CARRIZO OIL & GAS INC
Form 10-Q
May 10, 2006

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, 2006**

[ ] 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, 2006, the latest practicable date, was 24,404,063.

CARRIZO OIL & GAS, INC.

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2006
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CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS		December 31, 2005		March 31, 2006
		(In thousands except share amounts)		
CURRENT ASSETS:				
Cash and cash equivalents	$	28,725	$	25,096
Accounts receivable, trade (net of allowance for doubtful accounts of $253 at December 31, 2005 and March 31, 2006)		24,898		21,959
Advances to operators		3,049		3,582
Fair value of derivative financial instruments		-		1,566
Other current assets		3,512		2,015
Total current assets		60,184		54,218
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $71,581 and $77,091 at December 31, 2005 and March 31, 2006, respectively)		314,074		342,831
INVESTMENT IN PINNACLE GAS RESOURCES, INC.		2,687		2,771
DEFERRED FINANCING COSTS		5,858		5,557
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		-		253
OTHER ASSETS		298		240
	$	383,101	$	405,870
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES:				
Accounts payable, trade	$	17,571	$	16,635
Accrued liabilities		23,321		27,575
Advances for joint operations		5,887		15,449
Current maturities of long-term debt		1,535		1,520
Fair value of derivative financial instruments		1,563		-
Other current liabilities		-		548
Total current liabilities		49,877		61,727
LONG-TERM DEBT, NET OF CURRENT MATURITIES		147,759		147,382
ASSET RETIREMENT OBLIGATION		3,235		3,461
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		2,295		1,012
DEFERRED INCOME TAXES		24,550		27,054
COMMITMENTS AND CONTINGENCIES		-		-

SHAREHOLDERS' EQUITY:				
Common stock, par value $0.01 (40,000,000 shares authorized with 24,251,430 and				
24,391,963 issued and outstanding at December 31, 2005 and				
March 31, 2006, respectively)		243		244
Additional paid-in capital		124,586		130,947
Retained earnings		31,627		38,277
Unearned compensation - restricted stock		(1,071)		(4,234)
Total shareholders' equity		155,385		165,234
	$	383,101	$	405,870

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, 2005 (Restated)	2006
	(In thousands except per share amounts)	
OIL AND NATURAL GAS REVENUES	$ 15,249	$ 21,917
COSTS AND EXPENSES:		
Oil and natural gas operating expenses		
(exclusive of depletion, depreciation and amortization shown separately below)	2,235	3,457
Depreciation, depletion and amortization	4,678	7,438
General and administrative (inclusive of stock-based compensation of 976 and 559 at March 31, 2005 and 2006, respectively)	3,576	4,208
Accretion expense related to asset retirement obligations	18	79
Total costs and expenses	10,507	15,182
OPERATING INCOME	4,742	6,735
OTHER INCOME AND EXPENSES:		
Mark-to-market gain (loss) on derivatives, net	(1,727)	5,373
Equity in income (loss) of Pinnacle Gas Resources, Inc.	(1,068)	35
Other income and expenses	8	4
Interest income	44	365
Interest expense	(1,596)	(4,275)
Capitalized interest	988	2,078
INCOME BEFORE INCOME TAXES	1,391	10,315
INCOME TAXES	(909)	(3,664)
NET INCOME	$ 482	$ 6,651
BASIC EARNINGS PER COMMON SHARE	$ 0.02	$ 0.28
DILUTED EARNINGS PER COMMON SHARE	$ 0.02	$ 0.27
WEIGHTED AVERAGE SHARES OUTSTANDING:		
BASIC	22,501,696	24,166,801
DILUTED	23,402,248	24,845,302

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,	
	2005 (Restated)	2006
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 482	$ 6,651
Adjustment to reconcile net income to net		
cash provided by operating activities-		
Depreciation, depletion and amortization	4,678	7,438
Fair value loss (gain) of derivative financial instruments	1,936	(4,016)
Accretion of discounts on asset retirement obligations and debt	141	79
Stock option compensation	976	559
Equity in (income) loss of Pinnacle Gas Resources, Inc.	1,068	(35)
Deferred income taxes	862	3,598
Other	126	344
Changes in operating assets and liabilities		
Accounts receivable	3,495	2,939
Other assets	406	462
Accounts payable	(6,839)	(2,238)
Other liabilities	48	1,761
Net cash provided by operating activities	7,379	17,542
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(19,243)	(41,223)
Change in capital expenditure accrual	(1,212)	6,559
Proceeds from the sale of properties	9,000	5,195
Advances to operators	415	(533)
Advances for joint operations	1,327	9,562
Other	-	(172)
Net cash used in investing activities	(9,713)	(20,612)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from common stock activity:		
Warrants exercised	1,000	-
Stock options exercised and other	1,010	99
Advances under Borrowing Base Facility	5,024	-
Debt repayments	(2,025)	(547)
Deferred loan costs	(79)	(42)
Other	-	(69)
Net cash provided by (used in) financing activities	4,930	(559)
	2,596	(3,629)

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS				
CASH AND CASH EQUIVALENTS, beginning of period		5,668		28,725
CASH AND CASH EQUIVALENTS, end of period	$	8,264	$	25,096
SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for interest (net of amounts capitalized)	$	608	$	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 subsidiary 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 results for the quarter ended March 31, 2005 have been restated as a result of changes in the accounting and valuation of derivatives for interest rate swaps and oil and natural gas hedges, as further discussed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005 (the "2005 Form 10-K/A"). The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the 2005 Form 10-K/A.

Reclassifications

Certain reclassifications have been made to 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 disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. 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, bad debts, derivatives, stock-based compensation, contingencies and 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. Results of drilling, testing and production subsequent to the date of the estimate 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 the Company's common stock and corresponding volatility and the Company's 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

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 $0.5 million and $1.0 million for the three months ended March 31, 2005 and 2006, respectively. Maintenance and repairs are expensed as incurred.

Oil and natural gas properties are amortized based on the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not amortized until proved reserves associated with the projects can be determined or until

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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 are impaired, the amount of impairment is added to the proved oil and natural gas 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, 2005 and 2006 was $1.99 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.

In March 2006, we sold our average 20 percent working interest in 13 non-operated wells in the Barnett Shale area for approximately $5.2 million. The proceeds will be used to fund our drilling program and general corporate purposes.

The net capitalized costs of proved oil and natural gas properties are subject to a "ceiling test" which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves, based on current economic and operating conditions. If net capitalized costs exceed this limit, the excess is charged to operations through depreciation, depletion and amortization. For the three months ended March 31, 2005 and 2006, the Company did not have any charges associated with its ceiling test analysis.

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, 2005 does not include interest paid-in-kind of $0.7 million and the net exercise of $80,000 of warrants. The Company paid no taxes for the three months ended March 31, 2005 and 2006.

Stock-Based Compensation

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"), which authorizes the granting of incentive stock options and restricted stock awards to directors and selected employees. For the three months ended March 31, 2005 and 2006, the Company recognized $1.0 million and $0.6 million, respectively, for stock-based compensation. The 2005 expense is comprised of stock-based compensation expense associated with the repricing of certain stock options and the 2006 expense is comprised of $0.1 million of expense associated with stock options and $0.5 million associated with restricted stock issuances.

Stock Options. Prior to January 1, 2006, the Company accounted for stock-based compensation utilizing the intrinsic value method as permitted under Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." APB Opinion No. 25 recognized compensation expense only when the market price on the grant date exceeded the option exercise price. In February 2000, the Company repriced certain employee and director stock options. The Company accounted for these repriced stock options in accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 44 "Accounting for Certain Transactions involving Stock Based Compensation - An Interpretation of APB No. 25" ("FIN 44") which prescribes the variable plan accounting treatment for repriced stock options. Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company's common stock to the extent that the market value exceeds the exercise price of the option until the options are exercised, forfeited, or expire unexercised. Under these accounting guidelines, the Company recognized $1.0 million of stock-based compensation expense for the three month period ended March 31, 2005.

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"), which requires companies to measure all stock-based compensation awards using the fair value method and record such expense in the financial statements over the vesting period of the options which is generally three years. The Company implemented SFAS No. 123(R) using the modified prospective transition method. The Company recognizes compensation expense for all unvested options outstanding as of January 1, 2006, options issued after January 1, 2006, and those options that are subsequently modified, repurchased or cancelled. The compensation expense is based on the grant-date fair value of the options and expensed over the vesting period. The Company did not restate prior periods to reflect the impact of adopting the new standard. As part of the adoption of SFAS No. 123(R), the Company stopped recording stock compensation associated with the February 2000 repriced options mentioned above and the liability associated with the repriced options totaling $2.6 million was reclassed to equity during the first quarter of 2006.

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The Company uses the Black-Scholes option pricing model to compute the fair value of stock options which requires the Company to make the following assumptions:

- The risk-free interest rate is based on the five year Treasury bond at date of grant.
- The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.
- The market price volatility of the Company's common stock is based on daily, historical prices for the last three years.
- The term of the grants is based on the simplified method as described in Staff Accounting Bulletin No. 107.

In addition, the Company estimates a forfeiture rate at the inception of the option grant based on historical data and adjusts this prospectively as new information regarding forfeitures becomes available.

For the three months ended March 31, 2006, the Company recognized $0.1 million in stock option compensation expense and computed $0.7 million associated with nonvested awards that will be expensed in the future over a weighted-average period of 1.5 years.

The table below summarizes stock option activity for the three months ended March 31, 2006:

	Shares	**Weighted-Average Exercise Prices**	**Weighted-Average Remaining Life (In years)**	**Aggregate Intrinsic Value (In millions)**
Outstanding at December 31, 2005	1,025,204	$ 5.53		
Granted	-	-		
Exercised	(7,333)	13.59		
Forfeited	(30,001)	12.28		
Outstanding at March 31, 2006	987,870	$ 5.28	5.9	$ 20.3
Exercisable at March 31, 2006	857,052	$ 4.25	5.4	$ 18.5

The total intrinsic value (current market price less the option strike price) of options exercised during the three months ended March 31, 2006 was $0.1 million, and the Company received $0.1 million in cash in connection with these exercises.

The following table sets forth pro forma information for the three months ended March 31, 2005 as if compensation cost had been consistent with the requirements of SFAS No. 123, "Accounting for Stock-based Compensation":

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		For the Three Months Ended March 31, 2005 (Restated) (In thousands except per share amounts)
Net income as reported	$	482
Add: Stock based employee compensation expense recognized, net of tax		634
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects		(122)
Pro forma net income	$	994
Net income per common share, as reported:		
Basic	$	0.02
Diluted		0.02
Pro forma net income per common share, as if the fair value method had been applied to all awards		
Basic	$	0.04
Diluted		0.04

During the first quarter of 2005, the Company granted options with a weighted average grant date fair value of $6.97 based on the following assumptions:

Risk-free interest rate	4.3%
Dividend yield	-
Volatility	46%
Term (in years)	5.6%

Restricted Stock. In addition to stock options, the Company issues restricted stock and records deferred compensation based on the closing price of the Company's stock on the issuance date. The deferred compensation is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (one to three years). The unamortized deferred compensation obligation amounted to $4.2 million as of March 31, 2006, and the Company recorded $0.5 million of compensation expense related to restricted stock during the quarter ended March 31, 2006. The table below summarizes restricted stock activity for the first quarter of 2006:

	Shares	**Weighted-Average Price**
Unvested restricted stock at December 31, 2005	87,585	$ 15.98
Granted	137,850	26.55
Vested	-	-
Forfeited	(4,650)	15.59
Unvested restricted stock at March 31, 2006	220,785	22.59

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.

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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 December 31, 2005 and March 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 of the Company's risk management policies and reviews volumes, types of instruments and counterparties, on a quarterly basis. These policies are followed by management through the execution of trades 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 authorized 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:

	For the Three Months Ended March 31,	
	2005	**2006**
Cokinos Natural Gas Company	11%	-
Chevron/Texaco	16%	13%
WMJ Investments Corp.	12%	-
Sequent Energy Management	11%	-
Reichman Petroleum	-	11%

Earnings Per Share

Supplemental earnings per share information is provided below:

	For the Three Months Ended March 31, (In thousands except share and per share amounts)					
	Income		**Shares**		**Per-Share Amount**	
	2005 (Restated)	**2006**	**2005** (Restated)	**2006**	**2005** (Restated)	**2006**
Basic Earnings per Common Share:						
	$ 482	$ 6,651	22,501,696	24,166,801	$ 0.02	$ 0.28

Net income available to common shareholders						
Dilutive effect of Stock Options and Warrants	-	-	900,522	678,501		
Diluted Earnings per Common Share						
Net income available to common shareholders						
plus assumed conversions	$ 482	$ 6,651	23,402,218	24,845,302	$ 0.02	$ 0.27

Basic earnings per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings per common share is based on the weighted average number of common shares and all dilutive potential common shares outstanding during the periods. The Company had outstanding 53,334 and 24,167 stock options during the three months ended March 31, 2005 and 2006, respectively, which were antidilutive and were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options.

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2. LONG-TERM DEBT:

At December 31, 2005 and March 31, 2006, long-term debt consisted of the following:

	December 31, 2005	March 31, 2006
	(In thousands)	
First Lien Credit Facility	$ -	$ -
Second Lien Credit Facility	149,250	148,875
Capital lease obligations	27	12
Other	17	15
	149,294	148,902
Less: current maturities	(1,535)	(1,520)
	$ 147,759	$ 147,382

First Lien Credit Facility

On September 30, 2004, the Company entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the "First Lien Credit Facility"), which matures on September 30, 2007. The First Lien Credit Facility provides for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million (subject to the limit of the borrowing base, which was $22.5 million as of March 31, 2006). It is secured by substantially all of the Company's assets and is guaranteed by the Company's wholly-owned subsidiary. The First Lien Credit Facility was amended on June 21, 2005 in connection with entering into the Second Lien Credit Facility. At December 31, 2005 and March 31, 2006 there were no amounts outstanding under this facility. At December 31, 2005 two letters of credit totaling $5.6 million were outstanding under the facility and there were no letters of credit outstanding at March 31, 2006.

Second Lien Credit Facility

On July 21, 2005, the Company entered into a Second Lien Credit Agreement with Credit Suisse, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (the "Second Lien Credit Facility") that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $150.0 million. It is secured by substantially all of the Company's assets and is guaranteed by the Company's subsidiary. The liens securing the Second Lien Credit Facility are second in priority to the liens securing the First Lien Credit Facility, as more fully described in the intercreditor agreement among the Company, the Agent, the agent under the First Lien Credit Facility and the lenders.

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 5.0%. The interest rate on each eurodollar loan will be the adjusted LIBOR rate plus a margin of 6.0%. 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 30, 2006, the interest rate was approximately 10.53%, excluding the impact of the interest rate swap.

3. INVESTMENT IN PINNACLE GAS RESOURCES, INC.:

The Pinnacle Transaction

During the second quarter of 2003, the Company and its wholly-owned subsidiary CCBM, Inc. (“CCBM”) and Rocky Mountain Gas, Inc. (“RMG”) each 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. In exchange for the contribution of these assets, CCBM and RMG each received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock, or, on a fully diluted basis, CCBM and RMG each received an ownership interest in Pinnacle of 26.9%. U.S. Energy Corp. and Crested Corp (collectively, “U.S. Energy”) later succeeded to RMG’s interest in Pinnacle. CCBM no longer has a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle.

Simultaneously with the contribution of these assets, affiliates and related parties of CSFB Private Equity (the "CSFB Parties") contributed approximately $17.6 million of cash to Pinnacle in return for redeemable preferred stock of Pinnacle, 25% of Pinnacle's common stock as of the closing date and warrants to purchase Pinnacle common stock at an exercise price of $100.00 per share, subject to adjustments.

In March 2004, the CSFB Parties contributed additional funds of $11.8 million to continue funding the 2004 development program of Pinnacle. In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional acreage. CCBM and U.S. Energy elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. At December 31, 2005 and March 31, 2006, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and Pinnacle stock options, the CSFB Parties, CCBM and U.S. Energy would have had ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a "cashless" net exercise basis; and CCBM and U.S. Energy exercised their respective options on a "cashless" net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, CCBM owned 2,459,102 shares of Pinnacle's common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle's common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively.

Prior to the April 2006 Pinnacle private placement, the Company accounted for its interest in Pinnacle using the equity method. Beginning with the second quarter of 2006, the Company expects to use the cost method to account for the Pinnacle investment.

4 INCOME TAXES:

The Company provides deferred income taxes at the rate of 35%, which also approximates its statutory rate that amounted to $0.9 million and $3.7 million for the three-month periods ended March 31, 2005 and 2006.

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.

In January 2006 the Company exercised an option to purchase over an 18 month period a non-exclusive license to certain geophysical data at a cost of approximately $1.5 million.

6 SHAREHOLDERS' EQUITY:

In January 2005, all of the remaining 250,000 warrants that were originally issued to affiliates of Enron were exercised for 250,000 shares of the Company's common stock. The net cash proceeds from the exercise of the warrants amounted to $1.0 million.

On June 13, 2005, the Company sold 1.2 million shares of the Company's common stock to institutional investors (the "Investors") at a price of $15.25 per share in a private placement (the "Private Placement"), a 4.7% discount to the closing price on the NASDAQ stock market for the Company's common stock the day prior to closing. The number of shares sold was approximately 5% of the fully diluted shares outstanding before the offering. The net proceeds of the Private Placement, after deducting placement agents' fees but before paying offering expenses, were approximately $17.2 million. The Company used the proceeds from the Private Placement to fund a portion of its capital expenditure program for 2005, including the drilling programs in the Barnett Shale and onshore Gulf Coast areas, and for other corporate purposes.

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In connection with the Private Placement, the Company was required to file a resale shelf registration statement to register the resale of the shares sold under the Securities Act and will be required to cause the registration statement to become and be kept effective for resale of shares for two years from the date of their original sale. In certain situations, the Company is required to indemnify the investors in the Private Placement, including without limitation, for certain liabilities under the Securities Act.

The Company issued 574,097 and 145,183 shares of common stock during the three months ended March 31, 2005 and 2006, respectively. The shares issued during the three months ended March 31, 2005 consisted of 304,669 shares issued through the exercise of warrants, and the balance through the exercise of options granted under the Company's Incentive Plan. The shares issued during the three months ended March 31, 2006 consisted of 137,850 shares issued as restricted stock awards to employees and 7,333 shares issued through the exercise of options granted under the Company's Incentive Plan. Forfeited shares of previously issued restricted stock totaled 4,650 for the three months ended March 31, 2006.

7. DERIVATIVE INSTRUMENTS:

The Company's operations involve managing market risks related to changes in commodity prices. Derivative financial instruments, specifically swaps, futures, options and other contracts, are used to reduce and manage those risks. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. 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. While the use of derivative financial instruments limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination or expiration or exchanged for physical delivery contracts. The Company enters into the majority of its derivative transactions with two counterparties and a netting agreement is in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the derivative financial instruments.

For the quarters ended March 31, 2005 and 2006, the unrealized mark-to-market gain/(loss) on oil and natural gas derivative instruments was ($1.9) million and $3.3 million, respectively, which are presented as unrealized mark-to-market gain (loss) on derivatives, net in the other income and expense section of the Statement of Income.

At March 31, 2006 the Company had the following outstanding derivative positions:

	Contract Volumes				
Quarter	**BBls**	**MMbtu**	**Average Fixed Price**	**Average Floor Price**	**Average Ceiling Price**
Second Quarter 2006		1,092,000	$ 7.00	$ 7.40	$ 10.70
Second Quarter 2006	18,200			57.00	68.30
Third Quarter 2006		706,000	7.00	7.06	10.04
	27,600			59.00	70.22

Third Quarter 2006				
Fourth Quarter 2006		368,000	7.25	8.75
Fourth Quarter 2006	18,400		58.50	70.93
First Quarter 2007		360,000	7.50	9.45
Second Quarter 2007		273,000	6.68	8.08
Third Quarter 2007		276,000	6.80	8.20
Fourth Quarter 2007		276,000	6.92	8.32
First Quarter 2008		182,000	7.25	8.65

During the third quarter of 2005, the Company entered into interest rate swap agreements, with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements are designed to manage the Company's exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBOR rates. These agreements are treated as derivatives rather than fair value hedges and are marked-to-market as of each balance sheet date. For the three months ended March 31, 2006, the unrealized gain related to the mark-to-market value of these swap arrangements totaled $0.7 million. These derivatives will be

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marked-to-market at the end of each reporting period and the realized and unrealized gain or loss will be reported as mark-to-market gain or loss on derivatives, net in other income and expense on the Statement of Income.

The Company's outstanding positions under interest rate swap agreements at March 31, 2006 are as follows (dollars in thousands):

Quarter	Notional Amount	Fixed LIBOR Rate
Second Quarter 2006	148,875	4.39%
Third Quarter 2006	148,500	4.39%
Fourth Quarter 2006	148,125	4.39%
First Quarter 2007	147,750	4.51%
Second Quarter 2007	147,375	4.51%

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ITEM 2 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of certain significant factors that have affected certain aspects of the Company's financial position and results of operations during the periods included in the accompanying unaudited financial statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited financial statements included in our Annual Report on Form 10-K/A for the year ended December 31, 2005 and the unaudited financial statements included elsewhere herein.

General Overview

We began operations in September 1993 and initially focused on the acquisition of producing properties. As a result of the increasing availability of economic onshore 3-D seismic surveys, we began obtaining 3-D seismic data and optioning to lease substantial acreage in 1995 and began drilling our 3-D based prospects in 1996. In 2005, we drilled 65 gross wells (35.8 net), including 20 gross wells in the onshore Gulf Coast area, 37 gross wells in the Barnett Shale play, and eight wells in the Camp Hill field and other East Texas areas, with an apparent success rate of 94%. During the three months ended March 31, 2006, we were apparently successful drilling 21 of 22 (10.6 net) wells with an apparent success rate of 95% that was comprised of: (1) five of six gross (1.1 net) wells in the onshore Gulf Coast area, (2) 15 of 15 gross (8.5 net) wells in the Barnett Shale area and (3) one of one gross (1.0 net) well in the East Texas area. As of March 31, 2006, we have completed 8 of these wells and 13 are in the process of being completed. In 2006, we plan to drill 26 gross wells (11.7 net) in the onshore Gulf Coast area, 49 gross wells (35.0 net) in our Barnett Shale area and 35 to 40 gross wells (35 to 40 net) in our East Texas area, primarily in our Camp Hill oil field. 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 2006, depreciation, depletion and amortization, oil and natural gas operating expenses and production are expected to increase over levels incurred in 2005. 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 2005 and in the first quarter of 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

In March 2006, we sold our average 20 percent working interest in 13 non-operated wells in the Barnett Shale area for approximately $5.2 million. We expect the proceeds will be used to fund our drilling program and general corporate purposes.

In May 2006, we completed the sale of 1,800 undeveloped acres in the Barnett Shale for approximately $18 million and plan to reinvest the proceeds in other properties.

Pinnacle Gas Resources, Inc.

During the second quarter of 2003, we (through our wholly-owned subsidiary CCBM, Inc.) and Rocky Mountain Gas, Inc. ("RMG") each contributed our 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. In exchange for the contribution of these assets, we and RMG each received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock, or, on a fully diluted basis, we and RMG each received an ownership interest in Pinnacle of 26.9%. U.S. Energy Corp. and Crested Corp (collectively, “U.S. Energy”) later succeeded to RMG’s interest in Pinnacle. We no longer have a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle.

Simultaneously with the contribution of these assets, affiliates and related parties of CSFB Private Equity (the “CSFB Parties”) contributed approximately $17.6 million of cash to Pinnacle in return for redeemable preferred stock of Pinnacle, 25% of Pinnacle’s common stock as of the closing date and warrants to purchase Pinnacle common stock at an exercise price of $100.00 per share, subject to adjustments.

In March 2004, the CSFB Parties contributed additional funds of $11.8 million to continue funding the 2004 development program of Pinnacle. In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional acreage. CCBM and U.S. Energy elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle

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employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. At December 31, 2005 and March 31, 2006, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and Pinnacle stock options, the CSFB Parties, CCBM and U.S. Energy would have had ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a "cashless" net exercise basis; and we and U.S. Energy exercised our respective options on a "cashless" net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, we owned 2,459,102 shares of Pinnacle's common stock, and our ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle's common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively.

Derivative Transactions

Our financial results are largely dependent on a number of factors, including commodity prices. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Natural gas prices in particular have remained volatile during the last few years and more recently oil prices have become volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues.

Because natural gas and oil prices are unstable, we periodically enter into price-risk-management transactions such as swaps, collars, futures and options to reduce our exposure to price fluctuations associated with a portion of our natural gas and oil production and to achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from increases in the prices of natural gas and oil. Our derivative arrangements may apply to only a portion of our production and provide only partial protection against declines in natural gas and oil prices.

Results of Operations

Three Months Ended March 31, 2006,
Compared to the Three Months Ended March 31, 2005

Oil and natural gas revenues for the three months ended March 31, 2006 increased 44% to $21.9 million from $15.2 million for the same period in 2005. Production volumes for natural gas during the three months ended March 31, 2006 increased from 2.0 Bcf for the three months ended March 31, 2005 to 2.4 Bcf in the first quarter of 2006. Average natural gas prices excluding the impact of the gain from our cash settled derivatives of $1.3 million and $0.2 million for the quarters ended March 31, 2006 and 2005, respectively, increased 23% to $7.50 per Mcf in the first quarter of 2006 from $6.09 per Mcf in the same period in 2005. Average oil prices for the quarter ended March 31, 2006 increased 22% to $61.65 from $50.63 per barrel in the same period in 2005. The increase in natural gas production volume was principally due the commencement of production from the Galloway #1 and new wells in the Barnett Shale, Encinitas Project and Peters Ranch areas. These volume increases were partially offset by: (1) production declines from the Beach House #1 and other normal production declines, (2) an after-payout working interest reduction on the LL&E #1 Deepening and (3) the sale of the Shadyside #1 in the first quarter of 2005.

The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for our oil and natural gas operations for the three months ended March 31, 2005 and 2006:

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	March 31, 2005 (Restated)	2006	2006 Period Compared to 2005 Period Increase (Decrease)	% Increase (Decrease)
Production volumes -				
Oil and condensate (MBbls)	65	67	2	3%
Natural gas (MMcf)	1,966	2,367	401	20%
Average sales prices				
Oil and condensate (per Bbls)	$ 50.63	$ 61.65	$ 11.02	22%
Natural gas (per Mcf)	6.09	7.50	1.41	23%
Operating revenues (In thousands)-				
Oil and condensate	$ 3,280	$ 4,161	$ 881	27%
Natural gas	11,969	17,756	5,787	48%
Total Operating Revenues	$ 15,249	$ 21,917	$ 6,668	44%

Oil and natural gas operating expenses for the three months ended March 31, 2006 increased 55% to $3.5 million from $2.2 million for the same period in 2005 primarily as a result of higher severance taxes related to increased revenues of $0.2 million on higher commodity prices, higher lifting costs of $1.0 million primarily attributable to the increased number of producing wells added after the first quarter of 2005 and expense related to workovers on wells in 2006. Operating expenses per equivalent unit increased to $1.25 per Mcfe in the first quarter of 2006 compared to $0.95 per Mcfe in the same period in 2005.

Depreciation, depletion and amortization (DD&A) expense for the three months ended March 31, 2006 increased 59% to $7.4 million ($2.67 per Mcfe) from $4.7 million ($1.99 per Mcfe) for the same period in 2005. This increase was primarily due to (1) an increase in production volumes and (2) an increase in the DD&A rate attributable to the increased land, seismic and drilling costs added to the proved property cost base and increased future development costs largely related to the significant increase in the number of Barnett Shale wells.

General and administrative expense for the three months ended March 31, 2006 increased by $0.6 million to $4.2 the number million from $3.6 million for the same period in 2005 primarily as a result of (1) higher salary and incentive compensation costs, attributable to increased headcounts and an overall increase in salaries and incentive bonuses, (2) higher contract service costs of $0.4 million largely due to the recent vacancies in several key accounting positions during the year-end close process and (3) higher auditing fees of $0.2 million largely attributable to the financial restatement for mark-to-market accounting on derivatives. Partially offsetting these increases were lower stock-based compensation. In the first quarter of 2006 we discontinued the recognition of expense related to the 2000 repriced stock options. Partially offsetting this decline was the adoption of SFAS No. 123(R), which required us to recognize compensation expense related to our stock options as described under Note 1 to our consolidated financial statements included in Item 1 of this report.

The mark-to-market 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 the derivatives accounted for as nondesignated derivatives. The mark-to-market loss on derivatives of $1.7 million in the first quarter of 2005 was comprised of (1) $0.2 million of realized gain on net settled derivatives and (2) $1.9 million of net unrealized mark-to-market loss on the derivatives accounted for as nondesignated derivatives.

We recorded a $35,000 benefit on our equity interest in Pinnacle for the three months ended March 31, 2006. The increase in earnings is primarily due to the non-cash gains related to Pinnacle's hedging activity. In April 2006, our ownership interest in Pinnacle declined below 20 percent. As a result, in future periods we expect to use the cost method to account for this investment.

Interest expense and capitalized interest for the three months ended March 31, 2006 were $4.3 million and ($2.1) million, respectively, as compared to interest and capitalized interest of $1.6 million and ($1.0) million for the same period in 2005. The increases in 2006 are attributable to the debt refinancing in July 2005.

Income taxes increased to $3.7 million for the three months ended March 31, 2006 from $0.9 million for the same period in 2005 as a result of higher taxable income based on the factors described above.

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Net income for the three months ended March 31, 2006 increased by $6.2 million to $6.7 million for the first quarter of 2006 from $0.5 million for the same period in 2005 as a result of the factors described above.

Liquidity and Capital Resources

During the three months ended March 31, 2006, capital expenditures, net of $5.2 million in proceeds from property sales, exceeded our net cash flows provided by operating activities. For future capital expenditures in 2006, we expect to use cash on hand, cash generated by operating activities and available draws on the First Lien Credit Facility to partially fund our planned drilling expenditures and fund leasehold costs and geological and geophysical costs on our exploration projects in 2006. We may need to seek other financing alternatives to fund our 2006 capital expenditures program, including possible debt or equity financings.

We may not be able to obtain financing as may be needed in the future on terms that would be acceptable to us. If we cannot obtain adequate financing, we anticipate that 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 placement in 2005 of our common stock), and borrowings under our credit facilities.

Cash flows provided by operating activities were $7.4 million and $17.5 million for the three months ended March 31, 2005 and 2006, respectively. The increase was primarily due to increased production and higher commodity prices.

We have planned capital expenditures in 2006 of approximately $140 million to $145 million, of which $117.5 million is expected to be used for drilling activities in our project areas and the balance is expected to be used to fund 3-D seismic surveys and land acquisitions and capitalized interest and overhead costs. We plan to drill approximately 26 gross wells (11.7 net) in the onshore Gulf Coast area and 49 gross wells (35.0 net) in our Barnett Shale area and 35 to 40 gross wells (35 to 40 net) in our East Texas areas, primarily in our Camp Hill oil field in 2006. The actual number of wells drilled and capital expended is dependent upon our available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors.

We have continued to reinvest a substantial portion of our cash flows into our leasehold acreage and 3-D prospect portfolio, improving our 3-D seismic interpretation technology and funding our drilling program. Capital expenditures were $19.2 million (excluding $9.0 million of proceeds from an asset sale) and $41.8 million (excluding a $5.2 million asset sale) for the three months ended March 31, 2005 and 2006, respectively.

Our drilling efforts in the Gulf Coast region resulted in apparent successes in drilling five gross wells (1.1 net) during the three months ended March 31, 2006. In our Barnett Shale area, we had apparent successes in drilling 15 gross wells (8.5 net) during the first three months of 2006, and in our East Texas area, we had apparent successes in drilling one gross well (1.0 net) during that period. Of the 21 apparently successful wells, eight have been completed and the remaining wells were in various stages of completion at March 31, 2006.

We have accelerated the development of our Camp Hill project. In August 2005, management proposed the acceleration of the Camp Hill development to our board of directors. Accordingly, a development plan was formally approved by the board for increased drilling activity in the Camp Hill field, beginning with an initial 60-well drilling program. In February 2006, our board of directors formally approved a multi-year plan to fully develop the entire Camp Hill field. In furtherance of this plan, we expect to drill between 35 and 40 gross wells (35 to 40 net) in this area at an estimated cost of $3.2 million during 2006. To fully develop the field, we expect to drill approximately 326 wells from 2006 through 2017, at a total cost of approximately $22 million and total operating costs including steam of approximately $175.0 million. The precise timing and amount of our expenditures on additional well drilling and increased steam injection to develop the proved undeveloped reserves in this project will depend on several factors including the relative prices of oil and natural gas.

In our Camp Hill field in the East Texas area, we drilled seven gross wells (7.0 net) during 2005, all of which are apparent successes. During 2006 and the first half of 2007, we expect to drill between 55 and 60 gross wells (55 to 60 net) in this area at an estimated cost of approximately $4.2 million.

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Financing Arrangements

First Lien Credit Facility

On September 30, 2004, we entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the "First Lien Credit Facility"), maturing on September 30, 2007. The First Lien Credit Facility provides for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million (subject to the limit of the borrowing base, which was $22.5 million as of March 31, 2006). It is secured by substantially all of our assets and is guaranteed by our subsidiary. The First Lien Credit Facility was amended on July 21, 2005 in connection with the Second Lien Credit Facility and refinancing discussed in our 2005 Annual Report Form 10-K/A. At March 31, 2006, we had $22.5 million available for borrowing under the First Lien Credit Facility.

Second Lien Credit Facility

On July 21, 2005, we entered into a second lien credit agreement with Credit Suisse, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (the "Second Lien Credit Facility") that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $150.0 million. It is secured by substantially all of our assets and is guaranteed by our subsidiary. The liens securing the Second Lien Credit Facility are second in priority to the liens securing the First Lien Credit Facility, as more fully described in an intercreditor agreement dated July 21, 2005 among us, the Agent, the agent under the First Lien Credit Facility and the lenders.

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 5.0%. The interest rate on each eurodollar loan will be the adjusted LIBOR rate plus a margin of 6.0%. Interest on eurodollar loans is payable on either the last day of each interest period or every three months, whichever is earlier. Interest on base rate loans is payable quarterly.

The Second Lien Credit Facility is subject to customary events of default. Subject to certain exceptions, if an event of default occurs and is continuing, the Agent may accelerate amounts due under the Second Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable). If an event of default occurs under the Second Lien Credit Facility as a result of an event of default under the First Lien Credit Facility, the Agent may not accelerate the amounts due under the Second Lien Credit Facility until the earlier of 45 days after the occurrence of the event resulting in the default and acceleration of the loans under the First Lien Credit Facility.

We are subject to certain covenants under the terms of the Second Lien Credit Facility. These covenants include, but are not limited to, the maintenance of the following financial covenants: (1) a minimum current ratio of 1.0 to 1.0 including availability under the borrowing base under the First Lien Credit Facility; (2) a minimum quarterly interest coverage ratio of 2.75 to 1.0 through June 30, 2006 and 3.0 to 1.0 thereafter; (3) a minimum quarterly proved reserve coverage ratio of 1.5 to 1.0 through September 30, 2006 and 2.0 to 1.0 thereafter; and (4) a maximum total net recourse debt to EBITDA (as defined in the Second Lien Credit Facility) ratio of not more than 3.5 to 1.0 through June 30, 2006 and 3.25 to 1.0 thereafter. The Second Lien Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

Shelf Registration Statement

In the third quarter of 2005, we filed a registration statement on Form S-3 with the SEC for the proposed offering from time to time of up to $250 million of senior or subordinated debt securities, preferred stock, common stock and warrants to purchase debt securities, preferred stock, common stock or other securities. Due to the delay in our filing of our Annual Report on Form 10-K for the year ended December 31, 2005, we believe that we are not eligible to use a “short form” registration statement on Form S-3 at the present time. Accordingly, unless and until we regain eligibility to use Form S-3, we will not be able to offer and sell securities under our shelf registration statement without first amending it to convert it to a registration statement on Form S-1 and then obtaining a declaration of effectiveness for the registration statement from the SEC. The inability to use Form S-3 may increase the costs and complexity of the registration process. This registration statement has not yet been declared effective by the SEC.

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Effects of Inflation and Changes in Price

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

Recently Adopted Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"). SFAS No. 123(R) requires companies to measure all employee stock-based compensation awards using a fair value method and record such expense in their consolidated financial statements. In addition, the adoption of SFAS No. 123(R) requires additional accounting and disclosure related to the income tax and cash flow effects resulting from share-based payment arrangements. SFAS No. 123(R) was effective beginning as of the first annual reporting period after June 15, 2005. We adopted the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition and recognized approximately $0.1 million in compensation expense in the first quarter of 2006.

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, bad debts, derivatives, stock-based compensation, contingencies and 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. Results of drilling, testing and production subsequent to the date of the estimate 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 $0.5 million and $1.0 million for the three months ended March 31, 2005 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,

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dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the three months ended March 31, 2005 and 2006 was $1.99 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.

The net capitalized costs of proved oil and natural gas properties are subject to a “ceiling test” which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves, based on current economic and operating conditions (the “Full Cost Ceiling”). If net capitalized costs exceed this limit, the excess is charged to operations through depreciation, depletion and amortization.

In connection with our March 31, 2006 ceiling test computation, a price sensitivity study also indicated that a 20% increase in commodity prices at March 31, 2006 would have increased the pre-tax present value of future net revenues (“NPV”) by approximately $125.8 million. Conversely, a 20% decrease in commodity prices at March 31, 2006 would have reduced our NPV by approximately $94.2 million. The aforementioned price sensitivity and NPV is as of March 31, 2006 and, accordingly, does not include any potential changes in reserves due to second quarter 2006 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of March 2006 of approximately $68.9 million was based upon average realized oil and natural gas prices of $61.37 per Bbl and $6.93 per Mcf, respectively, or a volume weighted average price of $47.81 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $37.05 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 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 plus estimated future development costs 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, which are primarily oil reserves. We had 97.9 Bcfe of proved undeveloped reserves at both December 31, 2005 and March 31, 2006, representing 65% and 66% of our total proved reserves. As of December 31, 2005 and March 31, 2006, a large portion of these proved undeveloped reserves, or approximately 38.1 Bcfe as of both dates, 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) and (iv) an estimated $6.9 million in 2005 (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 cost and current prices were all to remain constant, this continued build-up of capitalized costs increases the probability of a ceiling test write-down.

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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

The proved reserve data as of December 31, 2005 included in this document are estimates prepared by Ryder Scott Company, DeGolyer and MacNaughton 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.

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 10% for the three months ended March 31, 2006.

As of December 31, 2005, approximately 81% 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, 2005 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. Although we have accelerated our development of the Camp Hill field in East Texas, we have in the past 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 8 years ago. Although we have recently accelerated 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. Given our limited internal resources, we have elected to account for all new 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.

We have initiated a program designed to manage our exposure to interest rate fluctuations by entering into financial derivative instruments. The primary objective of this program is to reduce the overall cost of borrowing. We have entered into interest rate swap agreements with respect to amounts borrowed under the Second Lien Credit Facility, which effectively exchange existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBOR rates.

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 are followed by management through the execution of trades 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 authorized counterparties identify the President and Chief Financial Officer as the only

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representatives authorized to execute trades. The Board of Directors also reviews the status and results of derivative activities quarterly.

During the third quarter of 2005, we entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements are designed to manage our exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBOR rates. 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 market to market gains and losses on derivatives, net within other income on our Statement of Income.

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 accounting rules of the Commission. See “—Critical Accounting Policies and Estimates—Oil and Natural Gas Properties.”

Total oil purchased and sold under swaps and collars during the three months ended March 31, 2005 and 2006 was 32,900 Bbls and 18,000 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the three months ended March 31, 2005 and 2006 was 928,000 MMBtu and 1,082,000 MMBtu, respectively. The net gain realized by us under such hedging arrangements was $0.2 million and $1.3 million for the three months ended March 31, 2005 and 2006, respectively, and is included in mark-to-market gain (loss) on derivatives, net.

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. We do not hold or issue derivative instruments for trading purposes.

For the quarter ended March 31, 2005 and 2006, the unrealized gain (loss) on oil and natural gas derivatives of ($1.9) million and $3.3 million, respectively, were included in mark-to-market gain (loss) on derivatives, net.

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 product 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 some 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.

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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 2006, a $0.10 change in the price per Mcf of gas sold would have changed revenue by $0.2 million. A $0.70 change in the price per barrel of oil would have changed revenue by less than $100,000.

The table below summarizes our total natural gas production volumes subject to derivative transactions during the three months ended March 31, 2006.

Natural Gas Collars		
Volumes (MMBtu)		1,082,000
Average price ($/MMBtu)		
Floor	$	8.51
Ceiling	$	11.06

The table below summarizes our total crude oil production volumes subject to derivative transactions for the three months ended March 31, 2006.

Crude Oil Collars		
Volumes (Bbls)		18,000
Average price ($/Bbls)		
Floor	$	55.00
Ceiling	$	68.25

At March 31, 2006 we had the following outstanding derivatives positions:

	Contract Volumes				
Quarter	**BBls**	**MMbtu**	**Average Fixed Price**	**Average Floor Price**	**Average Ceiling Price**
Second Quarter 2006		1,092,000	$ 7.00	$ 7.40	$ 10.70
Second Quarter 2006	18,200			57.00	68.30
Third Quarter 2006		706,000	7.00	7.06	10.04
Third Quarter 2006	27,600			59.00	70.22
Fourth Quarter 2006		368,000		7.25	8.75
	18,400			58.50	70.93

Fourth Quarter 2006			
First Quarter 2007	360,000	7.50	9.45
Second Quarter 2007	273,000	6.68	8.08
Third Quarter 2007	276,000	6.80	8.20
Fourth Quarter 2007	276,000	6.92	8.32
First Quarter 2008	182,000	7.25	8.65

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 hiring, future exploration activity, production rates, the exploration and development expenditures in the Barnett Shale trend, 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 that ident forward looking statements. Such statements involve risks and

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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 actual results of the initiatives designed to eliminate a material weakness in the Company’s internal control over financial reporting, availability of a qualified workforce to fill the Company’s accounting positions, completion of the implementation of the Company’s new accounting software system and the results of audits and assessments and other factors detailed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005 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/A for the year ended December 31, 2005, except for the Company’s hedging activity subsequent to December 31, 2005, which is described above in “Volatility of Oil and Natural Gas Prices.” There have been no material changes to the disclosure regarding our exposure to certain market risks made in the Annual Report on Form 10-K/A. For additional information regarding our long-term debt, see Note 2 of the Notes to Unaudited Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

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ITEM 4- CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. As described in more detail in our Form 10-K/A filed on April 11, 2006 (the "10-K/A"), we identified material weaknesses in the Company's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) in connection with the work related to Management's Annual Report on Internal Control over Financial Reporting. As a result of these material weaknesses, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2005, the Company's disclosure controls and procedures were not effective. Additionally, as a result of such material weaknesses, the Company was not able to file its Annual Report on Form 10-K for the year ended December 31, 2005 with the Securities and Exchange Commission in the time required. Because the control deficiencies leading to such material weaknesses were still present as of March 31, 2006, our Chief Executive Officer and Chief Financial Officer have concluded that as of the end of the period covered by this report, the Company's disclosure controls and procedures were not effective. The Company has outlined a number of initiatives, as discussed below, that it believes will remediate these material weaknesses in 2006.

Hedging

We completed a review of our documentation practices underlying our derivative positions in 2004 and 2005 and determined that we lacked sufficient contemporaneous documentation and did not timely designate our derivative positions at inception as cash flow hedges as required by Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" to account for these positions as cash flow hedges. Under cash flow hedge accounting, the after-tax change in the fair value of the open derivative positions ("fair value change") is reported as Other Comprehensive Income in the equity section of the balance sheet. Alternatively, if the derivative does not qualify as a cash flow hedge, mark-to-market accounting requires that the fair value change be reported in earnings. This error came to management's attention during the preparation of our Consolidated Financial Statements for the year ended December 31, 2005 which ultimately resulted in a restatement of our financial statements for 2004 as well as the first three quarterly periods in 2005.

In the process of restating our financials to account for our derivatives on a mark-to-market basis, we discovered certain computational errors in the fair value of the Company's derivatives that was previously reported in other comprehensive income in 2004 and 2005. These errors resulted from the information we had relied upon to establish oil and gas prices used in connection with determining the fair value of the derivatives. For all the periods covered by our consolidated financial statements, we used a third-party website source to obtain New York Mercantile ("NYMEX") oil and gas prices and then used those prices to determine the fair value of the derivatives. However, we determined in the course of our evaluation that the use of Houston Ship Channel prices was instead required for this purpose which matched the index used within our derivative agreements, furthermore we also determined that the information from the third party provider was not entirely reliable. As a result of the restatement relating to our change in the treatment of our derivatives, we no longer report the change in fair value of our derivatives in other comprehensive income but now record them as a change to earnings. Nevertheless, in marking these derivatives to market, the gains and losses reflected in other income and expense have been based upon corrected amounts that were not based upon the information from the third party provider. These items constituted a material weakness in our internal controls as of December 31, 2005.

Year-end Close Process and Other Controls

In the fourth quarter of 2005, we hired a manager of financial reporting, filling the prior vacancy described in our Annual Report on Form 10-K for the year ended December 31, 2004. This manager of financial reporting subsequently left the Company late in the fourth quarter of 2005, creating a new vacancy. Our manager of accounting left the Company in November 2005. In February 2006, our controller and our director of financial planning and analysis also both left the Company. We attempted to fill these vacancies, but were not able to do so as quickly as we would have liked. We subsequently hired a new controller and manager of accounting in March 2006, near the end of our year-end closing process. We have also hired a new manager of financial reporting, who joined the Company in April 2006.

The accounting and financial staff vacancies described above occurred during the year-end close process. While these vacancies were partially remedied by reliance upon independent financial reporting consultants for review of critical accounting areas and disclosures and material nonstandard transactions, these absences, combined with our complex manual, review intensive accounting system, placed greater burdens of detailed reviews on our remaining middle and upper-level accounting professionals, which in turn compromised the level of their qualitative review of the elements of the year end close, financial statements and disclosures. These review procedures are an important component of our controls surrounding the closing process and in financial reporting. As a result, we believe that these vacancies resulted in inadequate staffing, supervision and financial reporting expertise in our accounting and financial areas, which constituted a material weakness in our internal control over financial reporting as of December 31, 2005. These deficiencies ultimately affect the accuracy of our financial statement reporting and disclosures.

Accordingly, in connection with the audit of our 2005 financial results, Pannell Kerr Forster of Texas, P.C. (“PKF”), our independent registered public accounting firm, detected a number of errors and/or omissions that were an indication that the aforementioned material weaknesses were present at December 31, 2005, increasing the likelihood to more than remote that a material misstatement of the Company’s annual or interim financial statements will not be prevented or detected. The most notable of these errors included (1) our accounting for our derivatives as cash flow hedges rather than on a mark-to-market basis, (2) corrections for certain computational errors in the fair value of the Company’s derivatives previously reported in other comprehensive income in 2004 and 2005, (3) errors related to our capital expenditures accrual, (4) errors in the evaluation of our unproved property pool and (5) errors related to the evaluation of our asset retirement obligation. These errors came to management's attention in connection with the preparation of our consolidated financial statements for the year ended December 31, 2005. The controls in place related to items (3), (4) and (5) (“Other Controls”) were not properly designed and/or operating to provide reasonable assurance that amounts would be properly recorded in the Company’s consolidated financial statements. The failure of the Other Controls constituted a third material weakness in our internal controls as of December 31, 2005. Management determined that the restatement of our consolidated financial statements discussed in Note 3 to our consolidated financial statements included in Item 8 of our Annual Report on Form 10-K/A for the year ended December 31, 2005 was an additional effect of the year-end close process material weakness. All correcting adjustments were recorded by the Company prior to the finalization of its 2005 financial statements. The Company has implemented procedures to prevent these specific errors from occurring in the future. However, the additional initiatives (outlined below) are needed to remediate the material weaknesses in our internal controls, and thus lower the risk level to remote of other potential material errors or omissions.

As a result of these three material weaknesses, our management concluded in our Annual Report on Form 10-K/A for the year ended December 31, 2005 that our internal control over financial reporting was not effective as of December 31, 2005.

While there can be no assurance in this regard, we expect that the following initiatives will eliminate the material weaknesses relating to our year-end close process and Other Controls in 2006: (1) increasing the level of our professional accounting staff, including the successful placement of a new manager of financial reporting, new controller, new manager of accounting and new director of financial planning and analysis (including the placement in the first quarter of 2006 of a new manager of financial reporting, new controller and new manager of accounting), and (2) completing our transition to a new fully-integrated accounting software system (phase one was completed in the fourth quarter of 2005) to automate processes and improve qualitative reviews. Until these initiatives are fully implemented, we will continue to rely on manual processes and require additional commitment of resources to the closing process to produce our financial records and reports. We have engaged a consultant to assist us in evaluating our risk management program to provide guidance, and, where needed, assistance so that we may continue to account for our derivative activities as cash flow hedges in accordance with the requirements of SFAS No. 133 on a prospective basis. Given its limited internal resources, the Company has elected to account for all new derivative contracts as non-designated derivatives. As of the date of this report, we have not yet completed the initiatives described above. While we have hired three new accounting professionals, we have not yet hired a new director of financial planning and analysis. Also, our project team has made significant progress towards completing the transition to a new fully-integrated accounting software system described in the second initiative. We have discussed these material weaknesses and our remediation steps with our Audit Committee.

Changes in Internal Control over Financial Reporting. Except as described above, there have not been any changes in the Company's internal control over financial reporting during the fiscal quarter ended March 31, 2006 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. As described above, the Company identified material weaknesses in the Company's internal control over financial reporting and has described a number of planned changes to its internal control over financial reporting during 2006 designed to remediate these weaknesses. Some of these changes

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were effected in the first quarter of 2006, including some changes in staffing and changes in hedge accounting. This Item 4 should be read in conjunction with Item 9A included in our Annual Report on Form 10-K/A for the year ended December 31, 2005.

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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/A for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K/A are not the only risks facing us. 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

None

Item 3 - Defaults Upon Senior Securities

None

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

None.

Item 5 - Other Information

None

Item 6 - Exhibits

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

Exhibit Number	Description
†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).

10.1—Schedule of 2005 Annual Bonuses for Certain Executive Officers.

10.2—Second Amendment to Contribution and Subscription Agreement dated as of March 31, 2006 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein.

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

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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.

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 10, 2006	By: /s/S. P. Johnson, IV President and Chief Executive Officer (Principal Executive Officer)
Date: May 10, 2006	By: /s/Paul F. Boling Chief Financial Officer (Principal Financial and Accounting Officer)