CARRIZO OIL & GAS INC
Form 10-Q
November 09, 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 September 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 [ ]   Smaller reporting company [ ]
(Do not check if a smaller reporting company)

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

YES [ ]   NO [X]

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, as of November 2, 2009, the latest practicable date, was 31,072,006.

CARRIZO OIL & GAS, INC.

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

ASSETS	September 30, 2009 (Unaudited)	December 31, 2008
	(In thousands, except par value amount)	
CURRENT ASSETS:		
Cash and cash equivalents	$3,576	$5,184
Accounts receivable, trade (net of allowance for doubtful accounts of $1,552 and $1,264 at September 30, 2009 and December 31, 2008, respectively)	21,228	24,675
Advances to operators	325	336
Fair value of derivative financial instruments	6,062	22,791
Other current assets	5,567	3,335
Total current assets	36,758	56,321
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including costs not subject to amortization of $371,558 and $378,634 at September 30, 2009 and December 31, 2008, respectively)	878,646	986,629
DEFERRED FINANCING COSTS, NET	9,620	8,430
INVESTMENTS	3,577	3,274
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	-	15,876
DEFERRED INCOME TAXES	32,371	-
OTHER ASSETS	964	1,172
TOTAL ASSETS	$961,936	$1,071,702
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$50,922	$46,683
Accrued liabilities	30,632	54,149
Advances for joint operations	5,674	3,815
Current maturities of long-term debt	148	173
Deferred tax liability	2,197	9,103
Total current liabilities	89,573	113,923
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT	541,713	475,788
ASSET RETIREMENT OBLIGATION	9,902	6,503
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	5,915	-
DEFERRED INCOME TAXES	-	34,778
OTHER LIABILITIES	1,387	625
COMMITMENTS AND CONTINGENCIES		-
SHAREHOLDERS' EQUITY:		
Common stock, par value $0.01 (90,000 shares authorized; 31,056 and 30,860 issued and outstanding at September 30, 2009 and		

December 31, 2008, respectively)	311	309
Additional paid-in capital	428,960	420,778
Retained earnings (deficit)	(116,060)	20,297
Accumulated other comprehensive income (loss), net of tax	235	(1,299)
Total shareholders' equity	313,446	440,085
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$961,936	$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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In thousands except per share amounts)			
OIL AND NATURAL GAS REVENUES	$23,847	$58,527	$81,221	$179,475
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	5,213	10,427	22,837	28,047
Third party gas purchases	272	2,980	1,139	5,576
Depreciation, depletion and amortization	12,524	13,922	40,049	41,874
Impairment of oil and gas properties	-	-	216,391	-
General and administrative (inclusive of stock-based compensation expense of $2,780 and $1,560 for the three months ended September 30, 2009 and 2008, respectively, and $8,514 and $4,547 for the nine months ended September 30, 2009 and 2008, respectively)	7,633	5,809	21,894	17,908
Accretion expense related to asset retirement obligations	79	58	225	173
TOTAL COSTS AND EXPENSES	25,721	33,196	302,535	93,578
OPERATING INCOME (LOSS)	(1,874)	25,331	(221,314)	85,897
OTHER INCOME AND EXPENSES:				
Net gain (loss) on derivatives	(1,986)	77,686	25,802	(357)
Loss on early extinguishment of debt	-	16	-	(5,689)
Interest income	1	43	13	251
Interest expense	(9,903)	(8,491)	(28,617)	(20,950)
Capitalized interest	4,996	6,315	15,065	14,479
Impairment of investment in Pinnacle Gas Resources, Inc.	-	-	(2,091)	-
Other income (expenses), net	(23)	15	16	64
INCOME (LOSS) BEFORE INCOME TAXES	(8,789)	100,915	(211,126)	73,695
INCOME TAX (EXPENSE) BENEFIT	3,994	(35,200)	74,769	(26,056)
NET INCOME (LOSS)	$(4,795)	$65,715	$(136,357)	$47,639
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES:				
Increase (decrease) in market value of investment in Pinnacle Gas Resources, Inc.	64	(3,684)	179	(5,228)

Reclassification of cumulative decrease in market value of investment in Pinnacle				
Gas Resources, Inc.	-	-	1,359	-
COMPREHENSIVE INCOME (LOSS)	$(4,731)	$62,031	$(134,819)	$42,411
BASIC INCOME (LOSS) PER COMMON SHARE	$(0.15)	$2.15	$(4.40)	$1.59
DILUTED INCOME (LOSS) PER COMMON SHARE	$(0.15)	$2.12	$(4.40)	$1.56
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	31,053	30,531	30,980	30,005
DILUTED	31,053	30,973	30,980	30,452

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 Nine Months Ended September 30, 2009	2008
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$(136,357)	$47,639
Adjustment to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation, depletion and amortization	40,049	41,874
Impairment of oil and gas properties	216,391	-
Fair value (gain) loss of derivative financial instruments	38,519	(13,933)
Accretion of discounts on asset retirement obligations and debt	225	173
Stock-based compensation	8,514	4,547
Provision for allowance for doutbful accounts	288	(166)
Deferred income taxes	(74,834)	25,652
Loss on extenguishment of debt	-	4,601
Amortization of equity premium associated with Convertible Senior Notes	4,296	988
Impairment of investment in Pinnacle Gas Resources, Inc.	2,091	-
Other	4,857	3,550
Changes in operating assets and liabilities		
Accounts receivable	3,158	(1,394)
Other assets	(1,548)	(3,015)
Accounts payable	(2,053)	6,847
Accrued liabilities	4,242	8,995
Net cash provided by operating activities	107,838	126,358
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(143,036)	(456,696)
Change in capital expenditure accrual	(21,309)	(1,573)
Proceeds from the sale of properties	6	2,280
Advances to operators	12	(83)
Advances for joint operations	1,859	(453)
Other	(69)	(2,771)
Net cash used in investing activities	(162,537)	(459,296)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from debt issuance and borrowings	100,037	590,034
Debt repayments	(43,886)	(382,156)
Proceeds from common stock offering, net of offering costs	-	135,077
Proceeds from stock options exercised	9	240
Deferred loan costs and other	(3,069)	(9,260)
Net cash provided by financing activities	53,091	333,935
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,608)	997

CASH AND CASH EQUIVALENTS, beginning of period	5,184	8,026
CASH AND CASH EQUIVALENTS, end of period	$3,576	$9,023
CASH PAID FOR INTEREST (NET OF AMOUNTS CAPITALIZED)	$2,659	$1,872

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

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.

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, and also factor into the Company's borrowing base and evaluation of the recoverability of deferred tax assets, 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. In particular, the Company owns interests in

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approximately 2,630 gross acres in the Camp Hill Field in Anderson County, Texas, for which the Company reported approximately 8.2 MMBbls of proved reserves, including 5.0 MMBbls of proved undeveloped reserves (which represents approximately 6% of our total proved reserves) as of December 31, 2008. In connection with an ongoing review by the SEC's staff of the Company's Annual Report on Form 10-K for the year ended December 31, 2008, the staff has raised various issues regarding the classification of some of these reserves as proved. The Company's position that the Camp Hill proved reserves met the SEC's definition of proved reserves continues to be subject to review.

In late 2008, the SEC adopted new rules regarding the classification of reserves that will become effective for the Company as of year-end of 2009, which, among other things, generally require proved undeveloped reserves to be developed within five years, unless specific circumstances justify a longer time. As a result of various factors, including these new rules and our discussions with the SEC's staff regarding their applicability to the Camp Hill Field, the Company may be required under applicable SEC rules to reclassify as unproved substantially all of our proved undeveloped reserves in the Camp Hill Field at year-end 2009 because these reserves will not be developed within the next five years. The Company may also be required under applicable SEC rules to write-off or reclassify to proved undeveloped, a portion of our proved developed reserves. This possible write-off of the reserves could significantly impact depletion expense, ceiling test impairment and the realizability of the net deferred tax asset.

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 November 9, 2009 – see Note 10.

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 $4.1 million and $5.2 million for the nine months ended September 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 dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the quarters ended September 30, 2009 and 2008 was $1.50 and $2.24, 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 nine-month period ended September

30, 2009, the Company incurred an impairment charge of $216.4 million ($138.0 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 ($138.0 million net of tax). Had the Company used prices in effect as of March 31, 2009, an impairment of $323.2 million ($206.1 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 Company paid less than $100,000 in income taxes during the nine months ended September 30, 2009 and 2008.

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Stock-Based Compensation

The Company issues restricted stock and stock options, including stock appreciation rights ("SAR"), as compensation to employees, directors and certain contractors. Restricted stock is measured at grant date fair value and recorded as deferred compensation based on the average of the high and low prices 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). Stock option compensation, including SAR, is based on the grant-date fair value of the options and is recognized over the vesting period.

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

	Three Months Ended September 30,		NineMonths Ended September 30,	
	2009(1)	2008	2009(1)	2008
	(In millions)			
Stock Option Expense	$ 0.3	$ -	$ 0.4	$ 0.2
Restricted Stock Expense	2.5	1.5	8.1	4.3
Total Stock-Based Compensation Expense	$ 2.8	$ 1.5	$ 8.5	$ 4.5

(1) In 2009, the Company issued stock-based awards that vested in less than six months from grant date in lieu of annual and quarter cash bonuses.

General and Administrative Expenses

The Company recognizes and classifies general and administrative expenses as incurred and as required by accounting guidelines, including infrequent and/or non-cash items. The table below identifies the non-cash and/or unusual items included in general and administrative expenses:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Stock-based compensation	$ 2.8	$ 1.5	$ 8.5	$ 4.5
Non-cash charitable contribution(1)	0.9	-	0.9	-
Bad debt expnse	-	-	0.3	(0.2)
	$ 3.7	$ 1.5	$ 9.7	$ 4.3

(1) During the third quarter of 2009, the Company pledged $1.0 million to the University of Texas at Arlington, of which it paid $0.1 million in cash. The Company recognized the entire pledge in the period incurred.

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.

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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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Cokinos Natural Gas Company	10 %	11 %	10 %	11 %
Crosstex Energy Services, Ltd.	-	10 %	-	11 %
DTE Energy Trading, Inc.	48 %	37 %	53 %	36 %

Earnings Per Share

Supplemental earnings per share information is provided below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Net income (loss)	$(4,795)	$65,715	$(136,357)	$47,639
Average common shares outstanding				
Weighted average common shares outstanding(1)	31,053	30,531	30,980	30,005
Stock options and warrants	-	442	-	447
Diluted weighted average common shares outstanding	31,053	30,973	30,980	30,452
Net income (loss) per common share(1)				
Basic	$(0.15)	$2.15	$(4.40)	$1.59
Diluted	$(0.15)	$2.12	$(4.40)	$1.56

(1) In January 2009, the Company adopted and retroactively applied new accounting guidelines associated with restricted stock and participating securities. The Company 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 shares in the calculation of dilutive shares for the three and nine months ended September 30, 2009 due to the net loss reported in the periods. Shares of common stock subject to issuance pursuant to the conversion features of the 4.375% Convertible Senior Notes due 2028 (the "Convertible Senior Notes") did not have an effect on the calculation of dilutive shares for the three and nine months ended September 30, 2009 and 2008.

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Asset Retirement Obligation

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

	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
	(In thousands)	
Asset retirement obligation at beginning of year	$ 6,503	$ 5,869
Liabilities incurred	239	1,004
Liabilities settled	(12)	(177)
Accretion expense	225	154
Revisions to previous estimates	2,947	(347)
Asset retirement obligation at end of year	$ 9,902	$ 6,503

The $2.9 million revision to previous estimates relates primarily to location clean up costs in the Barnett Shale area.

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 new accounting guidelines related to convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. Under the accounting guidelines, issuers of convertible debt are required to 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. The new accounting guidelines require retrospective application to the terms of instruments as they existed for periods presented. The Company retrospectively applied the accounting guidelines to the Convertible Senior Notes. The Company valued the conversion premium of the convertible debt at $64.2 million and accordingly restated its balance sheet as of December 31, 2008 for the carrying value of debt and equity and restated its results of operations for interest expense, capitalized interest, and income taxes for the year ended December 31, 2008. See 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 new accounting guidelines related to restricted stock and participating securities. Under the new accounting treatment, 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. These new guidelines require retroactive application for all periods presented. The Company determined that its restricted shares of common stock are participating securities and applied the new accounting treatment retrospectively to all periods presented. See Note 2 for a discussion of the restatement related to the adoption of this accounting pronouncement.

In March 2008, new guidance for derivative disclosures was issued and requires 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, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The Company adopted these requirements effective January 1, 2009 and they did not have a significant effect on the Company's consolidated financial position, results of operations or cash flows.

In April 2009, additional guidance for estimating fair value was finalized. The Company adopted this pronouncement effective June 30, 2009, and it had no material impact on the Company's consolidated financial statements.

In April 2009, guidance on the recognition of other-than-temporary impairments of investments in debt securities was issued and provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. The Company adopted the requirements of this pronouncement effective June 30, 2009, and it had no material impact on the Company's consolidated financial statements.

In April 2009, accounting rules were amended to require disclosure about fair value of financial instruments in interim reporting periods, as well as in annual financial statements. The Company adopted the requirements of this pronouncement effective June 30, 2009, and included the additional disclosures in the Company's Notes to Consolidated Financial Statements.

In May 2009, general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued were established to set 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 the Company's Notes to Consolidated Financial Statements.

In June 2009, the Financial Accounting Standards Board established the 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. The Company adopted the Codification effective September 30, 2009 and updated its disclosure references accordingly.

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. Changes in reserve amounts could significantly impact depletion expense, ceiling test impairment and recoverability of deferred tax assets. For more information, see "Use of Estimates," discussed above.

2. ADJUSTMENT FOR IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENT

On January 1, 2009, the Company adopted new accounting guidelines related to convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. Under these guidelines, issuers of convertible debt are required to 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. The new accounting treatment requires retrospective application to the terms of instruments as they existed for periods presented. The retrospective application of this accounting pronouncement affects the Company's results of operations for the periods during December 31, 2008 as it relates to the Company's Convertible Senior Notes.

On January 1, 2009, the Company adopted and retroactively applied new accounting guidelines related to restricted stock and participating securities. Under the new accounting treatment, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and will be included in the computation of both basic and diluted earnings per share. The Company determined that its restricted shares of common stock are participating securities and applied this accounting treatment retroactively to all periods presented.

The following table sets forth the effect of the retrospective application of the new accounting guidelines for convertible debt and unvested share-based payment awards on certain previously reported items.

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Consolidated Statement of Income:

	For the three months ended September 30, 2008		For the nine months ended September 30, 2008	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted
	(In thousands, except per share amounts)			
Interest expense	5,297	8,491	16,694	20,950
Capitalized interest	3,866	6,315	11,211	14,479
Income tax expense	35,461	35,200	26,402	26,056
Net income (loss)	66,199	65,715	48,281	47,639
Basic Income Per Share	$ 2.18	$ 2.15	$ 1.62	$ 1.59
Diluted Income Per Share	$ 2.14	$ 2.12	$ 1.59	$ 1.56
Weighted Average Common Shares Oustanding				
Basic	30,424	30,531	29,842	30,005
Diluted	30,973	30,973	30,452	30,452

3. LONG-TERM DEBT

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

	September 30, 2009	December 31, 2008
	(In thousands)	
Convertible Senior Notes	$ 373,750	$ 373,750
Unamortized discount for Convertible Senior Notes	(48,197)	(57,269)
Senior Secured Revolving Credit Facility	216,000	159,000
Other	308	480
	541,861	475,961
Current maturities	(148)	(173)
	$ 541,713	$ 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

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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 (defined below), the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes.

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

In accordance with the accounting guidelines for convertible debt, 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 certain of the Company’s subsidiaries: CCBM, Inc.; CLLR, Inc.; Carrizo (Marcellus), LLC; Carrizo Marcellus Holdings, Inc.; Chama Pipeline Holding, LLC and Hondo Pipeline Inc.

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 the accounting guidelines related to convertible debt that may be settled in cash (including partial cash settlement) upon conversion: $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 2.25% to 3.25% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted daily LIBO rate plus a margin between 2.25% to 3.25% (depending on the then-current level of borrowing base usage). At September 30, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.3%.

The Company is subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.00 to 1.00; 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 September 30, 2009, the Company had $216.0 million of borrowings outstanding under the Senior Credit Facility and the amount available for borrowings was $68.4 million.

4. INVESTMENTS

Investments consisted of the following at September 30, 2009 and December 31, 2008:

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

Pinnacle Gas Resources, Inc.	$	1,054	$	751
Oxane Materials, Inc.		2,523		2,523
	$	3,577	$	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 September 30, 2009, the Company owned 2,510,324 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 September 30, 2009, the Company reported the fair value of the stock at $1.1 million (based on the closing price of Pinnacle's common stock on September 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 income tax expense (benefit) for the indicated periods was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Amount computed using the statutory rate	$ (3,076)	$ 35,320	$ (73,894)	$ 25,793
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	(109)	21	(2,618)	399
Other(1)	(809)	(141)	1,743	(136)
Total income tax expense (benefit)	$ (3,994)	$ 35,200	$ (74,769)	$ 26,056

(1) Includes a tax benefit of $0.9 million and a tax expense of $1.7 million for the three and nine months ended September 30, 2009, respectively, related to prior period state income taxes that were not recorded. The Company has concluded these amounts are not material to the current or prior financial statements.

At September 30, 2009, the Company had a net deferred tax asset of $30.2 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.

The Company classifies interest and penalties associated with income taxes as interest expense. At September 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 nine-month periods ended September 30:

	2009	2008
	(In thousands)	
Shares outstanding at January 1	30,860	28,009
Equity offering	-	2,588
Restricted stock issued, net of forfeitures	179	98
Employee stock options exercised	5	58
Common stock issued for oil and gas properties	10	-
Common stock repurchased and retired for tax withholding obligation	-	(6)
Shares outstanding at September 30	31,054	30,747

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 $135.1 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 three counterparties and netting agreements are in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price 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 nine months ended September 30, 2009 and 2008, the Company recorded the following related to its derivatives:

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	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
	(In millions)			
Realized gains (losses):				
Natural gas and oil derivatives	$ 18.7	$ 1.3	$ 64.3	$ (9.0)
Interest rate swaps - Second Lien Debt Outstanding	-	-	-	(1.2)
Loss on interest rate swap settlement related to Second Lien Credit Facility	-	-	-	(3.3)
	18.7	1.3	64.3	(13.5)
Unrealized gains (losses):				
Natural gas and oil derivatives	(20.7)	76.4	(38.5)	10.4
Interest rate swaps	-	-	-	2.8
	(20.7)	76.4	(38.5)	13.2
Net gain (loss) on derivatives	$ (2.0)	$ 77.7	$ 25.8	$ (0.3)

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

	Natural Gas Swaps		Natural Gas Collars		
Quarter	MMBtus(1)	Average Fixed Price(2)	MMBtus(1)	Average Floor Price(2)	Average Ceiling Price(2)
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
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
	910,000	5.88	455,000	9.55	11.55

First Quarter 2012					
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	-	-	-
	24,655,000		10,052,000		

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(1) During 2009, the Company entered into (i) 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 (ii) 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(2)
Fourth Quarter 2009	1,530,000	2.39
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	900,000	5.90
Second Quarter 2011	910,000	5.90
Third Quarter 2011	920,000	5.90
Fourth Quarter 2011	920,000	5.90
First Quarter 2012	455,000	6.80
Second Quarter 2012	455,000	6.80

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

At September 30, 2009, approximately 53% of the Company's open natural gas hedged volumes were with Credit Suisse, and the remaining 47% were with Shell Energy North America (US), L.P. In addition, the Company entered into put options for 2,745,000 MMBtus with Calyon Credit Agricole CIB covering certain production from October through December 2009 and January through December 2011.

The fair value of the outstanding derivatives at September 30, 2009 and December 31, 2008 was a net asset of $0.2 million and $38.7 million, respectively.

9. FAIR VALUE MEASUREMENTS

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

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

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

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

The following table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 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.	$ 1,054	$ -	$ -	$ 1,054
Oil and natural gas derivatives	-	6,062	-	6,062
Liabilities:				
Oil and natural gas derivatives	-	(5,915)	-	(5,915)
Total	$ 1,054	$ 147	$ -	$ 1,201

Oil and natural gas derivatives are valued by 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.

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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 September 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 Convertible Senior Notes at September 30, 2009 was estimated at approximately $303.7 million.

10. SUBSEQUENT EVENTS

In October 2009, the Company sold its Mansfield pipeline and gathering system in the Barnett Shale play for approximately $34.7 million, including a working capital adjustment of approximately $1.2 million. The net proceeds were used to reduce the debt outstanding under the Senior Credit Facility.

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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 in this quarterly report.

General Overview

Our third quarter 2009 included revenues of $23.8 million and production of 8.2 Bcfe. The key drivers to our results for the three and nine months ended September 30, 2009 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the nine months ended September 30, 2009, we drilled (1) 37 gross wells (26.4 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 September 30, 2009 we had an inventory of 42 gross wells (31.6 net) in the Barnett Shale that have been drilled and are waiting on hydraulic fracturing, completion or hook-up to sales.

Production. Our third quarter 2009 production of 8.2 Bcfe, or 89.2 MMcfe/d was a 37% increase from the third quarter 2008 production of 6.0 Bcfe, or 65.0 MMcfe/d. The third quarter 2009 production increased 4% from the second quarter 2009 production of 7.9 Bcfe primarily due to new production.

Commodity prices. Our average natural gas price during the third quarter of 2009 was $2.60 per Mcf (excluding the impact of our hedges), $6.17 per Mcf, or 70%, lower than the price in the third quarter of 2008 and $0.47 per Mcf, or 15%, lower than the price in the second 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. In October 2009, we sold certain of our pipeline gathering systems in the Barnett Shale for approximately $34.7 million. The net proceeds from the sale of this pipeline system were used to reduce the debt outstanding under the Senior Credit Facility. See "Recent Events – Mansfield Pipeline Sale."

Recent Events

Camp Hill Field Operational Update

Development activities continued at our Camp Hill Field during the course of the third quarter of 2009. Consistent with our prior disclosure in our Annual Report on Form 10-K/A for the year-ended December 31, 2008, we have completed the refurbishment of one steam generator for use in the field and continue to refurbish two others. Over the last three months, eight injection and seven production wells drilled in 2008 were completed and eight new steam lines were laid to injection wells.

Steam injection from one generator recommenced in the Camp Hill Field on September 14, 2009, with steam flowing into six newly completed injection wells in an area of the field that has never been previously steam flooded, as well as in seven existing patterns that were steamed on a pilot basis in the latter half of 2008. We expect to complete and connect 11 additional injector wells to steam lines during the fourth quarter of 2009. Heavy oil production from the Camp Hill Field for the month of August was 1,405 barrels, and we expect October production to be approximately 1,800 barrels, with additional improvement in production rates expected as the reservoir heats up in response to the steaming.

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Mansfield Pipeline Sale

We sold our Mansfield pipeline and gathering system in the Barnett Shale play to Delphi Midstream Partners, LLC ("Delphi") for net proceeds of $34.7 million, including a working capital adjustment of approximately $1.2 million. Net proceeds from the sale were used to reduce the debt outstanding under the Senior Credit Facility. We constructed the Mansfield pipeline system to gather and transport natural gas from our Southeast Tarrant County operating area. The pipeline consists of 19 miles of 6, 8 and 10 inch diameter pipe with a current maximum takeaway capacity of 70 MMcf/day. The system also includes an associated compression/dehydration facility that was included in the transaction. Over the 30 days preceding the date of sale, the pipeline transported an average of 55 MMcf/day. We have also entered into an agreement to continue to operate the Mansfield pipeline system on Delphi's behalf.

Northeast Pennsylvania Alliance

We have entered into an alliance with Delphi through which the parties have agreed to cooperate in solving gathering and mid-stream pipeline related issues for our Marcellus production in certain Northeast Pennsylvania counties including, among others, Bradford, Susquehanna, Tioga, Wayne and Wyoming counties. We have granted Delphi a right of first offer with respect to Northeast Pennsylvania if we seek to find a third party to develop and construct a gathering or intrastate pipeline and a right of first refusal with respect to Wyoming County if a third party other than Delphi makes a development proposal. This alliance will terminate on the earlier to occur of October 19, 2014 or the date that Delphi invests $100 million to develop and construct pipelines under the alliance.

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 nine months of 2009, excluding capitalized interest and overhead, we spent approximately $105 million of capital expenditures on our drilling program and $21.1 million on leasehold and seismic costs. Based upon our current outlook for operational performance in the remainder of 2009, we have revised our 2009 capital and exploration plan to approximately $155.0 million, which we currently expect to fund through cash generated from our operations, cash available under the Senior Credit Facility or from sales of assets, including our Mansfield pipeline system. 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 exploration and development activities in 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 (2.4 net) vertical wells in the Virginia and West Virginia parts of the Marcellus Shale to test the prospectivity of that area. In the later part of 2009, we started drilling two wells in Pennsylvania and plan to drill a third well pending further seismic data interpretation.

- We expect to continue to hedge production to limit our exposure to reductions in natural gas prices. At September 30, 2009, we had hedged approximately 34,707,000 MMBtus of natural gas production through 2012.

Results of Operations

Three Months Ended September 30, 2009,

Compared to the Three Months Ended September 30, 2008

Revenues from oil and natural gas production for the three months ended September 30, 2009 decreased 57% to $23.6 million from $55.4 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 September 30, 2009 increased 39% to 7.9 Bcf from 5.7 Bcf for the same period in 2008. Average natural gas prices, excluding the impact of our cash-settled derivatives comprised of a $18.7 million and a $1.6 million gain for the quarters ended September 30, 2009 and 2008, respectively, decreased to $2.60 per Mcf in the third quarter of 2009 from $8.78 per Mcf in the same period in 2008. Average oil prices, excluding the impact of our settled derivative loss of $0.3 million for the quarter ended September 30, 2008, decreased 45% to $66.25 per barrel from $120.09 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.

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

	Three Months Ended September 30,		2009 Period Compared to 2008 Period	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	44	43	1	1 %
Natural gas (MMcf)	7,947	5,724	2,223	39 %
Average sales prices				
Oil and condensate (per Bbl)	$ 66.25	$ 120.09	$ (53.84)	(45)%
Natural gas (per Mcf)	2.60	8.78	(6.18)	(70)%
Operating revenues (In thousands)				
Oil and condensate	$ 2,886	$ 5,194	$ (2,308)	(44)%
Natural gas	20,698	50,233	(29,535)	(59)%
Other(1)	263	3,100	(2,837)	(92)%
Total Operating Revenues	$ 23,847	$ 58,527	$ (34,680)	(59)%

(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 September 30, 2009 decreased 50% to $5.2 million from $10.4 million for the same period in 2008, primarily as a result of decreased transportation and other product costs of $2.9 million mainly attributable to a change in pricing and transportation contractual arrangements, a $1.3 million decrease in severance taxes associated with decreased revenues and a decrease of $1.0 million due to a general decline in oil field services.

Depreciation, depletion and amortization (DD&A) expense for the three months ended September 30, 2009 decreased 10% to $12.5 million ($1.53 per Mcfe) from $13.9 million ($2.33 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 of 2008 and the first quarter of 2009, partially offset by increased production.

General and administrative expense increased to $7.6 million for the three months ended September 30, 2009 from $5.8 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 compensation awards. In addition, during the third quarter of 2009, we made the first $100,000 cash payment of a $1.0 million pledge to establish a Carrizo Oil & Gas, Inc. endowed scholarship fund at the University of Texas at Arlington (“UTA”), a university which is located within the area of our significant operations in the Barnett Shale. We have the option to pay the remaining portion of this pledge in shares of our common stock.

The net loss on derivatives of $2.0 million in the third quarter of 2009 was comprised of $20.7 million of unrealized mark-to-market loss on derivatives and $18.7 million of realized gain on net settled oil and natural gas derivatives. The net gain on derivatives of $77.7 million in the third quarter of 2008 was comprised of a $76.4 million net unrealized mark-to-market gain on derivatives and a $1.3 million realized gain on cash-settled derivatives.

Interest expense and capitalized interest for the three months ended September 30, 2009 were $9.9 million and $5.0 million, respectively, as compared to $8.5 million and $6.3 million for the same period in 2008 primarily attributable to an increase of approximately $2.0 million in cash interest expense associated with higher debt levels on the Senior Credit Facility.

Nine Months Ended September 30, 2009,
Compared to the Nine Months Ended September 30, 2008

Revenues from oil and natural gas production for the nine months ended September 30, 2009 decreased 54% to $80.2 million from $173.7 million for the same period in 2008 due to declining oil and natural gas prices. Production volumes for natural gas for the nine months ended September 30, 2009 increased 34% to 23.6 Bcf from 17.6 Bcf for the same period in 2008. Average natural gas prices,

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excluding the impact of our settled derivatives gain of $61.5 million and loss of $7.9 million for the nine months ended September 30, 2009 and 2008, respectively, decreased to $3.10 per Mcf for the nine months ended September 30, 2009 from $8.98 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 $1.1 million for the nine months ended September 30, 2009 and 2008, respectively, decreased 52% to $54.08 per barrel from $112.19 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 nine months ended September 30, 2009 and 2008:

	Nine Months Ended September 30,		2009 Period Compared to 2008 Period	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	129	144	(15)	11 %
Natural gas (MMcf)	23,589	17,555	6,033	34 %
Average sales prices				
Oil and condensate (per Bbl)	$ 54.08	$ 112.19	$ (58.11)	(52)%
Natural gas (per Mcf)	3.10	8.98	(5.88)	(65)%
Operating revenues (In thousands)				
Oil and condensate	$ 6,952	$ 16,131	$ (9,179)	(57)%
Natural gas	73,235	157,564	(84,329)	(54)%
Other(1)	1,034	5,780	(4,746)	(82)%
Total Operating Revenues	$ 81,221	$ 179,475	$ (98,254)	(55)%

(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 for the nine months ended September 30, 2009 decreased 19% to $22.8 million from $28.0 million for the same period in 2008, primarily as a result of decreased severance tax expense of $5.1 million associated with refunds from certain wells that qualified for a tight-gas sands tax credit for prior production periods and decreased revenues and increased workover expenses of $0.4 million, partially offset by $0.8 million in decreased transportation costs mainly attributable to a change in the pricing and transportation contractual arrangements beginning in the third quarter of 2009.

Depreciation, depletion and amortization (DD&A) expense for the nine months ended September 30, 2009 decreased 4% to $40.0 million ($1.64 per Mcfe) from $41.9 million ($2.27 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 ($138.0 million after tax).

General and administrative expense for the nine months ended September 30, 2009 increased by $4.0 million to $21.9 million from $17.9 million for the corresponding period in 2008 primarily as a result of an increase in non-cash, stock-based compensation of $4.0 million as a result of additional deferred compensation awards. In addition, we made the first $100,000 cash payment of a $1.0 million pledge to establish a Carrizo Oil & Gas, Inc. endowed scholarship fund at UTA, a university which is located within the area of our significant operations in the Barnett Shale.

The net gain on derivatives of $25.8 million in the first nine months of 2009 was comprised of a $64.3 million realized gain on cash-settled oil and natural gas derivatives and a $38.5 million of net unrealized mark-to-market loss on derivatives. The net loss on derivatives of $0.4 million in the first nine months of 2008 was comprised of $10.2 million of realized loss on net settled derivatives,

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$13.1 million of net unrealized mark-to-market gain 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 nine months ended September 30, 2009 were $28.6 million and $15.1 million, respectively, as compared to $21.0 million and $14.5 million for the same period in 2008 primarily attributable to an increase of approximately $5.1 million in non-cash interest expense associated with the amortization of the debt discount on the Senior Convertible Notes 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 (excluding capitalized overhead and interest) of approximately $155 million including $130 million for our drilling program of which $125 million is designated for Barnett Shale drilling and development, and $10 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, the possible selective sale or monetization of non-core assets and available borrowings under the Senior Credit Facility. We may be required to reduce or defer part of our 2009 capital expenditures program if we are unable to obtain sufficient financing from these sources.

Sources and Uses of Cash. During the nine months ended September 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 sources of future liquidity include the following:

- Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oil and gas field services. We hedge a portion of our production to reduce the downside risk of declining natural gas and oil prices.

- Borrowings under the Senior Credit Facility. At November 2, 2009, $89.0 million was available for borrowing under the Senior Credit Facility. The next redetermination of our borrowing base is currently scheduled to occur in November 2009. A negative adjustment could occur if the estimate of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination which occurred earlier this year.

- 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, in October 2009, we completed the sale of our Mansfield pipelines and gathering system located in the Barnett Shale play for approximately $34.7 million, including a working capital adjustment of approximately $1.2 million. The net proceeds from the sale were used to reduce the debt outstanding under the Senior Credit Facility. We may consider the sale of additional non-core assets including the possible sale of our interest in the Huntington Field located in the North Sea, provided that we can obtain an acceptable price.

- 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.

- 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 in the Marcellus Shale, the Barnett Shale and other plays including those through which such third parties fund a portion of our land acquisition and 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.

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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 $130 million for drilling, and approximately $25 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 $5 million for our share of the remaining Marcellus 2009 joint venture capital expenditure program, primarily to drill wells in Virginia and West Virginia.

Overview of Cash Flow Activities. Cash flows provided by operating activities were $107.8 million and $126.4 million for the nine months ended September 30, 2009 and 2008, respectively. The decrease was primarily due to declining natural gas prices. 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 $162.5 million and $459.3 million for the nine months ended September 30, 2009 and 2008, respectively, and related primarily to oil and gas property expenditures.

Net cash provided by financing activities for the nine months ended September 30, 2009 was $53.1 million and related primarily to net borrowings under the Senior Credit Facility. Net cash provided by financing activities for the nine months ended September 30, 2008 was $333.9 million and related primarily to net proceeds of $135.1 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 $214.0 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 levels reached in July 2008. In an effort to mitigate declining prices, we hedge a portion of our production and, as of September 30, 2009, we had hedged approximately 6,256,000 MMBtus (74% of our estimated production from October through December 2009) of our 2009 natural gas production at a weighted average floor or swap price of $6.24 per MMBtu relative to WAHA and HSC prices. $89.0 million was available to us at November 2, 2009 under the Senior Credit Facility.

If cash from operations, the sale of material non-core assets, including our Mansfield pipeline system, 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, including those described above. 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 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. Effective October 19, 2009, these lease agreements were conveyed along with entities owning the Mansfield pipeline system to Delphi. See “Recent Events – Mansfield Pipeline Sale,”

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 November 2, 2009, we had $195.4 million of borrowings outstanding and a borrowing base availability of $89.0 million. The next borrowing base redetermination is scheduled for November 2009.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing natural gas and oil prices. The 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 new accounting guidelines related to convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. Under the accounting guidelines, issuers of convertible debt are required to 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. The new accounting guidelines require 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, 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 new accounting guidelines related to restricted stock and participating securities. Under the new accounting treatment, 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. These new guidelines require retroactive application for all periods presented. We determined that our restricted shares of common stock are participating securities and applied the new accounting treatment 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, new guidance for derivative disclosure was issued and requires 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 and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We adopted this pronouncement effective January 1, 2009 and they did not have a significant effect on our consolidated financial position, results of operations or cash flows.

In April 2009, additional guidance for estimating fair value was finalized. We adopted this pronouncement effective June 30, 2009, and it had no material impact on our consolidated financial statements.

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In April 2009, guidance on the recognition of other-than-temporary impairments of investments in debt securities was issued and provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. 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, accounting rules were amended to require disclosure about fair value of financial instruments in interim reporting periods, as well as in annual financial statements. 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, general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued were established to set 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.

In June 2009, the Financial Accounting Standards Board established the 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. We adopted the Codification effective September 30, 2009 and updated disclosures.

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. For more information, please read Part II, Item 1A. "Risk Factors As a result of an ongoing SEC staff review, we may be required to reclassify or write-off reserves."

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 $4.1 million and $5.2 million for the nine months ended September 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

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and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the three months ended September 30, 2009 and 2008 was $1.50 and $2.24, 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 September 30, 2009 of $5.1 million was based upon average realized oil, natural gas liquids and natural gas prices of $66.03 per Bbl, $31.69 per Bbl and $3.26 per Mcf, respectively, or a volume weighted average price of $26.28 per BOE. This cushion, however, would have been zero at such date at an estimated volume weighted average price of $26.12 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 September 30, 2009 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase in commodity prices at September 30, 2009 would have increased the Full Cost Ceiling test cushion by approximately $85.9 million and a 10% decrease in commodity prices would have resulted in a $80.4 million ceiling test impairment. The aforementioned price sensitivity is as of September 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, were 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. Additionally, a removal of nonproducing reserves could significantly affect this depletion rate as well as increase the chance of a non-cash ceiling test impairment and the realizability of the net deferred tax asset. Please read Part II, Item 1A. “Risk

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Factors As a result of an ongoing SEC staff review, we may be required to reclassify or write-off reserves" and " Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change 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 accounting guidelines 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 our Annual Report on Form 10-K/A for the year ended December 31, 2008.

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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Oil positions settled (Bbls)	-	18,400	5,900	45,700
Natural gas positions settled	6,256,000	3,312,000	19,934,000	11,026,000

(MMBtus)				
Realized gain/(loss) ($ millions) (1)	$ 18.7	$ 1.3	$ 64.3	$ (9.0)
Unrealized gain/(loss) ($ millions) (1)	$ (20.7)	$ 76.4	$ (38.5)	$ 10.4

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

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

	Natural Gas Swaps		Natural Gas Collars		
Quarter	MMBtus(1)	Average Fixed Price(2)	MMBtus(1)	Average Floor Price(2)	Average Ceiling Price(2)
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
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	-	-	-
	24,655,000		10,052,000		

(1) During 2009, the Company entered into (i) 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 (ii) 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:

Quarter	MMBtus	Put Price(2)
Fourth Quarter 2009	1,530,000	2.39
	455,000	3.74

Second Quarter 2010		
Third Quarter 2010	920,000	4.31
Fourth Quarter 2010	1,196,000	4.61
First Quarter 2011	900,000	5.90
Second Quarter 2011	910,000	5.90
Third Quarter 2011	920,000	5.90
Fourth Quarter 2011	920,000	5.90
First Quarter 2012	455,000	6.80
Second Quarter 2012	455,000	6.80

(1) Based on Houston Ship Channel (“HSC”) and WAHA spot prices.

At September 30, 2009, approximately 53% of the Company’s open natural gas hedged volumes were with Credit Suisse, and the remaining 47% were with Shell Energy North America (US), L.P. In addition, the Company entered into put options for 2,745,000 MMBtus with Calyon Credit Agricole CIB covering certain production from October through December 2009 and January through December 2011.

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 the Company's or management's intentions, beliefs, expectations, hopes, projections, assessment of risks, estimations, plans or predictions for the future, including our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, 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 reserves development and production, borrowing base redeterminations under the Senior Credit Facility, fair value of our investment in Pinnacle, the results of the SEC's staff's review of our filings, the impact of new SEC rules regarding oil and gas reserves, the results of the alliance with Delphi and all and any other statements regarding future operations, financial results, business plans and cash needs, and other statements that are not historical facts are forward looking statements. When used in this document, the words "anticipate," "estimate," "expect," "may," "project," "believe" and similar expressions are intended to be among the statements that identify forwarc looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to our dependence on 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, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, outcome of the SEC's staff's review of our filings, interpretations and impact of new SEC rules regarding oil and gas reserves, activities and approvals of our partners and parties with whom we have alliances, technological changes, significant capital requirements, 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, including proposed legislation and adverse regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, weather, availability of financing, actions by lenders, ability to obtain permits, the results of audits and assessments, and other factors detailed in the "Risk Factors" and other sections of our Annual Report on Form 10-K/A for the year ended December 31, 2008 and in this and our other filings with the SEC. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

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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 our Annual Report on Form 10-K/A for the year ended December 31, 2008. 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 15d-15(f) in connection with further review of our ceiling test impairments as of December 31, 2008 and March 31, 2009. We have implemented a number of initiatives, as discussed below, designed to remediate the material weakness. Based upon these changes and the evaluation of disclosure controls and procedures, our Chief Executive Officer and Chief Financial Officer have concluded that the controls were effective as of September 30, 2009 to provide reasonable assurance that the information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer , as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls. As described in more detail in our Annual Report on Form 10-K/A for the year ended December 31, 2008, our Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2009 and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, we identified material weaknesses in our internal control over financial reporting and described a number of planned procedures designed to remediate these weaknesses. The following initiatives were effected in the quarter ended September 30, 2009: (1) delegated preparation of certain critical workpapers to our financial reporting staff allowing our financial reporting manager to perform more qualitative review analysis, (2) removed the computational deficiencies from our standard ceiling test workpaper format, (3) improved workpaper formats and implement comparative analysis within these critical workpapers to enhance qualitative analysis and (4) prepared 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.

This Item 4 should be read in conjunction with Part II, Item 9A in our Annual Report on Form 10-K/A for the year ended December 31, 2008, Part II, Item 4 in our Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2009 and Part II, Item 4 in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009.

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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.

The global financial and credit crisis may have impacts on our liquidity and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have a material impact on our liquidity and our financial condition, and we may ultimately face major challenges if conditions in the financial markets do not continue to improve from their lows in early 2009. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on our natural gas and oil derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to further reductions in the demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial crisis cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial condition.

Natural gas and oil prices are highly volatile and have declined significantly since mid-2008, and lower prices will negatively affect our financial condition, planned capital expenditures and results of operations.

Since July 2008, publicly quoted spot natural gas and oil prices have declined significantly from the record levels reached at that time. In the past, some oil and gas companies have reduced or curtailed production to mitigate the impact of low natural gas and oil prices. We have made similar decisions on selected properties during the last year and may decide to curtail additional production as a result of a decrease in prices in the future. The decrease in natural gas prices has had a significant impact on our financial condition, planned capital expenditures and results of operations. Further volatility in natural gas and oil prices or a prolonged period of low natural gas and oil prices may materially adversely affect our financial condition, liquidity (including our borrowing capacity under our senior credit facility), ability to finance planned capital expenditures and results of operations.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of natural gas and oil. Historically, the markets for natural gas and oil prices have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict future natural gas and oil price movements with certainty. Prices for natural gas and oil are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond our control. These factors include:

• the level of consumer product demand;

• overall economic conditions;

• weather conditions;

• domestic and foreign governmental relations, regulations and taxes;

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• the price and availability of alternative fuels;

• political conditions;

• the level and price of foreign imports of oil and liquefied natural gas; and

• the ability of the members of the Organization of Petroleum Exporting Countries to agree upon and maintain production constraints and oil price controls.

As a result of an ongoing SEC staff review, we may be required to reclassify or write-off reserves.

We own interests in approximately 2,630 gross acres in the Camp Hill Field in Anderson County, Texas, for which we reported approximately 8.2 MMBbls of proved reserves, including 5.0 MMBbls of proved undeveloped reserves (which represents approximately 6% of our total proved reserves) as of December 31, 2008. In connection with an ongoing review by the SEC's staff of our Annual Report on Form 10-K for the year ended December 31, 2008, the staff has raised various issues regarding the classification of some of these reserves as proved. In late 2008, the SEC adopted new rules regarding the classification of reserves that will become effective with our reserve report as of year-end of 2009, which, among other things, generally require proved undeveloped reserves to be developed within five years, unless specific circumstances justify a longer time.

As a result of various factors, including these new rules and our discussions with the SEC's staff regarding their applicability to the Camp Hill Field, we may be required under applicable SEC rules to reclassify as unproved substantially all of our proved undeveloped reserves in the Camp Hill Field at year-end 2009 because these reserves will not be developed within the next five years. We may also be required under applicable SEC rules to write-off or reclassify to proved undeveloped, a portion of our proved developed reserves. The removal or reclassification of these reserves may be effective as of December 31, 2009, but could also involve removal of reserves in prior periods. A downward revision to our proved reserves in prior periods would likely result in amendments to our previously filed reports with the SEC to reflect a restatement of our financial statements, including a non-cash reduction in our historic net income. As an illustration, if we had removed all 8.2 MMBbls of our proved reserves in the Camp Hill Field, including both proved developed and proved undeveloped reserves, effective as of December 31, 2008, it would have resulted in a restatement of our financial statements to reflect an additional pre-tax non-cash ceiling test impairment of approximately $70.8 million.

As of September 30, 2009, using the unweighted arithmetic average of the first day of the month price for each month from January through November 2009 (similar to the pricing methodology that will be required under the new SEC rules discussed below), the PV-10 value of the proved reserves in Camp Hill was approximately $150.9 million (including a PV-10 value of approximately $58.7 million attributable to the proved undeveloped reserves). PV-10 is the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

We have actively engaged with and responded to the SEC throughout this review process. The staff continues to request, and we continue to provide, information regarding our reserves, including our proved developed nonproducing reserves and the economics of our proved reserves in the Camp Hill Field. However, we cannot predict the timing or final result of the staff's review, and there can be no assurance that our determination following such review will not result in material changes to the classification of our reserves in the Camp Hill Field, and other adverse effects on our historic financial results.

Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.

There are uncertainties inherent in estimating natural gas and oil reserves and their estimated value, including many factors beyond the control of the producer. The reserve data included in our filings with the SEC represent only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results.

Accordingly, reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, there recently has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. In late

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2008, the SEC adopted new rules regarding the classification of reserves. However, the interpretation of these rules and their applicability in different situations remains unclear in many respects. Changing interpretations of the classification standards or disagreements with our interpretations could cause us to write-down reserves. Please read " As a result of an ongoing SEC staff review, we may be required to reclassify or write-off reserves." In addition, the new SEC rules regarding classification of reserves require that in calculating economic producibility of proved reserves, a company must generally use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Natural gas prices on the first day of each month in 2009 have been historically low and, as a result, when the applying the new rules, we may be required to reclassify certain proved reserves as of year-end 2009.

As of December 31, 2008, approximately 58.6% of our proved reserves were proved undeveloped and proved nonproducing. Moreover, some of the producing wells included in our reserve reports as of December 31, 2008 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

The discounted future net cash flows included our filings with the SEC are not necessarily the same as the current market value of our estimated natural gas and oil reserves. As required by the SEC, the estimated discounted future net cash flows from proved reserves are currently based on prices and costs as of the date of the estimate and soon will be based on monthly averages. Actual future net cash flows also will be affected by factors such as:

• the actual prices we receive for natural gas and oil;

• our actual operating costs in producing natural gas and oil;

• the amount and timing of actual production;

• supply and demand for natural gas and oil;

• increases or decreases in consumption of natural gas and oil; and

• changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

We participate in oil and natural gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of the other working interest owners such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the current economic downturn, the credit crisis and the volatility in natural gas and oil prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Many of our project partners are experiencing liquidity and cash flow problems. These problems may lead our partners to attempt to delay the pace of drilling or project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases,, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition.

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Our senior credit facility contains operating restrictions and financial covenants, and we may have difficulty obtaining additional credit.

Over the past few years, increases in commodity prices and our successful drilling program led to increased proved reserve amounts, and the resulting increase in our estimated discounted future net revenue allowed us to increase the borrowing base under our senior credit facility. However, as a result of the significant decline in natural gas and oil prices, or other factors, the lenders under our senior credit facility may adjust our borrowing base downward, thereby reducing our borrowing capacity. Our senior credit facility is secured by a pledge of substantially all of our producing natural gas and oil properties and assets, guaranteed by our subsidiaries CCBM, Inc., CLLR, Inc., Hondo Pipeline, Inc., Carrizo (Marcellus) LLC, Carrizo Marcellus Holding Inc. and Chama Pipeline Holding LLC and contains covenants that limit additional borrowings, dividends, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common stock, speculative commodity transactions and other matters. The senior credit facility also requires that specified financial ratios be maintained. Although we currently believe that we can meet all of our financial covenants with the business plan that we have put in place, our 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 we receive 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 contained in our senior credit facility, including the covenants related to working capital, the ratio of EBITDA to debt coverage and the ratio of senior debt to EBITDA. In order to provide a further margin of comfort with regards to these financial covenants, we may seek to further reduce our capital and exploration budget, sell additional non-strategic assets or opportunistically modify or increase our natural gas hedges. There can be no assurance that we 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. We may not be able to refinance our debt or obtain additional financing, particularly in view of the restrictions of our senior credit facility on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the senior credit facility. The restrictions of our senior credit facility and our difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results including:

• our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes may be impaired;

• the covenants in our senior credit facility that limit our ability to borrow additional funds and dispose of assets may affect our flexibility in planning for, and reacting to, changes in business conditions;

• because our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates;

• any additional financing we obtain may be on unfavorable terms;

• we may be required to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;

• a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing; and

• we may become more vulnerable to downturns in our business or the economy.

In addition, under the terms of our senior credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing natural gas and oil prices. The next redetermination of our borrowing base is currently scheduled to occur in November 2009. Although we do not know at this time whether the borrowing base will be adjusted upwards or downwards, a negative adjustment could occur if the estimate of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination which occurred earlier this year. In the event the amount outstanding under our senior credit facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

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We have limited experience drilling wells in the Marcellus Shale and less information regarding reserves and decline rates in the Marcellus Shale than in other areas of our operations. We may face difficulties in securing and operating under authorizations and permits to drill and/or operate our Marcellus Shale wells.

We have limited exploration experience and no development experience in the Marcellus Shale. As of October 21, 2009, we have participated or are participating in the drilling of only seven wells in the Marcellus Shale area. Other operators in the Marcellus Shale area also have limited experience drilling in the area. As a result, we have less information with respect to the ultimate recoverable reserves and the production decline rate in the Marcellus Shale than we have in other areas in which we operate. Moreover, the recent growth in exploration in the Marcellus Shale has drawn intense scrutiny from environmental interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to our operations that may make it difficult or impossible to obtain permits and other needed authorizations to operate or otherwise make operating more costly or difficult than operating elsewhere.

If we are unable to acquire adequate supplies of water for our Marcellus Shale drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our Marcellus Shale drilling operations. Our inability to locate sufficient amounts of water, or dispose of water after drilling, could adversely impact our Marcellus Shale operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Furthermore, new environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may also increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial performance.

We cannot control the activities on properties we do not operate.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interests could reduce our production and revenues or could create liability for us for the operator’s failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards. With respect to properties that we do not operate:

• the operator could refuse to initiate exploration or development projects;

• if we proceed with any of those projects the operator has refused to initiate, we may not receive any funding from the operator with respect to that project;

• the operator may initiate exploration or development projects on a different schedule than we would prefer;

• the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects or participate in a substantial amount of the revenues from those projects; and

• the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploration and development activities.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering

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systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil or natural gas may have several adverse affects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

Historically, we have generally delivered natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Due to the lack of available pipeline capacity in the Barnett Shale, we have recently begun entering into firm transportation agreements in the Barnett Shale, which are more costly to us than the interruptible or short-term transportation agreements.

If production in the Marcellus Shale by oil and has companies continues to expand, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Marcellus Shale may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

We may record ceiling limitation write-downs that would reduce our shareholders’ equity.

We use the full-cost method of accounting for investments in natural gas and oil properties. Accordingly, we capitalize all the direct costs of acquiring, exploring for and developing natural gas and oil properties. Under the full-cost accounting rules, the net capitalized cost of natural gas and oil properties may not exceed a “ceiling limit” that is based on the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or the fair market value of unproved properties. If net capitalized costs of natural gas and oil properties exceed the ceiling limit, we must charge the amount of the excess to operations through depreciation, depletion and amortization expense. This charge is called a “ceiling limitation write-down.” This charge does not impact cash flow from operating activities but does reduce our shareholders’ equity. The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues, as further discussed under “Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.” Once incurred, a write-down of natural gas and oil properties is not reversible at a later date. We recorded non-cash ceiling test limitation write-downs at the end of 2008 and the end of the first quarter of 2009. We could incur additional write-downs in the future, particularly as a result of a decline of natural gas and oil prices or as a write-off of reserves.

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. In addition, various states are also studying or considering various regulatory measures relating to hydraulic fracturing, including a moratorium on drilling in the Marcellus Shale that has been instituted in New York until the completion of a study by state officials regarding the potential environmental impact of Marcellus Shale development. We make

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extensive use of hydraulic fracturing in our shale play operations and any federal, state or local 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.

Enactment of a Pennsylvania severance tax on natural gas could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

As a result of a funding gap in the state budget, the governor of the Commonwealth of Pennsylvania has proposed to its legislature the adoption of a severance tax on the production of natural gas in Pennsylvania. The amount of the proposed tax is 5% of the value of the natural gas at wellhead, plus 4.7 cents per 1,000 cubic feet of natural gas severed. A substantial portion of our Marcellus Shale acreage is located in the Commonwealth of Pennsylvania. If Pennsylvania adopts such a severance tax, it could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

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," in our Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2009 and in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, 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 and March 31, 2009 ceiling test calculations.

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

We implemented initiatives to remediate the material weaknesses in our internal controls. The steps we have taken 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.

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

None.

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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
31.1	—CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	—CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	—CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	—CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURES

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

	Carrizo Oil & Gas, Inc. (Registrant)
Date: November 9, 2009	By: /s/S. P. Johnson, IV President and Chief Executive Officer (Principal Executive Officer)
Date: November 9, 2009	By: /s/Paul F. Boling Chief Financial Officer (Principal Financial and Accounting Officer)