CARRIZO OIL & GAS INC
Form 10-Q
May 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 **March 31, 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 (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 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 May 1, 2007, the latest practicable date, was 26,001,692.

CARRIZO OIL & GAS, INC.

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2007
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CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

ASSETS		**March 31, 2007** (Unaudited)		**December 31, 2006**
		(In thousands)		
CURRENT ASSETS:				
Cash and cash equivalents	$	11,062	$	5,408
Accounts receivable, trade (net of allowance for doubtful accounts of $1,639				
at March 31, 2007 and December 31, 2006)		22,487		25,871
Advances to operators		1,360		2,107
Fair value of derivative financial instruments		-		5,737
Other current assets		2,144		1,934
Total current assets		37,053		41,057
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil				
and natural gas properties (including unevaluated costs of properties of $99,086 and				
$95,136 at March 31, 2007 and December 31, 2006, respectively)		484,688		445,447
DEFERRED FINANCING COSTS		7,122		4,817
INVESTMENT IN PINNACLE GAS RESOURCES, INC.		2,771		2,771
OTHER ASSETS		490		703
	$	532,124	$	494,795
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES:				
Accounts payable, trade	$	32,199	$	32,570
Accrued liabilities		24,572		20,885
Advances for joint operations		1,020		1,100
Current maturities of long-term debt		2,257		1,508
Fair value of derivative financial instruments		1,828		-
Deferred income tax		-		2,008
Total current liabilities		61,876		58,071
LONG-TERM DEBT, NET OF CURRENT MATURITIES		219,938		187,250
ASSET RETIREMENT OBLIGATION		4,498		3,625
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		186		-
DEFERRED INCOME TAXES		34,081		32,738
DEFERRED CREDITS		800		837
COMMITMENTS AND CONTINGENCIES		-		-

SHAREHOLDERS' EQUITY:				
Common stock, par value $0.01 (40,000 shares authorized with 25,991 and 25,981 issued and outstanding at March 31, 2007 and December 31, 2006, respectively)		260		260
Additional paid-in capital		168,760		168,469
Retained earnings		47,330		49,875
Unearned compensation - restricted stock		(5,605)		(6,330)
Total shareholders' equity		210,745		212,274
	$	532,124	$	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)

	For the Three Months Ended March 31, 2007	2006
	(In thousands except per share amounts)	
OIL AND NATURAL GAS REVENUES	$ 22,612	$ 21,917
COSTS AND EXPENSES:		
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	4,703	3,457
Depreciation, depletion and amortization	8,038	7,438
General and administrative (inclusive of stock-based compensation expense of $979 and $559 for the three months ended March 31, 2007 and 2006, respectively)	4,878	4,208
Accretion expense related to asset retirement obligations	88	79
Total costs and expenses	17,707	15,182
OPERATING INCOME	4,905	6,735
OTHER INCOME AND EXPENSES:		
Net gain (loss) on derivatives (Note 7)	(5,711)	5,373
Equity in income (loss) of Pinnacle Gas Resources, Inc.	-	35
Other income and expenses, net	116	4
Interest income	344	365
Interest expense	(6,154)	(4,275)
Capitalized interest	2,686	2,078
INCOME (LOSS) BEFORE INCOME TAXES	(3,814)	10,315
INCOME TAX (EXPENSE) BENEFIT (Note 4)	1,269	(3,664)
NET INCOME (LOSS)	$ (2,545)	$ 6,651
BASIC EARNINGS (LOSS) PER SHARE	$ (0.10)	$ 0.28
DILUTED EARNINGS (LOSS) PER SHARE	$ (0.10)	$ 0.27
WEIGHTED AVERAGE SHARES OUTSTANDING:		
BASIC	25,658	24,167

DILUTED	25,658	24,845

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 Three Months Ended March 31,	
	2007	**2006**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (2,545)	$ 6,651
Adjustment to reconcile net income (loss) to net		
cash provided by operating activities-		
Depreciation, depletion and amortization	8,038	7,438
Fair value loss (gain) of derivative financial instruments	8,062	(4,016)
Accretion of discounts on asset retirement obligations and debt	88	79
Stock-based compensation	979	559
Equity in loss of Pinnacle Gas Resources, Inc.	-	(35)
Deferred income taxes (credit)	(1,370)	3,598
Other	12	344
Changes in operating assets and liabilities		
Accounts receivable	3,384	2,939
Other assets	430	462
Accounts payable	1,539	(2,238)
Accrued liabilities	553	1,761
Net cash provided by operating activities	19,170	17,542
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(47,815)	(41,223)
Change in capital expenditure accrual	1,709	6,559
Proceeds from the sale of properties	1,363	5,195
Advances to operators	747	(533)
Advances for joint operations	(80)	9,562
Other	(74)	(172)
Net cash used in investing activities	(44,150)	(20,612)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from debt issuance and borrowings	75,000	-
Debt repayments	(41,564)	(547)
Stock options exercised	65	99
Deferred loan costs and other	(2,867)	(111)
Net cash provided by (used for) financing activities	30,634	(559)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,654	(3,629)
CASH AND CASH EQUIVALENTS, beginning of period	5,408	28,725

CASH AND CASH EQUIVALENTS, end of period	$	11,062	$	25,096
CASH PAID FOR INTEREST (NET OF AMOUNTS CAPITALIZED)	$	3,251	$	1,895

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 were of a recurring nature, and are in the opinion of management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). The Company believes that the disclosures presented are adequate to allow the information presented not to be misleading. The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 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 $1.4 million and $1.0 million for the three months ended March 31, 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 March 31, 2007 and 2006 was $2.47 and $2.67, 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 through DD&A. For the three-month periods ended March 31, 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 Statement of Cash Flows for the three months ended March 31, 2006 does not include 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)”). The Company paid no income taxes during the three months ended March 31, 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 for the three months ended March 31:

	2007	**2006**
	(In millions)	
Stock Option	$ 0.1	$ 0.1
Restricted Stock	0.9	0.5
Total Stock-Based Compensation	$ 1.0	$ 0.6

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 at March 31, 2007 and December 31, 2006 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 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.

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Major Customers

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

	For the Three Months Ended March 31, 2007	2006
Chevron/Texaco	-	13%
Reichmann Petroleum	-	11%
Cimarex Energy Co.	14%	-
Houston Pipeline Co.	20%	-

Earnings Per Share

Supplemental earnings per share information is provided below:

	For the Three Months Ended March 31, 2007	2006
	(In thousands except per share amounts)	
Net income (loss)	$ (2,545)	$ 6,651
Average common shares outstanding		
Weighted average shares outstanding	25,658	24,167
Stock options and warrants	-	678
Diluted weighted average shares outstanding	25,658	24,845
Earnings (loss) per share		
Basic	$ (0.10)	$ 0.28
Diluted	$ (0.10)	$ 0.27

Basic earnings (loss) per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings (loss) 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 outstanding 885,069 stock options and 329,412 shares of restricted stock that were excluded in the calculation of dilutive shares for the three-month period ended March 31, 2007 due to the net loss for the quarter. The Company excluded 24,167 stock options from the calculation for the three months ended March 31, 2006 because the exercise price of these instruments exceeded the underlying market value of the options.

2. LONG-TERM DEBT:

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

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		March 31, 2007		December 31, 2006
		(In thousands)		
Second Lien Credit Facility	$	222,188	$	147,750
Senior Secured Revolving Credit Facility		-		41,000
Other		7		8
		222,195		188,758
Current maturities		(2,257)		(1,508)
	$	219,938	$	187,250

Second Lien Credit Facility

On December 20, 2006, the Company amended the agreement 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 available under the amended agreement. The net proceeds of $72.1 million were used to repay the $41.0 million of borrowings outstanding under the Senior Secured Revolving Credit Facility and to fund a portion of the Company's capital expenditure program and 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 March 31, 2007, the interest rate was approximately 10.1%, 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.

As of March 31, 2007 the Company had no outstanding borrowings under the Senior Credit Facility. On May 1, 2007, the Company's total borrowing base availability line increased to $74.8 million from $54.25 million.

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 March 31, 2007, the borrowing base was $54.25 million.

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

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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 March 31, 2007, the Company owned less than ten percent of Pinnacle's outstanding equity and accounted for the investment under the cost method. Prior to the April 2006, the Company accounted for its interest in Pinnacle using the equity method. For a detailed discussion of the Company's investment in Pinnacle, see the 2006 Form 10-K.

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 benefit of $1.3 million and a tax expense of $3.7 million for the three-month periods ended March 31, 2007 and 2006, respectively. The rate for the three-month period in 2006 varied from the statutory rate of 35% primarily as a result of the preferred dividend and valuation allowance on Pinnacle.

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. At March 31, 2007, the Company had no material uncertain tax positions.

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 11,385 and 145,183 net shares of common stock during the three months ended March 31, 2007 and 2006, respectively. Shares issued during the three months ended March 31, 2007 consisted of 5,385 shares issued, net of 300 shares forfeited, as restricted stock awards to employees and the balance through the exercise of options granted under the Company's Incentive Plan. Shares issued during the three months ended March 31, 2006 consisted of 137,850 shares issued, net of 4,650 shares forfeited, as restricted stock awards to employees and 7,333 shares issued through the exercise of options granted under the Company's Incentive Plan. The Company also purchased and retired 859 shares to satisfy employee tax withholding obligations in connection with the vesting of the restricted stock during the three months ended March 31, 2007.

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.

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 net gain (loss) on derivatives in Other Income and Expenses in the Consolidated Statements of Income. For the quarters ended March 31, 2007 and 2006, the Company recorded the following related to its derivatives:

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	For the Three Months Ended March 31, 2007	2006
	(In millions)	
Realized gains:		
Natural gas and oil derivatives	$ 2.3	$ 1.3
Interest rate swaps	0.1	0.1
	2.4	1.4
Unrealized gains (losses):		
Natural gas and oil derivatives	$ (8.0)	$ 3.3
Interest rate swaps	(0.1)	0.7
	(8.1)	4.0
Net Gain (Loss) on Derivatives	$ (5.7)	$ 5.4

At March 31, 2007, the Company had the following outstanding derivative positions:

	Swaps		Collars		
Quarter	MMbtu	Average Fixed Price(1)	MMBtu	Average Floor Price(1)	Average Ceiling Price(1)
Second Quarter 2007	819,000	$ 7.42	728,000	$ 7.31	$ 8.87
Third Quarter 2007	828,000	7.39	552,000	7.53	9.10
Fourth Quarter 2007	828,000	7.44	276,000	6.92	8.32
First Quarter 2008	273,000	7.94	546,000	7.32	8.95
Second Quarter 2008	273,000	7.94	364,000	7.35	9.10
Third Quarter 2008	276,000	7.94	368,000	7.35	9.10
Fourth Quarter 2008	276,000	7.94	368,000	7.35	9.10

(1) Based on Houston Ship Channel spot prices.

The fair value of the outstanding derivatives at March 31, 2007 and December 31, 2006 was a liability of $2.0 million and an asset of $6.0 million, respectively.

During the first quarter of 2007, the Company entered into an interest swap agreement covering amounts outstanding under the Second Lien Credit Facility as amended in December 2006. This arrangement is designed to manage the Company's exposure to interest rate fluctuations through December 31, 2007 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 March 31, 2007 were as follows (dollars in thousands):

Quarter	**Notional Amount**	**Fixed LIBOR Rate**
Second Quarter 2007	$ 222,188	5.25%
Third Quarter 2007	221,625	5.25%
Fourth Quarter 2007	221,063	5.25%

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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

In 2006, we drilled 70 gross wells (44.9 net), including 19 gross wells in the onshore Gulf Coast area, 46 gross wells in the Barnett Shale area, one exploratory well in the North Sea and four wells (excluding six injection wells) in the Camp Hill Field and other East Texas areas, with an apparent success rate of 95.7%. During the three months ended March 31, 2007, we drilled 13 (9.8 net) wells with an apparent success rate of 100% that was comprised of: (1) two of the two gross (1.0 net) wells in the onshore Gulf Coast area and (2) eleven of eleven gross (8.8 net) wells in the Barnett Shale area. As of March 31, 2007, we have completed five of these wells and eight are in the process of being completed.

In 2007, we plan to drill 15 gross wells in the onshore Gulf Coast area, 53 gross wells in our Barnett Shale area, 25 to 30 gross wells in our East Texas area, primarily in our Camp Hill oil field, and five wells in other areas. 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. The shortage of available rigs in 2006 delayed the drilling of several wells, slowing our growth in production.

Since our initial public offering, we have grown primarily through the exploration of properties within our project areas, although we consider acquisitions from time to time and may in the future complete acquisitions that we find attractive.

Recent Developments

Our first quarter 2007 production of 3.2 Bcfe declined from fourth quarter 2006 production of 3.7 Bcfe primarily due to: (1) the sale of certain producing oil and gas properties, effective January 1, 2007 (estimated daily production of 2 MMcfe/d), (2) production interruptions due to mechanical problems with the Galloway Gas Unit II #1 well and (3) new production delays on the Baby Ruth #1 (put online in mid March) and certain Barnett Shale wells in Tarrant County awaiting pipeline hookups. By mid April 2007, production had increased to near record levels (an estimated 42,000 Mcfe/d) as the Galloway Gas Unit II #1 well was returned to production and the LL&E #1 production increased appreciably after it was recompleted up hole.

Our average daily production in the second quarter 2007 is expected to be notably higher than the first quarter of 2007 production, based upon the quarter-to-date estimated production and the new production expected from our Doberman #1 (initial production estimated in mid May) and several new Barnett Shale wells, including the three aforementioned wells in Tarrant County (initial production estimated in late May).

In December 2006, we amended the Second Lien Credit Facility to provide for $75.0 million of additional borrowings, which were subsequently drawn on January 3, 2007. We used a portion of the $72.1 million net proceeds to repay the $41.0 million of outstanding borrowings under the Senior Credit Facility. On May 1, 2007, the amended and undrawn borrowing base availability on our Senior Credit Facility was increased to $74.8 million from $54.25 million.

Results of Operations

Three Months Ended March 31, 2007,
Compared to the Three Months Ended March 31, 2006

Oil and natural gas revenues for the three months ended March 31, 2007 increased 3% to $22.6 million from $21.9 million for the same period in 2006. Production volumes for natural gas for the three months ended March 31, 2007 increased to 2.8 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 $2.3 million and $1.3 million for the quarters ended March 31, 2007 and 2006, respectively, decreased 10% to $6.76 per Mcf in the first

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quarter of 2007 from $7.50 per Mcf in the same period in 2006. Average oil prices for the quarter ended March 31, 2007 decreased 9% to $56.23 from $61.65 per barrel in the same period in 2006. The increase in natural gas production volume was principally from the addition of new Barnett Shale wells and production from the Galloway Gas Unit II #1 and Galloway Gas Unit I #2 wells in our onshore Gulf Coast region.

The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for the three months ended March 31, 2007 and 2006:

	For the Three Months Ended March 31,		2007 Period Compared to 2006 Period	
	2007	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	60	67	(7)	(10)%
Natural gas (MMcf)	2,845	2,367	478	20%
Average sales prices				
Oil and condensate (per Bbl)	$ 56.23	$ 61.65	$ (5.42)	(9)%
Natural gas (per Mcf)	6.76	7.50	(0.74)	(10)%
Operating revenues (In thousands)				
Oil and condensate	$ 3,383	$ 4,161	$ (778)	(19)%
Natural gas	19,229	17,756	1,473	8%
Total Operating Revenues	$ 22,612	$ 21,917	$ 695	3%

Oil and natural gas operating expenses for the three months ended March 31, 2007 increased 36% to $4.7 million from $3.5 million for the same period in 2006 primarily as a result of (1) higher lifting costs of $1.3 million primarily attributable to increased production, the increased number of producing wells and the rising costs of oilfield services, (2) higher workover expenses of $0.2 million and (3) increased ad valorem taxes of $0.2 million. The increased costs were partially offset by lower severance taxes of $0.5 million primarily due to high cost gas well tax credits in the Barnett Shale.

Depreciation, depletion and amortization (DD&A) expense for the three months ended March 31, 2007 increased 8% to $8.0 million ($2.51 per Mcfe) from $7.4 million ($2.67 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 March 31, 2007 increased by $0.7 million to $4.9 million from $4.2 million for the corresponding period in 2006 primarily as a result of higher non-cash stock-based compensation expense.

The net loss on derivatives of $5.7 million in the first quarter of 2007 was comprised of (1) $2.4 million of realized gain on net settled derivatives and (2) $8.1 million of net unrealized mark-to-market loss on derivatives. The net gain on derivatives of $5.4 million in the first quarter of 2006 was comprised of (1) $1.4 million of realized gain on net settled derivatives and (2) $4.0 million of net unrealized mark-to-market gain on derivatives.

Interest expense and capitalized interest for the three months ended March 31, 2007 were $6.2 million and ($2.7) million, respectively, as compared to $4.3 million and $(2.1) million for the same period in 2006. The increases in 2007 were largely attributable to the $75.0 million increase from our Second Lien Credit Facility in January 2007.

Income tax expense/(benefit) decreased to $(1.3) million for the three months ended March 31, 2007 from the $3.7 million expense for the same period in 2006 primarily due to the $8.1 million non-cash mark-to-market loss on derivatives.

Net loss for the three months ended March 31, 2007 was $(2.5) million as a result of the factors described above.

Liquidity and Capital Resources

During the three months ended March 31, 2007, capital expenditures, net of proceeds from property sales, exceeded our net cash flows provided by operating activities. For future capital expenditures in 2007, we expect to use cash on hand, cash generated by operations and available draws on the Senior Credit Facility to fund our planned drilling, lease acquisition and geological and geophysical

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expenditures. We may need to seek other financing alternatives, including additional debt or equity financings to fully fund our 2007 capital program.

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.

Our primary sources of liquidity have included funds generated by operations, proceeds from the issuance of various securities, including our common stock, preferred stock and warrants (including our public offering in 2004 and our private placements in 2005 and 2006 of our common stock), and borrowings under our credit facilities. Our liquidity position has been enhanced by the availability of funds under the Senior Credit Facility.

Cash flows provided by operating activities were $19.2 million and $17.5 million for the three months ended March 31, 2007 and 2006, respectively. The increase was primarily due to working capital changes.

The Company's Senior Credit Facility provides for maximum borrowings of $200 million. At May 1, 2007, $8.0 million was drawn and outstanding under a borrowing base availability limit of $74.8 million. The next scheduled borrowing base redetermination date is November 1, 2007.

During the first quarter of 2007, we increased our borrowings under our Second Lien Credit Facility by $75 million. A portion of the net proceeds from this borrowing was used to repay $41 million outstanding under the Senior Credit Facility and fund first quarter 2007 capital expenditures.

In April 2007, we filed a universal shelf registration statement on Form S-3 with the SEC which may serve as the platform for future issuances, as needed, of publicly registered securities.

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 reporting periods. 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 affect these significant estimates materially 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 $1.4 million and $1.0 million for the three months ended March 31, 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 March 31, 2007 and 2006 was $2.47 and $2.67, 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 through depreciation, depletion and amortization.

In connection with our March 31, 2007 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase or decrease in commodity prices at March 31, 2007 would have increased or decreased the Full Cost Ceiling test cushion by approximately $50 million. The aforementioned price sensitivity is as of March 31, 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 March 2007 of approximately $132 million was based upon average realized oil and natural gas prices of $61.09 per Bbl and $7.54 per Mcf, respectively, or a volume weighted average price of $48.39 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $36.75 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 127.0 Bcfe and 126.2 Bcfe of proved undeveloped reserves at March 31, 2007 and December 31, 2006, respectively, representing 58% and 60% of our total proved reserves. As of March 31, 2007

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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.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 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 March 31, 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

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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.

Derivative Instruments

We use derivatives to manage price and interest rate risk underlying our oil and 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 the first quarter of 2007, we entered into an interest rate swap agreement with respect to amounts outstanding under the amended Second Lien Credit Facility. The arrangement is designed to manage our exposure to interest rate fluctuations during the period beginning January 1, 2007 through December 31, 2007 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 mark-to-market 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 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.

Total oil sold under swaps and collars during the three months ended March 31, 2007 and 2006 was zero and 18,000 Bbls, respectively. Total natural gas sold under swaps and collars during the three months ended March 31, 2007 and 2006 was 1,887,000 MMBtu and 1,082,000 MMBtu, respectively. The net gain realized by us under such hedging arrangements was $2.3 million and $1.3

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million for the three months ended March 31, 2007 and 2006, respectively. These net gains are included in net gain (loss) on derivatives, in the Statements of Income.

For the quarters ended March 31, 2007 and 2006, the unrealized gain (loss) on oil and natural gas derivatives was $(8.0) million and $3.3 million, respectively. The net gains (losses) are reported as net gain (loss) on derivatives in the Consolidated Statements of Income.

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 first quarter of 2007, a 10% change in the price per Mcf of gas sold would have changed revenue by $1.9 million. A 10% change in the price per barrel of oil would have changed revenue by $0.3 million.

At March 31, 2007, we had the following outstanding natural gas derivative positions:

	Swaps		Collars		
Quarter	**MMbtu**	**Average Fixed Price**[(1)]	**MMBtu**	**Average Floor Price**[(1)]	**Average Ceiling Price**[(1)]
Second Quarter 2007	819,000	$ 7.42	728,000	$ 7.31	$ 8.87
Third Quarter 2007	828,000	7.39	552,000	7.53	9.10
Fourth Quarter 2007	828,000	7.44	276,000	6.92	8.32
First Quarter 2008	273,000	7.94	546,000	7.32	8.95
Second Quarter 2008	273,000	7.94	364,000	7.35	9.10
Third Quarter 2008	276,000	7.94	368,000	7.35	9.10
Fourth Quarter 2008	276,000	7.94	368,000	7.35	9.10

(1) Based on Houston Ship Channel spot prices.

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 implement the Company's business strategy, future exploration activity, production rates (including average daily production in the second quarter of 2007), exploration and development expenditures, the Company's initiatives designed to eliminate material weaknesses in the Company's internal control over financial reporting and the results of these initiatives 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 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

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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, the results of audits and assessments and other factors detailed in 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 additional 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 March 31, 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; provided, that we were required to seek relief under Rule 12b-25 in connection with the filing of our Annual Report on Form 10-K for the year ended December 31, 2006 as a result of the continued transition of newly hired accounting professionals in the second half of 2006 and the first quarter of 2007. 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 March 31, 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 other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 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 first 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**
January 2007	233	$ 27.87	-	-
February 2007	272	30.01	-	-
March 2007	354	29.48	-	-
Total	859	$ 29.20	-	-

(1) The 859 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)).

†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).

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

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

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

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

† Incorporated herein by reference as indicated.

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SIGNATURES

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

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