

CARRIZO OIL & GAS INC
Form 10-Q
August 08, 2007

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT
OF 1934

For the quarterly period ended **June 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
(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 NO

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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 August 1, 2007, the latest practicable date, was 26,170,188.

CARRIZO OIL & GAS, INC.

**FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2007
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Index**CARRIZO OIL & GAS, INC.****CONSOLIDATED BALANCE SHEETS**

ASSETS	June 30, 2007	December 31, 2006
	(Unaudited)	
	(In thousands)	
CURRENT ASSETS:		
Cash and cash equivalents	\$ 7,503	\$ 5,408
Accounts receivable, trade (net of allowance for doubtful accounts of \$1,363 and \$1,639 at June 30, 2007 and December 31, 2006, respectively)	33,371	25,871
Advances to operators	1,226	2,107
Fair value of derivative financial instruments	1,915	5,737
Other current assets	1,371	1,934
Total current assets	45,386	41,057
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of \$105,151 and \$95,136 at June 30, 2007 and December 31, 2006, respectively)		
	524,847	445,447
DEFERRED FINANCING COSTS	6,587	4,817
INVESTMENT IN PINNACLE GAS RESOURCES, INC.	18,709	2,771
OTHER ASSETS	649	703
	\$ 596,178	\$ 494,795
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	\$ 36,579	\$ 32,570
Accrued liabilities	21,843	20,885
Advances for joint operations	3,704	1,100
Current maturities of long-term debt	2,255	1,508
Deferred income tax	670	2,008
Total current liabilities	65,051	58,071
LONG-TERM DEBT, NET OF CURRENT MATURITIES		
	251,375	187,250
ASSET RETIREMENT OBLIGATION	5,073	3,625
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	250	-
DEFERRED INCOME TAXES	42,769	32,738
DEFERRED CREDITS	762	837
COMMITMENTS AND CONTINGENCIES	-	-

SHAREHOLDERS' EQUITY:

Common stock, par value \$0.01 (40,000 shares authorized with 26,164 and 25,981 issued and outstanding at June 30, 2007 and December 31, 2006, respectively)	262	260
Additional paid-in capital	173,347	168,469
Retained earnings	55,467	49,875
Accumulated other comprehensive income	10,390	-
Unearned compensation - restricted stock	(8,568)	(6,330)
Total shareholders' equity	230,898	212,274
	\$ 596,178	\$ 494,795

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

Index**CARRIZO OIL & GAS, INC.****CONSOLIDATED STATEMENTS OF INCOME**
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2007	2006	2007	2006
	(In thousands except per share amounts)			
OIL AND NATURAL GAS REVENUES	\$ 32,891	\$ 16,477	\$ 55,503	\$ 38,394
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	5,560	3,630	10,263	7,087
Depreciation, depletion and amortization	10,805	6,598	18,843	14,036
General and administrative (inclusive of stock-based compensation expense of \$1,013 and \$630 for the three months ended June 30, 2007 and 2006, respectively, and \$1,992 and \$1,189 for the six months ended June 30, 2007 and 2006, respectively)	4,339	3,143	9,217	7,351
Accretion expense related to asset retirement obligations	88	79	176	158
Total costs and expenses	20,792	13,450	38,499	28,632
OPERATING INCOME	12,099	3,027	17,004	9,762
OTHER INCOME AND EXPENSES:				
Gain (loss) on derivatives, net	4,080	3,030	(1,631)	8,403
Equity in income of Pinnacle Gas Resources, Inc.	-	-	-	35
Other income and expenses, net	140	169	256	173
Loss on early extinguishment of debt	-	(282)	-	(282)
Interest income	110	279	454	644
Interest expense	(6,529)	(4,594)	(12,683)	(8,869)
Capitalized interest	2,719	2,416	5,405	4,494
INCOME BEFORE INCOME TAXES	12,619	4,045	8,805	14,360
INCOME TAXES	(4,482)	(1,474)	(3,213)	(5,138)

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NET INCOME	\$	8,137	\$	2,571	\$	5,592	\$	9,222
BASIC EARNINGS PER COMMON SHARE	\$	0.32	\$	0.11	\$	0.22	\$	0.38
DILUTED EARNINGS PER COMMON SHARE	\$	0.31	\$	0.10	\$	0.21	\$	0.37
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:								
BASIC		25,702		24,215		25,680		24,191
DILUTED		26,553		24,971		26,508		24,908

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

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

	For the Six Months Ended June 30,	
	2007	2006
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	\$ 5,592	\$ 9,222
Adjustment to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	18,843	14,036
Fair value loss (gain) of derivative financial instruments	4,383	(5,569)
Accretion of discounts on asset retirement obligations and debt	176	158
Stock-based compensation	1,992	1,189
Provision for allowance for doubtful accounts	(275)	-
Equity in loss of Pinnacle Gas Resources, Inc.	-	(35)
Deferred income taxes	3,011	4,945
Other	(163)	179
Changes in operating assets and liabilities		
Accounts receivable	(7,224)	5,903
Other assets	563	1,791
Accounts payable	8,399	(1,282)
Accrued liabilities	(724)	1,133
Net cash provided by operating activities	34,573	31,670
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(98,281)	(91,843)
Change in capital expenditure accrual	(1,855)	1,610
Proceeds from the sale of properties	1,405	23,594
Advances to operators	880	(377)
Advances for joint operations	2,604	1,451
Other	88	(295)
Net cash used in investing activities	(95,159)	(65,860)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from debt issuance and borrowings	107,000	35,000
Debt repayments	(42,129)	(15,779)
Stock options exercised	777	565
Deferred loan costs and other	(2,967)	(529)
Net cash provided by financing activities	62,681	19,257
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,095	(14,933)
CASH AND CASH EQUIVALENTS, beginning of period	5,408	28,725
CASH AND CASH EQUIVALENTS, end of period	\$ 7,503	\$ 13,792

CASH PAID FOR INTEREST (NET OF AMOUNTS CAPITALIZED)	\$	6,204	\$	3,628
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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 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 \$2.3 million and \$1.7 million for the six months ended June 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 June 30, 2007 and 2006 was \$2.54 and \$2.70, 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 June 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 \$10.4, 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 six months ended June 30, 2007 and 2006, respectively. The Company paid no income taxes during the six months ended June 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 June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(In millions)			
Stock Option	\$ 0.1	\$ 0.1	\$ 0.2	\$ 0.2
Restricted Stock	0.9	0.5	1.8	1.0
Total Stock-Based Compensation	\$ 1.0	\$ 0.6	\$ 2.0	\$ 1.2

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 June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Chevron/Texaco	-	12%	-	13%
Reichmann Petroleum	-	12%	-	12%
Cokinos Natural Gas Company	11%	-	-	-
Houston Pipeline Co.	-	-	13%	-
Crosstex Energy Services	19%	-	16%	-
Energy Transfer	15%	-	10%	-

Earnings Per Share

Supplemental earnings per share information is provided below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(In thousands except per share amounts)			
Net income	\$ 8,137	\$ 2,571	\$ 5,592	\$ 9,222
Average common shares outstanding				
Weighted average common shares outstanding	25,702	24,215	25,680	24,191
Stock options and warrants	851	756	828	717
Diluted weighted average common shares outstanding	26,553	24,971	26,508	24,908
Earnings per common share				
Basic	\$ 0.32	\$ 0.11	\$ 0.22	\$ 0.38

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

	June 30, 2007	December 31, 2006
	(In thousands)	
Second Lien Credit Facility	\$ 221,625	\$ 147,750
Senior Secured Revolving Credit Facility	32,000	41,000
Other	5	8
	253,630	188,758
Current maturities	(2,255)	(1,508)
	\$ 251,375	\$ 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 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 June 30, 2007, the interest rate was approximately 10.11%, 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 June 30, 2007, the Company had \$32.0 million outstanding under the Senior Credit Facility.

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 June 30, 2007, the borrowing base was \$74.8 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 and customary events of default under the terms of the Senior Credit Facility. 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 June 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 June 30, 2007, Carrizo increased the book value of its Pinnacle investment by \$16.0 million, \$10.4 million net of tax, and reported the fair value of the stock at \$18.7 million (based on the closing price of Pinnacle’s common stock on June 30, 2007).

In June of 2007, Carrizo sold 41,894 shares 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.

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 \$4.5 million and \$1.5 million for the three-month periods ended June 30, 2007 and 2006, respectively, and \$3.2 million and \$5.1 million for the six-month periods ended June 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 June 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 jurisdiction.

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 186,665 and 292,593 net shares of common stock during the six months ended June 30, 2007 and 2006, respectively. Shares issued during the six months ended June 30, 2007 consisted of 103,933 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 six months ended June 30, 2006 consisted of 198,793 shares issued, net of 21,650 shares forfeited, as restricted stock awards to employees and 93,800 shares issued through the exercise of options granted under the Company's Incentive Plan. The Company also purchased and retired 3,311 and 794 shares to satisfy employee tax withholding obligations in connection with the vesting of the restricted stock during the six months ended June 30, 2007 and 2006, respectively.

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 gain (loss) on derivatives, net in Other Income and

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Expenses in the Consolidated Statements of Income. For the three and six-month periods ended June 30, 2007 and 2006, the Company recorded the following related to its derivatives:

	Three Months Ended June 30, 2007		Six Months Ended June 30, 2006	
	2007	2006	2007	2006
	(In millions)			
Realized gains:				
Natural gas and oil derivatives	\$ 0.3	\$ 1.2	\$ 2.6	\$ 2.5
Interest rate swaps	0.1	0.2	0.2	0.3
	0.4	1.4	2.8	2.8
Unrealized gains (losses):				
Natural gas and oil derivatives	\$ 3.5	\$ 1.3	\$ (4.5)	\$ 4.6
Interest rate swaps	0.2	0.3	0.1	1.0
	3.7	1.6	(4.4)	5.6
Gain (loss) on derivatives, net	\$ 4.1	\$ 3.0	\$ (1.6)	\$ 8.4

The fair value of the outstanding derivatives at June 30, 2007 and December 31, 2006 was an asset of \$1.6 million and \$6.0 million, respectively.

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

Quarter	Swaps		Collars		
	MMbtu	Average Fixed Price ⁽¹⁾	MMBtu	Average Floor Price ⁽¹⁾	Average Ceiling Price ⁽¹⁾
Third Quarter 2007	828,000	\$ 7.39	920,000	\$ 7.31	\$ 8.95
Fourth Quarter 2007	828,000	7.44	644,000	7.24	8.84
First Quarter 2008	273,000	7.94	910,000	7.71	9.49
Second Quarter 2008	273,000	7.94	546,000	7.33	9.07
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.

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 June 30, 2007 were as follows (dollars in thousands):

Quarter	Notional Amount	Fixed LIBOR Rate
Third Quarter 2007	\$ 221,625	5.25%
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 second quarter 2007 included record setting results – record production of 4.2 Bcfe and record revenues of \$32.9 million. The key drivers to our success for the three and six-month periods ended June 30, 2007 include the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the six months ended June 30, 2007, we drilled 25 gross wells (19.1 net wells) with an apparent success rate of 100% that was comprised of: (1) 22 of 22 gross wells (18.0 net wells) in the Barnett Shale area, (2) two of two gross wells (1.0 net wells) in the onshore Gulf Coast area and (3) one of one gross well (0.15 net well) in the North Sea. We also drilled six gross service wells (6.0 net wells) in the Camp Hill area. At June 30, 2007, we had eleven gross wells that were awaiting completion or pipeline connections.

Production. Our second quarter production of 4.2 Bcfe, or 46.2 Mmcfe/d was a record high. The second quarter production increased 74% from the second quarter 2006 production of 2.4 Bcfe and increased 30% from the first quarter 2007 production of 3.2 Bcfe. The increase was due primarily to new production from the three Campuzano wells in the Barnett Shale area put on line in early May 2007, and the Baby Ruth #1 and Doberman #1 in the Gulf Coast area put on line in mid-March and early May 2007, respectively.

Commodity prices. Natural gas prices continued to increase during the second quarter. We realized \$7.54 per Mcf for natural gas (excluding the impact of our hedges) during the second quarter of 2007, 20% higher than the price in the second quarter of 2006 and 12% higher than the price in the first 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. On May 1, 2007, our borrowing base availability on our Senior Secured Credit Facility increased from \$54.25 million to \$74.8 million.

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, 15 gross wells in the Gulf Coast area, 25 to 30 gross wells in our Camp Hill field and five wells in other areas. In the Barnett Shale, we plan to utilize two drillings rigs in SE Tarrant County, Texas for at least 18 months 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, Parker and Hood 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. The shortage of available rigs in 2006 delayed the drilling of several wells, slowing our growth in production.

- We expect to continue our efforts to grow production. At August 1, 2007, we had estimated daily production of 49 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 are drilling our first horizontal well in the Floyd Shale and should begin fracture stimulation of three zones in the third quarter. We are assessing development plans for the Huntington discovery in Block 22-14b in the North Sea. An appraisal well is scheduled for the fourth quarter of 2007 pending drilling rig availability.

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- We expect to hedge production to decrease commodity price fluctuations. At June 30, 2007, we had hedged approximately 6,500,000 MMBtus of natural gas production through 2008.

Results of Operations

Three Months Ended June 30, 2007,

Compared to the Three Months Ended June 30, 2006

Oil and natural gas revenues for the three months ended June 30, 2007 increased to \$32.9 million from \$16.5 million for the same period in 2006. Production volumes for natural gas for the three months ended June 30, 2007 increased to 3.8 Bcf from 2.2 Bcf for the same period in 2006. Average natural gas prices, excluding the impact of the gain from our cash settled derivatives of \$0.3 million and \$1.2 million for the quarters ended June 30, 2007 and 2006, respectively, increased to \$7.54 per Mcf in the second quarter of 2007 from \$6.29 per Mcf in the same period in 2006. Average oil prices for the quarter ended June 30, 2007 decreased 4% to \$64.25 from \$66.99 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 and production from the Baby Ruth and Doberman wells in the Gulf Coast and the successful 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 three months ended June 30, 2007 and 2006:

	Three Months Ended		2007 Period Compared to 2006 Period	
	June 30, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	63	43	20	47%
Natural gas (MMcf)	3,827	2,165	1,662	77%
Average sales prices				
Oil and condensate (per Bbl)	\$ 64.25	\$ 66.99	\$ (2.74)	(4)%
Natural gas (per Mcf)	7.54	6.29	1.25	20%
Operating revenues (In thousands)				
Oil and condensate	\$ 4,041	\$ 2,857	\$ 1,184	41%
Natural gas	28,850	13,620	15,230	112%
Total Operating Revenues	\$ 32,891	\$ 16,477	\$ 16,414	100%

Oil and natural gas operating expenses for the three months ended June 30, 2007 increased 53% to \$5.6 million from \$3.6 million for the same period in 2006 primarily as a result of (1) higher lifting costs of \$0.8 million primarily attributable to increased production, the increased number of producing wells and the rising costs of oilfield services, (2) higher severance taxes of \$0.4 million, (3) increased ad valorem taxes of \$0.3 million and (4) increased transportation and other product costs of \$0.4 million.

Depreciation, depletion and amortization (DD&A) expense for the three months ended June 30, 2007 increased 64% to \$10.8 million (\$2.57 per Mcfe) from \$6.6 million (\$2.72 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 June 30, 2007 increased by \$1.2 million to \$4.3 million from \$3.1 million for the corresponding period in 2006 primarily as a result of the increase in staff and increased stock-based compensation.

The net gain on derivatives of \$4.1 million in the second quarter of 2007 was comprised of (1) \$0.4 million of realized gain on net cash settled derivatives and (2) \$3.7 million of net unrealized mark-to-market gain on derivatives. The net gain on derivatives of \$3.0 million in the second quarter of 2006 was comprised of (1) \$1.4 million of realized gain on net cash settled derivatives and (2) \$1.6 million of net unrealized mark-to-market gain on derivatives.

Interest expense and capitalized interest for the three months ended June 30, 2007 were \$6.5 million and (\$2.7) million, respectively, as compared to \$4.6 million and \$(2.4) million for the same period in 2006. The increases in 2007 were largely attributable to the

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\$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 \$4.5 million for the three months ended June 30, 2007 from the \$1.5 million expense for the same period in 2006 as a result of higher income.

*Six Months Ended June 30, 2007,
Compared to the Six Months Ended June 30, 2006*

Oil and natural gas revenues for the six months ended June 30, 2007 increased 45% to \$55.5 million from \$38.4 million for the same period in 2006. Production volumes for natural gas for the six months ended June 30, 2007 increased to 6.7 Bcf from 4.5 Bcf for the same period in 2006. Average natural gas prices excluding the impact of the gain from our cash settled derivatives of \$2.6 million and \$2.5 million for the six months ended June 30, 2007 and 2006, respectively, increased 4% to \$7.21 per Mcf in the first half of 2007 from \$6.92 per Mcf in the same period in 2006. Average oil prices for the six months ended June 30, 2007 decreased 5% to \$60.33 from \$63.72 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, the addition of the Baby Ruth and Doberman wells in the Gulf Coast and the successful 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 six months ended June 30, 2007 and 2006:

	Six Months Ended		2007 Period Compared to 2006 Period	
	June 30, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	123	110	13	12%
Natural gas (MMcf)	6,672	4,533	2,139	47%
Average sales prices				
Oil and condensate (per Bbl)	\$ 60.33	\$ 63.72	\$ (3.39)	(5)%
Natural gas (per Mcf)	7.21	6.92	0.29	4%
Operating revenues (In thousands)				
Oil and condensate	\$ 7,424	\$ 7,018	\$ 406	6%
Natural gas	48,079	31,376	16,703	53%
Total Operating Revenues	\$ 55,503	\$ 38,394	\$ 17,109	45%

Oil and natural gas operating expenses for the six months ended June 30, 2007 increased 45% to \$10.3 million from \$7.1 million for the same period in 2006 primarily as a result of (1) higher lifting costs of \$1.6 million primarily attributable to increased production, the increased number of producing wells and the rising costs of oilfield services, (2) higher workover expenses of \$0.1 million, (3) increased ad valorem taxes of \$0.5 million and (4) increased transportation and other product costs of \$0.9 million.

DD&A expense for the six months ended June 30, 2007 increased 34% to \$18.8 million (\$2.54 per Mcfe) from \$14.0 million (\$2.70 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 six months ended June 30, 2007 increased by \$1.9 million to \$9.2 million from \$7.3 million for the corresponding period in 2006 due primarily to increased staffing and increased stock-based compensation.

The net loss on derivatives of \$1.6 million in the first half of 2007 was comprised of (1) \$2.8 million of realized gain on net cash settled derivatives and (2) \$4.4 million of net unrealized mark-to-market loss on derivatives. The net gain on derivatives of \$8.4 million in the first half of 2006 was comprised of (1) \$2.8 million of realized gain on net cash settled derivatives and (2) \$5.6 million of net unrealized mark-to-market gain on derivatives.

Interest expense and capitalized interest for the six months ended June 30, 2007 were \$12.7 million and (\$5.4) million, respectively, as compared to \$8.9 million and \$(4.5) million for the same period in 2006. The increases in 2007 were largely attributable to the \$75.0

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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 \$3.2 million for the six months ended June 30, 2007 from the \$5.1 million for the same period in 2006 as a result of lower income.

Liquidity and Capital Resources

During the six months ended June 30, 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 expenditures. We may need to seek other financing alternatives, including additional debt or equity financings, to fully fund our 2007 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.

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 and Second Lien Credit Facility.

Cash flows provided by operating activities were \$34.6 million and \$31.7 million for the six months ended June 30, 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 August 1, 2007, \$44.0 million was drawn and outstanding under a borrowing base availability limit of \$74.8 million. The next scheduled borrowing base redetermination date is September 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.

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:

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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 \$2.3 million and \$1.7 million for the six months ended June 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 June 30, 2007 and 2006 was \$2.54 and \$2.70, 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 June 30, 2007 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase or decrease in commodity prices at June 30, 2007 would have increased or decreased the Full Cost Ceiling test cushion by approximately \$51.0 million. The aforementioned price sensitivity is as of June 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 June 2007 of approximately \$118.2 million was based upon average realized oil and natural gas prices of \$65.68 per Bbl and \$7.03 per Mcf, respectively, or a volume weighted average price of \$46.84 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of \$36.05 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

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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 116.6 Bcfe and 126.2 Bcfe of proved undeveloped reserves at June 30, 2007 and December 31, 2006, respectively, representing 54% and 60% of our total proved reserves. As of June 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.

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%.

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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 June 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.

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 six months of 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 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.

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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 six-months period ended June 30, 2007 and 2006, and the unrealized gain/(loss) associated with the outstanding oil and natural gas derivatives at June 30, 2007 and 2006.

	Three months ended		Six months ended	
	June 30,		June 30,	
	2007	2006	2007	2006
Oil positions settled (Bbls)	-	18,200	-	36,200
Natural gas positions settled (MMBtu)	1,547,000	1,275,000	3,434,000	2,357,000
Realized gain (\$ millions) ⁽¹⁾	\$ 0.3	\$ 1.2	\$ 2.6	\$ 2.5
Unrealized gain/(loss) (\$ millions) ⁽¹⁾	\$ 3.5	\$ 1.3	\$ (4.5)	\$ 4.6

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

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

Quarter	Swaps			Collars	
	MMbtu	Average Fixed Price⁽¹⁾	MMBtu	Average Floor Price⁽¹⁾	Average Ceiling Price⁽¹⁾
Third Quarter 2007	828,000	\$ 7.39	920,000	\$ 7.31	\$ 8.95
Fourth Quarter 2007	828,000	7.44	644,000	7.24	8.84
First Quarter 2008	273,000	7.94	910,000	7.71	9.49
Second Quarter 2008	273,000	7.94	546,000	7.33	9.07
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.

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

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month. For the second quarter of 2007, a 10% change in the price per Mcf of gas sold would have changed revenue by \$0.3 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 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 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 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, 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 June 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 June 30, 2007, that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Index**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 second 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
April 2007	272	\$ 36.01	-	-
May 2007	2,180	39.30	-	-
June 2007	-	-	-	-
Total	2,452	\$ 38.94	-	-

(1) The 2,452 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

At the Annual Meeting of Carrizo Oil & Gas, Inc., held on May 22, 2007, there were represented by person or by proxy 20,807,168 shares out of 26,001,692 entitled to vote as of the record date, constituting a quorum.

The matters submitted to a vote of shareholders were:

(1) the reelection of Mr. S.P. Johnson IV; Mr. Steven A. Webster; Mr. Thomas L. Carter, Jr.; Mr. Paul B. Loyd, Jr.; Mr. F. Gardner Parker; Mr. Roger A. Ramsey and Mr. Frank A. Wojtek as directors, and

(2) the approval of the appointment of Pannell Kerr Forster of Texas, P.C. as the Company's Independent Registered Public Accounting Firm for the fiscal year ending December 31, 2007.

With respect to the election of directors, the following number of votes were cast for the nominees: 20,400,910 for Mr. Johnson and 406,258 withheld; 14,047,668 for Mr. Webster and 6,759,500 withheld; 20,567,337 for Mr. Carter and 239,831 withheld; 19,977,125 for Mr. Loyd and 830,043 withheld; 19,735,525 for Mr. Parker and 1,071,643 withheld; 20,597,150 for Mr. Ramsey and 210,018 withheld; 20,401,471 for Mr. Wojtek and 405,697 withheld. There were no abstentions in the election of directors.

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With respect to the approval of the appointment of Pannell Kerr Forster of Texas, P.C. as the Company's Independent Registered Public Accounting Firm, 20,792,025 votes were cast for the appointment, 10,824 votes were cast against, and 4,319 votes abstained.

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: August 8, 2007

By: /s/S. P. Johnson, IV
President and Chief Executive
Officer
(Principal Executive Officer)

Date: August 8, 2007

By: /s/Paul F. Boling
Chief Financial Officer
(Principal Financial and Accounting
Officer)