CARRIZO OIL & GAS INC
Form 10-Q
November 09, 2007

**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, 2007**

[ ] 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**<br>(State or other jurisdiction of<br>incorporation or organization) | **76-0415919**<br>(IRS Employer Identification No.) |
| **1000 Louisiana Street, Suite 1500, Houston, TX**<br>(Address of principal executive offices) | **77002**<br>(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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer [ ]     Accelerated filer [X]     Non-accelerated filer [ ]

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 1, 2007, the latest practicable date, was 27,982,089.

**CARRIZO OIL & GAS, INC.**

**FORM 10-Q**
**FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2007**
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**CARRIZO OIL & GAS, INC.**

**CONSOLIDATED BALANCE SHEETS**

| ASSETS | **September 30, 2007** | **December 31, 2006** |
|---|---|---|
| | (Unaudited) | |
| | (In thousands, except per share amount) | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 4,576 | $ 5,408 |
| Accounts receivable, trade (net of allowance for doubtful accounts of $1,395 and $1,639 at September 30, 2007 and December 31, 2006, respectively) | 29,391 | 25,871 |
| Advances to operators | 2,757 | 2,107 |
| Fair value of derivative financial instruments | 2,848 | 5,737 |
| Other current assets | 4,463 | 1,934 |
| Total current assets | 44,035 | 41,057 |
| | | |
| PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $117,398 and $95,136 at September 30, 2007 and December 31, 2006, respectively) | 567,152 | 445,447 |
| DEFERRED FINANCING COSTS, NET | 6,244 | 4,817 |
| INVESTMENT IN PINNACLE GAS RESOURCES, INC. | 11,941 | 2,771 |
| OTHER ASSETS | 640 | 703 |
| TOTAL ASSETS | $ 630,012 | $ 494,795 |
| | | |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| | | |
| CURRENT LIABILITIES: | | |
| Accounts payable, trade | $ 29,069 | $ 32,570 |
| Accrued liabilities | 22,464 | 20,885 |
| Advances for joint operations | 2,063 | 1,100 |
| Current maturities of long-term debt | 2,253 | 1,508 |
| Other current liabilities | 1,027 | 2,008 |
| Total current liabilities | 56,876 | 58,071 |
| | | |
| LONG-TERM DEBT, NET OF CURRENT MATURITIES | 218,813 | 187,250 |
| ASSET RETIREMENT OBLIGATION | 5,370 | 3,625 |
| FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS | 324 | - |
| DEFERRED INCOME TAXES | 43,004 | 32,738 |
| DEFERRED CREDITS | 724 | 837 |
| | | |
| COMMITMENTS AND CONTINGENCIES | - | - |
| | | |
| SHAREHOLDERS' EQUITY: | | |
| Common stock, par value $0.01 (40,000 shares authorized with 27,979 and 25,981 issued and outstanding at September 30, 2007 and December 31, 2006, respectively) | 280 | 260 |

| | | | | |
|---|---|---|---|---|
| Additional paid-in capital | | 246,008 | | 168,469 |
| Retained earnings | | 60,843 | | 49,875 |
| Accumulated other comprehensive income, net of tax | | 5,991 | | - |
| Unearned compensation - restricted stock | | (8,221) | | (6,330) |
| Total shareholders' equity | | 304,901 | | 212,274 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | $ | 630,012 | $ | 494,795 |

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

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**CARRIZO OIL & GAS, INC.**

**CONSOLIDATED STATEMENTS OF INCOME**
**(Unaudited)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | (In thousands, except per share amounts) | | | |
| OIL AND NATURAL GAS REVENUES | $ 30,305 | $ 20,333 | $ 85,808 | $ 58,727 |
| COSTS AND EXPENSES: | | | | |
| Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below) | 6,940 | 3,893 | 17,203 | 10,980 |
| Depreciation, depletion and amortization | 10,190 | 7,594 | 29,033 | 21,630 |
| General and administrative (inclusive of stock-based compensation expense of $1,058 and $810 for the three months ended September 30, 2007 and 2006, respectively, and $3,050 and $1,999 for the nine months ended September 30, 2007 and 2006, respectively) | 4,360 | 3,118 | 13,577 | 10,469 |
| Accretion expense related to asset retirement obligations | 89 | 79 | 265 | 237 |
| TOTAL COSTS AND EXPENSES | 21,579 | 14,684 | 60,078 | 43,316 |
| OPERATING INCOME | 8,726 | 5,649 | 25,730 | 15,411 |
| OTHER INCOME AND EXPENSES: | | | | |
| Gain on derivatives, net | 3,676 | 3,684 | 2,045 | 12,087 |
| Equity in income of Pinnacle Gas Resources, Inc. | - | - | - | 35 |
| Other income and expenses, net | 6 | 29 | 262 | 202 |
| Loss on early extinguishment of debt | - | (12) | - | (294) |
| Interest income | 131 | 199 | 585 | 843 |
| Interest expense | (7,018) | (4,883) | (19,701) | (13,752) |
| Capitalized interest | 2,921 | 2,740 | 8,326 | 7,234 |
| INCOME BEFORE INCOME TAXES | 8,442 | 7,406 | 17,247 | 21,766 |
| INCOME TAXES | (3,066) | (2,655) | (6,279) | (7,793) |
| NET INCOME | $ 5,376 | $ 4,751 | $ 10,968 | $ 13,973 |

| | | | | |
|---|---|---|---|---|
| BASIC EARNINGS PER COMMON SHARE | $ 0.21 | $ 0.19 | $ 0.42 | $ 0.57 |
| DILUTED EARNINGS PER COMMON SHARE | $ 0.20 | $ 0.18 | $ 0.41 | $ 0.55 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING: | | | | |
| BASIC | 26,142 | 25,254 | 25,836 | 24,549 |
| DILUTED | 26,982 | 25,987 | 26,668 | 25,272 |

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

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**CARRIZO OIL & GAS, INC.**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Unaudited)**

| | For the Nine Months Ended September 30, 2007 | 2006 |
|---|---|---|
| | (In thousands) | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income | $ 10,968 | $ 13,973 |
| Adjustment to reconcile net income to net cash provided by operating activities- | | |
| Depreciation, depletion and amortization | 29,033 | 21,630 |
| Fair value loss (gain) of derivative financial instruments | 3,552 | (7,734) |
| Accretion of discounts on asset retirement obligations and debt | 265 | 237 |
| Stock-based compensation | 3,050 | 1,999 |
| Provision for allowance for doutbful accounts | (243) | - |
| Loss on extinguishment of debt | - | 294 |
| Equity in income of Pinnacle Gas Resources, Inc. | - | (35) |
| Deferred income taxes | 5,906 | 7,503 |
| Other | 1,169 | 1,129 |
| Changes in operating assets and liabilities | | |
| Accounts receivable | (3,276) | (3,766) |
| Other assets | (2,514) | 1,705 |
| Accounts payable | 1,897 | (778) |
| Accrued liabilities | (308) | 1,087 |
| Net cash provided by operating activities | 49,499 | 37,244 |
| | | |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures | (150,514) | (146,196) |
| Change in capital expenditure accrual | (3,484) | 1,376 |
| Proceeds from the sale of properties | 1,405 | 33,604 |
| Advances to operators | 963 | (1,454) |
| Advances for joint operations | (651) | (1,894) |
| Other | 64 | (342) |
| Net cash used in investing activities | (152,217) | (114,906) |
| | | |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Proceeds from debt issuance and borrowings | 129,000 | 53,000 |
| Debt repayments | (96,693) | (36,159) |
| Common stock offering, net of costs | 72,003 | 33,593 |
| Stock options exercised | 790 | 585 |
| Deferred loan costs and other | (3,214) | (676) |
| Net cash provided by financing activities | 101,886 | 50,343 |
| | | |
| NET DECREASE IN CASH AND CASH EQUIVALENTS | (832) | (27,319) |
| | | |
| CASH AND CASH EQUIVALENTS, beginning of period | 5,408 | 28,725 |

| | | | | |
|---|---|---|---|---|
| CASH AND CASH EQUIVALENTS, end of period | $ | 4,576 | $ | 1,406 |
| CASH PAID FOR INTEREST (NET OF AMOUNTS CAPITALIZED) | $ | 9,867 | $ | 5,381 |

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

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**CARRIZO OIL & GAS, INC.**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(Unaudited)**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements included herein have been prepared by Carrizo Oil & Gas, Inc. (the "Company"), and are unaudited. The financial statements reflect the accounts of the Company and its subsidiaries after elimination of all significant intercompany transactions and balances. The financial statements reflect necessary adjustments, all of which are 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 included herein are adequate to allow the information presented not to be misleading. The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006 (the "2006 Form 10-K").

*Reclassifications*

Certain reclassifications have been made to the prior period's financial statements to conform to the current presentation.

*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 collectibility of outstanding accounts receivable, fair values of derivatives, stock-based compensation expense, contingencies and the results of current and future litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, 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 are vulnerable to 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 effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value 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.

*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 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 compensation costs for employees working directly on exploration activities of $3.3 million and $2.2 million for the nine months ended September 30, 2007 and 2006, 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. Investments in unproved properties are not subject to DD&A until proved reserves associated with the projects can be determined or until they are impaired. Unevaluated properties 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

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amount of such impairment is determined and added to the proved oil and natural gas property costs subject to DD&A. The depletable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the quarters ended September 30, 2007 and 2006 was $2.26 and $2.59, 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 (“Full Cost Ceiling”). If net capitalized costs exceed this limit, the excess is charged to earnings. For the three-month periods ended September 30, 2007 and 2006, the Company did not have any charges associated with its ceiling test.

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

*Supplemental Cash Flow Information*

The adjustment of the investment in Pinnacle of $6.0 million, net of tax and the capitalization of $1.7 million net of tax related to stock-based compensation associated with the adoption of the Statement of Financial Accounting Standards No. 123 (revised) (“SFAS No. 123 (R)”) are excluded from the Statement of Cash Flows for the nine months ended September 30, 2007 and 2006, respectively. The Company paid no income taxes during the nine months ended September 30, 2007 and 2006.

*Stock-Based Compensation*

The Company records stock-based compensation as prescribed by the SFAS No. 123 (R). The compensation expense associated with stock options is based on the grant-date fair value of the options and recognized over the vesting period. Restricted stock is recorded as deferred compensation based on the closing price of the Company’s stock on the issuance date and is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (generally one to three years).

The Company recognized the following stock-based compensation expense:

| | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | (In millions) | | | |
| Stock Option Expense | $ 0.1 | $ 0.2 | $ 0.3 | $ 0.4 |
| Restricted Stock Expense | 1.0 | 0.6 | 2.8 | 1.6 |
| Total Stock-Based Compensation Expense | $ 1.1 | $ 0.8 | $ 3.1 | $ 2.0 |

*Derivative Instruments*

The Company uses derivatives to manage price and interest rate risk underlying its oil and gas production and the variable interest rate on its Second Lien Credit Facility.

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 presented herein were treated as non-designated derivatives and the unrealized gain/(loss) related to the mark-to-market valuation was included in the Company's earnings.

The Company typically uses fixed-rate swaps and costless collars to hedge its exposure to material changes in the price of oil and natural gas and variable interest rates on long-term debt.

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

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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 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, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| Chevron/Texaco | - | 11% | - | 12% |
| Reichmann Petroleum | - | - | - | 11% |
| Cokinos Natural Gas Company | 17% | - | 10% | - |
| Houston Pipeline Co. | 14% | - | 13% | - |
| Crosstex Energy Services | 15% | - | 15% | - |
| Energy Transfer | 16% | 10% | 12% | - |
| Partner Energy Services | - | 10% | - | - |

*Earnings Per Share*

Supplemental earnings per share information is provided below:

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| | (In thousands, except per share amounts) | | | |
| **Net income** | $ 5,376 | $ 4,751 | $ 10,968 | $ 13,973 |
| **Average common shares outstanding** | | | | |
| Weighted average common shares outstanding | 26,142 | 25,254 | 25,836 | 24,549 |
| Stock options and warrants | 840 | 733 | 832 | 723 |
| Diluted weighted average common shares outstanding | 26,982 | 25,987 | 26,668 | 25,272 |
| **Earnings per common share** | | | | |
| Basic | $ 0.21 | $ 0.19 | $ 0.42 | $ 0.57 |
| Diluted | $ 0.20 | $ 0.18 | $ 0.41 | $ 0.55 |

Basic earnings per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings per common share is based on the weighted average number of common shares and all dilutive potential common shares issuable during the periods. The Company had 2,500 stock options that were excluded in the calculation of dilutive shares for the three-month period ended September 30, 2006 because the exercise price of these instruments exceeded the underlying market value of the options.

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## 2. LONG-TERM DEBT:

Long-term debt consisted of the following at September 30, 2007 and December 31, 2006:

| | September 30, 2007 (In thousands) | December 31, 2006 |
|---|---|---|
| Second Lien Credit Facility | $ 221,063 | $ 147,750 |
| Senior Secured Revolving Credit Facility | - | 41,000 |
| Other | 3 | 8 |
| | 221,066 | 188,758 |
| Current maturities | (2,253) | (1,508) |
| | $ 218,813 | $ 187,250 |

*Second Lien Credit Facility*

On December 20, 2006, the Company amended its second lien credit agreement (the “Second Lien Credit Facility”) to increase the principal amount of the term loan agreement, lower the interest rate and provide flexibility in the debt covenants. The amended Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $225.0 million that matures in July 2010. It is secured by substantially all of the Company’s assets and is guaranteed by the Company’s subsidiaries. The liens securing the Second Lien Credit Facility are second in priority to the liens securing the Senior Secured Revolving Credit Facility (discussed below).

In January 2007, the Company drew the additional $75.0 million then available under the amended agreement. The net proceeds of $72.1 million were used to repay the $41.0 million of borrowings then outstanding under the Senior Secured Revolving Credit Facility and to fund a portion of the Company’s capital expenditure program and for general corporate purposes.

The interest rate on each base rate loan will be (1) the greater of the Agent’s prime rate and the federal funds effective rate plus 0.5%, plus (2) a margin of 3.75%. The interest rate on each Eurodollar loan will be the adjusted LIBOR rate plus a margin of 4.75%. Interest on Eurodollar loans is payable on either the last day of each period or every three months, whichever is earlier. Interest on base rate loans is payable quarterly. On September 30, 2007, the interest rate was approximately 9.9%, excluding the impact of interest rate swaps.

Under this agreement, the Company is subject to certain covenants and restrictions on additional financing and other matters. See the 2006 Form 10-K for further discussion.

*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, that matures May 25, 2010. The Senior Credit

Facility provides 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 assets and is guaranteed by the Company's subsidiaries. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

On September 11, 2007, the Company entered into the Second Amendment (the "Second Amendment") to the Senior Credit Facility. The Second Amendment further provides that in the event the scheduled redetermination of the Borrowing Base is not made on or prior to January 1, 2008 as a result of the Company's failure to comply with the requirement to deliver required engineering reports, the Borrowing Base will be reduced by $3 million commencing on January 1, 2008 and continuing on the first day of each month thereafter until the Borrowing Base is redetermined. The Conforming Borrowing Base (as defined in the Senior Credit Facility) has been amended to be $100 million. In connection with the Second Amendment, JPMorgan Chase Bank has assigned 44.4% of its commitment to Guaranty Bank. In addition, the Second Amendment increases the amount of investments in others that the Company may make.

As of September 30, 2007, the Company had no outstanding borrowings under the Senior Credit Facility.

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The borrowing base will be determined by the lenders at least semi-annually on each May 1 and November 1, beginning November 1, 2006. The Company may request one unscheduled borrowing base determination subsequent to each scheduled determination, and the lenders may request unscheduled determinations at any time. At September 30, 2007, the borrowing base was $117.0 million. Because of the recent borrowing base redetermination, the next scheduled redetermination will be in December 2007.

The annual interest rate on each base rate borrowing will be (1) 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 (2) a margin between 0.25% and 1.75% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBOR Rate plus a margin between 1.5% to 3.0% (depending on the current level of borrowing base usage).

The Company is subject to certain covenants and customary events of default under the terms of the Senior Credit Facility. See the Company's 2006 Form 10-K for further discussion.

## 3. INVESTMENT IN PINNACLE GAS RESOURCES, INC.:

In 2003, the Company and its wholly-owned subsidiary CCBM, Inc. ("CCBM") 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"). At September 30, 2007, the Company owned less than ten percent of Pinnacle's outstanding equity and accounted for the investment under the cost method. Prior to April 2006, the Company accounted for its interest in Pinnacle using the equity method.

During the second quarter of 2007, Pinnacle became a publicly traded entity on the Nasdaq Global Market. For accounting purposes, the Pinnacle stock now has a readily determinable fair value. Carrizo classifies the Pinnacle investment as available-for-sale and adjusts the investment to fair value through other comprehensive income. At September 30, 2007, Carrizo increased the book value of its Pinnacle investment by $9.2 million, $6.0 million net of tax, and reported the fair value of the stock at $11.9 million (based on the closing price of Pinnacle's common stock on September 30, 2007).

In June of 2007, Carrizo sold 41,894 shares of Pinnacle stock for net proceeds of $0.4 million and recognized a $0.3 million gain, which is included in Other income and expenses, net on the Consolidated Statements of Income. As of September 30, 2007, Carrizo owned 2,417,208 shares of Pinnacle common stock.

On October 15, 2007, Pinnacle, Quest Resource Corporation ("Quest"), and Quest Merger Sub, Inc., a wholly owned subsidiary of Quest ("Merger Sub"), entered into an agreement and plan of merger whereby Merger Sub will merge with and into Pinnacle. The merger agreement provides for Quest's acquisition of all of the issued and outstanding shares of Pinnacle's common stock for aggregate consideration of approximately 19.1 million shares of Quest's common stock, or approximately $207 million based on the closing price of Quest's common stock on October 15, 2007. Upon completion of the merger, each share of Pinnacle's common stock will be converted into the right to receive 0.6584 of a share of common stock of Quest. Completion of the merger transaction is conditioned upon, among other things, adoption of the merger agreement by both Pinnacle's and Quest's stockholders and consummation of an initial public offering of common units by Quest Energy Partners, L.P. (an affiliate of Quest). Quest and Pinnacle have stated that they anticipate the closing of the merger will occur in the first or second quarter of 2008. This transaction does not impact the accounting method for the Pinnacle investment.

## 4. INCOME TAXES:

The Company provided deferred federal income taxes at the rate of 35% (which also approximates its statutory rate) that amounted to a tax expense of $2.9 million and $2.6 million for the three-month periods ended September 30, 2007 and 2006, respectively, and $5.9 million and $7.5 million for the nine-month periods ended September 30, 2007 and 2006, respectively.

On January 1, 2007, the Company adopted FASB Interpretation No. 48, *“Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109”* (“FIN 48”).  FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return.  Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.  Carrizo classifies interest and penalties associated with income taxes as interest expense.  At September 30, 2007, the Company had no material uncertain tax positions and the tax years 2003 through 2006 remained open to review by federal and various state tax jurisdictions.

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## 5. 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 expect these matters to have a materially adverse effect on the 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.

## 6. SHAREHOLDERS' EQUITY:

The Company issued 1,998,020 and 1,686,531 net shares of common stock during the nine months ended September 30, 2007 and 2006, respectively. Shares issued during the nine months ended September 30, 2007 consisted of 1,800,000 shares issued in the September 2007 registered direct offering, 116,482 shares issued, net of 7,301 shares forfeited, as restricted stock awards to employees and 85,732 shares through the exercise of options granted under the Company's Incentive Plan. Shares issued during the nine months ended September 30, 2006 consisted of 1,350,000 shares issued in the July 2006 private placement, 236,351 shares issued, net of 23,292 shares forfeited, as restricted stock awards to employees, 99,800 shares issued through the exercise of options granted under the Company's Incentive Plan and 2,000 shares issued in exchange for oil and gas properties in the Barnett Shale. The Company also purchased and retired 4,194 and 1,620 shares to satisfy employee tax withholding obligations in connection with the vesting of the restricted stock during the nine months ended September 30, 2007 and 2006, respectively.

In September 2007, the Company sold 1,800,000 shares of its common stock to certain qualified investors in a registered direct offering at a price of $41.40 per share. The number of shares sold was approximately 6.8% of the Company's fully diluted shares outstanding before the offering. The Company expects to use substantially all of the net proceeds to fund in part its capital expenditure program, including its drilling and leasing programs in the Barnett Shale and appraisal well drilling in the North Sea, and for other corporate purposes. Pending those uses, the Company used a portion of the net proceeds of approximately $72.0 million to repay $54 million of outstanding borrowings under the Senior Credit Facility.

## 7. DERIVATIVE INSTRUMENTS:

The Company enters into swaps, options, collars and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural gas production. The Company also uses interest rate swap agreements to manage the Company's exposure to interest rate fluctuations on the Second Lien Credit Facility.

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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 cash settlements of derivative instruments are reported as gain (loss) on derivatives, net in Other Income and Expenses in the Consolidated Statements of Income. For the three and nine-month periods ended September 30, 2007 and 2006, the Company recorded the following related to its derivatives:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | (In millions) | | | |
| **Realized gains:** | | | | |
| Natural gas and oil derivatives | $ 2.8 | $ 1.1 | $ 5.4 | $ 3.6 |
| Interest rate swaps | - | 0.4 | 0.2 | 0.7 |
| | 2.8 | 1.5 | 5.6 | 4.3 |
| **Unrealized gains (losses):** | | | | |
| Natural gas and oil derivatives | $ 1.0 | $ 2.9 | $ (3.5) | $ 7.5 |
| Interest rate swaps | (0.1) | (0.7) | - | 0.3 |
| | 0.9 | 2.2 | (3.5) | 7.8 |
| Gain on derivatives, net | $ 3.7 | $ 3.7 | $ 2.1 | $ 12.1 |

The fair value of the outstanding derivatives at September 30, 2007 and December 31, 2006 was an asset of $2.5 million and $6.0 million, respectively.

At September 30, 2007, the Company had the following outstanding derivative positions:

| | Natural Gas Swaps | | Natural Gas Collars | | |
|---|---|---|---|---|---|
| **Quarter** | **MMbtu** | **Average Fixed Price(1)** | **MMBtu** | **Average Floor Price(1)** | **Average Ceiling Price(1)** |
| Fourth Quarter 2007 | 828,000 | $ 7.44 | 644,000 | $ 7.24 | $ 8.84 |
| First Quarter 2008 | 273,000 | 7.94 | 1,456,000 | 7.49 | 9.26 |
| Second Quarter 2008 | 273,000 | 7.94 | 1,092,000 | 7.23 | 8.97 |
| Third Quarter 2008 | 276,000 | 7.94 | 920,000 | 7.22 | 8.97 |
| Fourth Quarter 2008 | 276,000 | 7.94 | 1,103,000 | 7.18 | 8.83 |
| First Quarter 2009 | - | - | 1,080,000 | 7.09 | 8.81 |

| | | | | | |
|---|---|---|---|---|---|
| Second Quarter 2009 | - | - | 1,092,000 | 7.09 | 8.81 |
| Third Quarter 2009 | - | - | 1,104,000 | 7.09 | 8.81 |
| Fourth Quarter 2009 | - | - | 1,104,000 | 7.09 | 8.81 |

| Quarter | Bbls | Oil Collars Average Floor Price(2) | Average Ceiling Price (2) |
|---|---|---|---|
| Fourth Quarter 2007 | 27,600 | $ 70.00 | $ 75.90 |
| First Quarter 2008 | 18,200 | 70.00 | 76.20 |
| Second Quarter 2008 | 9,100 | 70.00 | 76.75 |
| Third Quarter 2008 | 9,200 | 70.00 | 76.75 |
| Fourth Quarter 2008 | 9,200 | 70.00 | 76.75 |

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(1) Based on Houston Ship Channel spot prices.
(2) Based on West Texas intermediate index prices.

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During the first and second quarter of 2007, the Company entered into interest swap agreements covering amounts outstanding under the Second Lien Credit Facility as amended in December 2006. These arrangements are designed to manage the Company's exposure to interest rate fluctuations through December 31, 2008 by effectively exchanging existing obligations to pay interest based on floating rates with obligations to pay interest based on fixed LIBOR. The Company's outstanding positions under interest rate swap agreements at September 30, 2007 were as follows (dollars in thousands):

| Quarter | Notional Amount | Fixed LIBOR Rate |
|---|---|---|
| Fourth Quarter 2007 | $ 221,063 | 5.25% |
| First Quarter 2008 | 220,500 | 5.32% |
| Second Quarter 2008 | 219,938 | 5.32% |
| Third Quarter 2008 | 219,375 | 5.31% |
| Fourth Quarter 2008 | 218,813 | 5.31% |

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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 for the year ended December 31, 2006 and the unaudited financial statements included elsewhere herein.

**General Overview**

Our third quarter 2007 included revenues of $30.3 million and record production of 4.4 Bcfe. The key drivers to our success for the three and nine-month periods ended September 30, 2007 include the following:

*Drilling program*. Our success is largely dependent on the results of our drilling program. During the nine months ended September 30, 2007, we drilled 56 gross wells (38.4 net wells) with an apparent success rate of 96% that was comprised of: (1) 39 of 39 gross wells (31.3 net wells) in the Barnett Shale area, (2) five of six gross wells (1.5 of 1.8 net wells) in the onshore Gulf Coast area, (3) one of one gross well (0.2 net well) in the North Sea, (4) three of four gross wells (3.0 of 4.0 net wells) in the Camp Hill field and (5) six of six gross wells (1.1 net wells) in other areas. We also drilled eight gross service wells (8.0 net wells) in the Camp Hill area. At September 30, 2007, we had 25 gross wells that were awaiting completion or pipeline connections.

*Production*. Our third quarter production of 4.4 Bcfe, or 48.2 MMcfe/d was a record high. The third quarter production increased 55% from the third quarter 2006 production of 2.9 Bcfe and increased 6% from the second quarter 2007 production of 4.2 Bcfe. The increase between second and third quarter of 2007 was due primarily to production from nine new wells in the Barnett Shale area and production for the entire third quarter of 2007 from the Doberman #1 in the Gulf Coast. The increase from the third quarter of 2006 to the third quarter of 2007 was primarily due to new Barnett Shale wells, the addition of the Baby Ruth and Doberman wells in the Gulf Coast and the recompletion of the Galloway Gas Unit well #1 and the LL&E #1.

*Commodity prices.* Natural gas prices during the third quarter of 2007 were $6.33 per Mcf (excluding the impact of our hedges), $0.06 per Mcf less than the price in the third quarter of 2006 and $1.21 per Mcf, or 16% lower than the price in the second quarter of 2007. The decline in natural gas price from the second quarter of 2007 to the third quarter of 2007 was largely responsible for the decline in total revenues from $32.9 million in the second quarter of 2007 to $30.3 million in the third quarter of 2007.

*Capital funding.* In order to fund our growth, we have taken steps to enhance our liquidity. During the first quarter of 2007, we received $72.1 million of net proceeds under the amended Second Lien Facility. During the third quarter of 2007, we received approximately $72.0 million in net proceeds from a registered direct offering of 1.8 million shares of our common stock. The proceeds were used to retire borrowings under the Senior Credit Facility and to fund our drilling program and general corporate purposes. In September 2007, our borrowing base availability on our Senior Credit Facility increased from $74.8 million to $117.0 million. The next borrowing base redetermination is scheduled for December 2007.

**Outlook**

Our outlook for the future remains positive. To continue our success:

- We plan to continue with the 2007 drilling program to drill 53 gross wells in the Barnett Shale area, ten gross wells in the Gulf Coast area, 25 to 30 gross wells in our Camp Hill field (which includes approximately 14 service wells) and five wells in other areas. In the Barnett Shale, we plan to utilize two drillings rigs in SE Tarrant County, Texas through the third quarter 2008 with each rig scheduled to drill one horizontal well each month. Our other two drilling rigs will be dedicated to drilling horizontal wells in Tarrant, Denton and Parker counties. We expect to spend between $145 million and $165 million on our 2007 drilling program. The actual number of wells drilled will vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our cash flow, success of drilling programs, weather delays and other factors. If we drill the number of wells we have budgeted for 2007, depreciation, depletion and amortization, oil and natural gas operating expenses and production are expected to increase over levels incurred in 2006. Our ability to drill this number of wells is heavily dependent upon the timely access to oilfield services, particularly drilling rigs.

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- We expect to continue our efforts to grow production. Our estimated daily production for the month of October 2007 was approximately 53 Mcfe/day.

- We plan to continue the development of other new drilling programs in the Floyd Shale in Mississippi, the Fayetteville Shale in Arkansas and the North Sea. We fracture stimulated our horizontal well in the Floyd Shale and are swabbing back frac fluid currently. We are assessing development plans for the Huntington discovery in Block 22-14b in the North Sea. An appraisal well was spud on August 30, 2007 with expected drilling and testing time of approximately five months. As a result of our recent experience in the North Sea, we currently expect that we will seek to significantly expand our expenditures in that area over the next several years. We may seek project financing or other financing alternatives for the development of the North Sea assets.

- We expect to hedge production to decrease commodity price fluctuations. At September 30, 2007, we had hedged approximately 11,521,000 MMBtus of natural gas production through 2009 and 73,300 Bbls of oil production through 2008.

- During 2007, we experienced unexpected delays in the development of the Camp Hill field. Our 2007 drilling program in the Camp Hill field has been delayed primarily due to the unavailability of the rig we use to drill in the field. However, we recently received a firm commitment from our drilling contractor to drill exclusively for us for the remainder of 2007 and through February 2008. We believe that we are on track to drill 27 to 30 wells in 2007 (including 14 service wells). We also experienced operational and administrative problems with our steam injection process. The steam generators expected to be used were not available due to delays in repair work and/or permit issues. We injected steam in the Camp Hill field through one of our generators until it encountered operational damage in January 2007. We expect to receive a replacement generator in December 2007 and to commence steam injection as soon thereafter as possible. Our other two generators have not been available for injection due to unexpected permitting issues and the need for repair work. We currently expect that these two generators will be ready to inject steam by the end of March 2008 with respect to one generator and by the end of June 2008, with respect to the other. We recently received the permits for these two generators to recommence injection. Although these permits will only allow us to inject steam at 64% of the rate that we had anticipated, based upon the rate under the prior permits for these same generators, we expect to continue to appeal to the regulatory authorities to reinstate the 100 % rate of generation allowed under the original permits. Even if we are unsuccessful in increasing the generation rates under our permits, our proved reserve volumes for the Camp Hill field are not expected to decrease as a result. A lower generation rate assumption (incorporated into our internal September 30, 2007 proved reserve estimate), however, does extend the productive life of the field by approximately 33% with a corresponding 19%, or $31.2 million, reduction in the present value of the estimated future net revenues discounted at 10% per annum attributable to these proved reserves. Prospectively, we expect to continue to use the lower generation rate assumption in our proved reserve estimates, unless and until such time that we are successful in increasing the generation rates in our permits.

**Results of Operations**

*Three Months Ended September 30, 2007,*
*Compared to the Three Months Ended September 30, 2006*

Oil and natural gas revenues for the three months ended September 30, 2007 increased to $30.3 million from $20.3 million for the same period in 2006. Production volumes for natural gas for the three months ended September 30, 2007 increased to 4.1 Bcf from 2.4 Bcf for the same period in 2006. Average natural gas prices, excluding the impact of the gain from our cash settled derivatives of $2.8 million and $1.1 million for the quarters ended September 30, 2007 and 2006, respectively, decreased to $6.33 per Mcf in the third quarter of 2007 from $6.39 per Mcf in the same period in 2006. Average oil prices for the quarter ended September 30, 2007 increased 10% to $75.40 from $68.46

per barrel in the same period in 2006. The increase in natural gas production volume was due primarily to the addition of new Barnett Shale wells, production from the Baby Ruth and Doberman #1 wells in the Gulf Coast region and increased production from the recompleted Galloway Gas Unit 1 well #1 and LL&E #1 in the Gulf Coast area.

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The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for the three months ended September 30, 2007 and 2006:

| | Three Months Ended September 30, | | 2007 Period Compared to 2006 Period | |
|---|---|---|---|---|
| | 2007 | 2006 | Increase (Decrease) | % Increase (Decrease) |
| Production volumes | | | | |
| Oil and condensate (MBbls) | 59 | 69 | (10) | (14)% |
| Natural gas (MMcf) | 4,080 | 2,443 | 1,637 | 67% |
| Average sales prices | | | | |
| Oil and condensate (per Bbl) | $ 75.40 | $ 68.46 | $ 6.94 | 10% |
| Natural gas (per Mcf) | 6.33 | 6.39 | (0.06) | (1)% |
| Operating revenues (In thousands) | | | | |
| Oil and condensate | $ 4,457 | $ 4,716 | $ (259) | (5)% |
| Natural gas | 25,848 | 15,617 | 10,231 | 66% |
| Total Operating Revenues | $ 30,305 | $ 20,333 | $ 9,972 | 49% |

Oil and natural gas operating expenses for the three months ended September 30, 2007 increased 78% to $6.9 million from $3.9 million for the same period in 2006 primarily as a result of (1) higher lifting costs of $0.9 million primarily attributable to increased production and the increased number of producing wells, (2) increased workover expense of $0.3 million, (3) increased ad valorem taxes of $0.4 million and (4) increased transportation and other product costs of $1.3 million mainly attributable to the Barnett Shale area.

Depreciation, depletion and amortization (DD&A) expense for the three months ended September 30, 2007 increased 34% to $10.2 million ($2.30 per Mcfe) from $7.6 million ($2.66 per Mcfe) for the same period in 2006. This increase was primarily due to an increase in production volumes partially offset by a decrease in the DD&A rate attributable to the increase in the reserve base.

General and administrative expense for the three months ended September 30, 2007 increased by $1.3 million to $4.4 million from $3.1 million for the corresponding period in 2006 primarily as a result of (1) an increase in staff and related costs, (2) increased stock-based compensation, (3) increased legal and consulting fees and (4) higher rent expense as a result of office expansion.

The net gain on derivatives of $3.7 million in the third quarter of 2007 was comprised of (1) $2.8 million of realized gain on net cash settled derivatives and (2) $0.9 million of net unrealized mark-to-market gain on derivatives. The net gain on derivatives of $3.7 million in the third quarter of 2006 was comprised of (1) $1.5 million of realized gain on net cash settled derivatives and (2) $2.2 million of net unrealized mark-to-market gain on derivatives.

Interest expense and capitalized interest for the three months ended September 30, 2007 were $7.0 million and ($2.9) million, respectively, as compared to $4.9 million and $(2.7) million for the same period in 2006. The increases in 2007 were largely attributable to the $75.0 million increase in our Second Lien Credit Facility in January 2007, the borrowings under the Senior Secured Credit Facility and higher effective interest rates.

Income tax expense increased to $3.1 million for the three months ended September 30, 2007 from the $2.7 million expense for the same period in 2006 as a result of higher taxable income.

*Nine Months Ended September 30, 2007,*
*Compared to the Nine Months Ended September 30, 2006*

Oil and natural gas revenues for the nine months ended September 30, 2007 increased 46% to $85.8 million from $58.7 million for the same period in 2006. Production volumes for natural gas for the nine months ended September 30, 2007 increased to 10.8 Bcf from 7.0 Bcf for the same period in 2006. Average natural gas prices excluding the impact of the gain from our cash settled derivatives of $5.4 million and $3.6 million for the nine months ended September 30, 2007 and 2006, respectively, increased 2% to $6.88 per Mcf from $6.74 per Mcf in the same period in 2006. Average oil prices for the nine months ended September 30, 2007 decreased 1% to $65.22 from $65.54 per barrel in the same period in 2006. The increase in natural gas production volume was due primarily to new

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Barnett Shale wells and increased production in the Gulf Coast from the addition of the Doberman #1 and Baby Ruth wells and the recompletion of the Galloway Gas Unit #1 well #1.

The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for the nine months ended September 30, 2007 and 2006:

| | Nine Months Ended | | | | 2007 Period Compared to 2006 Period | |
|---|---|---|---|---|---|---|
| | September 30, | | | | Increase | % Increase |
| | | 2007 | | 2006 | (Decrease) | (Decrease) |
| Production volumes | | | | | | |
| Oil and condensate (MBbls) | | 182 | | 179 | 3 | 2% |
| Natural gas (MMcf) | | 10,753 | | 6,976 | 3,777 | 54% |
| Average sales prices | | | | | | |
| Oil and condensate (per Bbl) | $ | 65.22 | $ | 65.54 | $ (0.32) | (1)% |
| Natural gas (per Mcf) | | 6.88 | | 6.74 | 0.14 | 2% |
| Operating revenues (In thousands) | | | | | | |
| Oil and condensate | $ | 11,881 | $ | 11,734 | $ 147 | 1% |
| Natural gas | | 73,927 | | 46,993 | 26,934 | 57% |
| Total Operating Revenues | $ | 85,808 | $ | 58,727 | $ 27,081 | 46% |

Oil and natural gas operating expenses for the nine months ended September 30, 2007 increased 56% to $17.2 million from $11.0 million for the same period in 2006 primarily as a result of (1) higher lifting costs of $2.5 million primarily attributable to increased production, the increased number of producing wells and the rising costs of oilfield services, (2) higher workover expenses of $0.4 million, (3) increased ad valorem taxes of $0.9 million and (4) increased transportation and other product costs of $2.3 million mainly attributable to the Barnett Shale area.

DD&A expense for the nine months ended September 30, 2007 increased 34% to $29.0 million ($2.45 per Mcfe) from $21.6 million ($2.69 per Mcfe) for the same period in 2006. This increase was primarily due to an increase in production volumes partially offset by a decrease in the DD&A rate attributable to the increase in the reserve base.

General and administrative expense for the nine months ended September 30, 2007 increased by $3.1 million to $13.6 million from $10.5 million for the corresponding period in 2006 due primarily to (1) an increase in staff and related costs, (2) increased stock-based compensation, (3) higher rent and office expense due to office expansion and (4) increased legal and consulting fees.

The net gain on derivatives of $2.1 million in the first nine months of 2007 was comprised of (1) $5.6 million of realized gain on net cash settled derivatives and (2) $(3.5) million of net unrealized mark-to-market loss on derivatives. The net gain on derivatives of $12.1 million in the first nine months of 2006 was comprised of (1) $4.3 million of realized gain on net cash settled derivatives and (2) $7.8 million of net unrealized mark-to-market gain on derivatives.

Interest expense and capitalized interest for the nine months ended September 30, 2007 were $19.7 million and $(8.3) million, respectively, as compared to $13.8 million and $(7.2) million for the same period in 2006. The increases in 2007 were largely attributable to the $75.0 million increase in our Second Lien Credit Facility in January 2007, borrowings under the Senior Secured Credit Facility beginning mid-2006 and higher effective interest rates.

Income tax expense decreased to $6.3 million for the nine months ended September 30, 2007 from the $7.8 million for the same period in 2006 as a result of lower taxable income.

**Liquidity and Capital Resources**

*Sources and Uses of Cash.* During the nine months ended September 30, 2007, capital expenditures, net of proceeds for property sales, exceeded our net cash. During 2007, we have used cash generated from operations, additional borrowings under our Second Lien Credit Facility and the Senior Credit Facility and proceeds from the issuance of our common stock. Potential primary sources of future liquidity include the following:

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

- Available draws on the Senior Credit Facility. During the third quarter of 2007, we requested a borrowing base re-determination for the Senior Credit Facility and in September of 2007, the borrowing base availability increased from $74.8 million to $117.0 million. At November 1, 2007, cash available under the Senior Credit Facility was $105.0 million. The next borrowing base redetermination is scheduled for December 2007.

- Other debt and equity offerings. As situations or conditions arise, we may issue debt or equity instruments to supplement our cash flows.

- Asset sales. In order to fund our drilling program, we may consider the sale of certain properties or assets no longer deemed core to our future growth.

Our primary use of cash is capital expenditures related to our drilling program. We plan to spend approximately $145 million to $165 million on our 2007 drilling program. For the nine months ended September 30, 2007, we have incurred approximately $151 million in capital expenditures.

*Overview of Cash Flow Activities.* Cash flows provided by operating activities were $49.5 million and $37.2 million for the nine months ended September 30, 2007 and 2006, respectively. The increase was primarily due to an increase in income largely attributable to increased production.

Cash flows used in investing activities were $152.2 million for the nine months ended September 30, 2007 and related primarily to oil and gas property expenditures. Cash flows used in investing activities were $114.9 million for the nine months ended September 30, 2006 as capital expenditures for oil and gas properties of $146.2 million were partially offset by proceeds from the sale of properties of $33.6 million.

Net cash provided by financing activities for the nine months ended September 30, 2007 was $101.9 million and related primarily to the additional borrowings of $75.0 million under the Second Lien Credit Facility in January 2007 and net proceeds of $72.0 million from the issuance of common stock in September 2007 (see Notes 2 and 6 in the Notes to Consolidated Financial Statements for further discussion of these transactions). These cash proceeds were partially offset by the paydown of the Senior Credit Facility. Net cash provided by financing activities for the nine months ended September 30, 2006 was $50.3 million and related primarily to the additional borrowings under the Senior Credit Facility and the net proceeds of $33.6 million from the issuance of common stock, partially offset by $36.2 million of debt repayments.

*Liquidity/Cash Flow Outlook.* We believe that the cash generated from operations along with cash on hand and the cash available under the Senior Credit Facility is sufficient to meet our immediate needs but we may need to seek other financing alternatives, including additional debt or equity financings, to fully fund our 2007 and 2008 capital program, especially if there are additional capital needs in our Floyd Shale or North Sea plays.

We may not be able to obtain financing needed in the future on terms that would be acceptable to us. If we cannot obtain adequate financing, we may be required to limit or defer our planned oil and natural gas exploration and development program, thereby adversely affecting the recoverability and ultimate value of our oil and natural gas properties.

**Contractual Obligations**

During the third quarter of 2007, we entered into a firm drilling agreement for one rig over a three-year term scheduled to begin in the first quarter of 2008. The estimated obligation is approximately $8 million per year through 2010.

**Financing Arrangements**

*Senior Secured Revolving Credit Facility*

During the third quarter of 2007, we amended our Senior Credit Facility as discussed in Note 2 in the Notes to Consolidated Financial Statements.

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**Effects of Inflation and Changes in Price**

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in the operating cost that we are required to bear for operations, as well as an increase (decrease) in revenues. Inflation has had a minimal effect on us.

**Recently Adopted Accounting Pronouncements**

We adopted the Financial Accounting Standards Board's Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109"* ("FIN 48"), effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in financial statements and requires the impact of a tax position to be recognized in the financial statements if that position is more likely than not of being sustained by the taxing authority. The adoption of FIN 48 did not have a material effect on our consolidated financial position or results of operations.

**Critical Accounting Policies**

The following summarizes several of our critical accounting policies:

*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 disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates. The use of these estimates significantly affects our natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair values of derivatives, stock-based compensation expense, contingencies and the results of current and future litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling, testing and production may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to 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 effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value of our common stock and corresponding volatility and our ability to generate future taxable income. Future changes to these assumptions may materially affect these significant estimates in the near term.

*Oil and Natural Gas Properties*

We account for investments in natural gas and oil properties using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. These costs include lease acquisitions, seismic surveys, and drilling and completion equipment. We proportionally consolidate our interests in natural gas and oil properties. We capitalized compensation costs for employees working directly on exploration activities of $3.3 million and $2.2 million for the nine months ended September 30, 2007 and 2006, 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. We do not amortize investments in unproved properties until proved reserves associated with the projects can be determined or until these investments are impaired. We periodically evaluate, on a property-by-property basis, unevaluated properties for impairment. If the results of an assessment indicate that the properties are impaired, we add the amount of impairment to the proved natural gas and oil property costs to be amortized. The amortizable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the three months ended September 30, 2007 and 2006 was $2.26 and $2.59, respectively.

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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 through depreciation, depletion and amortization.

In connection with our September 30, 2007 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase or decrease in commodity prices at September 30, 2007 would have increased or decreased the Full Cost Ceiling test cushion by approximately $52 million. The aforementioned price sensitivity is as of September 30, 2007 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.

The Full Cost Ceiling cushion at the end of September 2007 of approximately $113.7 million was based upon average realized oil and natural gas prices of $76.79 per Bbl and $6.48 per Mcf, respectively, or a volume weighted average price of $45.63 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $35.61 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. 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 unevaluated costs, 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 116.9 Bcfe and 126.2 Bcfe of proved undeveloped reserves at September 30, 2007 and December 31, 2006, respectively, representing 48% and 60% of our total proved reserves. As of September 30, 2007 and December 31, 2006, a large portion of these proved undeveloped reserves, or approximately 32.8 Bcfe, are attributable to our Camp Hill properties that we acquired in 1994. The estimated future development costs to develop our proved undeveloped reserves on our Camp Hill properties are relatively low, on a per Mcfe basis, when compared to the estimated future development costs to develop our proved undeveloped reserves on our other oil and natural gas properties. Furthermore, the average depletable life (the estimated time that it will take to produce all recoverable reserves) of our Camp Hill properties is considerably longer, or approximately 15 years, when compared to the depletable life of our remaining oil and natural gas properties of approximately 10 years. Accordingly, the combination of a relatively low ratio of future development costs and a relatively long depletable life on our Camp Hill properties has resulted in a relatively low overall historical depletion rate and DD&A expense. This has resulted in a capitalized cost basis associated with producing properties being depleted over a longer period than the associated production and revenue stream, causing the build-up of nondepleted capitalized costs associated with properties that have been completely depleted. This combination of factors, in turn, has had a favorable impact on our earnings, which have been higher than they would have been had the Camp Hill properties not resulted in a relatively low overall depletion rate and DD&A expense and longer depletion period. As a hypothetical illustration of this impact, the removal of our Camp Hill proved undeveloped reserves starting January 1, 2002 would have reduced our earnings by (1) 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), (2) an estimated $5.9 million in 2003 (due to higher depletion expense), (3) an estimated $3.4 million in 2004 (due to higher depletion expense) (4) an estimated $6.9 million in 2005 (due to higher depletion expense) and (5) an estimated $0.7 million in 2006 (due to higher depletion expense).

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.

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

*Oil and Natural Gas Reserve Estimates*

Proved reserve data as of December 31, 2006 were estimates prepared by Ryder Scott Company, LaRoche Petroleum Consultants, Ltd., and Fairchild & Wells, Inc., Independent Petroleum Engineers. We estimated the reserve data for all other dates. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on judgment and the interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions regarding drilling and operating expense, capital expenditures, taxes and availability of funds. The SEC mandates some of these assumptions such as oil and natural gas prices and the present value discount rate.

Proved reserve estimates prepared by others may be substantially higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve quantities actually recovered may be significantly different than estimated. Material revisions to reserve estimates may be made depending on the results of drilling, testing, and rates of production.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate using a discount rate of 10%.

Our rate of recording depreciation, depletion and amortization expense for proved properties depends on our estimate of proved reserves. If these reserve estimates decline, the rate at which we record these expenses will increase. A 10% increase or decrease in our proved reserves would have increased or decreased our depletion expense by 9% for the three months ended September 30, 2007.

At December 31, 2006, approximately 75% 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, 2006 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. We have from time to time chosen to delay development of our proved undeveloped reserves in the Camp Hill field in East Texas in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field's development. The average life of the Camp Hill proved undeveloped reserves is approximately 15 years, with 50% of these reserves being booked over eight years ago. Although we have increased the pace of the development of the Camp Hill project, there can be no assurance that the aforementioned discontinuance will not occur. For more information on the development of the Camp Hill field, see "Outlook" above.

*Derivative Instruments*

We use derivatives to manage price and interest rate risk underlying our oil and natural gas production and the variable interest rate on the Second Lien Credit Facility. We have elected to account for our derivative contracts as non-designated derivatives that will be marked-to-market. For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see "Volatility of Oil and Natural Gas Prices" below.

During 2007, we entered into interest rate swap agreements with respect to amounts outstanding under the amended Second Lien Credit Facility. These arrangements are designed to manage our exposure to interest rate fluctuations through December 31, 2008 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBOR. These derivatives will be marked-to-market at the end of each period and the realized and unrealized gain or loss will be recorded as gain (loss) on derivatives, net within Other Income and Expenses on our Consolidated Statements of Income.

Our Board of Directors sets all of our risk management policies and reviews volume limitations, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by either the President or Chief Financial Officer after consultation and concurrence by the President, Chief Financial Officer and Chairman of the Board. The

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master contracts with the approved counterparties identify the President and Chief Financial Officer as the only representatives authorized to execute trades. The Board of Directors also reviews the status and results of derivative activities quarterly.

*Income Taxes*

Under Statement of Financial Accounting Standards No. 109 ("SFAS No. 109"), *"Accounting for Income Taxes,"* deferred income taxes are recognized at each year end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the realizability of our deferred tax assets. 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.

*Contingencies*

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

**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 options, in order to establish some price floor protection.

The following table includes oil and natural gas positions settled during the three and nine-months period ended September 30, 2007 and 2006, and the unrealized gain/(loss) associated with the outstanding oil and natural gas derivatives at September 30, 2007 and 2006.

| | Three months ended September 30, 2007 | Three months ended September 30, 2006 | Nine months ended September 30, 2007 | Nine months ended September 30, 2006 |
|---|---|---|---|---|
| Oil positions settled (Bbls) | 18,300 | 27,600 | 18,300 | 63,800 |
| Natural gas positions settled (MMBtu) | 1,898,000 | 1,163,000 | 5,332,000 | 3,520,000 |
| Realized gain ($ millions) (1) | $ 2.8 | $ 1.1 | $ 5.4 | $ 3.6 |
| Unrealized gain/(loss) ($ millions) (1) | $ 1.0 | $ 2.9 | $ (3.5) | $ 7.5 |

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

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At September 30, 2007, we had the following outstanding natural gas derivative positions:

| | Natural Gas Swaps | | Natural Gas Collars | | |
|---|---|---|---|---|---|
| Quarter | MMbtu | Average Fixed Price(1) | MMBtu | Average Floor Price(1) | Average Ceiling Price(1) |
| Fourth Quarter 2007 | 828,000 | $ 7.44 | 644,000 | $ 7.24 | $ 8.84 |
| First Quarter 2008 | 273,000 | 7.94 | 1,456,000 | 7.49 | 9.26 |
| Second Quarter 2008 | 273,000 | 7.94 | 1,092,000 | 7.23 | 8.97 |
| Third Quarter 2008 | 276,000 | 7.94 | 920,000 | 7.22 | 8.97 |
| Fourth Quarter 2008 | 276,000 | 7.94 | 1,103,000 | 7.18 | 8.83 |
| First Quarter 2009 | - | - | 1,080,000 | 7.09 | 8.81 |
| Second Quarter 2009 | - | - | 1,092,000 | 7.09 | 8.81 |
| Third Quarter 2009 | - | - | 1,104,000 | 7.09 | 8.81 |
| Fourth Quarter 2009 | - | - | 1,104,000 | 7.09 | 8.81 |

| | | Oil Collars | |
|---|---|---|---|
| Quarter | Bbls | Average Floor Price(2) | Average Ceiling Price (2) |
| Fourth Quarter 2007 | 27,600 | $ 70.00 | $ 75.90 |
| First Quarter 2008 | 18,200 | 70.00 | 76.20 |
| Second Quarter 2008 | 9,100 | 70.00 | 76.75 |
| Third Quarter 2008 | 9,200 | 70.00 | 76.75 |
| Fourth Quarter 2008 | 9,200 | 70.00 | 76.75 |

(1) Based on Houston Ship Channel spot prices.
(2) Based on West Texas intermediate index prices.

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 reporting settlement prices on the Houston Ship Channel index for the last three trading days of a particular contract month. Our oil derivative transactions are generally settled based on the average reporting settlement prices on the West Texas Intermediate index for each trading day of a particular calendar month. For the third quarter of 2007, a 10% change in the price per Mcf of natural gas sold would have changed revenue by $2.6 million. A 10% change in the price per barrel of oil would have changed revenue by $0.4 million.

**Forward Looking Statements**

The statements contained in all parts of this document, including, but not limited to, those relating to our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, 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, the ability of expected sources of liquidity to

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implement the Company’s business strategy, future exploration activity, production rates, 2007 drilling program, growth in production, development of new drilling programs, hedging of production and exploration and development expenditures, Camp Hill development 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 expression intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the Company's dependence on its exploratory drilling activities, the volatility of oil and natural gas prices, the need to replace reserves depleted by production, operating risks of oil and natural gas operations, the Company's dependence on its key personnel, factors that affect the Company's ability to manage its growth and achieve its business strategy, risks relating to limited operating history, technological changes, significant capital requirements of the Company, the potential impact of government regulations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, weather, availability of financing, ability to obtain permits, the results of audits and assessments and other factors detailed in the “Risk Factors” and other sections of the Company's Annual Report on Form 10-K for the year ended December 31, 2006 and other filings with the Securities and Exchange Commission. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and the Company undertakes no obligation to update or revise any forward-looking statement.

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## ITEM 3 – QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For information regarding our exposure to certain market risks, see "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2006. There have been no material changes to the disclosure regarding our exposure to certain market risks made in the Annual Report on Form 10-K. For information regarding our long-term debt, see Note 2 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. They concluded that the controls and procedures were effective as of September 30, 2007 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended September 30, 2007, that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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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 information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2006, 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.

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

The following table presents information regarding the Company's purchases of its common stock on a monthly basis during the third quarter of 2007:

| Period | (a) Total Number of Shares Purchased[1] | (b) Average Price Paid Per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | (d) Maximum Number (or Appropriate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs |
|---|---|---|---|---|
| July 2007 | 221 | $ 38.81 | - | - |
| August 2007 | 662 | 41.62 | - | - |
| September 2007 | - | - | - | - |
| Total | 883 | $ 40.92 | - | - |

(1) The 883 shares related to the surrender of shares of common stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under our long-term incentive plan.

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 |
| --- | --- |
| †2.1 | —Combination Agreement by and among the Company, Carrizo Production, Inc., Encinitas Partners Ltd., La Rosa Partners Ltd., Carrizo Partners Ltd., Paul B. Loyd, Jr., Steven A. Webster, S.P. Johnson IV, Douglas A.P. Hamilton and Frank A. Wojtek dated as of September 6, 1997 (incorporated herein by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)). |

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†3.1—Amended and Restated Articles of Incorporation of the Company (incorporated herein by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).

†3.2—Amended and Restated Bylaws of the Company, as amended by Amendment No. 1 (incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form 8-A (Registration No. 000-22915) Amendment No. 2 (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated December 15, 1999) and Amendment No. 3 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated February 20, 2002).

†10.1—Second Amendment effective as of September 11, 2007 to Credit Agreement dated as of May 25, 2006 among the Company, as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, National Association, as Administrative Agent and Lender, and Guaranty Bank as Lender (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 11, 2007).

†10.2—Form of Securities Purchase Agreement between the Company and the purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 12, 2007).

31.1—CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2—CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1—CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2—CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

† Incorporated herein by reference as indicated.

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## SIGNATURES

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

| | |
|---|---|
| | Carrizo Oil & Gas, Inc.<br>(Registrant) |
| Date: November 9, 2007 | By: /s/S. P. Johnson, IV<br>President and Chief Executive Officer<br>(Principal Executive Officer) |
| Date: November 9, 2007 | By: /s/Paul F. Boling<br>Chief Financial Officer<br>(Principal Financial and Accounting Officer) |