ended June 30, 2009 and 2008 was $1.52 and $2.14, respectively.

Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

Net capitalized costs are limited to a "ceiling-test" based on the estimated future net revenues, discounted at 10% per annum, from proved oil and natural gas reserves, based on current economic and operating conditions. If net capitalized costs exceed this limit, the excess is charged to earnings. During the six-month period ended June 30, 2009, the Company incurred an impairment charge of $216.4 million ($140.6 million net of tax). For the first quarter of 2009, the Company elected to use a pricing date subsequent to the balance sheet date, as allowed by current SEC guidelines, to measure the full cost ceiling test impairment. Using prices as of May 6, 2009, the Company incurred an impairment charge of $216.4 million ($140.6 million net of tax). Had the Company used prices in effect as of March 31, 2009, an 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 will no longer be available to the Company starting December 31, 2009 due to the adoption of the new oil and natural gas reporting requirements as described below under "Recently Issued Accounting Pronouncements."

Depreciation of other property and equipment is provided using the straight-line method based on estimated useful lives ranging from five to 10 years.

Supplemental Cash Flow Information

The adjustment of the investment in Pinnacle of $0.1 million, net of tax and $(1.5) million, net of tax is excluded from the Statement of Cash Flows for the six months ended June 30, 2009 and 2008, respectively. The Company paid no income taxes during the six months ended June 30, 2009 and 2008.

Stock-Based Compensation

The Company records stock-based compensation as prescribed by the Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"). The compensation expense associated with stock options is based on the grant-date fair value of the options and recognized over the vesting period. Restricted stock is also measured at grant date fair value and recorded as deferred compensation based on the closing price of the Company's stock on the issuance date and is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (generally one to three years).

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The Company recognized the following stock-based compensation expense for the three and six months ended June 30:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions)			
Stock Option Expense	$ 0.1	$ 0.1	$ 0.1	$ 0.2
Restricted Stock Expense	2.2	1.4	5.6	2.8
Total Stock-Based Compensation Expense	$ 2.3	$ 1.5	$ 5.7	$ 3.0

Derivative Instruments

The Company uses derivatives to manage price risk underlying its oil and natural gas production. The Company also used derivatives to manage the variable interest rate on its borrowings under the second lien credit facility, which was terminated in May 2008.

Upon entering into a derivative contract, the Company either designates the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of the Company's derivative instruments are treated as non-designated derivatives and the unrealized gain (loss) related to the mark-to-market valuation is included in the Company's earnings.

The Company typically uses fixed-rate swaps, costless collars, puts and calls to hedge its exposure to material changes in the price of oil and natural gas.

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

Major Customers

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cokinos Natural Gas Company	10 %	11 %	10 %	10 %
	-	-	-	10 %

Houston Pipeline Co.				
Crosstex Energy Services, Ltd.	-	10 %	-	11 %
DTE Energy Trading, Inc.	53 %	38 %	56 %	36 %
Energy Transfer Partners, L.P.	-	-	-	-

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Earnings Per Share

Supplemental earnings per share information is provided below:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands, except per share amounts)			
Net loss	$ (6,016)	$ (12,780)	$ (131,561)	$ (18,076)
Average common shares outstanding				
Weighted average common shares outstanding(1)	31,002	30,662	30,943	29,727
Stock options and warrants	-	-	-	-
Diluted weighted average common shares outstanding	31,002	30,662	30,943	29,727
Loss per common share(1)				
Basic	$ (0.19)	$ (0.42)	$ (4.25)	$ (0.61)
Diluted	$ (0.19)	$ (0.42)	$ (4.25)	$ (0.61)

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(1) In January 2009, the Company adopted and retroactively applied the Financial Accounting Standards Boards ("FASB") Staff Position ("FSP") Emerging Issues Task Force 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("EITF 03-6-1"). As prescribed in the accounting pronouncement, the Company has determined that all of its shares of restricted stock are participating securities and should be included in the basic earnings per share calculation (see Note 2 for additional details).

Basic earnings per common share is based on the weighted average number of shares of common stock (including restricted stock) outstanding during the periods. Diluted earnings per common share is based on the weighted average number of common shares and all dilutive potential common shares issuable during the periods. The Company did not include options to purchase 893,837 and 727,854 shares in the calculation of dilutive shares for the three and six months ended June 30, 2009 and 2008 due to the net loss for both quarters. Shares of common stock subject to issuance pursuant to the conversion features of the 4.375% Convertible Senior Notes due 2028 (the "Convertible Senior Notes") did not have an effect on the calculation of dilutive shares for the three months ended June 30, 2009.

Asset Retirement Obligation

The following table is a reconciliation of the asset retirement obligation liability:

Six Months	Year Ended

	Ended June 30, 2009	December 31, 2008
	(In thousands)	
Asset retirement obligation at beginning of year	$ 6,503	$ 5,869
Liabilities incurred	188	1,004
Liabilities settled	(12)	(177)
Accretion expense	146	154
Revisions to previous estimates	2,947	(347)
Asset retirement obligation at end of year	$ 9,772	$ 6,503

The revisions of $3.0 million to the six months 2009 relate primarily to location clean up costs related to wells in the Barnett Shale area.

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Income Taxes

Under SFAS No. 109 "Accounting for 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 under accounting standards, the deferred tax assets are reduced by a valuation allowance.

Recently Adopted Accounting Pronouncements

On January 1, 2009, the Company adopted the Financial Accounting Standards Boards ("FASB") Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)" ("APB 14-1"), which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. APB 14-1 requires that issuers of convertible debt separately account for the liability and equity components in a manner that reflects the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Once adopted, ABP 14-1 requires retrospective application to the terms of instruments as they existed for periods presented. The Company applied this accounting pronouncement to the Convertible Senior Notes. The Company valued the conversion premium of the convertible debt at $64.2 million and accordingly restated our balance sheet as of December 31, 2008 for the carrying value of debt and equity and restated our results of operations for interest expense, capitalized interest, and income taxes for the year ended December 31, 2008. See Item 1, Notes to Consolidated Financial Statements, Note 2 for a discussion of the restatement related to the adoption of this accounting pronouncement.

On January 1, 2009, the Company adopted and retroactively applied FASB Staff Position ("FSP") Emerging Issues Task Force 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("EITF 03-6-1"). This FSP provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. This FSP requires retroactive application for all periods presented. The Company determined that our restricted shares of common stock are participating securities as defined in this FSP and applied this FSP retroactively to all periods presented. See Item 1, Notes to Consolidated Financial Statements, Note 2 for a discussion of the restatement related to the adoption of this accounting pronouncement.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" ("SFAS No. 161"). This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements, how derivative instruments and related hedged items are accounted for under SFAS No. 133, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted this pronouncement effective January 1, 2009 and it did not have a significant effect on its consolidated financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" ("FSP FAS 157-4"), which provides additional guidance for estimating fair value in accordance with SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). FSP FAS 157-4 is effective for the quarter ending June 30, 2009. The Company adopted this pronouncement effective June 30, 2009 and it had no material impact on its consolidated financial statements.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP FAS 115-2"), which provides new guidance on the recognition of other-than-temporary impairments of investments in debt securities and provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. FSP FAS 115-2 is effective for the quarter ending June 30, 2009. The Company adopted the requirements of this pronouncement effective June 30, 2009 and it had no material impact on its consolidated financial statements.

In April 2009, the FASB issued FSP No. FAS 107-1 and ABP 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP FAS 107-1"). FSP FAS 107-1 amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" ("SFAS 107") to require disclosures about fair value of financial instruments in interim reporting periods. Such disclosures were previously required only in annual financial statements. FSP FAS 107-1 is effective for the quarter ending June 30, 2009. The Company adopted

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the requirements of this pronouncement effective June 30, 2009 and included the additional disclosures in its Notes to Consolidated Financial Statements.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events," which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. In particular, SFAS No. 165 sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The Company applied the requirement of this pronouncement effective June 30, 2009 and included additional disclosures in its Notes to Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

On December 31, 2008, the SEC adopted major revisions to its rules governing oil and gas company reporting requirements. These new rules will permit the use of new technologies to determine proved reserves and allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of its reserve estimates, and to file reports when a third party is relied upon to prepare or audit its reserves estimates. The new rules also require that the net present value of oil and gas reserves reported and used in the full cost ceiling test calculation be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. The Company is in the process of assessing the impact of these new requirements on its financial position, results of operations and financial disclosures.

In June 2009, the FASB issued SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles" ("SFAS No. 168"). SFAS No. 168 establishes the FASB Accounting Standards Codification (Codification), which became effective July 1, 2009, as the single source of authoritative U.S. GAAP to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. All other accounting literature excluded from the Codification will be considered nonauthoritative. The subsequent issuances of new standards will be in the form of Accounting Standards Updates that will be included in the Codification. Generally, the Codification is not expected to change U.S. GAAP. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company is currently evaluating the effect of the standard on its financial statement disclosures, as all future references to authoritative accounting literature will be made in accordance with the Codification.

2. ADJUSTMENT FOR IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENT

On January 1, 2009, the Company adopted FSP No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)" ("APB 14-1"), which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. APB 14-1 requires that issuers of convertible debt separately account for the liability and equity components in a manner that reflects the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Once adopted, APB 14-1 requires retrospective application to the terms of instruments as they existed for periods presented. The adoption of APB 14-1 affects the accounting for the Convertible Senior Notes. The retrospective application of this accounting pronouncement affects the Company's results of operations for the year ended December 31, 2008.

On January 1, 2009, the Company adopted and retroactively applied EITF 03-6-1. This FSP provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. This FSP requires retroactive application for all periods presented. The Company determined that its restricted shares of common stock are participating securities as defined in this FSP and applied this FSP retroactively to all periods presented.

The following table sets forth the effect of the retrospective application of EITF 03-6-1 and APB 14-1 on certain previously reported items.

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Consolidated Statement of Income:

	For the three months ended June 30, 2008		For the six months ended June 30, 2008	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted
	(In thousands, except per share amounts)			
Interest expense	4,942	6,004	11,397	12,459
Capitalized interest	3,627	4,446	7,345	8,164
Income tax benefit	(6,524)	(6,609)	(9,059)	(9,144)
Net loss	(12,622)	(12,780)	(17,918)	(18,076)
Basic Loss Per Share	$ (0.42)	$ (0.42)	$ (0.61)	$ (0.61)
Diluted Loss Per Share	$ (0.42)	$ (0.42)	$ (0.61)	$ (0.61)
Weighted Average Common Shares Oustanding				
Basic	30,296	30,662	29,548	29,727
Diluted	30,296	30,662	29,548	29,727

3. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
	(In thousands)	
Convertible Senior Notes	$ 373,750	$ 373,750
Unamortized discount for Convertible Senior Notes	(51,253)	(57,269)
Senior Secured Revolving Credit Facility	200,000	159,000
Other	308	480
	522,805	475,961
Current maturities	(148)	(173)
	$ 522,657	$ 475,788

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of the Convertible Senior Notes. Interest is payable on June 1 and December 1 each year, commencing December 1, 2008. The notes will be convertible, using a net share settlement process, into a combination of cash and Carrizo 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 Carrizo 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 Carrizo 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 June 30, 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, 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 Secured Revolving Credit Facility.

In connection with the implementation of APB 14-1 (described in Note 2), 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 will be 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 and will result in an effective interest rate of approximately 8% for the Convertible Senior Notes.

Senior Secured Revolving Credit Facility

On May 25, 2006, the Company entered into a Senior Secured Revolving Credit Facility (“Senior Credit Facility”) with JPMorgan Chase Bank, National Association, as administrative agent. The Senior Credit Facility provided for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of the Company’s proved oil & gas assets and is currently guaranteed by the Company’s subsidiaries, CCBM, Inc.; CLLR, Inc.; Carrizo (Marcellus), LLC; Carrizo Marcellus Holdings, Inc.; Chama Pipeline Holding, LLC; Hondo Pipeline Inc. and Pecos Pipeline, LLC.

In the fourth quarter of 2008, the Company amended the Senior Credit Facility to, among other things, (a) extend the maturity date to October 29, 2012; (b) change the semi-annual borrowing base redetermination dates to March 31 and September 30; and (c) replace JPMorgan Chase Bank with Guaranty Bank as the administrative agent bank.

In April 2009, the Company amended the Senior Credit Facility to, among other things, (a) adjust the maximum ratio of total net debt to Consolidated EBITDAX; (b) modify the calculation of total net debt for purposes of determining the ratio of total net debt to Consolidated EBITDAX to exclude the following amounts, which represent a portion of the Convertible Senior Notes deemed to be an equity component under APB 14-1: $51,252,980 during 2009, $38,874,756 during 2010, $26,021,425 during 2011 and $12,674,753 during 2012 until the maturity date; (c) add a new senior leverage ratio; (d) modify the interest rate margins applicable to Eurodollar loans; (e) modify the interest rate margins applicable to base rate loans; and (f) establish new procedures governing the modification of swap agreements.

In May 2009, the Company amended the Senior Credit Facility to, among other things, (1) replace Guaranty Bank with Wells Fargo Bank, N.A. as administrative agent, (2) provide that the aggregate notional volume of oil and natural 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, (3) remove a provision that limited the maximum duration of swap agreements permitted under the Senior Credit Facility to five years, and (4) 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. Also in April 2009, the Company amended the Senior Credit Facility to increase the borrowing base to $290,000,000 and, in May 2009, the total commitment of the lenders was increased from $250,000,000 to $259,400,000. On June 5, 2009, the total commitment was increased by $25,000,000 to $284,400,000 with the addition of a new lender to the bank syndicate.

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.

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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 2.0% to 3.5% (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, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.6%.

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; and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of (a) 4.25 to 1.00 for the quarter ending June 30, 2009, (b) 4.50 to 1.00 for the quarter ending September 30, 2009, (c) 4.75 to 1.00 for each quarter ending on or after December 31, 2009 and on or before September 30, 2010, (d) 4.25 to 1.00 for the quarter ending December 31, 2010, and (e) 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 debt attributable to the Convertible Senior Notes) to Consolidated EBITDAX of 2.25 to 1.00.

Although the Company currently believes that it can comply with all of the financial covenants with the business plan that it has put in place, the business plan is based on a number of assumptions, the most important of which is a relatively stable, natural gas price at economically sustainable levels. If the price that the Company receives for our natural gas production deteriorates significantly from current levels, it could lead to lower revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants in the Senior Credit Facility, including the financial covenants discussed above. In order to provide a further margin of comfort with regards to these financial covenants, the Company may seek to further reduce its capital and exploration budget, sell non-strategic assets, opportunistically modify or increase its natural gas hedges or approach the lenders under our Senior Credit Facility for modifications of either or both of the financial covenants discussed above. There can be no assurance that the Company will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our Senior Credit Facility if a precipitous decline in natural gas prices were to occur in the future. 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, 2009, the Company had $200.0 million of borrowings outstanding under the Senior Credit Facility and the amount available for borrowings was $84.4 million.

4. INVESTMENTS

Investments consisted of the following at June 30, 2008 and December 31, 2008:

June 30, 2009	December 31, 2008
(In thousands)	

Pinnacle Gas Resources, Inc.	$ 944	$ 751
Oxane Materials, Inc.	2,523	2,523
	$ 3,467	$ 3,274

Pinnacle Gas Resources, Inc.

In 2003, the Company and its wholly-owned subsidiary CCBM, Inc. contributed their interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle Gas Resources, Inc. (“Pinnacle”). As of June 30, 2009, the Company owned 2,483,935 shares of Pinnacle common stock.

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The Company classifies the Pinnacle investment as available-for-sale and adjusts the investment to fair value through other comprehensive income. At June 30, 2009, the Company reported the fair value of the stock at $0.9 million (based on the closing price of Pinnacle's common stock on June 30, 2009). 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.

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. The Company accounts for the investment using the cost method.

5. INCOME TAXES

The Company provided deferred federal income taxes at the rate of 35% (which also approximates its statutory rate) that amounted to a federal tax benefit of $3.2 million and $6.8 million for the three months ended June 30, 2009 and 2008, respectively and a tax benefit of $70.8 million and $9.5 million for the six months ended June 30, 2009 and 2008. At June 30, 2009, the Company had a net deferred tax asset of $26.2 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 asset is currently needed.

On January 1, 2007, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company classifies interest and penalties associated with income taxes as interest expense. At June 30, 2009, the Company had no material uncertain tax positions and the tax years since 1999 remain open to review by federal and various state tax jurisdictions.

6. 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 operations or financial position of the Company.

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

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7. SHAREHOLDERS' EQUITY

The following is a summary of changes in the Company's common stock for the six-month periods ended June 30:

	2009	2008
	(In thousands)	
Shares outstanding at January 1	30,860	28,009
Equity offering	-	2,588
Restricted stock issued, net of forfeitures	162	173
Employee stock options exercised	5	23
Common stock issued for oil and gas properties	10	-
Common stock repurchased and retired for tax withholding obligation	-	(5)
Shares outstanding at June 30	31,037	30,788

In February 2008, the Company completed an underwritten public offering of 2,587,500 shares of its common stock at a price of $54.50 per share. The number of shares sold was approximately 9.2% of the Company's outstanding shares before the offering. The Company received proceeds of approximately $135.2 million, net of expenses.

8. DERIVATIVE INSTRUMENTS

The Company enters into swaps, options, collars and other derivative contracts to manage price risks associated with a portion of anticipated future oil and natural gas production. Under these agreements, 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 two 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 risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the financial instruments. The Company also used interest rate swap agreements to manage the Company's exposure to interest rate fluctuations on borrowings under the Company's second lien credit facility, which was terminated in May 2008.

The Company accounts for its oil and natural gas derivatives and interest rate swap agreements as non-designated hedges. These derivatives are marked-to-market at each balance sheet date and the unrealized gains (losses) along with the realized gains (losses) associated with the settlements of derivative instruments are reported as net gain (loss) on derivatives, in other income and expenses in the Consolidated Statements of Operations. For the three and six months ended June 30, 2009 and 2008, the Company recorded the following related to its derivatives:

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	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions)			
Realized gains (losses):				
Natural gas and oil derivatives	$ 23.0	$ (8.8)	$ 45.6	$ (10.3)
Interest rate swaps - Second Lien Debt Outstanding	-	(1.0)	-	(1.2)
Loss on interest rate swap settlement related to Second Lien Credit Facility	-	(3.3)	-	(3.3)
	23.0	(13.1)	45.6	(14.8)
Unrealized gains (losses):				
Natural gas and oil derivatives	(25.3)	(40.1)	(17.8)	(66.0)
Interest rate swaps	-	5.0	-	2.8
	(25.3)	(35.1)	(17.8)	(63.2)
Net gain (loss) on derivatives	$ (2.3)	$ (48.2)	$ 27.8	$ (78.0)

At June 30, 2009, the Company had the following outstanding derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(3)	
Quarter	MMBtus(1)	Average Fixed Price(2)	MMBtus(1)	Average Floor Price(2)	Average Ceiling Price(2)	MMbtu	Fixed Price
Third Quarter 2009	3,680,000	5.31	2,576,000	7.16	8.88	1,840,000	0.27
Fourth Quarter 2009	3,680,000	5.58	2,576,000	7.17	8.90	-	-
First Quarter 2010	3,150,000	5.45	1,620,000	7.92	9.63	-	-
Second Quarter 2010	3,185,000	5.50	637,000	5.84	7.30	-	-
Third Quarter	1,840,000	5.57	1,104,000	6.07	7.62	-	-

2010							
Fourth Quarter 2010	1,840,000	5.57	1,380,000	6.49	7.90	-	-
First Quarter 2011	1,800,000	5.64	450,000	9.70	11.70	-	-
Second Quarter 2011	1,820,000	5.64	455,000	8.25	10.25	-	-
Third Quarter 2011	1,840,000	5.64	460,000	8.65	10.65	-	-
Fourth Quarter 2011	1,840,000	5.64	460,000	8.85	10.85	-	-
First Quarter 2012	910,000	5.88	455,000	9.55	11.55	-	-
Second Quarter 2012	910,000	5.88	455,000	8.35	10.35	-	-
Third Quarter 2012	920,000	5.88	-	-	-	-	-
Fourth Quarter 2012	920,000	5.88	-	-	-	-	-
	28,335,000		12,628,000			1,840,000	

(1) During 2009, the Company entered into (1) a \$5.35 put, a \$6.20 long-call and an \$8.00 short-call with respect to a portion of the Company's production hedged with swaps (10,000 MMBtus per day) in 2011 and 2012 and (2) a \$4.35 put, a \$6.00 long-call and a \$6.50 short-call with respect to a portion of the Company's production hedged with swaps 20,000 MMBtus per day for April through October of 2010). The table below presents additional put positions the Company has entered into associated with a portion of hedged volumes presented above:

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Quarter	MMBtus	Put Price
Third Quarter 2009	920,000	$ 3.00
Fourth Quarter 2009	920,000	3.00
Second Quarter 2010	455,000	3.74
Third Quarter 2010	920,000	4.31
Fourth Quarter 2010	1,196,000	4.61
First Quarter 2011	450,000	6.80
Second Quarter 2011	455,000	6.80
Third Quarter 2011	460,000	6.80
Fourth Quarter 2011	460,000	6.80
First Quarter 2012	455,000	6.80
Second Quarter 2012	455,000	6.80

(2) Based on Houston Ship Channel ("HSC") and WAHA spot prices.

(3) Basis differential swaps covering the price differential for natural gas between NYMEX and HSC.

At June 30, 2009, approximately 55% of the Company's open natural gas hedged volumes were with Credit Suisse, and the remaining 45% were with Shell Energy North America (US), L.P.

The fair value of the outstanding derivatives at June 30, 2009 and December 31, 2008 was a net asset of $20.9 million and $38.7 million, respectively.

9. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted SFAS No. 157, which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of SFAS No. 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company's own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

The Company elected to implement SFAS No. 157 with the one-year deferral permitted by FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," issued February 2008, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis.

SFAS No. 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

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

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

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

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

	Level 1	Level 2	Level 3	Total
		(in thousands)		
Assets:				
Investment in Pinnacle Gas Resources, Inc.	$ 944	$ -	$ -	$ 944
Oil and natural gas derivatives	-	20,861	-	20,861
Total	$ 944	$ 20,861	$ -	$ 21,805

Oil and natural gas derivatives are valued by a third-party consultant using valuation models that are primarily industry-standard 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.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings, including borrowings under the Senior Credit Facility. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank and vendor borrowings approximate the carrying amounts as of June 30, 2009 and December 31, 2008, and were determined based upon interest rates currently available to the Company for borrowings with similar terms. The fair value of the Senior Notes at June 30, 2009 was estimated at approximately $261.6 million.

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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 certain significant factors that have affected certain aspects of 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/A for the year ended December 31, 2008 and the unaudited financial statements included elsewhere herein.

General Overview

Our second quarter 2009 included revenues of $26.2 million and production of 7.9 Bcfe. The key drivers to our results for the three and six months ended June 30, 2009 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the six months ended June 30, 2009, we drilled (1) 28 gross wells (20.4 net wells) in the Barnett Shale area with an apparent success rate of 100%, (2) one of two gross (0.3 net) wells in the Gulf Coast and (3) two gross (0.6 net) wells in the Marcellus Shale. At June 30, 2009 we had an inventory of 51 gross wells (40.3 net) in the Barnett Shale that have been drilled and are waiting on hydraulic fracturing, completion or hook-up to sales.

Production. Our second quarter 2009 production of 7.9 Bcfe, or 86.7 MMcfe/d was a 29% increase from the second quarter 2008 production of 6.1 Bcfe, or 67.1 MMcfe/d. The second quarter 2009 production decreased 4% from the first quarter 2009 production of 8.3 Bcfe primarily due to shut in wells partially offset by new production.

Commodity prices. Our average natural gas price during the second quarter of 2009 was $3.08 per Mcf (excluding the impact of our hedges), $7.04 per Mcf, or 70%, lower than the price in the second quarter of 2008 and $0.55 per Mcf, or 15%, lower than the price in the first quarter of 2009. Primarily as a result of these depressed commodity prices, we recorded a full cost ceiling test impairment of $216.4 million for the first quarter of 2009.

Financial flexibility. In April 2009, we improved our financial flexibility through an amendment to our senior secured revolving credit facility (the “Senior Credit Facility”) that (a) increased the maximum total debt leverage ratio under the Senior Credit Facility through 2010 to as high as 4.75 to 1, (b) refined the definition of Net Debt in the leverage ratio to exclude a portion of our 4.375% Senior Convertible Notes due 2028 (the “Senior Convertible Notes”) (starting at $51 million in 2009) and (c) added a senior debt leverage covenant with a maximum ratio of 2.25 to 1. In addition, the borrowing base under the Senior Credit Facility was increased to $290 million and, on June 5, 2009, the total commitments of the lenders were increased to $284.4 million. See “Senior Credit Facility” for more information.

Outlook

Our outlook for 2009 remains challenging as near-term natural gas futures prices for the remainder of 2009 remain low and possibly could decline further but the outlook for our long-term future remains positive. Production growth, preservation of liquidity and stable upward movement in commodity prices are key to our future success. We believe the following measures will continue to have a positive impact on our 2009 results:

- We plan to continue efforts to control capital costs. During the first six months of 2009, we spent approximately $74.2 million of capital expenditures on our drilling program and $13.6 million on leasehold and seismic costs. Based upon our current outlook for operational performance in the second half of 2009, we have a 2009 capital and exploration plan ranging between $105.0 million and $120.0 million, which we currently expect to fund through cash generated from our operations, sale of assets or from cash available under the Senior Credit Facility. For a further discussion of our 2009 capital budget and funding strategy, see “Liquidity and Capital Resources—2009 Capital Budget and Funding Strategy” and “Liquidity and Capital Resources—Sources and Uses of Cash.”

- We plan to continue the development of the Marcellus Shale in the Northeastern United States, primarily through joint ventures with ACP II Marcellus, LLC and with other industry partners. Among other activities, we currently plan to drill five gross (0.8 net) vertical wells in the West Virginia part of the Marcellus Shale play to test the prospectivity of that area.

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- We expect to continue to hedge production to decrease our exposure to reductions in natural gas prices. At June 30, 2009, we had hedged approximately 42,803,000 MMBtus of natural gas production through 2012. During the first and second quarter of 2009, we put additional calls and puts on our production designed to further decrease our exposure to declining natural gas prices.

Results of Operations

Three Months Ended June 30, 2009,
Compared to the Three Months Ended June 30, 2008

Revenues from oil and natural gas production for the three months ended June 30, 2009 decreased 60% to $25.9 million from $64.7 million for the same period in 2008 due to declining oil and natural gas prices. Production volumes for natural gas for the three months ended June 30, 2009 increased 31% to 7.6 Bcf from 5.8 Bcf for the same period in 2008. Average natural gas prices, excluding the impact of our cash-settled derivatives comprised of a $23.0 million gain and a $8.4 million loss for the quarters ended June 30, 2009 and 2008, respectively, decreased to $3.08 per Mcf in the second quarter of 2009 from $10.12 per Mcf in the same period in 2008. Average oil prices, excluding the impact of our settled derivative loss of $0.4 million for the quarter ended June 30, 2008, decreased 54% to $56.95 per barrel from $122.95 per barrel in the same period in 2008. The increase in natural gas production volume was due primarily to new production contributions from Barnett Shale development.

The following table summarizes production volumes, average sales prices (excluding the impact of derivatives) and operating revenues for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		2009 Period Compared to 2008 Period	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	41	48	(7)	(14)%
Natural gas (MMcf)	7,648	5,817	1,831	31%
Average sales prices				
Oil and condensate (per Bbl)	$ 56.95	$ 122.95	$ (66.00)	(54)%
Natural gas (per Mcf)	3.08	10.12	(7.04)	(70)%
Operating revenues (In thousands)				
Oil and condensate	$ 2,331	$ 5,843	$ (3,512)	(60)%
Natural gas	23,538	58,865	(35,327)	(60)%
Other(1)	302	2,680	(2,378)	(89)%
Total Operating Revenues	$ 26,171	$ 67,388	$ (41,217)	(61)%

(1) Includes gathering income and third party gas sales that is also included as third-party purchases in operating expense.

Oil and natural gas operating expenses for the three months ended June 30, 2009 increased four percent to $9.6 million from $9.2 million for the same period in 2008, primarily as a result of increased transportation and other product costs of $1.2 million mainly attributable to increased production in the Barnett Shale area and higher lifting costs of $0.5 million primarily attributable to increased production and the increased number of producing wells. The increase was partially offset by decreased severance tax expense of $1.3 million associated with decreased revenues.

Depreciation, depletion and amortization (DD&A) expense for the three months ended June 30, 2009 decreased 12% to $12.2 million ($1.55 per Mcfe) from $13.9 million ($2.27 per Mcfe) for the same period in 2008. 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 fourth quarter 2008 and the first quarter of 2009, partially offset by increased production.

General and administrative expense increased to $6.4 million for the three months ended June 30, 2009 from $5.6 million for the corresponding period in 2008. The increase was due primarily to an increase in non-cash, stock-based compensation of $1.2 million as a result of additional deferred compensation awards.

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The net loss on derivatives of $2.3 million in the second quarter of 2009 was comprised of $25.3 million of unrealized mark-to-market loss on derivatives and $23.0 million of realized gain on net settled oil and natural gas derivatives. The net loss on derivatives of $48.2 million in the second quarter of 2008 was comprised of a $13.1 million realized loss on cash-settled derivatives, including $3.3 million of realized loss in interest rate derivatives associated with the early termination of the interest rate swaps, and a $35.1 million net unrealized mark-to-market loss on derivatives.

In May 2008, we repaid our outstanding borrowings under the Second Lien Facility and terminated the facility. As a result, we recorded a $5.7 million loss associated with the early extinguishment of debt consisting of a $4.6 million non-cash write-off of deferred loan costs and $1.1 million in penalties paid for early retirement.

Interest expense and capitalized interest for the three months ended June 30, 2009 were $9.7 million and $5.1 million, respectively, as compared to $6.0 million and $4.4 million for the same period in 2008 primarily attributable to an increase of approximately $2.0 million in non-cash interest expense associated with the amortization of the debt discount on the Senior Convertible Notes as prescribed by APB 14-1 and higher debt levels on the Senior Credit Facility.

Six Months Ended June 30, 2009,
Compared to the Six Months Ended June 30, 2008

Revenues from oil and natural gas production for the six months ended June 30, 2009 decreased 52% to $56.6 million from $118.3 million for the same period in 2008 due to declining oil and natural gas prices. Production volumes for natural gas for the six months ended June 30, 2009 increased 32% to 15.6 Bcf from 11.8 Bcf for the same period in 2008. Average natural gas prices, excluding the impact of our settled derivatives gain of $42.8 million and loss of $9.5 million for the six months ended June 30, 2009 and 2008, respectively, decreased to $3.36 per Mcf for the six months ended June 30, 2009 from $9.07 per Mcf in the same period in 2008. Average oil prices, excluding the impact of our settled derivative gain of $2.8 million and loss of $0.8 million for the six months ended June 30, 2009 and 2008, respectively, decreased 56% to $47.84 per barrel from $108.79 per barrel in the same period in 2008. The increase in natural gas production volume was due primarily to new production in the Barnett Shale development.

The following table summarizes production volumes, average sales prices (excluding the impact of derivatives) and operating revenues for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,		2009 Period Compared to 2008 Period	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	85	101	(16)	(15)%
Natural gas (MMcf)	15,642	11,831	3,811	32%
Average sales prices				
	$ 47.84	$ 108.79	$ (60.95)	(56)%

Oil and condensate (per Bbl)				
Natural gas (per Mcf)	3.36	9.07	(5.71)	(63)%
Operating revenues (In thousands)				
Oil and condensate	$ 4,065	$ 10,938	$ (6,873)	(63)%
Natural gas	52,537	107,330	(54,793)	(51)%
Other(1)	772	2,680	(1,908)	(72)%
Total Operating Revenues	$ 57,374	$ 120,948	$ (63,574)	(53)%

(1) Includes gathering income and third party gas sales that is also included as third-party purchases in operating expense.

Oil and natural gas operating expense was comparable at $17.6 million for both the six months ended June 30, 2009 and 2008, primarily as a result of decreased severance tax expense of $3.8 million associated with refunds from certain wells that qualified for a tight-gas sands tax credit for prior production periods and decreased revenues, offset by increased transportation and other product costs of $2.2 million mainly attributable to increased production in the Barnett Shale area and higher lifting costs of $1.6 million primarily attributable to increased production and the increased number of producing wells.

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Depreciation, depletion and amortization (DD&A) expense for the six months ended June 30, 2009 decreased 2% to $27.5 million ($1.70 per Mcfe) from $28.0 million ($2.25 per Mcfe) for the same period in 2008. This decrease in DD&A was primarily due to impairment charges in the fourth quarter of 2008 and the first quarter of 2009 that reduced the depletable full-cost pool, partially offset by increased production.

The significant decline in oil and natural gas prices since December 31, 2008, indicated by average posted prices of $3.17 per Mcf for natural gas and $51.76 per Bbl for oil on May 6, 2009, caused the discounted present value (discounted at ten percent) of future net cash flows from our proved oil and gas reserves to fall below our net book basis in the proved oil and gas properties at March 31, 2009. This resulted in a non-cash, ceiling test write-down of $216.4 million ($140.6 million after tax).

General and administrative expense for the six months ended June 30, 2009 increased by $2.2 million to $14.3 million from $12.1 million for the corresponding period in 2008 primarily as a result of increased employee-related expenses due to the increase in staff. This increase was partially offset by decreased insurance costs and lower legal and professional fees.

The net gain on derivatives of $27.8 million in the first six months of 2009 was comprised of a $45.6 million realized gain on cash-settled oil and natural gas derivatives and a $17.8 million of net unrealized mark-to-market loss on derivatives. The net loss on derivatives of $78.0 million in the first six months of 2008 was comprised of $11.5 million of realized loss on net settled derivatives, $63.2 million of net unrealized mark-to-market loss on derivatives and $3.3 million of realized loss on interest rate derivatives associated with the early termination of the interest rate swaps.

In May 2008, we repaid our outstanding borrowings under the Second Lien Facility and terminated the facility. As a result, we recorded a $5.7 million loss associated with the early extinguishment of debt consisting of a $4.6 million non-cash write-off of deferred loan costs and $1.1 million in penalties paid for early retirement.

Interest expense and capitalized interest for the six months ended June 30, 2009 were $18.7 million and $10.1 million, respectively, as compared to $12.5 million and $8.2 million for the same period in 2008 primarily attributable to an increase of approximately $5.0 million in non-cash interest expense associated with the amortization of the debt discount on the Senior Convertible Notes as prescribed by APB 14-1 and higher debt levels on the Senior Credit Facility.

Liquidity and Capital Resources

2009 Capital Budget and Funding Strategy. For 2009, management estimates a capital and exploration expenditures plan ranging between $105 million and $120 million, including $90 million to $100 million for our drilling program, of which $85 million to $95 million is designated for Barnett Shale development and $4 million for our share of capital expenditures related to Marcellus Shale joint venture. We intend to finance our 2009 capital and exploration budget primarily from cash flows from operations, supplemented by available borrowings under the Senior Credit Facility and the possible selective sale or monetization of non-core assets. We may be required to reduce or defer part of our 2009 capital expenditures program if we are unable to obtain sufficient financing from these sources.

Sources and Uses of Cash. During the six months ended June 30, 2009, capital expenditures, net of proceeds from property sales, exceeded our net cash provided by operations. During 2009, we have funded our capital expenditures with cash generated from operations and net additional borrowings under the Senior Credit Facility. Potential primary sources of future liquidity include the following:

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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 natural gas and oil prices.

- Available borrowings under the Senior Credit Facility. At August 10, 2009, $81.4 million was available for borrowing under the Senior Credit Facility. The next borrowing base redetermination is currently scheduled for the fourth quarter of 2009.

- Debt and equity offerings. As situations or conditions arise, we may need to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.

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- Asset sales. In order to fund our capital and exploration budget, we may consider the sale of certain properties or assets that are not part of our core business, can be monetized at a price we find acceptable, or are no longer deemed essential to our future growth. To this end, we have announced that we are pursuing the possible sale or monetization of certain of our gathering systems located in the Barnett Shale play.

- Project financing in certain limited circumstances.

- 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 with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage, such as our joint venture in the Marcellus Shale play.

- 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.

Our primary use of cash is capital expenditures to fund our drilling and development programs and, to a lesser extent, our lease and seismic acquisition programs. Our current 2009 capital expenditures plan provides for approximately \$90 million to \$100 million for drilling, and approximately \$15 million to \$20 million for leasing, land costs, seismic acquisitions and other capital expenses. During the second quarter of 2009, our partner in the Marcellus Shale joint venture completed its initial contribution of cash related to the formation of the joint venture. At that point, we became obligated to fund our share of the Marcellus joint venture costs and expenses. We expect to pay approximately \$7 million for our share of the remaining Marcellus 2009 joint venture capital expenditure program, primarily to drill wells in West Virginia.

Overview of Cash Flow Activities. Cash flows provided by operating activities were \$80.9 million and \$69.0 million for the six months ended June 30, 2009 and 2008, respectively. The increase was primarily due to the Company's efforts to manage cash flows and control operational costs. Natural gas prices have fallen since the third quarter of 2008 and have continued to decline in 2009, having a negative impact on our cash flow from operations and on our 2009 drilling plans. Despite our increase in natural gas production, further decreases in natural gas prices could have a further negative impact on our cash flow from operations and on our 2009 drilling plans.

Cash flows used in investing activities were \$117.9 million and \$326.6 million for the six months ended June 30, 2009 and 2008 and related primarily to oil and gas property expenditures.

Net cash provided by financing activities for the six months ended June 30, 2009 was \$36.6 million and related primarily to net borrowings under the Senior Credit Facility. Net cash provided by financing activities for the six months ended June 30, 2008 was \$261.6 million and related primarily to net proceeds of \$135.2 million from the issuance of common stock in February 2008, net proceeds of \$365.3 million in additional borrowings under the Senior Convertible Notes and \$142.0 million in additional borrowings under the Senior Credit Facility. The cash proceeds were partially offset by the payoff and termination of the Second Lien Credit Facility and partial paydown of the Senior Credit Facility.

Liquidity/Cash Flow Outlook.

We currently believe that cash generated from operations, supplemented by borrowings under the Senior Credit Facility and selected assets sales, 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, oil and natural gas prices have declined 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, 2009, we had hedged approximately 12,512,000 MMBtus (70 MMcf per day for the full year 2009, or 85% of our estimated production from July through December 2009) of our 2009 natural gas production at a weighted average floor or swap price of $6.15 per MMBtu relative to WAHA and HSC prices. We believe the funds available to us under the Senior Credit Facility, $81.4 million at August 10, 2009, will be accessible to us.

If cash from operations and funds available under the Senior Credit Facility are insufficient to fund our 2009 capital and exploration budget, we may need to reduce our capital and exploration budget 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 2009 natural gas and oil exploration and development program, thereby adversely

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affecting the recoverability and ultimate value of our natural gas and oil properties. The recent worldwide financial and credit crisis has adversely affected our ability to access the capital markets.

Contractual Obligations

In 2009, we entered into a two-year and one-year term lease agreements for compressor rentals with an estimated obligation of approximately $2.4 million and $0.5 million, respectively.

Financing Arrangements

Senior Credit Facility

In April 2009, we amended the Senior Credit Facility to, among other things, (1) adjust the maximum ratio of total net debt to Consolidated EBITDAX to a maximum ratio of (a) 4.25 to 1.00 for the quarter ending June 30, 2009, (b) 4.50 to 1.00 for the quarter ending September 30, 2009, (c) 4.75 to 1.00 for each quarter ending on or after December 31, 2009 and on or before September 30, 2010, (d) 4.25 to 1.00 for the quarter ending December 31, 2010, and (e) 4.00 to 1.00 for each quarter ending on or after March 31, 2011; (2) modify the calculation of total net debt for purposes of determining the ratio of total net debt to Consolidated EBITDAX to exclude the following amounts, which represent a portion of the Convertible Senior Notes deemed to be an equity component under APB 14-1: $51,252,980 during 2009, $38,874,756 during 2010, $26,021,425 during 2011 and $12,674,753 during 2012 until the maturity date; (3) add a new senior leverage ratio, which requires that our ratio of senior debt (which excludes debt attributable to the Convertible Senior Notes) to Consolidated EBITDAX not exceed 2.25 to 1.00; (4) modify the interest rate margins applicable to Eurodollar loans to a range of between 2.25% and 3.25% (depending on the then-current level of borrowing base usage); (5) modify the interest rate margins applicable to base rate loans to a range of between 1.00% and 2.00% (depending on the then-current level of borrowing base usage); and (6) establish new procedures governing the modification of swap agreements.

In May 2009, we amended the Senior Credit Facility to, among other things, (1) replace Guaranty Bank with Wells Fargo Bank, N.A. as administrative agent, (2) provide that the aggregate notional volume of oil and natural 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, (3) remove a provision that limited the maximum duration of swap agreements permitted under the Senior Credit Facility to five years, and (4) 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. Also in April 2009, the Company amended the Senior Credit Facility to increase the borrowing base to $290,000,000 and, in May 2009, the total commitment of the lenders was increased from $250,000,000 to $259,400,000. On June 5, 2009, the total commitment was increased by $25,000,000 to $284,400,000 with the addition of a new lender to the bank syndicate.

As of August 10, 2009, we had $201.0 million of borrowings outstanding and a borrowing base availability of $81.4 million.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing natural gas and oil prices. The dramatic drop in natural gas and oil prices since the third quarter of 2008 has resulted in a significant drop in revenue per unit of production. Although operating costs have also declined, the rate of decline in natural gas and oil 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

On January 1, 2009, we adopted the Financial Accounting Standards Boards (“FASB”) Staff Position No. APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)” (“APB 14-1”), which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. APB 14-1 requires that issuers of convertible debt separately account for the liability and equity components in a manner that reflects the entity’s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Once adopted, ABP 14-1 requires retrospective application to the terms of instruments as they existed for periods presented. We applied this accounting pronouncement to the Convertible Senior Notes. We valued the conversion premium of the convertible debt at $64.2 million and accordingly restated our balance sheet as of December 31, 2008 for the carrying value of debt and equity and restated our results of operations for interest expense, capitalized interest, and income taxes for the year ended December 31, 2008. See Item 1,

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Notes to Consolidated Financial Statements, Note 2 for a discussion of the restatement related to the adoption of this accounting pronouncement.

On January 1, 2009, we adopted and retroactively applied FASB Staff Position ("FSP") Emerging Issues Task Force 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("EITF 03-6-1"). This FSP provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. This FSP requires retroactive application for all periods presented. We determined that our restricted shares of common stock are participating securities as defined in this FSP and applied this FSP retroactively to all periods presented. See Item 1, Notes to Consolidated Financial Statements, Note 2 for a discussion of the restatement related to the adoption of this accounting pronouncement.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities ("SFAS No. 161"). This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements, how derivative instruments and related hedged items are accounted for under SFAS No. 133, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted this pronouncement effective January 1, 2009 and it did not have a significant effect on our consolidated financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" ("FSP FAS 157-4"), which provides additional guidance for estimating fair value in accordance with SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). FSP FAS 157-4 is effective for the quarter ending June 30, 2009. We adopted this pronouncement effective June 30, 2009 and it had no material impact on our consolidated financial statements.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP FAS 115-2"), which provides new guidance on the recognition of other-than-temporary impairments of investments in debt securities and provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. FSP FAS 115-2 is effective for the quarter ending June 30, 2009. We adopted the requirements of this pronouncement effective June 30, 2009 and it had no material impact on our consolidated financial statements.

In April 2009, the FASB issued FSP FAS No. 107-1 and APB Opinion No. 28-1, "Interim Disclosures About Fair Value of Financial Instruments," which requires quarterly fair value disclosures for financial instruments that are not reflected on the Company's Consolidated Balance Sheet at fair value in interim financial statements effective for interim periods ending after June 15, 2009. We adopted the requirements of this pronouncement effective June 30, 2009 and included additional disclosures in our Notes to Consolidated Financial Statement.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events," which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. In particular, SFAS No. 165 sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. We applied the requirement of this pronouncement effective June 30, 2009 and included additional disclosures in our Notes to Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

On December 31, 2008, the SEC adopted major revisions to its rules governing oil and gas company reporting requirements. These new rules permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of its reserve estimates, and to file reports when a third party is relied upon to prepare or audit its reserves estimates. The new rules also require that the net present value of oil and gas reserves reported and used in the full cost ceiling test calculation be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

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In June 2009, the FASB issued SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles" ("SFAS No. 168"). SFAS No. 168 establishes the FASB Accounting Standards Codification ("Codification"), which became effective July 1, 2009, to become the single source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. All other accounting literature excluded from the Codification will be considered nonauthoritative. The subsequent issuances of new standards will be in the form of Accounting Standards Updates that will be included in the Codification. Generally, the Codification is not expected to change U.S. GAAP. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We are currently evaluating the effect of the standard on our financial statement disclosures, as all future references to authoritative accounting literature will be made in accordance with the Codification.

Critical Accounting Policies

The following summarizes our critical accounting policies:

Oil and Natural Gas Properties

We account for investments in natural gas and oil properties using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. These costs include lease acquisitions, seismic surveys, and drilling and completion equipment. We proportionally consolidate our interests in natural gas and oil properties. We capitalized compensation costs for employees working directly on exploration activities of $3.0 million and $3.4 million for the six months ended June 30, 2009 and 2008, respectively. We expense maintenance and repairs as they are incurred.

We amortize natural gas and oil properties based on the unit-of-production method using estimates of proved reserve quantities. Costs not subject to amortization includes costs of unevaluated leaseholds, seismic costs associated with specific unevaluated properties and wells in progress. These costs are periodically evaluated on a property-by-property basis for impairment. If the results of an assessment indicate that the properties are impaired, we add the amount of impairment to the proved natural gas and oil property costs to be amortized. The amortizable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the three months ended June 30, 2009 and 2008 was $1.52 and $2.14, respectively.

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

Net capitalized costs of proved oil and natural gas properties are limited to a "ceiling test" based on the estimated future net revenues, discounted at 10% per annum, from proved oil and natural gas reserves based on current economic and operating conditions ("Full Cost Ceiling"). If net capitalized costs exceed this limit, the excess is charged to earnings.

The Full Cost Ceiling test cushion at June 30, 2009 of $69.6 million was based upon average realized oil, natural gas liquids and natural gas prices of $65.35 per Bbl, $31.76 per Bbl and $3.52 per Mcf, respectively, or a volume weighted average price of $27.69 per BOE. This cushion, however, would have been zero at such date at an estimated volume weighted average price of $25.63 per BOE. A BOE means one barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. In connection with our June 30, 2009 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase in commodity prices at June 30, 2009 would have increased the Full Cost Ceiling test cushion by approximately $11.7 million and a 10% decrease in commodity prices would have resulted in a $24.1 million ceiling test impairment. The aforementioned price sensitivity is as of June 30, 2009 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. Prices have historically been higher or substantially higher, more often for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value of our oil and natural gas properties, excluding the costs not subject to amortization as discussed above, plus estimated future development costs and salvage value, to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We have a significant amount of proved undeveloped reserves. We had 239.1 Bcfe of proved undeveloped reserves at December 31, 2008, representing 48% of our total proved reserves. As of December 31, 2008, a portion of these proved undeveloped reserves, or approximately 29.9 Bcfe, are attributable to our Camp Hill properties that we acquired in 1994. The estimated future development costs to develop our proved undeveloped reserves on our Camp Hill properties are relatively low, on a per Mcfe basis, when compared to the estimated future development costs to develop our proved undeveloped reserves on our other oil and natural gas properties. Furthermore, the average depletable life (the estimated time that it will take to produce all recoverable reserves) of our Camp Hill properties is considerably longer, or approximately 15 years, when compared to the depletable life of our remaining oil and natural gas properties of approximately 10 years. Accordingly, the combination of a relatively low ratio of future development costs and a relatively long depletable life on our Camp Hill properties has resulted in a relatively low overall historical depletion rate and DD&A expense. This has resulted in a capitalized cost basis associated with producing properties being depleted over a longer period than the associated production and revenue stream, causing the build-up of nondepleted capitalized costs associated with properties that have been completely depleted. This combination of factors, in turn, has had a favorable impact on our earnings, which have been higher than they would have been had the Camp Hill properties not resulted in a relatively low overall depletion rate and DD&A expense and longer depletion period. As a hypothetical illustration of this impact, the removal of our Camp Hill proved undeveloped reserves starting January 1, 2002 and through December 31, 2008 would have reduced our earnings by (a) an estimated $11.2 million in 2002 (comprised of after-tax charges for a $7.1 million full cost ceiling impairment and a $4.1 million depletion expense increase), (b) an estimated $5.9 million in 2003 (due to higher depletion expense), (c) an estimated $3.4 million in 2004 (due to higher depletion expense), (d) an estimated $6.9 million in 2005 (due to higher depletion expense), (e) an estimated $0.7 million in 2006 (due to higher depletion expense), (f) an estimated $2.0 million in 2007 (due to higher depletion expense), and (g) an estimated $9.2 million in 2008 (comprised of after tax charges for an $8.5 million full cost ceiling test impairment and a $0.7 million depletion expense increase).

We expect our relatively low historical depletion rate to continue until the high level of nonproducing reserves to total proved reserves is reduced and the life of our proved developed reserves is extended through development drilling and/or the significant addition of new proved producing reserves through acquisition or exploration. If our level of total proved reserves, finding costs and current prices were all to remain constant, this continued build-up of capitalized cost increases the probability of a ceiling test write-down in the future.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to ten years.

Income Taxes

Under Statement of Financial Accounting Standards No. 109 (“SFAS No. 109”), “Accounting for Income Taxes,” deferred income taxes are recognized at each year end 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. We routinely assess the realizability of our deferred tax assets based upon our estimated production of proved reserves at estimated future pricing. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

For information regarding our other critical accounting policies, see the 2008 Form 10-K/A.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition 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 natural gas.

We periodically review the carrying value of our oil and natural gas properties under the full cost method of accounting rules. See "—Critical Accounting Policies—Oil and Natural Gas Properties."

To mitigate some of our commodity price risk, we engage periodically in certain other limited derivative activities including price swaps, costless collars and, occasionally, put and call options, in order to establish some price floor protection.

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The following table includes oil and natural gas positions settled during the three and six-month periods ended June 30, 2009 and 2008, and the unrealized gain/(loss) associated with the outstanding oil and natural gas derivatives at June 30, 2009 and 2008.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Oil positions settled (Bbls)	-	9,100	5,900	27,300
Natural gas positions settled (MMBtus)	7,293,000	3,458,000	13,678,000	7,590,000
Realized gain/(loss) ($ millions) (1)	$ 23.0	$ (8.8)	$ 45.6	$ (10.3)
Unrealized gain/(loss) ($ millions) (1)	$ (25.3)	$ (40.1)	$ (17.8)	$ (66.0)

(1) Included in net gain (loss) on derivatives in the Consolidated Statements of Operations.

At June 30, 2009, we had the following outstanding natural gas derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(3)	
Quarter	MMBtus(1)	Average Fixed Price(2)	MMBtus(1)	Average Floor Price(2)	Average Ceiling Price(2)	MMbtu	Fixed Price
Third Quarter 2009	3,680,000	5.31	2,576,000	7.16	8.88	1,840,000	0.27
Fourth Quarter 2009	3,680,000	5.58	2,576,000	7.17	8.90	-	-
First Quarter 2010	3,150,000	5.45	1,620,000	7.92	9.63	-	-
Second Quarter 2010	3,185,000	5.50	637,000	5.84	7.30	-	-
Third Quarter 2010	1,840,000	5.57	1,104,000	6.07	7.62	-	-
	1,840,000	5.57	1,380,000	6.49	7.90	-	-

Fourth Quarter 2010							
First Quarter 2011	1,800,000	5.64	450,000	9.70	11.70	-	-
Second Quarter 2011	1,820,000	5.64	455,000	8.25	10.25	-	-
Third Quarter 2011	1,840,000	5.64	460,000	8.65	10.65	-	-
Fourth Quarter 2011	1,840,000	5.64	460,000	8.85	10.85	-	-
First Quarter 2012	910,000	5.88	455,000	9.55	11.55	-	-
Second Quarter 2012	910,000	5.88	455,000	8.35	10.35	-	-
Third Quarter 2012	920,000	5.88	-	-	-	-	-
Fourth Quarter 2012	920,000	5.88	-	-	-	-	-
	28,335,000		12,628,000			1,840,000	

(1) During 2009, the Company entered into (1) a $5.35 put, a $6.20 long-call and an $8.00 short-call with respect to a portion of the Company's production hedged with swaps (10,000 MMBtus per day) in 2011 and 2012 and (2) a $4.35 put, a $6.00 long-call and a $6.50 short-call with respect to a portion of the Company's production hedged with swaps (20,000 MMBtus per day for April through October of 2010). The table below presents additional put positions the Company has entered into associated with a portion of hedged volumes presented above:

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Quarter	MMBtus	Put Price
Third Quarter 2009	920,000	$3.00
Fourth Quarter 2009	920,000	3.00
Second Quarter 2010	455,000	3.74
Third Quarter 2010	920,000	4.31
Fourth Quarter 2010	1,196,000	4.61
First Quarter 2011	450,000	6.80
Second Quarter 2011	455,000	6.80
Third Quarter 2011	460,000	6.80
Fourth Quarter 2011	460,000	6.80
First Quarter 2012	455,000	6.80
Second Quarter 2012	455,000	6.80

(2) Based on Houston Ship Channel ("HSC") and WAHA spot prices.
(3) Basis differential swaps covering the price differential for natural gas between NYMEX and HSC.

As of June 30, 2009, approximately 55% of our open natural gas hedged volumes were with Credit Suisse as the counterparty, and the remaining 45% were with Shell Energy North America (U.S.), L.P. as the counterparty.

While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of natural gas and oil. We enter into the majority of our derivatives transactions with two counterparties and have a netting agreement 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. Under these arrangements, payments are received or made based on the differential between a fixed and a variable commodity price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would be exposed again to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction. Moreover, our derivatives arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

Our natural gas derivative transactions are generally settled based upon the average of the reported settlement prices on the HSC or WAHA indices for the last three trading days of a particular contract month. Our oil derivative transactions are generally settled based on the average reported settlement prices on the West Texas Intermediate index for each trading day of a particular calendar month.

Forward Looking Statements

The statements contained in all parts of this document, including, but not limited to, those relating to 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, efforts to control capital costs, risk profile of oil and natural gas exploration, acquisition of 3-D seismic data (including number, timing and size of projects), planned evaluation of prospects, probability of prospects having oil and natural gas, expected production or reserves, increases in reserves, acreage, working capital requirements, hedging activities, credit risk of hedging counterparties, the ability of expected sources of liquidity to implement the Company's business strategy, future exploration activity, production rates, 2009 drilling program, growth in production, development of new drilling programs, hedging of production and exploration and development expenditures, Camp Hill development, addition of new lenders under the Senior Credit Facility, fair value of the Company's investment in Pinnacle and all and any other statements regarding future operations, financial results, business plans and cash needs, potential borrowing base increases and other statements that are not historical facts are forward looking statements. When used in this document, the words "anticipate," "estimate," "expect," "may," "project," "believe" and similar expressions are intended among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the Company's dependence on its exploratory drilling activities, the volatility of oil and natural gas prices, the need to replace reserves depleted by production, operating risks of oil and natural gas operations, the Company's dependence on its key personnel, factors that affect the Company's ability to manage its growth and achieve its business strategy, technological changes, significant capital requirements of the Company, borrowing base determinations and availability under the Senior Credit Facility, evaluations of the Company by potential lenders under the Senior Credit Facility, results of operation of Pinnacle, the potential impact of government regulations, 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, and other factors detailed in the "Risk Factors" and other sections of the Company's Annual Report on Form 10-K/A for the year ended December 31, 2008 and in this and its other filings with the Securities and Exchange Commission. 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 the Company undertakes no obligation to update or revise any forward-looking statement.

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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/A for the year ended December 31, 2008. There have been no material changes to the disclosure regarding our exposure to certain market risks made in the Annual Report on Form 10-K/A. For additional information regarding our long-term debt, see Note 3 of the Notes to Consolidated Financial Statements (Unaudited) in Item 1 of Part I of this Quarterly Report on Form 10-Q.

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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. As described in more detail in our Form10-K/A filed on August 17, 2009, we identified a material weakness in our internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15-d15(f) in connection with further review of our ceiling test impairments as of December 31, 2008 and March 31, 2009. As a result of this material weakness, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2009, our disclosure controls and procedures were not effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission'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. We have outlined a number of initiatives, as discussed below, designed to remediate the material weakness.

Subsequent to the issuance of the Form 10-Q for the quarterly period ended March 31, 2009, we identified an error resulting from the presence of certain computational deficiencies in our standard ceiling test computation format, most notably the absence of the pre-tax, gross-up computation and a reconciling proof of the oil and gas property and related deferred tax amounts to the financial statements (in the event of an after-tax, ceiling test write-down). Upon further review, we also discovered additional errors which partially offset the impact of the pre-tax, gross up error. These offsetting errors included: (1) the incorrect classification of a portion of the capitalized interest in the full cost pool that related to unevaluated properties, (2) the failure to properly consider certain deferred tax amounts and (3) the incorrect classification of certain unevaluated leasehold costs in the full cost pool.

These errors and/or omissions resulted in a restatement of the March 31, 2009 consolidated financial statements and were an indication that a material weakness was present at March 31, 2009, as we concluded there was a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. These deficiencies ultimately affect the accuracy of our financial statement reporting and disclosures. As a result, management has concluded that our internal controls over financial reporting were not effective as of March 31, 2009. We have implemented procedures discussed below designed to prevent these specific errors from occurring in the future.

We have taken or plan to take the following initiatives in the third quarter of 2009: (1) delegate preparation of certain critical workpapers to our financial reporting staff allowing our financial reporting manager to perform more qualitative review analysis, (2) remove the computational deficiencies from our standard ceiling test workpaper format, (3) improve workpaper formats and implement comparative analysis within these critical workpapers to enhance qualitative analysis and (4) prepare a reconciliation of the quarter-to-quarter changes in costs associated with unevaluated property and proved undeveloped locations that will be used to determine the reclassification of costs to the full cost pool.

We have discussed this material weakness and our planned remediation steps with our Audit Committee and believe that such enhanced procedures and workpaper formats, once fully implemented, will prospectively mitigate this material weakness.

We applied the above-mentioned analysis of the ceiling test computation to help ensure the proper calculation of the ceiling test impairment as of June 30, 2009.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended June 30, 2009, that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. As described above we identified a material weakness in our internal control over financial reporting and have described a number of planned changes to our internal control over financial reporting during the third quarter of 2009 designed to remediate this material weakness. This Item 4 should be read in conjunction with Item 9A included in the Form 10-K/A.

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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 factor 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/A for the year ended December 31, 2008, which could materially affect our business, financial condition or future 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.

There is recently proposed legislation that could adversely affect our business.

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 the oil and gas industry in the hydraulic fracturing process. 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 Senate and House of Representatives have asserted that chemicals used in fracturing process could adversely affect drinking water supplies. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase the Company's costs of compliance and doing business. We make extensive use of hydraulic fracturing in our shale play operations and increased regulation could increase our costs, limit our ability to conduct operations or otherwise adversely affect our business.

In addition to various other federal, regional, state and local greenhouse gas legislation and regulations that are currently in effect or under development, the United States Congress is currently considering legislation that would significantly curtail national greenhouse gas emissions. The United States Environmental Protection Agency has also taken steps to declare that certain greenhouse gas emissions are contributing to air pollution which is an endangerment to human health, and may regulate greenhouse gas emissions under the federal Clean Air Act. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating costs and could have an adverse affect on the price or demand of the oil and gas we produce.

President Obama's Proposed 2010 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.

As of December 31, 2008, March 31, 2009 and June 30, 2009, we had material weaknesses in our internal controls, and our internal control over financial reporting was not effective as of those dates. If we fail to maintain an effective system of internal controls, we may not be able to provide timely and accurate financial statements.

As more fully described in our annual report on Form 10-K/A for the year ended December 31, 2008 under Item 9A, “Controls and Procedures,” our management identified material weaknesses related to the ceiling test impairment and the classification of proved costs. As a result of the material weaknesses, management concluded that, as of December 31, 2008, March 31, 2009 and June 30, 2009 we did not maintain effective internal control over financial reporting.

Management identified the material weaknesses referred to above in August of 2009 in a subsequent review of the December 31, 2008 ceiling test calculation.

The Public Company Accounting Oversight Board has defined a material weakness as a control deficiency, or combination of control deficiencies, that results in a reasonable possibility that a material misstatement of the annual or interim statements will not be

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prevented or detected on a timely basis. Accordingly, a material weakness increases the risk that the financial information we report contains material errors.

We are in the process of implementing initiatives to remediate the material weaknesses in our internal controls. The steps we have taken and are taking to address the material weaknesses may not be effective. However, any failure to effectively address a material weakness or other control deficiency or implement required new or improved controls, or difficulties encountered in their implementation, could limit our ability to obtain financing, harm our reputation, disrupt our ability to process key components of our result of operations and financial condition timely and accurately and cause us to fail to meet our reporting obligations under rules of the SEC and NASDAQ and our various debt arrangements. Any failure to remediate the material weaknesses identified in our evaluation of our internal controls could preclude our management from determining our internal control over financial reporting is effective or otherwise from issuing in a timely manner our management report in 2010.

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

None.

Item 3 - Defaults Upon Senior Securities

None.

Item 4 - Submission of Matters to a Vote of Security Holders

None.

Item 5 - Other Information

None.

Item 6 - Exhibits

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

Exhibit Number	Description
†10.1	— Tenth Amendment dated as of May 20, 2009 to Credit Agreement dated May 25, 2006 by and among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and Guaranty Bank, as administrative agent and as resigning issuing bank, and Wells Fargo Bank N.A., as successor administrative agent and as successor issuing bank (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on April 28, 2009).
†10.2	— Second Supplemental Indenture dated May 14, 2009 among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.21 to the Company’s Registration Statement on Form S-3 (Registration No. 333-159237).
†10.3	— Lender Certificate dated June 5, 2009 of Calyon New York Branch regarding joinder as Lender to Credit Agreement, as amended, dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Guaranty Bank, as Administrative Agent and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on June 9, 2009).
†10.4	—

Amended and Restated Employment Agreement between Carrizo Oil & Gas, Inc. and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.5— Amended and Restated Employment Agreement between Carrizo Oil & Gas, Inc. and Paul F. Boling (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.6— Amended and Restated Employment Agreement between Carrizo Oil & Gas, Inc. and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.7— Amended and Restated Employment Agreement between Carrizo Oil & Gas, Inc. and Gregory E. Evans (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.8— Amended and Restated Employment Agreement between Carrizo Oil & Gas, Inc. and Richard H. Smith (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.9— Form of 2009 Employee Restricted Stock Unit Award Agreement (with performance-based vesting and time-based vesting) (incorporated herein by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on June 9, 2009).

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†10.10—Form of 2009 Employee Restricted Stock Unit Award Agreement (with performance-based vesting only) (incorporated herein by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.11—Form of 2009 Employee Stock Appreciation Rights Award Agreement (incorporated herein by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.12—Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K filed on June 9, 2009).

†10.13—Form of 2009 Employee Cash-Settled Stock Appreciation Rights Award Agreement pursuant to the Carrizo Oil & Gas, Inc. Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K filed on June 9, 2009).

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.

† Incorporated herein by reference as indicated.

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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 17, 2009	By: /s/S. P. Johnson, IV President and Chief Executive Officer (Principal Executive Officer)
Date: August 17, 2009	By: /s/Paul F. Boling Chief Financial Officer (Principal Financial and Accounting Officer)