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**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended **June 30, 2008**

or

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

For the transition period from _____ to _____

Commission file number: **001-33457**

Pinnacle Gas Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

30-0182582

(I.R.S. Employer Identification No.)

**1 E. Alger Street
Sheridan, WY**

(Address of principal executive offices)

82801

(Zip code)

(307) 673-9710

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

29,085,551 shares of the registrant's Common Stock were outstanding as of August 11, 2008.

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We are including the following discussion to inform you of some of the risks and uncertainties that can affect our company and to take advantage of the “safe harbor” protection for forward-looking statements that applicable federal securities law affords. Various statements in this prospectus, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward looking statements. These include statements relating to such matters as:

- projections and estimates concerning the timing and success of specific projects;
- our financial position or operating results;
- our business strategy;
- our budgets;
- the amount, nature and timing of capital expenditures;
- the drilling of wells;
- the development of recently acquired natural gas and oil properties;
- the timing and amount of future production of natural gas and oil;
- our operating costs and other expenses;
- our estimated future net revenues from natural gas and oil reserves and the present value thereof;
- our cash flow and anticipated liquidity; and
- our other plans and objectives for future operations.

When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “estimate,” “plan,” “predict,” “project,” their negatives, or other similar expressions, the statements which include those words are usually forward looking statements. When we describe strategy that involves risks or uncertainties, we are making forward looking statements. The forward looking statements in this quarterly report on Form 10-Q speak only as of the date of this report. We disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- our ability to implement our business strategy;
- the extent of our success in discovering, developing and producing reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- fluctuations in the commodity prices for natural gas and crude oil;
- engineering, mechanical or technological difficulties with operational equipment, in well completions and workovers, and in drilling new wells;
- the effects of government regulation and permitting and other legal requirements;
- labor problems;
- environmental related problems;

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- the uncertainty inherent in estimating future natural gas and oil production or reserves;
- production variances from expectations;
- the substantial capital expenditures required for construction of pipelines and the drilling of wells and the related need to fund such capital requirements through commercial banks and/or public securities markets;
- disruptions of, capacity constraints in or other limitations on our or others' pipeline systems;
- our ability to effectively market our production;
- land issues and the costs associated with perfecting title for natural gas rights in some of our properties;
- our ability to develop and replace reserves;
- our dependence upon key personnel;
- the lack of liquidity of our equity securities;
- operating hazards attendant to the natural gas and oil business, including down-hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under performance of significant wells;
- climatic conditions or natural disasters;
- acts of terrorism;
- the availability and cost of materials and equipment;
- delays in anticipated start-up dates;
- our ability to find and retain skilled personnel;
- the availability of capital;
- competition from, and the strength and financial resources of, our competitors;
- general economic conditions; and
- regional price differentials.

When you consider these forward-looking statements, you should keep in mind these factors and the other factors discussed in the "Risk Factors" section of our annual report on Form 10-K for the year ended December 31, 2007 and this quarterly report on Form 10-Q.

[Table of Contents](#)**PART I. FINANCIAL INFORMATION****ITEM 1. FINANCIAL STATEMENTS****PINNACLE GAS RESOURCES, INC.
Balance Sheets**

	<u>June 30, 2008</u>	<u>December 31, 2007</u>
	(unaudited)	
	(in thousands, except share and per share data)	
Assets		
Current assets		
Cash and cash equivalents	\$ 1,172	\$ 8,151
Deposits	643	—
Receivables		
Accrued gas sales	4,497	3,062
Joint interest receivables, net of \$100 allowance for doubtful accounts	8,580	6,040
Derivative instruments	—	556
Inventory of material for drilling and completion	134	174
Prepaid expenses	178	1,322
Total current assets	<u>15,204</u>	<u>19,305</u>
Property and equipment, at cost, net of accumulated depreciation	2,095	2,226
Oil and gas properties, using full cost accounting, net of accumulated depletion and impairment		
Proved	43,846	33,965
Unproved	92,701	88,820
Inventory held for exploration and development	390	505
Deposits, non-current	—	20
Restricted certificates of deposit, non-current	2,718	1,752
Total assets	<u>\$ 156,954</u>	<u>\$ 146,593</u>
Liabilities and Stockholders' Equity		
Current liabilities		
Long-term debt, current portion	\$ 24	\$ 23
Derivative instruments, current	5,035	—
Trade accounts payable	13,103	7,767
Revenue distribution payable	8,348	6,534
Drilling prepayments from joint interest owners	9	28
Asset retirement obligations, current	380	363
Accrued liabilities	2,511	2,241
Total current liabilities	<u>29,410</u>	<u>16,956</u>
Asset retirement obligations, non-current	2,774	2,404
Derivative instruments, non-current	875	—
Production taxes, non-current	1,401	633
Long-term debt, non-current	5,751	763
Total liabilities	<u>40,211</u>	<u>20,756</u>
Contingencies		
Series A Redeemable Preferred stock, \$0.01 par value; 25,000,000 authorized, 0 shares issued and outstanding at June 30, 2008 and December 31, 2007, respectively	—	—
Stockholders' equity		
Common stock, \$0.01 par value; 100,000,000 authorized and 29,000,101 and 29,019,751 shares issued and outstanding at June 30, 2008 and December 31, 2007, respectively	289	289
Additional paid-in capital	150,128	149,701
Accumulated deficit	(33,674)	(24,153)
Total stockholders' equity	<u>116,743</u>	<u>125,837</u>
Total liabilities and stockholders' equity	<u>\$ 156,954</u>	<u>\$ 146,593</u>

See Notes to Financial Statements (unaudited)

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Statements of Operations
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands, except share and per share data)			
Revenues				
Gas sales	\$ 7,573	\$ 3,436	\$ 13,234	\$ 7,090
Total revenues	<u>7,573</u>	<u>3,436</u>	<u>13,234</u>	<u>7,090</u>
Cost of revenues and expenses				
Lease operating expenses	1,348	1,219	3,398	2,136
Production taxes	860	357	1,519	759
Marketing and transportation	1,210	898	2,287	1,683
General and administrative, net	3,217	1,220	4,591	2,327
Depreciation, depletion, amortization and accretion	2,284	1,612	4,013	3,096
Impairment of oil and gas properties	—	1,151	—	18,155
Total cost of revenues and expenses	<u>8,919</u>	<u>6,457</u>	<u>15,808</u>	<u>28,156</u>
Operating loss	(1,346)	(3,021)	(2,574)	(21,066)
Other income (expense)				
Gain (loss) on derivatives	(2,664)	664	(7,235)	465
Interest income	34	251	99	298
Other income	122	113	223	224
Interest expense	(20)	(78)	(35)	(142)
Total other income (expense)	<u>(2,528)</u>	<u>950</u>	<u>(6,948)</u>	<u>845</u>
Net loss before income taxes	(3,874)	(2,071)	(9,522)	(20,221)
Income taxes	—	—	—	—
Net loss attributable to common stockholders	<u>\$ (3,874)</u>	<u>\$ (2,071)</u>	<u>\$ (9,522)</u>	<u>\$ (20,221)</u>
Basic and diluted net loss per share	<u>\$ (0.13)</u>	<u>\$ (0.08)</u>	<u>\$ (0.33)</u>	<u>\$ (0.79)</u>
Weighted average shares outstanding — basic and diluted	29,000,101	27,115,114	29,008,000	25,517,025

See Notes to Financial Statements (unaudited)

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Statements of Cash Flows
(in thousands)
(unaudited)

	For the Six Months Ended June 30,	
	2008	2007
Cash flows from operating activities		
Net loss	\$ (9,522)	\$ (20,221)
Adjustments to reconcile net loss to net cash provided by (used in) / operating activities		
Impairment of oil and gas properties	—	18,155
Depreciation, depletion, amortization and accretion	4,013	3,096
(Gain) Loss on derivatives	7,235	(465)
Stock-based compensation	433	362
Changes in assets and liabilities		
(Increase) decrease in receivables	(3,975)	4,023
Decrease in inventory of material for drilling and completion	40	32
Decrease in prepaid expenses	1,144	30
Increase (decrease) in trade accounts payable and accrued liabilities and production taxes	3,853	(10,283)
Increase (decrease) in revenue distribution payable	1,814	(60)
Decrease in drilling prepayments	(19)	(135)
Net cash provided by (used in) operating activities	<u>5,016</u>	<u>(5,466)</u>
Cash flows from investing activities		
Capital expenditures — exploration and production	(14,377)	(11,491)
Capital expenditures — property and equipment	(358)	(421)
Purchase of restricted certificate of deposit	(966)	(5)
(Increase) decrease in inventory held for exploration and development	115	(158)
Deposits	(623)	(501)
Realized gain (loss) on derivatives	(769)	1,676
Net cash used in investing activities	<u>(16,978)</u>	<u>(10,900)</u>
Cash flows from financing activities		
Principal payments on note payable	(11)	(11)
Proceeds from long-term debt	5,000	—
Proceeds from the issuance of common stock	—	33,750
Issuance costs related to common stock	(6)	(4,010)
Net cash provided by financing activities	<u>4,983</u>	<u>29,729</u>
Net increase (decrease) in cash and cash equivalents	(6,979)	13,363
Cash and cash equivalents at beginning of the year	8,151	4,762
Cash and cash equivalents at June 30, 2008 and 2007, respectively	<u>\$ 1,172</u>	<u>\$ 18,125</u>
Non-cash investing and financing activities		
Capital expenditures included in trade accounts payable	\$ 8,352	\$ 1,368
Asset retirement obligation included in oil and gas properties	268	69
Accrued offering costs	—	419
Inventory used in oil and gas properties	—	116
Supplemental cash flow information		
Cash payments for interest, net of amount capitalized	\$ 35	\$ 64

See Notes to Financial Statements (unaudited)

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Statement of Stockholders' Equity
(in thousands, except for share data)

	<u>Common Stock</u>		<u>Warrants and Options</u>	<u>Stockholders' Equity</u>		<u>Total</u>
	<u>Shares</u>	<u>Amount</u>		<u>Additional Paid-In Capital</u>	<u>Accumulated Deficit</u>	
	Balance at December 31, 2007	29,019,751		\$ 289	—	
Forfeiture of restricted shares (unaudited)	(19,650)	—	—	—	—	—
Offering costs related to the issuance of common stock (unaudited)	—	—	—	(6)	—	(6)
Stock-based compensation (unaudited)	—	—	—	433	—	433
Net loss (unaudited)	—	—	—	—	(9,522)	(9,522)
Balance at June 30, 2008 (unaudited)	<u>29,000,101</u>	<u>\$ 289</u>	<u>—</u>	<u>\$ 150,128</u>	<u>\$ (33,674)</u>	<u>\$ 116,743</u>

See Notes to Financial Statements (unaudited)

[Table of Contents](#)**Notes to Financial Statements
(Unaudited)****Note 1 — Organization and Nature of Operations**

Pinnacle Gas Resources, Inc. (the “Company” or “Pinnacle”) was formed as a Delaware corporation in June 2003 through a contribution of cash by funds affiliated with DLJ Merchant Banking and oil and gas reserves and leasehold interests by subsidiaries of Carrizo Oil & Gas, Inc. and U.S. Energy Corporation.

Pinnacle’s primary business is the exploration for, and the acquisition, development and production of, coalbed methane natural gas in the United States. The Company is also engaged in gas property operations and the construction of low pressure gas collection systems which provide transportation for the Company’s coalbed methane production.

Note 2 — Basis of Presentation

The accompanying unaudited financial statements include the Company’s proportionate share of assets, liabilities, income and expenses from the properties in which the Company has a participating interest. The Company has no subsidiaries or affiliates with which intercompany transactions are recorded.

The accompanying financial statements are unaudited, and in the opinion of management, reflect all adjustments that are necessary for a fair presentation of the financial position and results of operations for the periods presented. All such adjustments are of a normal and recurring nature. The following notes describe only the material changes in accounting policies, account details, or financial statement notes during the first six months of 2008. The results for the three and six months ended June 30, 2008 are not necessarily indicative of the results expected for the entire year. These financial statements should be read in conjunction with the audited financial statements and the summary of significant accounting policies for prior years contained on the Company’s website www.pinnaclegas.com.

Use of Estimates

The preparation of the Company’s financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates. Significant estimates with regard to the Company’s financial statements include the estimated carrying value of unproved properties, the estimate of proved oil and gas reserve volumes and the related present value of estimated future net cash flows and the ceiling test applied to capitalized oil and gas properties, the estimate of the timing and cost of the Company’s future drilling activity, the estimated cost and timing related to asset retirement obligations, the estimated fair value of derivative assets and liabilities, the realizability of deferred tax assets, the estimates of expenses and timing of exercise of stock options, accrual of operating costs and capital expenditures and revenue.

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities are capitalized within a cost center. The Company’s oil and gas properties are all located within the United States, which constitutes a single cost center. The Company has not capitalized any overhead costs. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties (“DD&A”) is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. The Company invests in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the

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costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonment of unproved properties is accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized. No impairment was recorded for unevaluated properties for the three and six months ended June 30, 2008. Substantially all of the remaining unproved property costs are expected to be developed and included in the amortization base over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on the Company's estimate of the value of equipment and supplies at the time the well is abandoned. As of June 30, 2008 and December 31, 2007, the estimated salvage value was approximately \$7.1 million and \$6.4 million, respectively.

Under full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a "ceiling" value which is the sum of (1) the present value discounted at 10% of estimated future net revenue using current prices and costs, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. This is referred to as the "full cost ceiling limitation." If capitalized costs exceed the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, the Company calculates the full cost ceiling limitation. At June 30, 2008, the full cost ceiling limitation exceeded the capitalized cost of oil and gas by approximately \$35.0 million based upon a natural gas price of \$8.73 per Mcf (based on the Colorado Interstate Gas Rocky Mountain Index) in effect at that date. As a result, the Company was not required to record an impairment for the six months ended June 30, 2008. An impairment of approximately \$18.2 million was recorded for the six months ended June 30, 2007. The impairment of the Company's oil and gas properties resulted from low commodity prices throughout 2007, specifically at the end of the first, second and third quarters of 2007. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable reserve quantities could result in the recognition of additional impairments of the Company's oil and gas properties in future periods.

Per Share Information

Basic loss per share is computed by dividing net loss from continuing operations attributable to common stock by the weighted average number of shares of common stock outstanding during each period. Diluted earnings per share is computed by adjusting the average number of shares of common stock outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share was the same as basic loss per share for the three and six months ended June 30, 2007 and 2008 because potential common stock equivalents were anti-dilutive.

Certain options to purchase shares of Pinnacle's common stock were excluded from the dilution calculations because the shares were anti-dilutive. At June 30, 2008, 750,000 options were excluded because they were anti-dilutive. At June 30, 2007, 990,000 options were excluded because they were anti-dilutive.

General and Administrative Expenses

General and administrative expenses are reported net of amounts allocated and billed to working interest owners of gas properties operated by the Company. The administrative expenses billed to working interest owners may change in accordance with the terms of the joint operating agreements. Administrative expenses are charged to working interest owners based on productive well counts. A 10% change in well counts for the six months ended June 30, 2008 would have increased or decreased the Company's expenses billed to working interest owners by approximately \$91,000. As the Company operates and drills additional wells in the future, additional administrative expenses will be charged to the working interest owners when the wells become productive. General and administrative expenses for the six months ended June 30, 2008 also include \$2.1 million of merger related costs attributable to the failed merger with Quest Resource Corporation. Any future costs associated with any merger, acquisition or divestiture will be expensed in the period of the transaction outcome.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statements and tax basis of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of June 30, 2008 and December 31, 2007, the Company had recorded a full valuation allowance for its net deferred tax asset.

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On January 1, 2007, the Company adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires that the Company recognize in its consolidated financial statements only those tax positions that are "more-likely-than-not" of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, the Company performed a comprehensive review of its material tax positions in accordance with recognition and measurement standards established by FIN 48.

As a result of this review, the Company did not identify any material tax positions that required adjustment. As of January 1, 2007, the date of adoption of FIN 48, and as of June 30, 2008, the Company had not accrued any interest or penalties related to any material uncertain tax positions.

The Company is subject to the following material taxing jurisdictions: U.S. federal. The Company also has material operations in the state of Wyoming; however, Wyoming does not impose a corporate income tax. The tax years that remain open to examination by the U.S. Internal Revenue Service are years 2004 through 2007. Due to the Company's net operating loss carry forwards, the Internal Revenue Service may also adjust the amount of loss realizable under examination back to 2003.

Recent Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, SFAS No. 157 does not require any new fair value measurements. However, for some entities, the application of SFAS No. 157 will change current practice. SFAS No. 157 was effective as of January 1, 2008. However, FASB Financial Staff Position No. FAS 157-2 deferred implementation for other non-financial assets and liabilities until January 1, 2009. The adoption of SFAS No. 157 did not have a material impact on the Company's financial position but caused additional disclosure. Please see Note 8 — Fair Value Measurements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 was effective as of January 1, 2008 for us. SFAS No. 159 offers various options in electing to apply the provisions of SFAS No. 159. The Company decided not to elect fair value accounting for any of its eligible items other than derivatives (See Note 7) which were being accounted for under a fair value method prior to the adoption of SFAS No. 159.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations," which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141 (R) also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for the Company beginning with the 2009 fiscal year. The Company is evaluating the potential impact of SFAS No. 141(R), if any, on its financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements — an amendment of ARB 51," which establishes accounting and reporting standards that require noncontrolling interests to be reported as a component of equity. SFAS No. 160 also requires that changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained noncontrolling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008 and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. SFAS No. 160 will be effective for the Company beginning with the 2009 fiscal year. The Company is evaluating the potential impact of SFAS No. 160, if any, on the Company's financial statements.

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In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." SFAS No. 161 is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements, how derivative instruments and related hedged items are accounted for under FAS No. 133, and how derivative instruments and related hedged items affect its financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company does not believe the adoption of SFAS No. 161 will have a significant effect on its financial statements.

Note 3 — Asset Retirement Obligations

The Company follows the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize an estimated liability for costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units-of-production method, and the discounted liability is increased through accretion over the remaining economic life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. The Company's liability is discounted using the Company's best estimate of its credit-adjusted risk free rate. Revisions to the liability could occur due to changes in estimated abandonment costs or changes in well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells.

The following is a summary of the Company's asset retirement obligation activity for the three and six months ended June 30, 2008 and June 30, 2007 (unaudited).

	For the Three Months Ended June 30, <u>2008</u>	For the Six Months Ended June 30, <u>2008</u>	For the Three Months Ended June 30, <u>2007</u>	For the Six Months Ended June 30, <u>2007</u>
Beginning balance asset retirement obligations	\$ 2,926	\$ 2,767	\$ 2,438	\$ 2,321
Additional obligation added during the period	167	268	45	113
Accretion expense	61	119	50	99
Ending balance of asset retirement obligations	<u>\$ 3,154</u>	<u>\$ 3,154</u>	<u>\$ 2,533</u>	<u>\$ 2,533</u>

Note 4 — Restricted Certificates of Deposit and Deposits

Restricted Certificates of Deposit. The Company holds a certificate of deposit ("CD"), which expires in July 2009, totaling \$150,000. The CD is collateral on bonding required by the State of Wyoming, the State of Montana and the Federal Bureau of Land Management. Because the Company intends to renew the CD in order to maintain its bonding requirements, the Company has included the CD in non-current assets as of June 30, 2008. Additionally, the Company holds two CDs for \$604,000 and \$964,000 which were issued in February 2006 and May 2008 and which expire in February and May 2009, respectively. These CDs collateralize letters of credit in favor of Powder River Energy Corporation, a local rural electric association, in order to secure power lines to the Kirby, Deer Creek and Cabin Creek areas. The Company has included this amount in non-current assets as of June 30, 2008 because the Company also intends to renew these CDs in order to maintain a power supply on a long-term basis. In April 2006, the Company issued a \$1,000,000 letter of credit that expires in April 2009 in favor of Bitter Creek Pipelines, LLC to secure the construction of a high pressure pipeline and related compression facilities to the Company's Deer Creek and Kirby areas. The Company has included this amount in non-current assets as of June 30, 2008 because the Company anticipates that the construction of the pipeline and compression facility will not be completed and fully utilized until the end of 2009.

Deposits. The Company included approximately \$153,000 related to royalty payments in deposits. These amounts are included in deposits in the balance sheet at June 30, 2008. The Company has also included \$490,000 in deposits for pipe to be purchased in the third quarter of 2008.

[Table of Contents](#)**Note 5 — Derivatives**

The Company accounts for derivative instruments or hedging activities under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires the Company to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings.

The Company periodically hedges a portion of its oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Management of the Company decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings.

As of June 30, 2008 and 2007, the Company had natural gas hedges in place as follows:

Product and Type of Hedging Contract	MMbtu Per Day	Fixed Price Range CIG Index Price	Time Period
June 30, 2008 (unaudited)			
Natural Gas—Swap	2,500	\$6.63	02/08-12/08
Natural Gas—Collar	2,000	\$6.50–\$7.50	01/09-12/09
Natural Gas—Swap	1,500	\$7.44	03/08-12/08
Natural Gas—Swap	2,500	\$7.17	01/09-12/09
Natural Gas—Collar	3,000	\$6.50–\$8.20	01/08-12/08
June 30, 2007 (unaudited)			
Natural Gas—Collar	1,000	\$5.00–\$5.20	10/04-09/07
Natural Gas—Collar	1,000	\$6.50–\$10.50	09/06-12/07
Natural Gas—Collar	3,000	\$7.00–\$9.05	01/07-12/07
Natural Gas—Collar	3,000	\$6.50–\$8.20	01/08-12/08

The Company realized a hedging loss of \$676,000 and realized a hedging gain of \$1,240,000 for the three months ended June 30, 2008 and 2007, respectively. As a result of the change in the fair value of the commodity derivatives, the Company had an unrealized loss of \$1,988,000 for the three months ended June 30, 2008 and an unrealized loss of \$576,000 for the three months ended June 30, 2007. The aggregate of these contracts resulted in the loss on derivatives of \$2,664,000 and a gain on derivatives of \$664,000 for the three months ended June 30, 2008 and 2007, respectively. For the six months ended June 30, 2008, the Company realized a hedging loss of \$769,000 compared to a hedging gain of \$1,676,000 for the six months ended June 30, 2007. The Company had an unrealized loss of \$6,466,000 and \$1,211,000 for the six months ended June 30, 2008 and 2007, respectively. The aggregate of these contracts resulted in a loss of derivatives of \$7,235,000 and a gain of \$465,000 for the six months ended June 30, 2008 and 2007, respectively. Unrealized and realized gains and losses are included in gains or losses on derivatives in the accompanying statements of operations. Because the Company's derivative contracts were not accounted for as cash flow hedges, the Company classifies the realized gains and losses in the investment activities in the accompanying statements of cash flows.

The Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Note 6 — Stock Based Compensation*Options under Employee Option Plans*

The Company has adopted a stock incentive plan containing both incentive and non-statutory stock options. All options allow for the purchase of common stock at prices not less than the fair market value of such stock at the date of grant. If the option holder owns more than 10% of the total combined voting power of all classes of the Company's stock, the exercise price cannot be less than 110% of the fair market value of such stock at the date of grant.

Options granted under the plan become vested as directed by the Company's Board of Directors and generally expire seven or ten years after the date of grant, unless the option holder owns more than 10% of the total combined voting power of all classes of the

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Company's stock, in which case the non-statutory stock options must be exercised within five years of the date of grant. At June 30, 2008, there were options to purchase 750,000 shares granted under the plan.

The options granted since formation in June 2003 vest in general as follows:

Year 1	20%
Year 2	30%
Year 3	50%
	<u>100%</u>

Stock-Based Compensation

At June 30, 2008, the Company had unvested options to purchase 249,250 shares with a weighted average grant date fair value of \$741,000. During the three months ended June 30, 2008, the Company did not grant any options to purchase common stock. The Company will recognize compensation expense relating to non-vested options granted after January 1, 2006 ratably over the next three years. During the three and six months ended June 30, 2008, the Company recognized compensation expense of approximately \$158,000 and \$256,000, respectively, based on the fair value of the vested options.

The following table summarizes stock option activity for the six months ended June 30, 2008:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life	Aggregate Intrinsic value
Outstanding, December 31, 2007	871,000	\$ 6.56		
Canceled or forfeited	(121,000)	7.37		
Outstanding, June 30, 2008 (unaudited)	<u>750,000</u>	<u>\$ 6.42</u>	<u>3.90</u>	<u>\$ —</u>
Exercisable, June 30, 2008 (unaudited)	<u>500,750</u>	<u>\$ 5.72</u>	<u>3.83</u>	<u>\$ —</u>

The following table summarizes information about stock options outstanding at June 30, 2008:

Exercise Prices	Options Outstanding			Options Exercisable		Fair Value Determination
	Number of shares Outstanding	Weighted Average Remaining Contractual Life	Number Exercisable	Weighted Average Exercise Price		
\$ 4.00	137,500	2.3 years	137,500	\$ 4.00	Black-Scholes (minimum value)	
\$ 4.80	282,500	3.8 years	216,250	\$ 4.80	Black-Scholes (minimum value)	
\$ 5.20	112,500	4.5 years	56,250	\$ 5.20	Black-Scholes	
\$ 8.40	25,000	5.9 years	5,000	\$ 8.40	Black-Scholes	
\$ 11.00	192,500	4.9 years	85,750	\$ 11.00	Black-Scholes	
Total	<u>750,000</u>		<u>500,750</u>			

Restricted Stock

The Company has a stock incentive plan whereby grants of restricted stock have been awarded to members of the Board of Directors and certain executives and employees. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements.

During the three and six months ended June 30, 2008, the Company recognized compensation expense of approximately \$71,000 and \$178,000, respectively, based on the fair value of the vested shares.

A summary of the status and activity of the restricted stock for the six months ended June 30, 2008 is presented below.

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	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2007	147,540	\$ 8.57
Forfeited	(10,560)	\$ 7.45
Vested	(26,090)	\$ 11.00
Non-vested at June 30, 2008 (unaudited)	<u>110,890</u>	<u>\$ 7.91</u>

As of June 30, 2008, the Company had approximately \$706,000 of unrecognized share-based compensation expense related to non-vested stock awards, which is expected to be amortized over the remaining vesting periods of three to five years.

Note 7 — Long-Term Debt*Credit Facility*

Effective February 12, 2007, the Company entered into a new \$100 million credit facility (the “Credit Agreement”) with The Royal Bank of Scotland (“RBS”), with an initial commitment of \$27 million which permits borrowings up to the borrowing base as designated by the administrative agent. As of June 30, 2008, the borrowing base under the Credit Agreement was \$17.8 million, although the Company’s actual borrowing availability was approximately \$6.6 million due to covenant limitations, of which \$5.0 million of debt was outstanding under the Credit Agreement.

The borrowing base is determined on a semi-annual basis and at such other times as may be requested by the borrower or administrative agent. As part of the annual borrowing base redetermination, in April 2008, the Company entered into a letter agreement with the administrative agent whereby the borrowing base under the credit facility will be automatically reduced on a monthly basis until a formal determination or redetermination of the borrowing base comes into effect. Under such agreement, the borrowing base may be reduced from \$17.8 million on June 30, 2008 to \$16.5 million on October 1, 2008. However, we expect that a redetermination of our borrowing base will occur in September 2008.

Borrowing under the Credit Agreement bears interest either: (i) at a domestic bank rate plus an applicable margin between 0.25% and 1.25% per annum based on utilization or (ii) on a sliding scale from the one, two, three, or six month LIBOR rate plus 1.25% to 2.25% per annum based on utilization. The Credit Agreement matures February 12, 2011, and replaced the Company’s previous credit facility. The Credit Agreement with RBS is collateralized by substantially all of the Company’s producing assets.

The Credit Agreement contains covenants that, among other things, restrict the Company’s ability, subject to certain exceptions, to do the following:

- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend the Company’s organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, the Credit Agreement provides that acceptable commodity hedging arrangements cannot be greater than 80 to 85%, depending on the measurement date, of the Company’s monthly production from its hydrocarbon properties that are used in the borrowing base determination and that the fixed or floor price of the Company’s hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The Credit Agreement also requires that the Company satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants as of June 30, 2008 included requirements to maintain: (i) earnings before income taxes, depreciation, depletion, amortization and accretions (“EBITDA”) to cash interest expense of not less than 3.00 to 1.00, (ii) current ratio of not less than 1.00 to 1.00, (iii) total debt to annualized EBITDA of not more than 3.0 to 1.0, (iv) quarterly total senior debt to annualized EBITDA equal to or less than 2.00 to 1.0, and

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(v) total proved PV-10 value of reserves to total debt of at least 1.50 to 1.00. The Credit Agreement contains customary events of default, including, without limitation, payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material permits and licenses and a change in control. The Company was in compliance with the covenants under the Credit Agreement as of June 30, 2008.

Effective August 4, 2008, the parties to the Credit Agreement entered into the Second Amendment (the "Second Amendment") to the Credit Agreement. The Second Amendment provides, among other things, for (i) the increase in the total quarterly senior debt to annualized EBITDA ratio from 2.0 to 1.0, to 3.0 to 1.0, (ii) an increase in interest at each utilization level for LIBOR borrowings, (iii) the amendment of the utilization calculation to be determined as the greater of (x) the percentage of credit exposure over the borrowing base or (y) the percentage of credit exposure over three times EBITDA minus permitted subordinated debt, and (iv) the payment of an amendment fee.

Office Building Loan

On November 15, 2005, the Company entered into a mortgage loan secured by its office building in Sheridan, Wyoming in the aggregate principal amount of \$829,000. The promissory note provides for monthly payments of principal and interest in the initial amount of \$6,400, and unpaid principal bears interest at 6.875% during the first three years, at a variable base rate thereafter and at 18% upon a default. The variable base rate is based on the lender's base rate. The maturity date of this mortgage is November 15, 2015, at which time a principal and interest payment of \$615,400 will become due. As of June 30, 2008, the Company had \$775,000 outstanding in principal and interest on this mortgage.

Note 8 — Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, "Fair Value Measurements" for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

- Level 1 — Quoted prices in active markets for identical assets or liabilities
- Level 2 — Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable.
- Level 3 — Significant inputs to the valuation model are unobservable.

The following is a listing of the Company's liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of June 30, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total
Liabilities				
Oil and Gas derivative instruments	\$ —	\$ 5,910	\$ —	\$ 5,910
Total	\$ —	\$ 5,910	\$ —	\$ 5,910

A financial asset or liability is categorized within the hierarchy based upon the lowest level of input that is significant to the fair value measurement. The Company's valuation methodologies for oil and gas derivative instruments, which are measured at fair value and are included in the accompanying balance sheet, are listed below.

The Company uses Level 2 inputs to measure the fair value of oil and gas derivative instruments. The fair value is based on interpolated data. The Company uses an industry standard model that considers various inputs including; (a) quoted forward prices for the specific commodity and area which was hedged, (b) volatility factors with consistent time data that correlates to the remaining life

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of the derivative instruments and (c) time value. The Company believes that this approach provides a reasonable, non-biased and consistent methodology for valuing oil and gas derivative instruments. In addition, the Company also evaluates company credit risk and counterparty credit risk to determine fair value of the asset or liability and further action as needed.

Note 9 — Contingencies

From time to time, Pinnacle is subject to legal proceedings and claims that arise in the ordinary course of its business. In addition, like other natural gas and oil producers and marketers, Pinnacle's operations are subject to extensive and rapidly changing federal and state environmental, health and safety laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As a result, it is extremely difficult to reasonably quantify future environmental and regulatory related expenditures.

The following represent legal actions in which Pinnacle is involved. No assurance can be given that these legal actions will be resolved in Pinnacle's favor. However, management believes, based on its experiences to date, that these matters will not have a material adverse impact on Pinnacle's business, financial position or results of operations.

Pinnacle, together with the State of Montana, the Montana Department of Environmental Quality, the Montana Board of Oil and Gas Conservation and the Department of Natural Resources, have been named as defendants in a lawsuit (Civil Cause No. DV-05-27) filed on May 19, 2005 in the Montana 22nd Judicial District Court, Bighorn County by Diamond Cross Properties, LLC relating to the Coal Creek POD. The plaintiff is a surface owner with properties located in Big Horn County and Rosebud County, Montana where Pinnacle serves as operator and owns a working interest in the minerals under lease. The plaintiff seeks to permanently enjoin the State of Montana and its administrative bodies from issuing licenses or permits, or authorizing the removal of ground water from under the plaintiff's ranch. In addition, the plaintiff further seeks to preliminarily and permanently enjoin Pinnacle on the basis that Pinnacle's operations lack adequate safeguards required under the Montana state constitution. On August 25, 2005, the district judge issued an order denying without prejudice the application for temporary restraining order and preliminary injunction requested by the plaintiff. The case was appealed by the plaintiff to the Montana Supreme Court. On November 16, 2005, the Montana Supreme Court issued an order that denied enjoining the Coal Creek POD, and subsequently, the Montana Supreme Court remanded the case back to the district court for a decision on the merits.

Approximately 59% and 61% of Pinnacle's gross acreage in Montana and Wyoming, respectively, is on U.S. federal land. Federal leases in Montana and Wyoming must be developed pursuant to the U.S. BLM's Resource Management Plans. Federal leases are also subject to the National Environmental Policy Act and Federal Land Policy Management Act. The National Environmental Policy Act process imposes obligations on the federal government that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals. The Montana and Wyoming BLMs have been subject to several lawsuits from various environmental and tribal groups challenging Resource Management Plan amendments and supporting Environmental Impact Statements addressing CBM development in Montana and Wyoming. In 2003, the Montana BLM and Wyoming BLM each amended their Resource Management Plans based in part on Environmental Impact Statements prepared pursuant to the National Environmental Policy Act. Shortly after the issuance of the Environmental Impact Statements and amended Resource Management Plans, various plaintiffs brought legal actions challenging the Montana and Wyoming Environmental Impact Statements and Resource Management Plans. There have been at least five federal district court challenges to the Montana Environmental Impact Statements. There are also at least three federal district court challenges to the Wyoming Environmental Impact Statements currently pending before the United States District Court for the District of Wyoming. Pinnacle has intervened in several of these cases to protect its interests in these proceedings. The outcome and timing of these cases could affect the Montana and Wyoming BLM's ability to approve PODs and issue drilling permits and thus could affect Pinnacle's ability to further develop its federal leases in Montana and Wyoming. In particular, the Ninth Circuit previously granted a motion for a blanket injunction prohibiting the Montana BLM from approving any CBM production projects on federal lands in the Powder River Basin of Montana pending disposition of two of three appeals pending before that court. While a panel of the Ninth Circuit issued a favorable decision affirming an earlier order by the Montana District Court that allows phased CBM development to continue pending completion of a Supplemental Environmental Impact Statement, or SEIS, Pinnacle cannot predict how or when the courts will ultimately resolve these matters, including the dissolution of the injunction, nor can it foresee future challenges which may arise. Pinnacle believes it will ultimately be successful in developing its leases as planned, but cannot give any assurances as to when or how these suits will be resolved or when Pinnacle will be able to develop its federal leases in the Powder River Basin of Montana.

[Table of Contents](#)**Note 10 — Recent Developments**

On July 1, 2008, Pinnacle granted an aggregate of 86,650 shares of restricted common stock to employees who were employed as of December 31, 2007. The restricted shares will vest 33.4%, 33.3% and 33.3% over three years on each anniversary date of the grant.

Effective August 4, 2008, the parties to the Company's Credit Agreement entered into the Second Amendment (the "Second Amendment") to the Credit Agreement. The Second Amendment provides, among other things, for (i) the increase in the total quarterly senior debt to annualized EBITDA ratio from 2.0 to 1.0, to 3.0 to 1.0, (ii) an increase in interest at each utilization level for LIBOR borrowings, (iii) the amendment of the utilization calculation to be determined as the greater of (x) the percentage of credit exposure over the borrowing base or (y) the percentage of credit exposure over three times EBITDA minus permitted subordinated debt, and (iv) the payment of an amendment fee. For more information, see Note 7 — Long-Term Debt.

As of June 30, 2008, the borrowing base under the Credit Agreement was \$17.8 million, although the actual borrowing availability was \$6.6 million due to covenant limitations, of which \$5.0 million of debt was outstanding indebtedness under the Credit Agreement.

[Table of Contents](#)**ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

The discussion and analysis that follows should be read together with the accompanying financial statements and notes related thereto that are included elsewhere in this quarterly report on Form 10-Q. It includes forward looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward looking statements. Factors that could cause or contribute to these differences include, but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this quarterly report on Form 10-Q and in our annual report on Form 10-K for the year ended December 31, 2007, including in "Risk Factors" and "Cautionary Statement Concerning Forward Looking Statements," all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward looking matters discussed may not occur.

Overview

We are an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas reserves. We primarily focus our efforts on the development of CBM properties located in the Powder River Basin in northeastern Wyoming and southern Montana. In addition, in April 2006, we acquired properties located in the Green River Basin in southern Wyoming. As of June 30, 2008, we owned natural gas and oil leasehold interests in approximately 494,000 gross (316,000 net) acres, approximately 93% of which were undeveloped. As of June 30, 2008, we had estimated net proved reserves of approximately 29.8 Bcf based on the CIG index price of \$8.73 per Mcf. We have a total capital expenditure budget of \$30.1 million for 2008 and expect to drill 146 gross (110 net) wells during that period. Depending on CIG index prices and available capital resources, we may re-evaluate our 2008 capital expenditure budget in the future. We incurred capital expenditures of approximately \$17.2 million during the six months ended June 30, 2008, primarily related to our drilling, completion and infrastructure costs on our Cabin Creek acreage, and drilled 76 gross (54 net) wells and completed 49 gross (35 net) wells during the six months ended June 30, 2008. We operated 100% of those wells.

We were formed in June 2003 as a Delaware corporation through a contribution of proved producing properties and undeveloped leaseholds by subsidiaries of Carrizo and U.S. Energy and a cash contribution from DLJ Merchant Banking.

In April 2006, we completed a private placement, exempt from registration under the Securities Act of 1933, of 12,835,230 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. In May 2007, we completed our initial public offering of 3,750,000 shares of common stock.

Effective February 12, 2007, we entered into a new \$100 million credit facility with an initial commitment of \$27 million which permits borrowings up to the borrowing base as designated by the administrative agent. As of June 30, 2008, the borrowing base was \$17.8 million, although our actual borrowing availability was approximately \$6.6 million due to covenant limitations, of which \$5.0 million of debt was outstanding. Effective August 4, 2008, we entered into an amendment to our credit facility. Among other things, the amendment increased the total quarterly senior debt to annualized EBITDA ratio to 3.0 to 1.0. Please see "Note 10 — Recent Developments" in the notes to the financial statements for more information regarding the amendment to the credit facility and the information under the heading "—Liquidity and Capital Resources—Credit Facility" in this Item 2 and the risk factors under Part II, Item 1A for further information regarding our credit facility and the covenant limitations.

Critical Accounting Policies

The most subjective and complex judgments used in the preparation of our financial statements are:

- Reserve evaluation and determination.
- Estimates of the timing and cost of our future drilling activity.
- Estimates of the fair valuation of hedges in place.

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- Estimates of timing and cost of asset retirement obligations.
- Estimates of the expense and timing of exercise of stock options.
- Accruals of operating costs, capital expenditures and revenue.
- Estimates for litigation.

Oil and Gas Properties

We use the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, are capitalized within a cost center. Our oil and gas properties are all located within the United States, which constitutes a single cost center. We have not capitalized any overhead costs. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. We invest in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. We recorded an impairment of unevaluated properties of \$0 and \$740,000 as of June 30, 2008 and June 30, 2007, respectively. Abandonment of unproved properties are also accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

Substantially all remaining unproved property costs are expected to be developed and included in the amortization base ratably over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on our estimate of the value of equipment and supplies at the time the well is abandoned. The estimated salvage value of equipment included in determining the depletion rate was approximately \$7.1 million and \$6.4 million as of June 30, 2008 and December 31, 2007, respectively.

Under the full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a "ceiling" value which is the sum of (1) the present value discounted at 10% of estimated future net revenue using current costs and prices, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. If capitalized cost exceeds the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, we calculate the full cost ceiling limitation. At June 30, 2008, the full cost ceiling of our oil and gas properties exceeded the capitalized cost by approximately \$35.0 million based upon a natural gas price of approximately \$8.73 per Mcf (based on the CIG Rocky Mountain Index) in effect at that date. As a result, we were not required to record an impairment for the six months ended June 30, 2008. An impairment of approximately \$18.2 million was recorded for the six months ended June 30, 2007. The impairment of our oil and gas properties resulted from low commodity prices throughout 2007, specifically at the end of the first, second and third quarters of 2007. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Gas Sales

We use the sales method for recording natural gas sales. Sales of gas applicable to our interest in producing natural gas and oil leases are recorded as revenues when the gas is metered and title transferred pursuant to the gas sales contracts covering our interest in gas reserves. During such times as our sales of gas exceed our pro rata ownership in a well, such sales are recorded as revenues unless

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total sales from the well have exceeded our share of estimated total gas reserves underlying the property at which time such excess is recorded as a gas imbalance liability. At June 30, 2008 and December 31, 2007, no liability was recorded. Although there was no liability recorded for prior periods, gas reserves are an estimate and are updated on an annual and interim basis. Gas pricing, expenses and production may impact future gas reserves remaining which in turn, could impact the recording of liabilities in the future. Gas sales accruals at June 30, 2008 and December 31, 2007 were based on the actual volume statements from our purchasers and distribution process. If accruals were to change by 10% at June 30, 2008 and December 31, 2007, the impact would have been a \$450,000 and \$306,000 change, respectively.

Asset Retirement Obligations

We follow the provisions of SFAS No. 143, "Accounting for the Asset Retirement Obligations." SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize an estimated liability for costs associated with the abandonment of our oil and gas properties.

A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units of production method, and the discounted liability is increased through accretion over the remaining life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. Our liability is discounted using our best estimate of our credit-adjusted risk-free rate. Revisions to the liability could occur due to changes in estimated abandonment costs, changes in well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells. For example, a 10% change in our estimated retirement costs would have a \$315,000 effect on our asset retirement obligation liability at June 30, 2008.

The following is a summary of our asset retirement obligation activity for the three and six months ended June 30, 2008 and June 30, 2007 (unaudited):

	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Beginning balance of asset retirement obligations	\$ 2,926	\$ 2,767	\$ 2,438	\$ 2,321
Additional obligation added during the period	167	268	45	113
Accretion expense	61	119	50	99
Ending balance of asset retirement obligations	<u>\$ 3,154</u>	<u>\$ 3,154</u>	<u>\$ 2,533</u>	<u>\$ 2,533</u>

Inventory

We acquire inventory of oil and gas equipment, primarily tubulars, to take advantage of quantity pricing and to secure a readily available supply. Inventory is valued at the lower of average cost or market. Inventory is used in the development of gas properties and to the extent it is estimated that it will be billed to other working interest owners during the next year, it is included in current assets. Otherwise, it is recorded in noncurrent assets. The price of steel is a primary factor in valuing our inventory. Under the valuation method of lower of average cost or market, a 10% reduction in the price of steel would have caused a \$52,000 reduction in our inventory valuation as of June 30, 2008. The market price of steel is evaluated each quarter using prices quoted by authorized vendors in the area.

Property and Equipment

Property and equipment is comprised primarily of a building, computer hardware and software, vehicles and equipment, and is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation and amortization are provided using the straight-line method over the estimated useful lives of the assets, ranging as follows: buildings — 30 years; computer hardware and software — 3 to 5 years; machinery, equipment and vehicles — 5 years; and office furniture and equipment — 3 to 5 years.

[Table of Contents](#)***Long-Lived Assets***

Long-lived assets to be held and used in our business are reviewed for impairment whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. When the carrying amounts of long-lived assets exceed the fair value, which is generally based on discounted expected future cash flows, we record an impairment. No impairments on long-lived assets were recorded during the year ended December 31, 2007 and the six months ended June 30, 2008.

General and Administrative Expenses

General and administrative expenses are reported net of amounts allocated and billed to working interest owners of gas properties operated by us. The administrative expenses billed to working interest owners may change in accordance with the terms of the joint operating agreements. Administrative expenses are charged to working interest owners based on productive well counts. A 10% change in well counts for the six months ended June 30, 2008 would have increased or decreased our expenses billed to working interest owners by approximately \$91,000. As we operate and drill additional wells in the future, additional administrative expenses will be charged to the working interest owners when the wells become productive. General and administrative expenses for the six months ended June 30, 2008 also include \$2.1 million of merger related costs attributable to the failed merger with Quest Resource Corporation. Any future costs associated with any merger, acquisition or divestiture will be expensed in the period of the transaction outcome.

Income Taxes

We use the asset and liability method of accounting for income taxes, in accordance with SFAS No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statement and tax bases of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of December 31, 2007 and June 30, 2008, we had recorded a full valuation allowance for our net deferred tax asset.

On January 1, 2007, we adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes." FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires that we recognize in our consolidated financial statements only those tax positions that are "more-likely-than-not" of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, we performed a comprehensive review of our material tax positions in accordance with recognition and measurement standards established by FIN 48.

As a result of this review, we did not identify any material deferred tax assets that required adjustment. As of January 1, 2007, the date of adoption of FIN 48, and as of June 30, 2008, we had not accrued any penalties or interest related to any material uncertain tax positions.

Our policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of June 30, 2008, we had not recognized any interest or penalties in our statement of operations or statement of financial position.

We are subject to the following material taxing jurisdictions: U.S. federal. We also have material operations in the state of Wyoming; however, Wyoming does not impose a corporate income tax. The tax years that remain open to examination by the U.S. Internal Revenue Service are years 2004 through 2007. Due to our net operating loss carry forwards, the Internal Revenue Service may also adjust the amount of loss realizable under examination back to 2003.

Derivatives

We use derivative instruments to manage our exposure to fluctuating natural gas prices through the use of natural gas swap and option contracts. We account for derivative instruments or hedging activities under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires us to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings. Please see

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“Note 5 — Derivatives” of the notes to the unaudited financial statements appearing elsewhere in this quarterly report for additional discussion of derivatives.

We periodically hedge a portion of our oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Our management decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123(R), “*Share-Based Payments*,” which requires companies to recognize compensation expense for share-based payments based on the estimated fair value of the awards.

SFAS No. 123(R) also requires that the benefits of tax deductions in excess of compensation cost recognized for stock awards and options (“excess tax benefits”) be presented as financing cash inflows in the Statement of Cash Flows. Prior to January 1, 2006, we accounted for share-based payments under the recognition and measurement provisions of APB Opinion No. 25, “*Accounting for Stock Issued to Employees*,” and related interpretations, as permitted by SFAS No. 123, “*Accounting for Stock-Based Compensation*.” In accordance with APB No. 25, no compensation cost was required to be recognized for options granted that had an exercise price equal to or greater than the market value of the underlying common stock on the date of the grant.

Accounts Receivable

Our revenue producing activities are conducted primarily in Wyoming. We grant credit to qualified customers, which potentially subjects us to credit risk resulting from, among other factors, adverse changes in the industry in which we operate and the financial condition of our customers. We continuously monitor collections and payments from our customers and, if necessary, record an allowance for doubtful accounts based upon historical experience and any specific customer collection issues identified. We recorded an allowance of \$100,000 as of June 30, 2008 and December 31, 2007.

Transportation Costs

We account for transportation costs under Emerging Issues Task Force Issues 00-10, “*Accounting for Shipping and Handling Fees and Costs*,” whereby amounts paid for transportation are classified as operating expenses.

Legal Estimates

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. We account for these costs under SFAS No. 5, “*Accounting for Contingencies*,” which states that a loss contingency be recorded if it is probable that a liability has been incurred and it is reasonably estimatable. At June 30, 2008 and December 31, 2007, we recorded \$0, respectively, for legal proceedings.

Per Share Information

Basic loss per share is computed by dividing net income loss from continuing operations attributable to common stock by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share was the same as basic net loss per share for the three months ended June 30, 2008 because potential common stock equivalents were anti-dilutive. Certain option to purchase shares of our common stock were excluded from the dilution calculations because the shares were anti-dilutive. At June 30, 2008 and 2007, 750,000 and 990,000 options, respectively, were excluded because they were anti-dilutive due to the net loss attributable to stockholders incurred in such periods.

New Accounting Pronouncements

For information concerning new accounting pronouncements, please see “Note 2 — Basis of Presentation” of the notes to the unaudited financial statements appearing elsewhere in this quarterly report.

[Table of Contents](#)**Trends Affecting Our Business**

We have experienced increasing costs since our inception in 2003 due to increased demand for oilfield products and services. The cyclical nature of the natural gas industry causes fluctuations in demand for goods and services from oilfield companies, suppliers and others associated with the industry, which in turn affects the prices for those goods and services. Typically, as prices for natural gas increase, so do all the costs associated with natural gas production. Recently, we have seen increases in the cost of tubulars, drilling rigs and cement in particular. We expect that increased demand for the goods and services we use in our business will continue to put pressure on prices in the near to medium term.

Historically, natural gas prices have been extremely volatile, and we expect that volatility to continue. For example, during the six months ended June 30, 2008, the NYMEX natural gas index price ranged from a high of \$13.21 per MMBtu to a low of \$7.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$9.43 per MMBtu to a low of \$6.08 per MMBtu. During the year ended December 31, 2007, the NYMEX natural gas index price ranged from a high of \$8.64 per MMBtu to a low of \$5.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$7.11 per MMBtu to a low of \$0.06 per MMBtu. Changes in natural gas pricing have impacted our revenue streams, production taxes, prices used in reserve calculations, borrowing base calculations and the carrying value of our properties and the valuation of potential property acquisitions. During the three and six months ended June 30, 2008, estimated future gas prices had an impact on our revenues and the costs attributable to our future operations. We expect that changing natural gas prices will continue to impact our operations and financial results in the future.

Transportation of natural gas and access to throughput capacity have a direct impact on natural gas prices in the Rocky Mountain region, where our operations are concentrated. As drilling activity increases throughout the Rocky Mountain region, additional production may come on line, which could cause bottlenecks or capacity constraints. Generally speaking, a surplus of natural gas production relative to available transportation capacity has a negative impact on prices. Conversely, as capacity increases and bottlenecks are eliminated, prices generally increase. Although there is currently adequate transportation capacity out of the Powder River Basin, a surplus of natural gas arriving at key marketing hubs from the Powder River Basin and elsewhere relative to available takeaway capacity from these hubs has caused Rocky Mountain gas to generally trade at a discount to the NYMEX natural gas index price. The Rockies Express Pipeline, which was completed to Audrain County, Missouri in early 2008, has increased takeaway capacity by approximately 2 Bcf per day from these hubs. We expect that the completion of this pipeline along with additional proposed pipelines will help reduce the differential between gas produced in the Rocky Mountain region and the NYMEX natural gas index price.

Results of Operations

Net loss attributable to stockholders for the three months ended June 30, 2008 was \$3.9 million, or \$0.13 per diluted share, on total revenue of \$7.6 million. Other income for the three months ended June 30, 2008 included a \$2.0 million unrealized loss associated with the change in the fair valuation of our natural gas hedges in place in accordance with the provisions of SFAS No. 133. Absent such change in the valuation, we would have shown a loss of \$1.9 million. This compares to a reported net loss attributable to stockholders of \$2.1 million for the three months ended June 30, 2007 on total revenue of \$3.4 million. Adjusted for an unrealized loss in the fair valuation of our natural gas hedges in place of \$0.6 million shown in other income, our results for the three months ended June 30, 2007 would have been a net loss attributable to stockholders of \$1.5 million. In addition, for the three months ended June 30, 2007, an impairment of the capitalized costs due to the ceiling limitation was \$1.2 million. Absent the impairment and unrealized loss, the net loss attributable to stockholders would have been \$0.3 million.

Net loss attributable to stockholders for the six months ended June 30, 2008 was \$9.5 million, or \$0.33 per diluted share, on total revenue of \$13.2 million. Other income for the six months ended June 30, 2008 included a \$6.5 million unrealized loss associated with the change in the fair valuation of our natural gas hedges in place in accordance with the provisions of SFAS No. 133. Absent such change in the valuation, we would have shown a loss of \$3.0 million. This compares to a reported net loss attributable to stockholders of \$20.2 million for the six months ended June 30, 2007 on total revenue of \$7.1 million. Adjusted for an unrealized loss in the fair valuation of our natural gas hedges in place of \$1.2 million shown in other income, our results for the six months ended June 30, 2007 would have been a net loss attributable to stockholders of \$19.0 million. In addition, for the six months ended June 30, 2007, an impairment of the capitalized costs due to the ceiling limitation was \$18.2 million. Absent the impairment and unrealized loss, the net loss attributable to stockholders would have been \$0.8 million.

In order to provide a measure of stability to the cash flow in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk, we choose to periodically hedge a portion of our oil and gas production using swap and collar agreements. We account for our derivative instruments under the provisions of SFAS No. 133. SFAS No. 133 requires us to record

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derivative instruments at their fair value. Management has chosen not to use hedge accounting for these arrangements. Therefore, in accordance with SFAS No. 133, changes in the fair market value are recognized in earnings.

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007*Gas sales volume.*

Gas sales volume increased approximately 9%, from 917 MMcf in the three months ended June 30, 2007 to 1,001 MMcf in the three months ended June 30, 2008. Daily sales volume was 10.9 MMcf for the three months ended June 30, 2008 compared to 10.0 MMcf for the three months ended June 30, 2007, a 0.9 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas.

Gas sales revenue.

Revenue from gas sales increased approximately \$4.1 million during the three months ended June 30, 2008, to approximately \$7.6 million, a 120% increase compared to the three months ended June 30, 2007. This increase was primarily due to an increase in gas sales volume coupled with an increase in the average realized price per Mcf. The average realized price per Mcf increased approximately 102%, from \$3.75 per Mcf before transportation in the three months ended June 30, 2007 to \$7.57 per Mcf in the three months ended June 30, 2008.

Derivatives.

For the three months ended June 30, 2008, we had an unrealized loss of \$2.0 million compared to an unrealized loss of \$0.6 million for the three months ended June 30, 2007. The unrealized loss is a non-cash expense based primarily on the Black-Scholes model for valuing future cash flows utilizing price volatility with a normal discount rate. Hedges settled during the three months ended June 30, 2008 resulted in a realized loss of \$0.7 million compared to a realized hedge gain of \$1.2 million during the three months ended June 30, 2007. The hedge loss for the three months ended June 30, 2008 was primarily due to the fact that gas prices were higher than the weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased \$0.1 million in the three months ended June 30, 2008 to \$1.3 million, an 11% increase compared to the three months ended June 30, 2007. This increase resulted from an increase in the number of wells in the productive cycle during the three months ended June 30, 2008, along with a workover program which replaced or repaired pumps in over 50 wells which were underperforming. We elected to expense the workover costs because such costs were \$5,000 to \$10,000 on a per well basis. On an Mcf basis, lease operating expenses increased 1% from \$1.33 per Mcf in the three months ended June 30, 2007 to \$1.35 per Mcf in the three months ended June 30, 2008. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Additionally, increases in generator rentals and associated fuel while waiting on permanent power contributed to the increase along with increased water management costs associated with water treatment.

Production taxes.

Production taxes increased \$0.5 million in the three months ended June 30, 2008 to \$0.9 million, a 141% increase from the three months ended June 30, 2007. Production taxes generally correlate to gross sales revenue because production taxes are based on a percentage of sales value. In Wyoming, the percentage averages 11% to 13%, depending on rates in effect for the respective year along with a 9% average rate for production sold derived in Montana. The increase in production taxes for the three months ended June 30, 2008 was primarily due to increased revenues associated with increased volume and realized pricing. On an Mcf basis, production taxes were \$0.86 per Mcf for the three months ended June 30, 2008 and \$0.39 per Mcf for the three months ended June 30, 2007, a 121% increase, which correlates to the increase in the price per Mcf received in the three months ended June 30, 2008 from the three months ended June 30, 2007.

Marketing and transportation.

Marketing and transportation expenses increased approximately \$0.3 million in the three months ended June 30, 2008 to approximately \$1.2 million, a 35% increase from the three months ended June 30, 2007. The increase related primarily to increased

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sales volume in the three months ended June 30, 2008, together with a slight increase in transportation fees and compression due to inflationary adjustments in the contracts along with fees paid for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 23% to \$1.21 per Mcf in the three months ended June 30, 2008 from \$0.98 per Mcf in the three months ended June 30, 2007.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees were \$0.5 million and \$0.4 million in the three months ended June 30, 2008 and June 30, 2007, respectively. General and administrative expenses, net, increased \$2.0 million in the three months ended June 30, 2008 to \$3.2 million from \$1.2 million in the three months ended June 30, 2007. This increase was due primarily to a \$2.1 million charge related to merger costs attributable to the failed Quest Resources Corporation merger. On an Mcf basis, general and administrative expenses, net increased 142%, from \$1.33 per Mcf in the three months ended June 30, 2007 to \$3.21 per Mcf in the three months ended June 30, 2008.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense increased \$0.7 million for the six months ended June 30, 2008 to \$2.3 million, a 42% increase compared to the three months ended June 30, 2007. This increase was due to a 9% increase in gas sales volumes for the three months ended June 30, 2008 along with additional capitalized costs in the full cost pool. On an Mcf basis, the depreciation, depletion, amortization and accretion rate increased 42% to \$2.20 per Mcf in the three months ended June 30, 2008 from \$1.61 per Mcf in the three months ended June 30, 2007.

Impairment.

At June 30, 2008, the full cost ceiling of our oil and gas properties exceeded the capitalized cost by approximately \$35.0 million based upon a natural gas price of approximately \$8.73 per Mcf (based on the CIG Rocky Mountain Index) in effect at that date. As a result, we were not required to record an impairment for the three months ended June 30, 2008. An impairment of approximately \$18.2 million was recorded for the year ended December 31, 2007. The impairment of our oil and gas properties resulted from low commodity prices throughout the year, specifically at the end of the first, second and third quarters of 2007. For further information regarding this impairment, please see "Note 2 — Basis of Presentation" in the notes to the unaudited financial statements appearing elsewhere in this quarterly report. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007*Gas sales volume.*

Gas sales volume increased approximately 15%, from 1,634 MMcf in the six months ended June 30, 2007 to 1,880 MMcf in the six months ended June 30, 2008. Daily sales volume was 10.3 MMcf for the six months ended June 30, 2008 compared to 9.0 MMcf for the six months ended June 30, 2007, a 1.3 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas.

Gas sales revenue.

Revenue from gas sales increased approximately \$6.1 million during the six months ended June 30, 2008, to approximately \$13.2 million, an 87% increase compared to the six months ended June 30, 2007. This increase was primarily due to an increase in gas sales volume coupled with an increase in the average realized price per Mcf. The average realized price per Mcf increased approximately 62%, from \$4.34 per Mcf in the six months ended June 30, 2007 to \$7.04 per Mcf in the six months ended June 30, 2008.

Derivatives.

For the six months ended June 30, 2008, we had an unrealized loss of \$6.4 million compared to an unrealized loss of \$1.2 million for the six months ended June 30, 2007. The unrealized loss is a non-cash expense based primarily on the Black-Scholes model for

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valuing future cash flows utilizing price volatility with a normal discount rate. Hedges settled during the six months ended June 30, 2008 resulted in a realized loss of \$0.8 million compared to a realized hedge gain of \$1.7 million during the six months ended June 30, 2007. The hedge loss for the six months ended June 30, 2008 was primarily due to the fact that gas prices were higher than the weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased \$1.3 million in the six months ended June 30, 2008 to \$3.4 million, a 59% increase compared to the six months ended June 30, 2007. This increase resulted from an increase in the number of wells in the productive cycle during the six months ended June 30, 2008, along with a workover program which replaced or repaired pumps in over 170 wells which were underperforming. We elected to expense the workover costs because such costs were \$5,000 to \$10,000 on a per well basis. On an Mcf basis, lease operating expenses increased 38% from \$1.31 per Mcf in the six months ended June 30, 2007 to \$1.81 per Mcf in the six months ended June 30, 2008. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Additionally, increases in generator rentals and associated fuel while waiting on permanent power contributed, along with increased water management costs associated with water treatment.

Production taxes.

Production taxes increased \$0.8 million in the six months ended June 30, 2008 to \$1.5 million, a 100% increase from the six months ended June 30, 2007. Production taxes generally correlate to gross sales revenue because production taxes are based on a percentage of sales value. In Wyoming, the percentage averages 11% to 13%, depending on rates in effect for the respective year while in Montana the percentage averages 9%. The increase in production taxes for the six months ended June 30, 2008 was primarily due to increased revenues associated with increased volume and realized pricing. On an Mcf basis, production taxes were \$0.81 per Mcf for the six months ended June 30, 2008 and \$0.46 per Mcf for the six months ended June 30, 2007, a 74% increase, which correlates to the increase in the price per Mcf received in the six months ended June 30, 2008 from the six months ended June 30, 2007.

Marketing and transportation.

Marketing and transportation expenses increased approximately \$0.6 million in the six months ended June 30, 2008 to approximately \$2.3 million, a 36% increase from the six months ended June 30, 2007. The increase related primarily to increased sales volume in the six months ended June 30, 2008, together with a slight increase in transportation fees and compression due to inflationary adjustments in the contracts along with fees paid for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 18% to \$1.22 per Mcf in the six months ended June 30, 2008 from \$1.03 per Mcf in the six months ended June 30, 2007.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees were \$0.9 million in the six months ended June 30, 2008 compared to \$0.8 million for the six months ended June 30, 2007, a 13% increase. General and administrative expenses, net, increased \$2.3 million in the six months ended June 30, 2008 to \$4.6 million from \$2.3 million in the six months ended June 30, 2007. This increase was due primarily to a \$2.1 million charge related to merger costs attributable to the failed Quest Resource Corporation merger. On an Mcf basis, general and administrative expenses, net increased 71%, from \$1.42 per Mcf in the six months ended June 30, 2007 to \$2.44 per Mcf in the six months ended June 30, 2008.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense increased \$0.9 million for the six months ended June 30, 2008 to \$4.0 million, a 30% increase compared to the six months ended June 30, 2007. This increase was due to a 15% increase in gas sales volumes for the three months ended June 30, 2008 along with additional capitalized costs in the full cost pool. On an Mcf basis, the depreciation, depletion, amortization and accretion rate increased 13% to \$2.13 per Mcf in the six months ended June 30, 2008 from \$1.89 per Mcf in the six months ended June 30, 2007.

[Table of Contents](#)*Impairment.*

At June 30, 2008, the full cost ceiling of our oil and gas properties exceeded the capitalized cost by approximately \$35.0 million based upon a natural gas price of approximately \$8.73 per Mcf (based on the CIG Rocky Mountain Index) in effect at that date. As a result, we were not required to record an impairment for the six months ended June 30, 2008. An impairment of approximately \$18.2 million was recorded for the six months ended June 30, 2007. The impairment of our oil and gas properties resulted from low commodity prices throughout the year, specifically at the end of the first, second and third quarters of 2007. For further information regarding this impairment, please see "Note 2 — Basis of Presentation" in the notes to the unaudited financial statements appearing elsewhere in this quarterly report. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Liquidity and Capital Resources

Our primary source of liquidity since our formation has been the private sale of our equity. During the period from our formation in June 2003 through September 2005, DLJ Merchant Banking contributed \$44.1 million cash in exchange for shares of our common stock, shares of our Series A Redeemable Preferred Stock and detachable warrants to purchase additional shares of common stock. The proceeds were used to fund our acquisitions and capital expenditures. In April 2006, we completed a private placement of an aggregate of 12,835,230 shares of our common stock at a price per share of \$11.00, or \$10.23 net of the initial purchaser's discount and placement fee. In May 2007, we completed an initial public offering of an aggregate of 3,750,000 shares of our common stock at a price per share of \$9.00, or \$8.37 net of the underwriters' discounts and commissions.

Credit Facility.

Effective February 12, 2007, we entered into a \$100 million credit facility with an initial commitment of \$27 million which permits borrowings up to the borrowing base as designated by the administrative agent. As of June 30, 2008, the borrowing base was \$17.8 million, although our actual borrowing availability was approximately \$6.6 million due to covenant limitations, of which \$5.0 million of debt was outstanding under the credit facility. Please see the information under the heading "Recent Developments" in the notes to the financial statements. Please see risk factors under Part II, Item 1A for more information regarding the covenant limitations under our credit facility.

The borrowing base is determined on a semi-annual basis and at such other additional times, up to twice yearly, as may be requested by either the borrower or the administrative agent and is determined by the collateral agent, although the determination is at the administrative agent's discretion as the credit agreement does not provide a specific borrowing base formula. Based on future reserve reports, fluctuations in CIG index prices, covenant limitations and possible title defects on certain of our properties, our borrowing base and borrowing availability could be further reduced. As part of the annual borrowing base redetermination, in April 2008 we entered into a letter agreement with the administrative agent whereby the borrowing base under our credit facility will be automatically reduced on a monthly basis until a formal determination or redetermination of the borrowing base comes into effect. Under such agreement, the borrowing base may be reduced from \$18.5 million on April 1, 2008 to \$16.5 million on October 1, 2008. However, we expect that a redetermination of our borrowing base will occur in September 2008.

Borrowings under this credit facility may be used solely to acquire, explore or develop oil and gas properties and for general corporate purposes. The credit facility matures February 12, 2011.

Our obligations under the credit facility are secured by liens on (i) no less than 90% of the net present value of the oil and gas to be produced from our oil and gas properties that are included in the borrowing base determination, calculated using a discount rate of 10% per annum and reserve estimates, prices and production rates and costs, (ii) options to lease, seismic options, permits, and records related to such properties, and (iii) seismic data.

Borrowings under our credit facility bear interest either: (i) at a domestic bank rate plus an applicable margin between 0.25% and 1.25% per annum based on utilization, or (ii) at the London interbank offered rate, or LIBOR, plus an applicable margin between 1.25% and 2.25% per annum based on utilization. The credit agreement provides for various fees, including a quarterly commitment fee of 1/2 of 1.00% per annum and engineering fees to the administrative agent in connection with a borrowing base determination. In addition, the credit facility provided for an up front fee of \$27,000, which was paid on the closing date of the credit facility, and an additional arrangement fee of 1% based on utilization. Borrowings under this credit facility may be prepaid without premium or penalty, except on Eurodollar advances. If an event of default exists, the default rate will be equal to 2% plus the floating rate.

The credit agreement contains covenants that, among other things, restrict our ability, subject to certain exceptions, to do the following:

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- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend our organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, the credit facility provides that acceptable commodity hedging arrangements cannot be greater than 80 to 85%, depending on the measurement date of our monthly production from our hydrocarbon properties that are used in the borrowing base determination, and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The credit agreement also requires that we satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants as of June 30, 2008 included requirements to maintain: (i) EBITDA to cash interest expense of not less than 3.00 to 1.00, (ii) current ratio of not less than 1.00 to 1.00, (iii) total debt to annualized EBITDA of not more than 3.0 to 1.0, (iv) quarterly total senior debt to annualized EBITDA equal to or less than 2.00 to 1.0, and (v) total proved PV-10 value to total debt of at least 1.50 to 1.00.

The credit agreement contains customary events of default, including payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material permits and licenses and a change in control. We were in compliance with the covenants under our credit agreement as of June 30, 2008.

The credit agreement requires any wholly-owned subsidiaries to guarantee the obligations under the credit agreement.

Effective August 4, 2008, the parties to the Credit Agreement entered into the Second Amendment (the "Second Amendment") to the Credit Agreement. The Second Amendment provides, among other things, for (i) the increase in the total quarterly senior debt to annualized EBITDA ratio from 2.0 to 1.0, to 3.0 to 1.0, (ii) an increase in interest at each utilization level for LIBOR borrowings, (iii) the amendment of the utilization calculation to be determined as the greater of (x) the percentage of credit exposure over the borrowing base or (y) the percentage of credit exposure over three times EBITDA minus permitted subordinated debt, and (iv) the payment of an amendment fee.

Office Building Loan.

On November 15, 2005, we entered into a mortgage loan secured by our office building in Sheridan, Wyoming in the aggregate principal amount of \$829,000. The promissory note provides for monthly payments of principal and interest in the initial amount of \$6,400, and unpaid principal bears interest at 6.875% during the first three years, at a variable base rate thereafter and at 18% upon a default. The variable base rate is based on the lender's base rate. The maturity date of this mortgage is November 15, 2015, at which time a principal and interest payment of \$615,400 will become due. As of June 30, 2008, we had \$775,000 outstanding in principal on this mortgage.

[Table of Contents](#)*Capital Expenditure Budget.*

During 2007, we reduced our total capital expenditure budget for 2007 from approximately \$52.6 million to approximately \$30.0 million. Consequently, we also reduced our drilling and completion targets for 2007 from approximately 260 gross (207 net) wells to approximately 140 gross (102 net) wells. During the year ended December 31, 2007, we incurred capital expenditures of \$21.2 million and drilled 87 gross (61 net) wells.

We have a total capital expenditure budget of \$30.1 million for 2008 and expect to drill 146 gross (110 net) wells during that period. During the six months ended June 30, 2008, we incurred capital expenditures of \$17.2 million, drilled 76 gross (54 net) wells and completed 49 gross (35 net) wells. Our capital expenditures were used to drill and complete wells, to construct related gas and water infrastructure, to fund plans of development costs for future wells, to fund undeveloped leasehold acquisition costs carried over from 2007, to recomplete certain wells, and to fund infrastructure and completion costs related to wells drilled in 2007. While we believe we will have adequate resources from cash flows from operations to implement a majority of our drilling plan for the remainder of 2008, our ability to complete our 2008 drilling plan and develop future projects will depend on access to additional sources of capital, including our credit facility. The CIG index price was extremely volatile during 2007 and at times reached unusually low levels. If prices decrease, our cash flows from operations could decrease and the borrowing base and borrowing availability under our credit facility could be further reduced. If we do not have sufficient cash flows and could not obtain capital through our credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves and maintain production levels could be greatly limited. Depending on CIG index prices and available capital resources, we may re-evaluate our capital expenditure budget in the future.

Cash Flow from Operating Activities

Net cash provided by operating activities was approximately \$5.0 million for the six months ended June 30, 2008, compared to net cash used in operating activities of approximately \$5.5 million for the six months ended June 30, 2007. The change was primarily due to an increase in our accounts payable balance offset partially by an increase in our accounts receivable balance.

While we believe that cash flows from operations will be sufficient to meet a majority of our capital expenditures and other cash needs during the remaining six months of 2008, the CIG Rocky Mountain index price was extremely volatile during 2007 and at times reached unusually low levels. If natural gas prices trend downward, our cash flows from operations could decrease and the borrowing base and borrowing availability under our credit facility could be reduced.

Cash Flow from Investing Activities

Net cash used in investing activities was approximately \$17.0 million for the six months ended June 30, 2008, compared to net cash used in investing activities of approximately \$10.9 million for the six months ended June 30, 2007. The increase was primarily due to an increase in capital spending on development drilling and infrastructure along with a realized loss recognized on gas derivatives.

Cash Flow from Financing Activities

Net cash provided by financing activities was approximately \$5.0 million for the three months ended June 30, 2008, compared to net cash provided by financing activities of approximately \$29.7 million for the six months ended June 30, 2007. The decrease was primarily due to net proceeds from an initial public offering of \$30.3 million in the second quarter of 2007 offset by \$5.0 million drawn on our credit facility in the second quarter of 2008.

In May 2007, we completed an initial public offering of 3,750,000 shares of our common stock at a price of \$9.00 per share, or \$8.37 per share net of underwriters' discounts and commissions. Out of the approximately \$30.3 million of net proceeds (after underwriters' discounts and commissions and offering expenses) we received in our initial public offering, we used \$7.0 million to pay down all of the outstanding indebtedness under our credit facility. We used the remainder of the net proceeds from our initial public offering for capital expenditures, infrastructure development and general corporate purposes.

Contractual Obligations

Please see Notes 3, 5 and 7 of the notes to the unaudited financial statements appearing elsewhere in this quarterly report for information regarding our credit facility and other indebtedness.

The following table summarizes by period our contractual obligations as of June 30, 2008:

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	<u>Total</u>	<u>2008</u>	<u>2009-2010</u> (In thousands)	<u>2011-2012</u>	<u>Thereafter</u>
Derivative instruments	\$ 5,910	\$ 2,673	\$ 3,237	—	—
Notes payable in connection with the mortgage	775	12	51	58	654
Asset retirement obligations	3,154	380	609	800	1,365
Production and property taxes	3,387	1,354	2,033	—	—
Total	<u>\$ 13,226</u>	<u>\$ 4,419</u>	<u>\$ 5,930</u>	<u>\$ 858</u>	<u>\$ 2,019</u>

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas prices. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposure. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. The prices we receive for our production depend on many factors beyond our control. We seek to reduce our exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. The fixed-price contracts are comprised of energy swaps and collars. These contracts allow us to predict with greater certainty the effective natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided by the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts.

The following table summarizes the estimated volumes, fixed prices, fixed price sales and fair value attributable to the fixed price contracts as of June 30, 2008. At June 30, 2008, we had hedged volumes through December 2009. Please see “Note 5 — Derivatives” of the notes to the unaudited financial statements appearing elsewhere in this quarterly report for further information regarding our derivatives.

	<u>Year Ending</u> <u>December 31, 2008</u> (Unaudited)	<u>Year Ending</u> <u>December 31, 2009</u> (Unaudited)
Natural Gas Collars:		
Contract volumes (MMBtu)		
Floor	552,000	730,000
Ceiling	552,000	730,000
Weighted-average fixed price per MMBtu(1)		
Floor	\$ 6.50	\$ 6.50
Ceiling	\$ 8.20	\$ 7.50
Fixed-price sales(2)	\$ 8.20	\$ 7.50
Fair value, net (thousands)(3)	\$ (1,068)	\$ (1,695)
Natural Gas Swaps:		
Contract volumes (MMBtu)		
	736,000	912,500
Weighted-average fixed price sales per MMBtu(1)		
	\$ 6.93	\$ 7.17
Fair value, net (thousands)(3)	\$ (1,605)	\$ (1,542)
Total Natural Gas Contracts:		
Contract volumes (MMBtu)		
	1,288,000	1,642,500
Fixed-price sales(2)	\$ 7.48	\$ 7.32
Fair value, net (thousands)(3)	\$ (2,673)	\$ (3,237)

(1) Volumes hedged using the CIG index price published in the first issue of Inside FERC’s Gas Market Report for each calendar month of the derivative transaction.

(2) Assumes ceiling prices for natural gas collar volumes.

(3) Fair value based on CIG index price in effect for each month as of June 30, 2008.

[Table of Contents](#)**Interest Rate Risk**

Borrowings under our credit facility bear interest at fluctuating market-based rates. Accordingly, our interest expenses are sensitive to market changes, which expose us to interest rate risk on current and future borrowings under our credit facility.

As of June 30, 2008, we had \$5.0 million in outstanding indebtedness under our credit facility. Borrowing under the credit facility bears interest either: (i) at a domestic bank rate plus an applicable margin between 0.25% and 1.25% per annum based on utilization or (ii) on a sliding scale from one, two, three, or six month LIBOR rate plus an applicable margin between 1.50% and 2.50% per annum based on utilization. The weighted average interest rate for borrowings under our credit facility was 3% for the six months ended June 30, 2008 and 3% at June 30, 2008.

A hypothetical change of 1% in either the domestic bank rate or the LIBOR interest rates would increase gross interest expense approximately \$50,000 per year.

ITEM 4T. CONTROLS AND PROCEDURES**Disclosure Controls and Procedures**

Based on their evaluation as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Control Over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION**ITEM 1. LEGAL PROCEEDINGS**

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of our business. While the outcome of these proceedings cannot be predicted with certainty, we do not currently expect them to have a material adverse effect on the financial statements.

There have been no material developments during the quarter ended June 30, 2008 regarding our currently pending legal proceedings. For a discussion of certain of our current legal proceedings, please see "Note 9 — Contingencies" of the notes to the unaudited financial statements appearing elsewhere in this quarterly report.

ITEM 1A. RISK FACTORS

The following discussion supplements or updates the risk factors set forth under the heading "Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2007 and in our quarterly report on Form 10-Q for the three months ended March 31, 2008.

The volatility of natural gas and oil prices could have a material adverse effect on our business.

Our revenues, profitability and future growth and the carrying value of our natural gas and oil properties depend to a large degree on prevailing natural gas and oil prices. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon natural gas and oil prices. Prices for natural gas and oil are subject to large fluctuations in response to relatively minor changes in the supply and demand for natural gas and oil, uncertainties within the market and a variety of other factors in large part beyond our control, such as:

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- the domestic and foreign supply of natural gas and oil;
- the activities of the Organization of Petroleum Exporting Countries and state-owned oil companies relating to oil price and production controls;
- overall domestic and global economic and political conditions;
- the consumption pattern of industrial consumers, electricity generators and residential users;
- weather conditions;
- natural disasters;
- acts of terrorism;
- political stability in the Middle East and elsewhere;
- domestic and foreign governmental regulations;
- the price and quantity of foreign imports; and
- the price and availability of alternative fuels.

In the past, natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, during the six months ended June 30, 2008, the NYMEX natural gas index price ranged from a high of \$13.21 per MMBtu to a low of \$7.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$9.43 per MMBtu to a low of \$6.08 per MMBtu. During the year ended December 31, 2007, the NYMEX natural gas index price ranged from a high of \$8.64 per MMBtu to a low of \$5.38 per MMBtu, while the CIG natural gas index price ranged from a high of \$7.11 per MMBtu to a low of \$0.06 per MMBtu.

A sharp decline in natural gas prices would result in a commensurate reduction in our revenues, income and cash flows from the production of natural gas and could have a material adverse effect on our borrowing base and proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our production and would operate at a loss, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Lower natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. For example, if natural gas prices decline by \$0.10 per Mcf, then the pre-tax PV-10 of our proved reserves as of June 30, 2008 would decrease from \$87.9 million to \$85.9 million. Accounting rules may also require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. As such, we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period such impairment charges are taken. For example, we reported an impairment of our oil and gas properties of approximately \$18.2 million for the year ended December 31, 2007 due to low and volatile CIG index prices throughout the year. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in the economically recoverable quantities could result in the recognition of additional ceiling write-downs of our gas properties in future periods.

Our credit facility imposes restrictions on us that may affect our ability to successfully operate our business.

Our credit facility imposes certain operational and financial restrictions on us. These restrictions, among other things, limit our ability to:

- incur indebtedness;
- create liens;
- sell our assets or consolidate or merge with or into other companies;
- make investments and other restricted payments, including dividends; and

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- engage in transactions with affiliates.

These limitations are subject to a number of important qualifications and expectations. In addition, our credit facility requires us to maintain certain financial ratios and to satisfy certain financial conditions which may limit our borrowing availability or require us to reduce our debt or to take some other action in order to comply with them. These restrictions could also limit our ability to obtain future financing, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. For example, as of June 30, 2008, our borrowing base under the credit facility was \$17.8 million. However, due to covenant restrictions, the actual borrowing availability under our credit facility was approximately \$6.6 million, of which \$5.0 million was outstanding under the credit facility. Effective August 4, 2008, we entered into an amendment to our credit facility. Among other things, the amendment increased the total quarterly senior debt to annualized EBITDA ratio to 3.0 to 1.0. Please see “Note 10 — Recent Developments” in the notes to the financial statements for more information regarding the amendment to the credit facility. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit facility. Please see Part I, Item 2, “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Credit Facility” for further discussion of our credit facility and the covenant restrictions.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibit No.	Description
3.1	— Second Amended and Restated Certificate of Incorporation of Pinnacle Gas Resources, Inc. (incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
3.2	— Amended and Restated Bylaws of Pinnacle Gas Resources, Inc. (incorporated herein by reference to Exhibit 3.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.1	— Amended and Restated Securityholders Agreement, dated February 16, 2006 (incorporated herein by reference to Exhibit 4.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.2	— Registration Rights Agreement, dated April 11, 2006 (incorporated herein by reference to Exhibit 4.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
*31.1	— Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	— Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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- *32.1 — Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *32.2 — Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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SIGNATURES

Pursuant to the requirements 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.

PINNACLE GAS RESOURCES, INC.

By: /s/ Peter G. Schoonmaker

Name: Peter G. Schoonmaker

Title: *President, Chief Executive Officer and Director*
(Principal Executive Officer)

Date: August 14, 2008

By: /s/ Ronald T. Barnes

Name: Ronald T. Barnes

Title: *Senior Vice President, Chief Financial Officer and Secretary*
(Principal Financial Officer and
Principal Accounting Officer)

Date: August 14, 2008

DOC 2 Header

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Peter G. Schoonmaker, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 14, 2008

/s/ Peter G. Schoonmaker

Peter G. Schoonmaker

President and Chief Executive Officer

DOC 3 Header

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Ronald T. Barnes, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 14, 2008

/s/ Ronald T. Barnes

Ronald T. Barnes
Senior Vice President, Chief Financial
Officer and Secretary

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**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc. (the "Company") for the period ending June 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter G. Schoonmaker, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: August 14, 2008

/s/ Peter G. Schoonmaker

Peter G. Schoonmaker

President and Chief Executive Officer

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**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc. (the "Company") for the period ending June 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ronald T. Barnes, Senior Vice President, Chief Financial Officer and Secretary of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: August 14, 2008

/s/ Ronald T. Barnes

Ronald T. Barnes

Senior Vice President, Chief Financial
Officer and Secretary
