TETON ENERGY CORP
Form 10-Q
August 14, 2009

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

(Mark One)

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

For quarterly period ended June 30, 2009

or

o **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 1-31679

TETON ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE	**84-1482290**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)

600 17th Street, Suite 1600 North, Denver, Colorado 80202

(Address of principal executive offices) (Zip code)

(303) 565-4600

(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. þ Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). o Yes o No

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer þ Non-accelerated filer o Smaller reporting company þ

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding as of August 11, 2009
Common stock, $.001 par value	23,948,285

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

TETON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(000s except shares and per share data)

	June 30, 2009 (Unaudited)	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 977	$
Restricted cash	800	
Trade accounts receivable	1,255	4,176
Current assets held for sale (Note 4)	987	
Tubular inventory	455	373
Fair value of oil and gas derivative contracts	1,290	5,217
Prepaid expenses and other assets	293	249
Deferred debt issuance costs net	534	540
Total current assets	6,591	10,555
Oil and gas properties, successful efforts method:		
Developed properties	47,340	94,529
Wells and facilities in progress	2,579	7,702
Undeveloped properties	9,118	22,005
Corporate and other assets	1,322	1,460
Total property and equipment	60,359	125,696
Less accumulated depreciation and depletion	(8,607)	(18,317)
Net property and equipment	51,752	107,379
Fair value of oil and gas derivative contracts		6,991
Deferred debt issuance costs net	1,657	1,933
Total assets	**$ 60,000**	**$ 126,858**
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 801	$ 1,915
Current liabilities held for sale (Note 4)	911	
Accrued liabilities	2,535	6,272
Accrued payroll	71	202
Short-term debt senior secured bank debt	8,484	
Total current liabilities	12,802	8,389

Long-term liabilities:				
Long-term debt senior secured bank debt		14,000		29,650
Long-term debt 10.75% Secured Convertible Debentures net of discount of $1,922 and $0, respectively		23,579		26,250
Asset retirement obligations		526		1,298
Total long-term liabilities		38,105		57,198
Total liabilities		50,907		65,587
Commitments and contingencies (see Note 11)				
Stockholders equity:				
Preferred stock, $.001 par value; 25,000,000 shares authorized; none outstanding				
Common stock, $.001 par value; 250,000,000 shares authorized; 23,948,285 and 23,821,573 shares issued and outstanding as of June 30, 2009 and December 31, 2008, respectively		24		24
Additional paid-in capital		103,532		103,267
Accumulated deficit		(94,463)		(42,020)
Total stockholders equity		9,093		61,271
Total liabilities and stockholders equity	**$**	**60,000**	**$**	**126,858**

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

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TETON ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(000s except share and per share data)
(Unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating revenues:				
Oil and gas sales	$ 2,259	$ 7,454	$ 4,002	$ 8,654
Loss on sale of oil and gas properties	(293)		(293)	
Miscellaneous income (expense), net	12		(1)	
Total operating revenues	1,978	7,454	3,708	8,654
Operating expenses:				
Lease operating expense	521	767	1,200	983
Workover expense	13	41	151	41
Transportation expense	219	315	463	316
Production taxes	225	272	362	343
Exploration expense	112	445	361	532
General and administrative	1,858	4,756	3,748	8,575
Depreciation, depletion and accretion expense	1,528	1,534	2,943	1,789
Surrendered leases	3,292		3,292	
Impairment expense			406	
Total operating expenses	7,768	8,130	12,926	12,579
Operating loss	(5,790)	(676)	(9,218)	(3,925)
Other income (expense):				
Realized gain (loss) on oil and gas derivative contracts	3,476	(1,186)	7,241	(1,253)
Unrealized loss on oil and gas derivative contracts	(7,042)	(22,246)	(10,917)	(23,479)
Gain on derivative warrant liabilities		51		876
Gain on retirement of convertible debt			480	
Interest expense, net	(1,368)	(5,418)	(2,674)	(9,634)
Total other expense	(4,934)	(28,799)	(5,870)	(33,490)
Net loss before discontinued operations	$ (10,724)	$ (29,475)	$ (15,088)	$ (37,415)
Loss from discontinued operations	(8,368)	(553)	(39,521)	(836)
Net loss applicable to common shares	$ (19,092)	$ (30,028)	$ (54,609)	$ (38,251)

Basic loss per common share before discontinued operations	$	(0.45)	$	(1.37)	$	(0.63)	$	(1.91)
Discontinued operations per share of common stock	$	(0.35)	$	(0.03)	$	(1.65)	$	(0.04)
Basic loss per share of common stock	$	(0.80)	$	(1.40)	$	(2.28)	$	(1.95)
Fully diluted loss per common share	$	(0.80)	$	(1.40)	$	(2.28)	$	(1.95)
Basic weighted-average common shares outstanding		23,946,107		21,477,811		23,922,558		19,625,383
Fully diluted weighted-average common shares outstanding		23,946,107		21,477,811		23,922,558		19,625,383

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

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TETON ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(000s) (Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating activities:		
Net loss	$ (54,609)	$ (38,251)
Discontinued operations:		
Loss on discontinued operations	775	836
Adjustments to reconcile net loss to net cash provided by operating activities:		
Loss on sale of discontinued operations	2,268	
Impairment of discontinued operations	36,478	
Depreciation, depletion and accretion expense	2,943	1,789
Impairment expense	406	
Surrendered leases	3,292	
Debt issuance cost amortization	282	1,439
Debt discount amortization	242	7,370
Stock-based compensation expense, exclusive of cash withheld for payroll taxes of $5,000 and $1.107 million, respectively	265	4,129
Gain on derivative warrant liabilities		(876)
Unrealized loss on oil and gas derivative contracts	10,917	23,479
Loss on sale of oil and gas properties	293	
Gain on retirement of 10.75% convertible debt	(480)	
Changes in current assets and liabilities:		
Restricted cash	(800)	
Trade accounts receivable	545	(1,353)
Tubular inventory, prepaid expenses and other assets	(126)	493
Accounts payable and accrued liabilities	(773)	2,248
Accrued payroll	(131)	797
Net cash provided by operating activities	1,787	2,100
Investing activities:		
Proceeds from sale of oil and gas properties	7,134	
Acquisition of corporate fixed assets	(16)	(347)
Acquisition and development of oil and gas properties	(492)	(59,308)
Net cash provided by (used in) investing activities	6,626	(59,655)
Financing activities:		
Proceeds from exercise of options/warrants		1,905
Proceeds from 10.75% convertible debt, including $10 million classified as short-term debt		40,000
Retirement of 10.75% convertible debt	(270)	
Net (repayments on) borrowings from senior bank credit facility	(7,166)	13,867

Payments on 8% convertible notes				(6,600)
Debt issuance costs				(2,256)
Net cash (used in) provided by financing activities		(7,436)		46,916
Increase (decrease) in cash and cash equivalents		977		(10,639)
Cash and cash equivalents beginning of period				24,616
Cash and cash equivalents end of period	$	977	$	13,977
Supplemental disclosure of cash and non-cash transactions:				
Cash paid for interest, net of amounts capitalized	$	2,056	$	887
Capitalized interest	$	7	$	155
Reclassification of oil and gas properties, net to current assets held for sale	$	908	$	
Reclassification of accrued liabilities to current liabilities held for sale	$	904	$	
Stock-based compensation expense included in capital expenditures	$		$	88
Capital expenditures included in accounts payable and accrued liabilities	$	77	$	3,083
Reclassification of ARO liabilities to current liabilities held for sale	$	7	$	
ARO disposed of in sale of assets	$	781	$	
ARO additions, revisions and acquired obligations	$		$	440
Conversion of 8% Subordinated Debt into Common Stock	$		$	2,400
Common Stock and Warrants issued in connection with the acquisition of oil and gas properties	$		$	13,423
Adoption of EITF 07-5 cumulative effect adjustment	$	2,164	$	

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

TETON ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Basis of Presentation

The accompanying unaudited interim consolidated financial statements were prepared by Teton Energy Corporation (Teton or the Company) pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and note disclosures normally included in the annual consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted as allowed by such rules and regulations. These consolidated financial statements include all of the adjustments, which, in the opinion of management, are necessary for a fair presentation of the financial position and results of operations. All such adjustments are of a normal recurring nature only. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full fiscal year.

As part of Teton s strategy to become an operator of all of its assets and to improve liquidity, the Company divested all of its non-operated working interests during the first half of the fiscal year December 31, 2009. Effective July 1, 2009, the Company sold its non-operated working interest in the Goliath project acreage located in the Williston Basin of North Dakota to American Oil & Gas, Inc. for gross proceeds of $900,000. Effective June 1, 2009, the Company sold its 12.5% non-operated working interest in the Piceance Basin to an undisclosed third party for $7.0 million in cash net of purchase price adjustments. On March 31, 2009, the Company sold its 25% non-operated working interest in the Teton Noble AMI non-operated properties to Noble Energy, Inc., the operator. The results of operations and any loss on sale associated with the disposal of these three properties are classified as discontinued operations in the current year results. Certain amounts for the period ending June 30, 2008 have been reclassified to conform to the current year presentation, including, but not limited to, the reclassification of oil and gas revenues and operating expenses related to the operations in the Williston Basin, the Piceance Basin and the Teton-Noble AMI.

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2008 (the 2008 Form 10-K), and are supplemented throughout the notes to this quarterly report on Form 10-Q.

The interim consolidated financial statements should be read in conjunction with the financial statements and notes thereto for the year ended December 31, 2008 included in the 2008 Form 10-K filed with the SEC.

Cash and cash equivalents

Cash and cash equivalents includes all cash balances and any highly liquid investments with an original maturity of 90 days or less. The Company uses excess cash on-hand to repay, to the extent possible, amounts outstanding under its line of credit and to fund daily operating and corporate expenses. The Company had a total cash balance of $977,000 and $0 at June 30, 2009 and December 31, 2008, respectively.

Restricted cash

On June 22, 2009, the Compensation Committee of the Board of Directors approved in concept, and on June 29, 2009, the group of banks which participate in the Company s Amended Credit Facility (the Senior Lenders) consented to, a retention program (the Program) for the Company s current employees. The total Program pool may not exceed $1,027,000, of which $800,000 is already funded and is classified as restricted cash. In the Program, each employee will receive, provided the time and event milestones are achieved, a proportionate percentage of the Program pool in (i) the aggregate amount of $250,000 on August 15, 2009 and (ii) the aggregate amount of $250,000 on the earlier of (x) October 15, 2009 and (y) the closing date of a transaction, which is defined as any acquisition, divestiture, merger, change of control, sale of all or substantially all the Company s assets, or a consolidation, reorganization, or recapitalization of the Company, provided that the employee is employed by the Company on such date. The Senior Lenders further consented to negotiate with the Company in good faith for the payment of additional employee retention payments, which would be comprised of $300,000 of restricted cash and $227,000 of cash generated from future cash flows. The employee would be entitled to such retention in addition to any rights the employee has under an existing employment agreement with the Company. The Program is funded by proceeds from the Williston Basin sale, the proceeds from the Company s 2010 and 2011 hedge position sale, and future cash flows, which was approved by the Senior Lenders. The Company is accruing for this liability over the requisite period the cash is earned from the date of the Program s conceptual approval, June 29, 2009. The Compensation Committee formally approved each employee s respective percentage on August 12, 2009.

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Accrued liabilities

At June 30, 2009, accrued liabilities consisted of $1.7 million accrued interest payable related to the Company s 10.75% Secured Convertible Debentures due on June 18, 2013 (the Debentures), and interest on the balance outstanding on its line of credit, $355,000 of severance liability to terminated employees who held employee agreements with the Company, approximately $253,000 of accrued production taxes related to oil and gas sales, franchise taxes, and approximately $227,000 of accrued liabilities related to operations. In an effort to facilitate the Company s evaluation of strategic alternatives, the holders of the Debentures consented to forebear with respect to the interest payable on July 1, 2009 until August 25, 2009. At December 31, 2008, accrued liabilities consisted of $1.7 million of accrued interest payable related to the Debentures and interest on the balance outstanding on its line of credit, approximately $856,000 of accrued production taxes related to oil and gas sales and $3.7 million of accrued liabilities related to operations. There are no other liabilities which are individually material for discussion.

Recently adopted accounting pronouncements

On January 1, 2009, the Company adopted the provisions of FSP FAS 157-2, Effective Date of FASB Statement No. 157 for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis, which include, among others, those nonfinancial long-lived assets measured at fair value for impairment assessment and asset retirement obligations initially measured at fair value. Fair value used in the initial recognition of asset retirement obligations is determined based on the present value of expected future dismantlement costs incorporating our estimate of inputs used by industry participants when valuing similar liabilities. Accordingly, the fair value is based on unobservable pricing inputs and therefore, is considered a level 3 value input in the fair value hierarchy. The adoption of FSP FAS 157-2 did not have a material impact on the Company s consolidated financial statements.

On January 1, 2009, the Company adopted the provisions of SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R requires the acquiring Company to measure almost all assets acquired and liabilities assumed in the acquisition at fair value as of the acquisition date. The Company will apply the provisions of SFAS No. 141R to future acquisitions.

On January 1, 2009, the Company adopted the provisions of SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, (SFAS No. 161), an amendment to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 161 requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The Company has applied the provisions of SFAS No. 161 and has included the required disclosures in this quarterly report on Form 10-Q.

On January 1, 2009, the Company adopted the provisions of FSP No. APB 14-1, Accounting for Convertible Debt Instruments that May Be Settled in Cash upon Conversion (Including Partial Cash Settlement,) (FSP APB 14-1). FSP APB 14-1 addresses the accounting for convertible debt securities that, upon conversion, may be settled by the issuer either fully or partially in cash. The adoption of APB 14-1 did not have a material impact on the Company s financial position or results of operations.

On January 1, 2009, the Company adopted the provisions of FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 clarified that all outstanding unvested share-based payment awards that contain rights to non-forfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. The adoption of FSP EITF 03-6-1 did not have a material impact on the Company s consolidated financial statements or results of operations.

On January 1, 2009, the Company adopted the provisions of EITF Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own stock (EITF No. 07-5). EITF No. 07-5 provides guidance for determining whether an equity-linked financial instrument (or embedded feature) is indexed to an entity s own stock. EITF No. 07-5 applies to any freestanding financial instrument or embedded feature that has all of the characteristics of a derivative or freestanding instrument that is potentially settled in an entity s own stock. To meet the definition of indexed to own stock, an instrument s contingent exercise provisions must not be based on (a) an observable market, other than the market for the issuer s stock (if applicable), or (b) an observable index, other than an index calculated or measured solely by reference to the issuer s own operations, and the variables that could affect the settlement amount must be inputs to the fair value of a fixed-for-fixed forward or option on equity shares. The Company has evaluated the impact of adoption of EITF 07-5; see Notes 5 and 6 for a discussion regarding the impact to the Company of adoption.

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On January 1, 2009, the Company adopted the provisions of EITF 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5 (EITF 08-4). EITF 08-4 provides transition guidance with respect to conforming changes made to EITF 98-5, that result from EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments, and SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. The adoption of EITF 98-5 did not have a material impact on the Company s consolidated financial statements or results of operations.

On January 1, 2009, the Company adopted the provisions of EITF Issue No. 08-5, Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement (EITF 08-5). EITF 08-5 provides guidance for measuring liabilities issued with an attached third-party credit enhancement (such as a guarantee). It clarifies that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. The adoption of EITF 08-5 did not have a material impact on the Company s consolidated financial statements or results of operations.

New accounting pronouncements

On April 1, 2009, the FASB issued FSP 141(R)-1, Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies (FSP 141R-1). FSP 141R-1 amends and clarifies SFAS No. 141R to address application issues associated with initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. FSP 141R-1 is effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company will apply the provisions of FSP 141R-1 to future acquisitions.

On April 9, 2009, the FASB issued FSP SFAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, which provides additional guidance for estimating fair value in accordance with SFAS No. 157 when the volume and level of activity for the asset or liability have significantly decreased. This FSP re-emphasizes that regardless of market conditions the fair value measurement is an exit price concept as defined in SFAS No. 157. This FSP clarifies and includes additional factors to consider in determining whether there has been a significant decrease in market activity for an asset or liability and provides additional clarification on estimating fair value when the market activity for an asset or liability has declined significantly. FSP 157-4 is applied prospectively to all fair value measurements where appropriate and will be effective for interim and annual periods ending after June 15, 2009. The adoption of FSP 157-4 did not have a material impact on the Company s consolidated financial statements or results of operations.

On April 29, 2009, the FASB issued FSP SFAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FSP which amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to require publicly-traded companies, as defined in APB Opinion No. 28, Interim Financial Reporting, to provide disclosures on the fair value of financial instruments in interim financial statements. FSP SFAS 107-1 and APB 28-1 are effective for interim periods ending after June 15, 2009. The adoption of FSP SFAS 107-1 and APB 28-1 did not have a material impact on the Company s consolidated financial statements or results of operations.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (SFAS No.165), which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This statement sets forth the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements. SFAS No. 165 also requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date that is, whether that date represents the date the financial statements were issued or were available to be issued. This statement is effective for interim or annual reporting periods ending after June 15, 2009. During the quarter ended June 30, 2009, the Company adopted SFAS No. 165. The Company evaluated subsequent events through August 14, 2009. The adoption of SFAS No. 165 did not have a material impact on the Company s consolidated financial statements.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162, (Codification), as the single source of authoritative generally accepted accounting principles in the United States (US GAAP) for all nongovernmental entities, with the exception of the SEC and its staff. The Codification, which launched July 1, 2009, changes the referencing and organization of accounting guidance and is effective for interim and annual periods ending after September 15, 2009. Since it is not intended to change or alter existing US GAAP, the Codification is not expected to have any impact on the Company s financial condition or results of operations.

2. Going Concern

These unaudited interim consolidated financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. Effective May 1, 2009, the Senior Lenders redetermined the Company s borrowing base downward from $32.5 million to $20.0 million. At that time, Teton had drawn $31.4 million on the credit facility. After divesting the Company s non-operated working interests in the Piceance Basin and selling certain long term hedge positions, the borrowing base was further reduced to $14.0 million and Teton had drawn $22.5 million. The outstanding excess of the borrowing base is due to the Senior Lenders on August 25, 2009. The next redetermination of the Company s borrowing base will be effective on August 1, 2009. It is anticipated that the banks will communicate their results to the Company during the second half of August 2009. The Company does not currently have sufficient resources to fund its current working capital requirements, service its Debentures, or repay the balance in excess of the borrowing base. As of the date of this report, the Company has not received a notification from its Senior Lenders regarding the August 1, 2009 redetermination.

The Company plans to obtain additional capital and credit through alternative financing arrangements with third parties. Teton will require additional sources of capital in order to reinstate a capital program to develop its leasehold position in the Central Kansas Uplift and drill the internally generated prospects, or implement any other business plan intended to maximize the value for its shareholders, as well as for its creditors and other constituents. However, there is no assurance that the Company s plans could be consummated on acceptable terms or at all. The adverse developments in financial and credit markets during the fourth quarter of 2008 have continued into 2009 and have made it extremely difficult to access capital and credit markets, relative to the efforts that have historically been required in order to raise capital. As a result, there is substantial doubt as to the ability of the Company to continue as a going concern. Should the Company be unable to continue as a going concern, it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due. These unaudited interim consolidated financial statements do not include any adjustments for this uncertainty.

The Company s ability to continue as a going concern is dependent upon the success of the Company s financial and strategic alternatives process, which may include the sale of some or all of the Company s assets, a merger or other business combination involving the Company or the restructuring or recapitalization of the Company. The Company has engaged RBC Richardson Barr (RBC) as an investment banker to assist further in the evaluation of the Company s strategic and financial alternatives. The Company had also engaged Barrier Advisors, Inc. as its restructuring advisor, however, that relationship was terminated effective June 22, 2009. Until the possible completion of the financial and strategic alternatives process, the Company s future remains uncertain and there can be no assurance that the Company s efforts in this regard will be successful. For additional comments, refer to Note 4 under the heading *Dispositions*.

During the first half of 2009, Teton implemented and substantially executed a Feasibility Plan designed to improve the Company s financial situation. This Feasibility Plan was presented to the Senior Lenders for their consideration, and has sustained the Company through the first half of fiscal year 2009. The key elements of the Feasibility Plan include divesting non-operated assets (see Note 4 under heading *Dispositions*), reducing labor costs, delaying capital expenditures and liquidating crude oil hedges not relating to 2009 production. Executing the Feasibility Plan resulted in reducing Teton s outstanding senior indebtedness by 27% from March 31, 2009 to June 30, 2009 and creating an operating environment with positive monthly recurring cash flow commencing in July 2009.

Teton continues to act on its Feasibility Plan into the third quarter of fiscal year 2009, as the Company believes that the successful implementation of the Feasibility Plan thus far has strengthened its financial position, enabling the Company to look further into the future and evaluate its options in order to maximize creditor and shareholder values. An integral component of the evolving strategy therefore includes a focus on restructuring the balance sheet and raising new capital. Teton is exploring various alternatives with its Senior Lenders and Debenture holders as well as new sources of equity in order to improve its liquidity. In order to facilitate the evaluation of Teton s strategic alternatives, the holders of its Debentures consented to forbear with respect to the interest payable July 1, 2009 until August 25, 2009. The Company is currently working with its Senior Lenders and Debenture holders to enter into a forbearance agreement beyond

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August 25, 2009, the due date of its borrowing base deficiency. Both sets of creditors concur with the Company s belief that it can maximize value for all of its constituencies by seeking new equity, reinitiating a development capital program and organically growing the Company through the drillbit. Teton is exploring all options available, both financially and operationally, which includes, but is not limited to, public and/or private placement of equity or debt, conversion of the Debentures into shares of Teton common stock, merging with other companies, as well as pre-packaged or pre-negotiated bankruptcy filings under the United States Bankruptcy Code, or any combination of the above. The Company does not yet know which of these actions, if any, it will choose to take, and, even if taken, there can be no assurance that any such action(s) will be successful. Additionally, the Company continues to re-examine all aspects of its business for areas of improvement and continues to focus on its fixed cost base to better align with operating levels and market demand.

3. Earnings per share of common stock

Basic loss per common share is computed by dividing net loss by the weighted average number of basic common shares outstanding during each period. The shares represented by vested restricted stock and vested performance share units under the Company s 2005 Long Term Incentive Plan (see Note 9) are considered issued and outstanding at June 30, 2009 and 2008, respectively, and are included in the calculation of the weighted average basic common shares outstanding. Diluted loss per common share reflects the potential dilution that would occur if contracts to issue common stock were exercised or converted into common stock. For the periods ending June 30, 2009 and 2008, basic loss per common share and diluted loss per common share are the same as any potentially dilutive shares would be anti-dilutive to the periods.

The following is the calculation of basic and fully diluted weighted average shares outstanding and earnings per share of common stock for the periods indicated:

	Six Months Ended	
(in thousands, except share and per share data)	**June 30, 2009**	**June 30, 2008**
Net loss before discontinued operations	$ (15,088)	$ (37,415)
Loss from discontinued operations	(39,521)	(836)
Net loss applicable to common shares	$ (54,609)	$ (38,251)
Weighted average common shares outstanding basic	23,922,558	19,625,383
Dilution effect of restricted stock, performance share units, options and warrants		
Weighted average common shares outstanding fully diluted	23,922,558	19,625,383
Earnings (loss) per share of common stock:		
Basic loss per share before discontinued operations	$ (0.63)	$ (1.91)
Discontinued operations per share of common stock	(1.65)	(0.04)
Basic loss per share of common stock	$ (2.28)	$ (1.95)
Fully diluted	$ (2.28)	$ (1.95)

Options to purchase 1,415,844 shares of common stock and 1,272,451 warrants to purchase common stock were outstanding during the first half of fiscal 2009 but were not included in the computation of diluted EPS because the exercise price was greater than the average market price of the common shares. Additionally, 1,138,800 unvested Performance Share Units, 129,600 unvested Restricted Share Units and 3,932,639 shares to be issued upon conversion of the Company s Debentures were excluded as the effect of these shares would have been anti-dilutive. The potentially dilutive shares are calculated using the treasury stock method, whereby a company uses the proceeds from the exercise or purchase of shares as well as the average unrecognized compensation to repurchase common stock at the average market price during the period. If the average market price during the period is less than the purchase or exercise price, the outstanding security will have an anti-dilutive effect on earnings per share. At June 30, 2009, the maximum number of shares that could potentially be included in the basic earnings per share calculation, if all shares above were exercised, purchased or converted, is 7,889,334 shares.

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For the period ended June 30, 2008, the maximum number of shares that could have potentially been included in basic earnings per share, if all shares were exercised, purchased or converted, was 16,500,374 shares.

4. Oil and Gas Properties

Dispositions

It is strategically important to the Company s future growth and maturation as an independent exploration and production company to be able to serve as operator of the Company s properties when possible in order to be able to exert greater control over costs and timing in, and the manner of, the Company s exploration, development and production activities. Successful execution of this strategy has resulted in the Company operating all four of its projects, effective July 1, 2009, and improving its liquidity.

Noble AMI

On March 31, 2009, the Company closed on the sale of its 25% non-operated working interest position in the Teton-Noble AMI. The Company sold its interest to its operating partner and 75% working interest owner, Noble Energy, Inc. (Noble). Included in the sale is the Company s 50% operated working interest in its undeveloped Frenchman Creek acreage in eastern Colorado. The net sales price of $4.0 million was received in the form of forgiveness of all outstanding and future amounts owed to Noble by the Company, related to the development of the Teton-Noble AMI project of $4.4 million, net of revenue receivables of approximately $400,000 for the same period.

At the time of sale, the carrying value of the Company s working interest in the Teton-Noble AMI and undeveloped Frenchmen Creek acreage was $4.4 million, and $281,000, respectively. The loss on sale of $799,000 and the income of $177,870 and the expenses of $166,690, resulted in a net gain of $11,180, are reported in discontinued operations on the face of the financial statements.

Piceance

Effective June 1, 2009, the Company divested its 12.5% non-operated working interest in the Piceance Basin to an undisclosed third party for $7.0 million net of purchase price adjustments. The carrying value of the Company s working interest in the Piceance Basin was $10.012 million at June 30, 2009. The loss on sale of approximately $1.469 million, the impairment loss of $28.949 million, and the income of $1.324 million and the expenses of $1.862 million, resulted in a net loss of $537,900, which is reported in discontinued operations on the face of the financial statements.

Williston

Effective July 1, 2009, the Company divested its non-operated working interest in the Williston Basin for $900,000, $688,463 net of purchase price adjustments. The impairment loss of $7.529 million and the income of $112,250 and the expenses of $360,380, resulted in a net loss of $248,130, are reported in discontinued operations on the face of the financial statements. The assets and liabilities outstanding at June 30, 2009 related to the Williston properties and are classified as held for sale on the face on the financial statements. The amounts included in current assets and liabilities held for sale include the following:

	At June 30, 2009 (in thousands)
Production receivable	$ 79
Developed properties	375
Wells and facilities in progress	647
Undeveloped properties	1,727
Less accumulated depreciation and depletion	(1,841)
Total current assets held for sale	$ 987
Accrued liabilities	$ 904
Asset retirement obligations	7

Total current liabilities held for sale	$	911

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Impairment of Long-Lived Assets
The Company reviews the carrying values of its long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the estimated undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties including undeveloped leaseholds. The Company incurred impairment expenses of $0 and $0 during the three months ended and $406,000 and $0 during the six months ended June 30, 2009 and 2008, respectively. The lack of industry activity and lower prices have had a negative effect on the value of the Company s leasehold interests in all areas, since the fourth quarter of 2008. See Note 5 for further discussion on the valuation of the Company s impaired assets.
Suspended Well Costs
The Company had no exploratory well costs that had been suspended for a period of one year or more as of June 30, 2009 or 2008.
Asset Retirement Obligations
The Company s asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells and removal of related equipment and facilities, in accordance with applicable state and federal laws. The following table provides a reconciliation of the Company s asset retirement obligations:

		Six Months Ended June 30, 2009 (in thousands)
Asset retirement obligation beginning of period	$	1,298
Accretion expense		16
Obligations sold or held for sale		(788)
Asset retirement obligation end of period	$	526

5. Fair Value of Financial Instruments
Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157 for all financial instruments. The valuation techniques required by SFAS No. 157 are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent resources, while unobservable inputs reflect the Company s market assumptions. The standard established the following fair value hierarchy:
Level 1 Quoted prices for identical assets or liabilities in active markets.
Level 2 Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.
Level 3 Significant inputs to the valuation model are unobservable.
The following describes the valuation methodologies the Company used to measure financial instruments at fair value.
Debt and Equity Securities
The recorded value of the Company s long-term debt approximates its fair value as it bears interest at a floating rate. The Debentures were negotiated instruments and are therefore recorded at fair value. The Company evaluated the Debentures and determined that, upon adoption of EITF 07-5 on January 1, 2009, embedded conversion features existed which were required to be bifurcated and accounted for separately as a derivative instrument. See discussion

below on the embedded conversion features.

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Derivative Instruments

The Company uses derivative financial instruments to mitigate exposures to oil and gas production cash flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, the Company recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At June 30, 2009, the Company did not have any derivative contracts that qualify as cash flow hedges.

Derivative assets in Level 2 include costless collars for the sale of oil hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through the end of June 30, 2009 for a total of approximately 68,407 Bbls of oil production. During the six months ended June 30, 2009, the Company recognized a realized gain of approximately $7.241 million related to the hedging settlements and to the sale of its open positions for the first quarter of 2010 through April 2013. A loss of approximately $10.917 million for the six months ended June 30, 2009, is included under unrealized loss on oil and gas derivative contracts, and relates to the change in fair value of the open hedging positions.

The Company also uses various types of financing arrangements to fund its business capital requirements, including convertible debt and other financial instruments indexed to the market price of the Company s common stock. The Company evaluates these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants), whether certain conditions for equity classification have been achieved.

On April 2, 2008, in conjunction with the purchase of production and reserves related to certain oil and gas producing properties in the Central Kansas Uplift, the Company issued 625,000 warrants to acquire shares of Teton common stock. Each warrant is exercisable on or after July 2, 2008 at an exercise price of $6.00 per share, and expires on April 1, 2010. The Company evaluated these instruments in accordance with SFAS No. 133 and EITF 00-19 and determined, based on the facts and circumstances, that these instruments qualify for classification in stockholders equity and therefore are not reported as a liability or measured at fair value on a recurring basis.

The Company adopted the provisions of EITF 07-5 on January 1, 2009. The Company evaluated its Debentures under the provisions of this EITF and determined that the embedded conversion features constitute embedded derivatives which are not linked to the equity of the Company. These embedded features, which include provisions to protect the investor in the event the Company issues stock dividends, goes through a subsequent rights offering or enters into a fundamental or change of control transaction, were valued using a probability weighted Black-Scholes-Merton valuation technique. The inputs to this model include significant unobservable inputs which require management s judgment and are considered to be level 3 inputs within the meaning of FAS No. 157. As of June 30, 2009, the fair value of compound embedded derivative instruments was $0. The initial adoption was recorded as a debt discount and a cumulative effect of a change in accounting principle and recorded in retained earnings. The embedded derivative conversion features are re-measured at each reporting period with subsequent changes in the fair value being recorded under the other income and expense caption in the consolidated statements of operations.

Additionally, the Company has freestanding warrants which were evaluated and determined to meet the scope exceptions in SFAS No. 133. Accordingly, these warrants are not measured at fair value.

The following table summarizes Teton s assets and liabilities measured at fair value on a recurring basis at June 30, 2009.

	Level 1	Level 2	Level 3	Total
Assets:				
Oil and gas derivative contracts	$	$ 1,290	$	$ 1,290
Liabilities:				

Embedded conversion features	$	$	$	$

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Assets Measured at Fair Value on a Non-Recurring Basis

The fair value of long-lived assets is determined using, to the extent possible, level 2 inputs which may include, third party valuations of the PV10 value of reserves, and level 1 inputs, which may include, public information regarding the sales price of like assets in active markets. In the absence of available information, the Company uses significant unobservable level 3 inputs to assess the fair value of long-lived assets.

In accordance with the provisions of SFAS No. 144, long-lived assets held for sale are recorded at their fair value. As a result of the sale of the Company s non-operated working interest in the Goliath project acreage located in the Williston Basin which was effective July 1, 2009, an impairment charge of $6.691 million was taken, and is included in discontinued operations. The fair value of the assets held for sale was valued using level 2 inputs. The fair value is the cash received and agrees to the quoted price for the sale of these assets.

The Company s undeveloped properties are subject to impairment under the provisions of SFAS No. 19. The recoverability of the carrying value of the properties is compared to the expected future cash flows, or the fair value of the asset. For the period ended June 30, 2009, the Company used level 2 and level 3 inputs to determine the fair value of its undeveloped properties. The current economic state and lack of market activity constitutes an inactive market under the provisions of SFAS No. 157. Accordingly, the Company applied judgment to adjust level 2 inputs, including Q4 2008 sales of similar assets and its knowledge of transactions between private companies, as current and relevant observable data is unavailable. As a result, for the six months ended June 30, 2009 an impairment of $837,000 and $406,000 was recorded related to the undeveloped properties in the Williston Basin and Central Kansas Uplift, respectively.

The following table summarizes the changes in value of Teton s assets measured at fair value on a non-recurring basis at June 30, 2009.

	Change in Fair Value Measure Using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total Losses**
Long-lived assets held and used	$	$	$ (406)	$ (406)
Long-lived assets held for sale		(6,691)	(837)	(7,528)
	$	$ (6,691)	$ (1,243)	$ (7,934)

6. 10.75% Secured Convertible Debentures

On June 18, 2008, the Company closed the private placement of $40 million aggregate principal amount of Debentures due on June 18, 2013. The Debentures are convertible by the holders at a conversion rate of $6.50 per share and contain a two year no-call provision and a provisional call thereafter if the price of the underlying common stock of the Company exceeds the conversion price by 50%, or is $9.75, for any 20 trading days in a 30 trading-day period. If the holders convert into common stock, or the Debentures are called by the Company before the three-year anniversary of the original issuance date, the holders will be entitled to a payment in an amount equal to the present value of all interest that would have accrued if the principal amount had remained outstanding through such three-year anniversary. The Debentures are secured by a second lien on all assets in which the Company s Senior Lenders maintain a first lien.

The Debentures bear interest at a rate of 10.75% per year payable semiannually in arrears on July 1 and January 1 of each year beginning with July 1, 2008. The holders each had a 90-day put option, expiring September 18, 2008, whereby they elected to reduce their investment in the Debentures by a total of 25% of the face amount, or $10 million in the aggregate. The Company repaid the $10 million to its investors on September 18, 2008, reducing the total outstanding amount on the Debentures to $30 million.

The net proceeds from the issuance of the Debentures, after fees and related expenses (and excluding the 90-day 25% put options) were approximately $28 million. These funds were used to pay down the Company s outstanding indebtedness on its revolving credit facility (see Note 7).

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On September 19, 2008, the Company entered into the Secured Subordinated Convertible Debenture Indenture (the Indenture) with each of the Company s subsidiary guarantors and the Bank of New York Mellon Trust Company, N.A., a national banking association (Bank of New York or the Trustee), and, in an exchange transaction on the same date, pursuant to the Purchase Agreement and the Indenture, the Company exchanged the Original Debentures for a Global Debenture in the amount of $30 million, which the Company deposited with the Depository Trust Company (DTC) and registered in the name of Cede & Co., as DTC s nominee. Pursuant to the Indenture, Bank of New York is acting as Trustee with respect to the Global Debenture and the Company s obligations thereunder. Initially, the Trustee is also serving as the paying agent, conversion agent and registrar with respect to the Indenture.

In connection with the Exchange and the closing of the Indenture, the Company entered into a letter agreement with each of the parties to the original Purchase Agreement, which amends and supplements the Purchase Agreement to, among other things, appoint Bank of New York as Representative, replacing Whitebox Advisors, LLC. The Company also entered into an amended and restated Intercreditor and Subordination Agreement with JPMorgan Chase and Bank of New York, and an amended and restated Subordinated Guaranty and Pledge Agreement, which reflect, among other things, the Exchange and the appointment of Bank of New York as successor in interest to Whitebox Advisors LLC as Representative and collateral agent.

On November 13, 2008, one of the investors, which held a $3.75 million investment in the Debentures, elected to convert, bringing the total outstanding amount on the Debentures to $26.25 million. The Company issued 576,924 shares of its common stock (based on the $6.50 stated conversion rate), 216,541 shares of the Company s common stock related to the interest make-whole provision and paid approximately $893,000 in cash related to accrued interest through the conversion date and for the remaining amount of the interest make-whole. On January 16, 2009, the Company retired an additional $750,000 of the Debentures for 273,000 in cash, bringing the total outstanding on the Debentures to $25.5 million.

In an effort to facilitate the Company s evaluation of strategic alternatives, the holders of the Debentures consented to forebear with respect to the interest payable on July 1, 2009 until August 25, 2009.

Deferred debt issuance costs of approximately $1.92 million associated with the Debentures are included in assets as of June 30, 2009 and will be amortized to interest expense over the life of the related Debenture. The Company recorded $282,000 of amortization of deferred debt issuance costs during the six months ended June 30, 2009 related to the Debentures.

The Company adopted the provisions of EITF 07-5 on January 1, 2009 (see Note 5) and as a result, recorded a debt discount related to the Debentures of approximately $2.16 million. During the six months ended June 30, 2009, the Company recorded approximately $242,000 of interest expense related to the amortization of the debt discount.

7. Senior Bank Facility

On April 2, 2008, the Company amended its $50 million Credit Facility to a $150 million revolving credit facility (the Amended Credit Facility) with a $50 million borrowing base.

In connection with the privately placed Debentures, the borrowing base on the Company s $150 million revolving credit facility was reduced from $50.0 million to $32.5 million. On August 1, 2008, the borrowing base was re-determined and increased to $34.5 million. Subsequently, on April 1, 2009, the borrowing base was reduced to $32.5 million related to the sale of hedge positions that were included in the value of the borrowing base. The borrowing base was further re-determined effective May 1, 2009, as a result of which the borrowing base was reduced from $32.5 million to $20.0 million. As of June 6, 2009, the borrowing base was further reduced to $15 million due to the divesture of the Company s non-operated working interest in the Piceance Basin. Finally and effective June 30, 2009, the Senior Lenders reduced the borrowing base to $14.0 million due to the divesture of Teton s hedges in place for production related to January 1, 2010 through September 30, 2011. At June 30, 2009, Teton s total outstanding balance on the revolving credit facility was $22.5 million. The $8.5 million excess of the borrowing base is recorded as short-term debt and is due to the Senior Lenders on August 25, 2009. The Company s total borrowings under the Debentures and the Amended Credit Facility are $47.985 million as of June 30, 2009.

Effective May 21, 2009, Teton and the Senior Lenders entered into the Second Amendment to the Second Amended and Restated Credit Agreement (the Second Amendment). Under the Second Amendment, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 2.50% to 4.25% or a base rate (the higher of the Prime Rate, the Federal Funds Rate plus 0.5% or the adjusted LIBO rate for a one month interest period on such day plus 1%) plus applicable margins of 1.50% to 3.25%, determined on a sliding scale based on the percentage of total borrowing base in use. The Company is also required to pay a commitment fee of 0.50% per annum, based on the daily average unused amount of the commitment. Loans made under the Amended Credit Facility are secured primarily by a first mortgage against the Company s oil and gas assets, by a pledge of the Company s equity interests in its subsidiaries and by a guaranty by its subsidiaries. The Amended Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage.

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Effective August 1, 2009, the Senior Lenders will redetermine the Company s borrowing base. It is anticipated that the banks will communicate their results to the Company during mid to late August 2009. The Company does not currently have sufficient resources to fund its current working capital requirements and service a borrowing base deficiency on its debt, and is negotiating with the bank group to extend the repayment period for any borrowing base deficiency. The Company plans to obtain additional capital availability through alternative financing arrangements third parties and the sale of assets to service its current working capital requirements, and its debt obligations. Additionally, the Company continues to re-examine all aspects of its business for areas of improvement and continues to focus on its fixed cost base to better align with operating levels and market demand. However, there is no assurance that the Company s plans can be consummated on acceptable terms or at all. The amount of the bank borrowing base immediately subsequent to the redetermination cannot be estimated at this time. It is possible that it would exceed the amounts realized from the sale of assets, in which case the excess deficiency could become a current liability. These unaudited interim consolidated financial statements do not include any adjustments for these uncertainties.

The balance outstanding on the senior debt at June 30, 2009 was approximately $22.5 million. For the three and six months ended June 30, 2009, interest expense with respect to the Company s senior debt and the Debentures described in Note 5 was $1.06 million and $2.06 million, respectively, and capitalized interest totaled $0 and $7,000, respectively. During the three and six months ended June 30, 2008, interest expense related to the Company s senior debt totaled approximately $687,000 and $1.04 million, respectively, and capitalized interest totaled $77,000 and $155,000, respectively.

8. Stockholders Equity

Warrants

The following table presents the composition of warrants outstanding and exercisable as of June 30, 2009. The weighted average exercise price of the outstanding warrants is $5.51.

Range of Exercise Prices	Number	Weighted Average Remaining Contractual Life (years)
$3.24	232,904	3.5
$6.00	625,000	0.8
$6.06	414,547	3.1
Total warrants outstanding and exercisable	1,272,451	2.0

9. Stock-Based Compensation

During 2008, 2,659,214 performance share units, net of forfeitures, were granted to participants, pursuant to the 2005 Long Term Incentive Plan (LTIP) by the Compensation Committee of the Company s Board of Directors (the 2008 Grants). The 2008 Grants vest in three tranches, provided the goals set forth by the Compensation Committee are met. The performance measures under these Awards are based on increases in the Company s net asset value per share. The grants vest at 20%, 30% and 50% when the net asset value per share of the Company increases by 40%, 100% and 200%, respectively, from a base level set by the Compensation Committee as of December 31, 2007. An additional 241,616 shares of restricted common stock, net of forfeitures, granted pursuant to the Company s LTIP, were awarded during 2008 and the first half of 2009. These shares vest over three years based solely on service.

Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the six months ended June 30, 2009, the Company recorded approximately $265,000 for stock-based compensation expense applicable to the vesting of restricted stock grants. The Company expects to recognize an additional $202,000 during the six months ending December 31, 2009 related to the restricted stock grants outstanding at June 30, 2009.

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10. Income Taxes

For each of the three and six months ended June 30, 2009 and 2008, the current and deferred provision for income taxes was $0.

At December 31, 2008, the Company had net operating loss carryforwards (NOLs), for federal income tax purposes, of approximately $59.5 million. These NOLs, if not utilized to reduce taxable income in future periods, will expire in various amounts from 2018 through 2028. Approximately $2.2 million of such NOL s are subject to limitation under Section 382 of the Internal Revenue Code, all of which will free up in 2009. During 2008, the Company had no deductions from the exercise of nonqualified stock options. The Company has established a valuation allowance for deferred taxes equal to its entire net deferred tax assets as management currently believes that it is more likely than not that these losses will not be utilized.

On January 1, 2007, the Company adopted the provisions of FIN 48, which 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. The Company had no accrued interest or penalties related to uncertain tax positions as of June 30, 2009.

11. Commitments and Contingencies

To mitigate a portion of the potential exposure to adverse market changes in the price of oil the Company has entered into derivative contracts. The outstanding commodity hedges as of June 30, 2009 are summarized below:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index(1)	Remaining Period
Oil Costless Collar	68,407 Bbls	$90.00 Floor/$104.00 Ceiling	WTI	07/01/09-12/31/09

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

On April 30, 2008, the Company entered into a lease agreement for new office space in Denver beginning September 1, 2008 for a period of 69 months. The start of the new lease agreement was delayed to November 1, 2008. Rental payments, before expenses, under the lease are approximately $132,000 for the remainder of 2009, approximately $269,000 for 2010 and an aggregate approximately $971,000 thereafter, for the remaining 41 months of the agreement.

The Company has engaged RBC as an investment banker to assist further in the evaluation of the Company s strategic and financial alternatives. Per the Company s contract, the Company agreed to pay RBC a non-refundable fee of $50,000 in the first quarter of fiscal year 2009. An additional fee of $1.0 million is contingent upon a significant transaction (i.e., significant asset sale, consolidation, etc) effected by the Company. Management evaluated the likelihood of the RBC liability as defined in SFAS No. 5 and determined that it was reasonably possible, but not probable, a transaction would occur triggering the $1.0 million payment to RBC, thus only a disclosure is made and no accrual has been recorded on the face of the financial statements.

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

The terms Teton, Company, we, our and us refer to Teton Energy Corporation and subsidiaries, as a consol entity, unless the context suggests otherwise.

Forward-Looking Statements

This Quarterly Report on Form 10-Q contains both historical and forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements, written, oral or otherwise made, represent the Company s expectation or belief concerning future events. All statements, other than statements of historical fact, are or may be forward-looking statements. For example, statements concerning projections, predictions, expectations, estimates or forecasts, and statements that describe our objectives, future performance, plans or goals are, or may be, forward-looking statements. These forward-looking statements reflect management s current expectations concerning future results and events and can generally be identified by the use of words such as may, will, should, could, would, likely, predict continue, future, estimate, believe, expect, anticipate, intend, plan, foresee and other similar words as statements in the future tense.

Forward-looking statements involve known and unknown risks, uncertainties, assumptions and other important factors that may cause our actual results, performance or achievements to be different from any future results, performance and achievements expressed or implied by these statements. The following important risks and uncertainties could affect our future results, causing those results to differ materially from those expressed in our forward-looking statements:

- Our ability to execute our Feasibility Plan (discussed below) in order to sustain our ability to continue as a going concern;
- Our ability to service current and future indebtedness and comply with the covenants related to the debt facilities or our ability to receive forbearance therefrom;
- General economic and political conditions, including governmental energy policies, tax rates or policies, inflation rates and constrained credit markets;
- The market price of, and supply/demand balance for, oil and natural gas;
- Our success in completing development and exploration activities, when and if we are able to resume those activities;
- Expansion and other development trends of the oil and gas industry;
- Acquisitions and other business opportunities that may be presented to and pursued by us;
- Our ability to integrate our acquisitions into our company structure; and
- Changes in applicable laws and regulations.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors, including unknown or unpredictable ones, could also have material adverse effects on our future results.

The following discussion should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

Overview and Strategy

We are an independent oil and gas exploration and production company focused on the acquisition, exploration and development of North American properties. Our current operations are concentrated in the prolific Midcontinent and Rocky Mountain regions of the U.S. We have leasehold interests in the Central Kansas Uplift, the eastern Denver-Julesburg Basin in Colorado, and the Big Horn Basin in Wyoming.

Teton was formed in November 1996 and is incorporated in the State of Delaware. Effective September 8, 2008, our common shares are publicly traded on the NASDAQ Capital Market LLC under the symbol TEC. Prior to September 8, 2008, our common shares were publicly traded on the American Stock Exchange under the symbol TEC.

Our principal executive offices are located at 600 17th Street, Suite 1600 North, Denver, CO 80202, and our telephone number is (303) 565-4600. Our website is www.teton-energy.com.

Current Economic Conditions and Credit Crisis

Our long-term plans have been, and will continue to be, to economically grow reserves and production, primarily by:

(1) acquiring under-valued properties with reasonable risk-reward potential and by participating in, or actively conducting, drilling operations in order to further exploit our existing properties,

(2) seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories, and

(3) selectively pursuing strategic acquisitions that may expand or complement our existing operations.

However, with the recent slowdown in the global economy, tightening of the credit and equity markets and depressed oil and gas commodity prices, we have evaluated our short-term objectives and the impact of these factors on our 2009 capital, operating and G&A budgets. In light of the current economic environment and its impact on our industry, our focus for 2009 is largely centered on production of our operated properties in the Central Kansas Uplift. Additionally, we are focusing our efforts on the execution of our Feasibility Plan (discussed below) in an attempt to solidify our position as a going concern. Refer to the heading Liquidity and Capital Resources for further discussion on the impacts of current economic factors on our short-term strategic plans.

Following are summary comments of our performance in several key areas during the three and six month periods ended June 30, 2009:

Net income (loss)

During the three and six month periods ended June 30, 2009, our net loss before discontinued operations decreased from approximately $29.475 million (or $1.37 per share) for the three months ended June 30, 2008, to approximately $10.724 million (or $0.45 per share) for the three months ended June 30, 2009 and from approximately $37.415 million (or $1.91 per share) for the six months ended June 30, 2008 to approximately $15.088 million (or $0.63 per share) for the six months ended June 30, 2009. The decrease in net loss before discontinued operations of $18.751 million for the three month period and $22.327 million for the six month period are due largely to a decrease in the unrealized loss on oil and gas derivative contracts, a non-cash item required by SFAS No. 133, of $15.204 million and $12.562 million, respectively; an increase in realized gain on oil and gas derivative contracts of $4.662 million and $8.494 million, respectively; a decrease in general and administrative expenses of $2.898 million and $4.827 million, respectively (largely due to decrease in non-cash compensation of $2.974 million and $4.595 million, respectively); and a decrease in cash and non-cash interest expense of $4.05 million and $6.96 million, respectively. See RESULTS OF OPERATIONS, below, for further discussion.

Production

During the three and six month periods ended June 30, 2009, average company-wide daily production decreased 28%, to 3,094 Mcfed and increased 21%, to 3,238 Mcfed, respectively, as compared to average daily production of 4,321 Mcfed and 2,677 Mcfed, respectively, during the same prior year periods. The fluctuations in production by major operating area are discussed below.

Central Kansas Uplift. On April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift, and we began recognizing our share of production from the 53 producing wells at that time (59 currently). Average daily production, net to us, from the area was 2,360 and 2,490 Mcfed for the three and six months ended June 30, 2009, respectively, compared to 3,527 Mcfed for the three months ended June 30, 2008. The second quarter 2008 was our first production from the Central Kansas Uplift properties, so there were no production volumes included in the first quarter 2008 results. The decrease in production is due to a lack of drilling and the normal decline curve.

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At June 30, 2009, we had more than 90% of the current oil production hedged, with contracts in place through December 31, 2009 on costless collars at a floor price of $90.00 per barrel of oil and a ceiling price of $104.00. At $90.00 per barrel of oil and today s drilling costs, a typical well in the Central Kansas Uplift project would generate an approximate 88% internal rate of return.

Washco. As of June 30, 2009, there were 26 gross producing wells in our operated Washco area of the DJ Basin which produced an average of 616 Mcfed and 689 Mcfed, net to us, during the three and six months ended June 30, 2009, respectively, compared to 774 Mcfed and 904 Mcfed, net to us, respectively, for the same prior year periods. The decrease in production is due to the normal decline curve and the fact that we have not drilled any wells in the Washco area since we acquired the property. We are currently seeking a partner to drill additional wells in the Washco area in the future.

Piceance. For the three and six months ended June 30, 2009, production, net to us, in the area, averaged 1,809 Mcfed and 2,451 Mcfed, as compared to 2,707 Mcfed and 2,801 Mcfed during the same prior year periods. Effective June 1, 2009, we divested our 12.5% non-operated working interest in the Piceance Basin to an undisclosed third party for $7.0 million net of purchase price adjustments. The sale was made as a part of our ongoing effort to sell the non-operated assets, to be more heavily weighted towards our own operations to be able to better control our pace of capital expenditures and to improve upon our liquidity.

In accordance with generally accepted accounting principles, we recorded an impairment expense on this property for the quarter ended March 31, 2009 of $28.949 million. The current global economic conditions and credit crisis, coupled with low commodity prices for natural gas in the Rockies, resulted in a current market value of the assets that is lower than our book carrying value. At June 1, 2009, the carrying value of the Piceance developed and undeveloped properties exceeded the negotiated sales price of the assets, which resulted in a loss on sale of discontinued operations of $1.47 million.

Noble AMI. Effective February 1, 2009, we sold our 25% non-operated working interest position in the Teton-Noble AMI to Noble Energy Inc. (Noble) in exchange for the forgiveness of all outstanding and future amounts we owed to Noble, related to the development of the project ($4 million after post-effective date adjustments). Included in the sale is our 50% operated working interest in the undeveloped Frenchman Creek acreage in eastern Colorado. The sale closed on March 31, 2009, with an effective date of February 1, 2009. As of the date of the sale, the carrying value of the Teton-Noble AMI developed and undeveloped properties exceeded the sales price of the assets, which resulted in a loss on the sale in discontinued operations of $799,000.

Williston. For the three and six months ended June 30, 2009, production, net to us, in the area, averaged 137 Mcfed and 126 Mcfed, as compared to 16 Mcfed and 63 Mcfed during the same prior year periods. Prior to June 30, 2009, we held an interest in 9 gross wells in the Williston Basin, including 7 producing Bakken wells and 2 Red River wells (one producing and one well in process). On June 30, 2009, we sold our non-operated working interest in the Goliath project acreage located in the Williston Basin to American Oil & Gas, Inc. for gross proceeds of $900,000. The effective date of the sale is July 1, 2009. The sale was made in furtherance of our ongoing effort to sell our non-operated assets and to improve our liquidity.

In accordance with generally accepted accounting principles, we recorded an impairment expense on this property for the quarter ended June 30, 2009 of $7.529 million. The current global economic conditions and credit crisis, coupled with low commodity prices, resulted in a current market value of the assets that is lower than our carrying value.

Oil and Gas Sales

Oil and gas sales decreased from approximately $7.5 million for the three months ended June 30, 2008 to approximately $2.3 million for the three months ended June 30, 2009, and from approximately $8.7 million for the six months ended June 30, 2008 to approximately $4.0 million for the six months ended June 30, 2009. The decrease in revenue is due to a decrease in production due to a lack of drilling and a decrease in commodity prices due to general market conditions.

LIQUIDITY AND CAPITAL RESOURCES

Going Concern

Our consolidated financial statements have been prepared assuming that we will continue as a going concern, which contemplates the realization of assets and the liquidation of liabilities in the normal course of business. We have incurred significant net losses in the quarter and six months ended June 30, 2009, attributable largely to loss on the sale of discontinued operations which were all non-operated properties and the unrealized loss on oil and gas derivative contracts, which are non-cash mark-to-market calculations. Also, the sudden and rapid decline in oil and gas prices adversely affected our operating results. We have managed our liquidity during this time through a series of cost reduction initiatives and sales of assets. However, the global credit market crisis and depressed commodity prices have had a dramatic effect on our industry. In the second half of 2008 and the first half of 2009, the turmoil in the overall credit markets, the volatility in the prices of oil and natural gas, the recession in the United States and Western Europe and the slowdown of economic growth in the rest of the world created a substantially more difficult business environment. The ability to execute capital markets transactions or sales of assets was extremely limited. Our liquidity position, as well as our operating performance, was negatively affected by these economic and industry conditions and by other financial and business factors, many of which are beyond our control. We do not believe it is likely that these adverse economic conditions, and their effect on the oil and gas industry, will improve significantly during the remainder of 2009.

Historically, our primary sources of liquidity have been cash provided by debt and equity offerings and borrowings under our bank credit facility. In the past, these sources have been sufficient to meet our business needs. However, the adverse developments in financial and credit markets during the fourth quarter of 2008 have continued into 2009 and have made it extremely difficult to access capital and credit markets, relative to the efforts that have historically been required in order to raise capital. Although the credit markets tightened in the latter half of 2008, we believed at December 31, 2008 that the amounts available to us under our existing $150 million credit facility ($14 million borrowing base at June 30, 2009 see additional comments below related to the redetermination of the bank borrowing base), together with the anticipated net cash provided by operating activities during 2009 and proceeds from potential sales of non-operated properties, would provide us with sufficient funds to maintain our current facilities and complete our limited capital expenditure program through 2009. As a result of significantly lower asset divestiture prices, lower commodity prices and continued constrained capital markets, our capital expenditure budget for 2009 has shifted, and instead we are focusing primarily on optimizing production in our operated properties in the Central Kansas Uplift (refer to discussion below under the heading Cash Flows and Capital Requirements), integral lease expenditures and seismic costs.

We will require additional sources of capital in order for us to reinstate a capital program to develop our leasehold position in the Central Kansas Uplift and drill the internally generated prospects, or implement any other business plan intended to maximize the value for our shareholders, as well as for our creditors and other constituents. However, due to the uncertain state of the current capital markets, we can provide no assurance that we will be able to secure any such additional financing, or as to the terms of any such additional financing. Securing additional financing is expected to be much more difficult than it has been in the past, and, if secured, the terms likely will be more onerous.

We had previously publicly stated our plans to sell non-operated properties as part of our strategic plan and also to improve our liquidity. During the first half of 2009, we successfully divested our non-operated working interests in the Piceance Basin and the Teton-Noble AMI in the DJ Basin, and effective July 1, 2009, we divested our non-operated working interest in the Williston Basin.

Current developments in the capital markets, combined with our lack of a drilling program, have led to a decrease in our borrowing base. The significant decline in commodity prices since the summer of 2008 resulted in a reduction of our Senior Lenders price decks, the commodity prices upon which the Senior Lenders base their determinations of borrowing bases. Each individual bank determines its own pricing deck based on its analysis of various factors, including the general economy, current commodity prices and the specific bank s expectations of future commodity prices. The reduced price decks coupled with the fact that we have not drilled a well in the Central Kansas Uplift since September 2008 (which prevents us from increasing our production, cash flows and reserves) has resulted in a decline of the borrowing base. As of June 30, 2009, we had outstanding borrowings of $22.5 million and a borrowing base of

$14 million. We have until August 25, 2009 to cure the excess above the borrowing base. The next redetermination of our borrowing base will be effective on August 1, 2009, and we expect the banks to communicate their results to us mid to late August 2009. At this time, we do not have adequate funds available to repay the borrowing base deficiency. As of the date of this report, we have not received notification from our Senior Lenders regarding the August 1, 2009 redetermination.

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During the first half of 2009, we implemented and substantially executed a Feasibility Plan designed to improve our financial situation. This Feasibility Plan was presented to the Senior Lenders for their consideration, and has sustained us through the first half of fiscal year 2009. We reduced our outstanding indebtedness with the Senior Lenders by 27% from March 31, 2009 to June 30, 2009, divested all of our non-operated non-core assets, sold certain crude oil hedges, reduced our general and administrative expenses by 56% compared to the first half of fiscal year 2008, became substantially current on our accounts payable and created an operating environment with positive monthly recurring cash flow commencing in July 2009. The key elements of our Feasibility Plan included:

Asset sales As noted above, the Teton-Noble AMI sale was closed on March 31, 2009, with an effective date of February 1, 2009, in exchange for the forgiveness of $4.0 million of payables to the buyer. Effective June 1, 2009, we divested our interest in the Piceance Basin to an undisclosed third party for $7.0 million net of purchase price adjustments. Additionally, effective July 1, 2009, we sold our interest in the Williston Basin for $900,000. Of the total proceeds from these transactions, we applied $6.925 million to pay down outstanding senior bank debt.

Labor costs We have reduced the number of our employees (both regular employees and contractors) by 58%. We have already experienced positive effects on expenses and cash flow. Salaries of all remaining employees were temporarily reduced by 10% during the second quarter of 2009, the 401(K) plan was eliminated and our contribution to employee benefit plan premiums was reduced to 50% from a range of 90% to 100%. The non-salary reductions were effective in early April 2009. The resultant annual reduction to G&A expenses is estimated at approximately $1.3 million. Additionally, we did not pay any bonuses in early 2009 for 2008 and have no intention of doing so in the foreseeable future.

Delay in capital expenditures We have evaluated our 2009 capital and drilling program through an analysis of each item on a discretionary and nondiscretionary basis, and have significantly reduced the 2009 program by eliminating or reducing those items we believe to be discretionary. We estimate capital expenditures will be less than $2.0 million in 2009, which is approximately $8.5 million less than our original projection. Additionally, we have renegotiated several supply and service contracts in the field and expect to realize savings on those items through the remainder of the year.

Crude Oil Hedges At the end of June 2009, we liquidated our hedge positions for January 2010 through September 2011 for an aggregate of $2.4 million, of which we applied $2.1 million to reduce our outstanding indebtedness with the Senior Lenders. We remain substantially hedged through the end of 2009. We do not view the liquidation of the 2009 hedges as a viable alternative since the successful execution of the Feasibility Plan and the day-to-day operations for the remainder of the year rely upon the hedge settlements to protect us against depressed oil prices.

We are continuing to act on our Feasibility Plan into the third quarter of fiscal 2009, as we believe that the successful implementation of our Feasibility Plan thus far has strengthened our financial position, enabling us to look further into the future and evaluate our options in order to maximize creditor and shareholder values. An integral component of our evolving strategy therefore includes a focus on restructuring our balance sheet and raising new capital. We are exploring various alternatives with our Senior Lenders and Debenture holders as well as new sources of equity in order to improve our liquidity. In order to facilitate our evaluation of strategic alternatives, the holders of our Debentures consented to forbear with respect to interest payable July 1, 2009 until August 25, 2009. We are currently working with our Senior Lenders and Debenture holders to enter into a forbearance agreement beyond August 25, 2009, the due date of our borrowing base deficiency. Both sets of creditors concur with our belief that we can maximize value for all of our constituencies by seeking new equity, reinitiating a development capital program and organically growing the Company through the drillbit. We are exploring all options available to us, both financially and operationally, which includes, but is not limited to, public and/or private placement of equity or debt, conversion of the Debentures into shares of our common stock, merging with other companies, as well as pre-packaged or pre-negotiated bankruptcy filings under the United States Bankruptcy Code, or any combination of the above. We do not yet know which of these actions, if any, we will choose to take, and, even if taken, there can be no assurance that any such action(s) will be successful.

Our Amended Credit Facility contains two financial covenants with which we are required to comply quarterly:

1. Ratio of total debt to EBITDAX (as defined in the Credit Facility agreement): We will not, as of the last day of any fiscal quarter, permit our ratio of total debt as of the end of such fiscal quarter to EBITDAX for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to be greater than 3.5 to 1.0.

2. Current ratio: We will not, as of the last day of any fiscal quarter, permit our ratio of (i) consolidated current assets (including the unused amount of the total commitments under the Credit Facility, but excluding non-cash assets under SFAS No. 133) to (ii) consolidated current liabilities (excluding non-cash obligations, SFAS No. 133 liabilities and current maturities under or with respect to the Credit Facility, the convertible debt or any other senior subordinated debt, whether such amounts are reflected as a liability under GAAP or not) to be less than 1.0 to 1.0.

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There exists an intercreditor agreement between the holders of our Debentures and the banks in the Credit Facility whereby the same financial covenants apply to the Debentures.

As of June 30, 2009, we were in compliance with all financial and non-financial covenants of our debt agreements. However, the lower commodity prices being experienced, coupled with a reduced capital spending budget during this time of tight capital markets, will result in our EBITDAX measurement being lower in the upcoming months. Lower EBITDAX may require us to lower our debt outstanding to be able to maintain compliance with the total debt to EBITDAX ratio requirement. As discussed above, we do not regard the liquidation of our 2009 hedges as a viable interim strategy as we believe these hedges currently provide protection against further lowering of the borrowing base. For every dollar that the price of oil declines, our hedge value increases by one dollar, and for every dollar a falling oil price decreases EBITDAX, the oil hedges will increase EBITDAX by one dollar for the hedged volumes. We expect our oil hedges to cover over 90% of our volumes of existing wells production in 2009, with new production from workovers or completions of previously drilled wells being the only volumes sensitive to actual pricing of crude oil.

Our operating cash flows also may fluctuate throughout the year due to weather, changes in prices and volumes, as well as the timely collection of receivables. The availability of oil field services and supplies such as concrete, pipe and compression equipment are expected to have a significant influence on our capital budget and net cash provided by operating activities. Our future growth is further dependent upon the success and timing of our exploration and production activities, new project development, efficient operation of our facilities and our ability to obtain financing at acceptable terms. New exploration and production activities and new project development are currently not being pursued, and are not expected to be resumed until we have improved our liquidity position.

As of June 30, 2009, we have more than 90% of our total oil production hedged for the remainder of 2009 at a floor price of $90.00 and a ceiling price of $104.00 per barrel. Our hedges are transacted with JPMorgan Chase Bank NA and are currently in place through December 31, 2009. At July 23, 2009, the liquidation value of our oil hedges was $1.4 million. Refer to the section entitled *Contractual Obligations* below for further discussion.

Additionally, 100% of our operated production is purchased by credit worthy third parties. However, we believe that in the absence of these third parties sufficient resources exist to bring this production to market. During the three months ended June 30, 2009, revenues from our operated properties accounted for 100% of total revenues from continuing operations and 59% of total production including discontinued operations. During the six months ended June 30, 2009, revenues from our operated properties accounted for 100% of total revenues from continuing operations and 51% of total production including discontinued operations.

In the past we also have received proceeds from the exercise of outstanding warrants and/or options. However, based on the current price of our common stock compared to the exercise price of the outstanding warrants ($3.24, $6.00 and $6.06 for all outstanding warrants) and options ($3.11 - $3.71 per share) and the current economic environment, we do not anticipate receiving such proceeds during 2009. At June 30, 2009, warrants to purchase 1,272,451 shares of common stock were outstanding. These warrants have a weighted average exercise price of $5.51 per share and expire between April 2010 and December 2012. At June 30, 2009, options to purchase 1,415,844 shares of common stock were outstanding. These options have a weighted average exercise price of $3.55 per share and expire between April 2013 and May 2015.

The following table provides information about our financial position (amounts in thousands, except ratios):

Financial Position Summary		June 30, 2009		December 31, 2008
Cash and cash equivalents	$	977	$	
Working capital	$	(6,211)	$	2,166
Long-term debt outstanding	$	37,579	$	55,900
Stockholders equity	$	9,093	$	61,271

Ratios

Total debt to total capital ratio	83.5%	47.7%
Total debt to equity ratio	506.6%	91.2%

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At June 30, 2009, we had negative working capital of approximately $6.2 million, due primarily to the reclassification of the $8.5 million of senior secured bank debt from long-term debt to short-term debt. Pursuant to the Amended Credit Facility, the current ratio calculation for the covenant provides for the exclusion of current maturities with respect to the Credit Facility. Excluding the $8.5 million current maturity of the Credit Facility, we would have positive working capital of $2.3 million. This positive adjusted working capital is largely due to the lack of drilling and the resultant lower accrued liabilities, and various smaller normal fluctuations in current assets and current liabilities. Additionally, in accordance with SFAS No. 144, we have recorded $39.5 million of loss from discontinued operations to recognize the impairment of the carrying value on the Piceance and Williston Basins of $36.478 million, the loss on sale of discontinued operations related to the Piceance Basin and the Teton-Noble AMI property of $2.268 million and the loss on discontinued operations related to the Piceance Basin, Teton-Noble AMI and Williston Basin of $775,000. These transactions result in a significant increase to our accumulated deficit at June 30, 2009, as compared to December 31, 2008. The accumulated deficit is a component of stockholders equity and is reflected in that line in the above table Financial Position Summary. The higher accumulated deficit, in turn, results in inflating both the total debt to total capital and the total debt to equity ratios, as noted above. The volatility of the oil and gas commodity prices used to value the unrealized gains (losses) on the related derivative contracts, as required by SFAS No. 133, may also continue to increase the volatility of results from operations and stockholders equity, specifically our accumulated deficit, and that could have a significant effect on the related ratios going forward.

Cash Flows and Capital Requirements

The following table summarizes our cash flows for the periods indicated (amounts in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash provided by (used in):		
Operating Activities	$ 1,787	$ 2,100
Investing Activities	6,626	(59,655)
Financing Activities	(7,436)	46,916
Net change in cash	$ 977	$ (10,639)

During the six months ended June 30, 2009, net cash provided by operating activities was $1.8 million as compared to $2.1 million during the same prior year period. Our net loss increased by $16.4 million during the six months ended June 30, 2009 as compared to the same prior year period. This increase in net loss is due largely to a $39.5 million loss on the sale of discontinued operations, a $4.7 million decrease in revenue due to a decrease in production and a decrease in commodity prices and a $1.2 million increase in depreciation, depletion and amortization. These were offset by a $4.8 million decrease in G&A due primarily to a reduction in stock compensation expense, a $8.5 million increase in realized gain on oil and gas derivative contracts due to lower commodity prices, a $12.6 million decrease on the unrealized loss on oil and gas derivative contracts due to the volatility of commodity prices, and a $7.0 million decrease in interest expense (prior year interest expense included the non-cash amortization of the deferred debt discount and issue costs related to the 8% Senior Subordinated Convertible Notes which were repaid during the second quarter of 2008 (the Convertible Notes)).

During the six months ended June 30, 2009, net cash provided by investing activities was $6.6 million as compared to net cash of $59.7 million used in investing activities in the same prior year period. Cash provided during the six month period ended June 30, 2009 relates largely to the sale of the Piceance Basin with net proceeds of $7.0 million which was offset by additions in the Central Kansas Uplift, through the conversion of saltwater disposal wells, capital workovers and seismic shots. Our 2009 capital budget has been revised to less than $2.0 million in light of the current economic and capital market constraints.

During the six months ended June 30, 2009, net cash used in financing activities was $7.4 million as compared to net cash provided by financing activities of $46.9 million in the same prior year period. During the six months ended June 30, 2009, our net repayments on our Amended Credit Facility were $7.2 million.

As a result of divesting all of our non-operated assets and a lack of liquidity, our revised capital budget for 2009 of less than $2.0 million includes recompletions, 3D seismic activities and maintenance of important leases in the Central Kansas Uplift.

Contractual Obligations

We have a Company hedging policy in place, to protect a portion of our production against future pricing fluctuations. Our outstanding hedges as of June 30, 2009 are summarized below:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index(1)	Remaining Period
Oil Costless Collar	68,407 Bbls	$90.00 Floor/$104.00 Ceiling	WTI	07/01/09-12/31/09

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

The costless collar hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements to a fixed point. Consequently, while these hedges are designed to decrease our exposure to price decreases while allowing us to share in some upside potential of price increases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the oil contracts listed above, a $1.00 hypothetical change in the WTI price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2009 of $68,407. We plan to continue to evaluate the possibility of entering into derivative contracts, as prices change and additional volumes become available in the future, to decrease exposure to commodity price volatility.

Off Balance Sheet Arrangements

We do not participate in transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities are often referred to as structured finance or special purpose entities (SPEs) or variable interest entities (VIEs). SPEs and VIEs can be established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We were not involved in any unconsolidated SPEs or VIEs at any time during any of the periods presented in this Quarterly Report on Form 10-Q.

RESULTS OF OPERATIONS

Three months ended June 30, 2009 compared to the three months ended June 30, 2008

Sales volume and price comparisons

	Three Months Ended June 30, (2)					
	2009			2008		
	Volume		Average Price (1)	Volume		Average Price (1)
Product:						
Gas (Mcf)	57,313	$	2.80	44,444	$	8.43
Oil (Bbls)	37,374	$	86.07	58,121	$	101.46
Mcfe	281,557	$	12.00	393,170	$	15.95

(1) Average price includes the impact of hedging activity.

(2) Volumes and prices exclude production from the Teton Noble AMI, Piceance Basin and the Williston basin which are presented below the line in discontinued operations. Including these areas, production volumes and prices would have been 220,099 Mcf and 332,046 Mcf at an average price of $2.61 and $7.47 per Mcf for 2009 and 2008, respectively, and 39,760 Bbl and 58,710 Bbl at an average price of $82.98 and $101.98 per barrel for 2009 and 2008, respectively. Including the production from discontinued operations, production volumes would have been 458,659 Mcfe and 684,306 Mcfe in total at an average price of $8.45 and $12.37 for 2009 and 2008, respectively.

For the three months ended June 30, 2009, we had net loss from continuing operations of $10.724 million as compared to $29.475 million in the same prior year period. Factors contributing to the $18.751 million decrease in net loss from continuing operations include the following:

Oil and gas production from continuing operations for the three months ended June 30, 2009 decreased 28% to 281,557 Mcfe as compared to 393,170 Mcfe in the same prior year period. The decrease in production is primarily the result of a decrease in oil production in the CKU property of 119,036 Mcfe due to the normal decline of the wells and only limited workovers performed due to cost-cutting measures we took.

Oil and gas sales from continuing operations decreased 70% from $7.454 million for the three months ended June 30, 2008 to $2.259 million for the three months ended June 30, 2009. The decrease in revenue from continuing operations is due to both decreased production volume, as discussed above by operating area, and a decrease in the average price per Mcfe. The average price per Mcfe decreased $3.95 per Mcfe, from $15.95 to $12.00, after the effect of hedging gains/losses.

Oil and gas production expenses

	Three Months Ended June 30, 2009	2008
	(in dollars per Mcfe)	
Average price	$ 12.00	$ 15.95
Production costs	2.67	2.86
Production taxes	0.80	0.69
Total operating costs	3.47	3.55
Gross margin before DD&A	$ 8.53	$ 12.40
Gross margin percentage	71%	78%

Our production costs (lease operating expenses, workover expense and transportation costs) and production taxes, all from continuing operations, for the three months ended June 30, 2009 decreased $417,000, from $1.395 million to $978,000, for the same period in the prior year, due primarily to reduced management fees in the Central Kansas Uplift and decreased transportation costs due to decreased production. Production costs per Mcfe decreased from $2.86 per Mcfe to $2.67 per Mcfe primarily due to reduced management fees in the Central Kansas Uplift and decreased transportation costs due to decreased production. Production taxes increased from $0.69 per Mcfe to $0.80 per Mcfe. The increase is due to equipment taxes increasing the production tax rate per Mcfe as they are spread over few Mcfe in 2009 than in 2008.

General and administrative expenses decreased $2.9 million, from $4.756 million to $1.858 million, for the three months ended June 30, 2009. The decrease is due primarily due to (1) a 58% reduction in the number of our employees (both regular employees and ongoing contractors), combined with reduced benefits for current employees; (2) a decrease in non-cash compensation of $2.974 million, as only costs associated with restricted stock awards were incurred (no LTIP tranches are deemed probable to be achieved as of June 30, 2009, and accordingly no costs related thereto were incurred); and (3) a decrease in office related expenses of $87,673 as a result in the reduction of the number of employees and other cost-cutting measures we implemented. There were no other individually significant increases or decreases.

Surrendered lease expense related to oil and gas properties increased from $0 for the three months ended June 30, 2008 to $3.292 million for the three months ended June 30, 2009. This increase is due to lease expirations of $2.62 million in CKU, $330,000 in Big Horn, $250,000 in South Frenchman Creek, and $90,000 in Washco.

Depletion, depreciation and amortization (DD&A) expense related to oil and gas properties decreased from $1.534 million for the three months ended June 30, 2008 to $1.528 million for the three months ended June 30, 2009. This decrease is due to decreased production, which is offset by an increase in the DD&A rate due to lower reserves at June 30, 2009, as compared to June 30, 2008.

During the three months ended June 30, 2009, we recorded a realized gain on oil and gas derivative contracts of $3.476 million and a net unrealized loss (non-cash) on derivative contracts of $7.042 million. The realized gain results from the hedged value of the contracts for the second quarter being higher than the actual price received for the product and the fact that we liquidated our future contracts for the period from January 2010 through September 2011, for net proceeds of $2.358 million. The unrealized loss represents marking the derivative contracts to market at June

30, 2009, based on the future expected prices of the related commodities (see discussion on fair value measurement above).

Net interest expense for the three months ended June 30, 2009 was $1.368 million compared to $5.418 million for the same prior year period. The 2009 interest expense reflects the actual interest incurred on the Amended Credit Facility and the Debentures of $1.059 million, as well as related amortization of $123,000 of debt issuance costs on those facilities and the amortization of the deferred debt discount related to the Debentures of $121,000. The 2008 interest expense reflects the actual interest incurred on the Credit Facility and the Convertible Notes, as well as the amortization of $4.585 million of debt issuance discount and costs on the Convertible Notes.

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Six months ended June 30, 2009 compared to the six months ended June 30, 2008

Sales volume and price comparisons

	Six Months Ended June 30, (2)					
	2009			2008		
	Volume		Average Price (1)	Volume		Average Price (1)
Product:						
Gas (Mcf)	99,416	$	2.94	64,933	$	8.10
Oil (Bbls)	81,115	$	81.79	70,372	$	97.69
Mcfe	586,106	$	11.82	487,165	$	15.19

(1) Average price includes the impact of hedging activity.

(2) Volumes and prices exclude production from the Teton Noble AMI, the Piceance Basin and the Williston Basin which are presented below the line in discontinued operations. Including these areas, production volumes and prices would have been 608,241 Mcf and 670,232 Mcf at an average price of $2.94 and $7.19 per Mcf for 2009 and 2008, respectively, and 85,810 Bbl and 72,722 Bbl at an average price of $78.97

and $97.14 per barrel for 2009 and 2008, respectively. Including the production from discontinued operations, production volumes would have been 1,123,101 Mcfe and 1,106,564 Mcfe in total at an average price of $7.63 and $10.74 for 2009 and 2008, respectively.

For the six months ended June 30, 2009, we had net loss from continuing operations of $15.088 million as compared to $37.415 million in the same prior year period. Factors contributing to the $22.327 million, or 60%, decrease in net loss from continuing operations include the following:

Oil and gas production from continuing operations for the six months ended June 30, 2009 increased 20% to 586,106 Mcfe as compared to 487,165 Mcfe in the same prior year period. The increase in production is the result of the addition of the CKU property which was acquired on April 2, 2008 which included only three months of production during the six month period in 2008.

Oil and gas sales from continuing operations decreased 54% from $8.654 million for the six months ended June 30, 2008 to $4.002 million for the six months ended June 30, 2009. The decrease in revenue from continuing operations is due to a decrease in the average price per Mcfe, somewhat offset by an increase in production volume, as discussed above. The average price per Mcfe decreased $3.37 per Mcfe, from $15.19 to $11.82, after the effect of hedging gains/losses.

Oil and gas production expenses

	Six Months Ended June 30,	
	2009	2008
	(in dollars per Mcfe)	
Average price	$ 11.82	15.19
Production costs	3.09	2.75
Production taxes	0.62	0.70
Total operating costs	3.71	3.45
Gross margin before DD&A	$ 8.11	11.74
Gross margin percentage	69%	77%

Our production costs (lease operating expenses, workover expense and transportation costs) and production taxes, all from continuing operations, for the six months ended June 30, 2009, increased $493,000, from $1.683 million to $2.176 million for the same period in the prior year. Our production costs are higher for the six months ended June 30, 2009, primarily because we acquired the Central Kansas Uplift in April 2008, therefore, costs for the CKU are included for the entire six month period ended June 30, 2009, as compared to the six month period ended June 30, 2008, which included CKU costs only for three months out of such six month period. Production costs per Mcfe increased from $2.75 to $3.09 per Mcfe primarily due to the addition of the new operating area with higher oil production which results in higher per unit LOE costs. Production taxes decreased from $0.70 per Mcfe to $0.62 per Mcfe. The decrease is due to a decrease in oil prices in 2009 compared to 2008 and the production tax rates being based primarily on revenue (not volumes).

General and administrative expenses decreased $4.827 million from $8.575 million in the six months ended June 30, 2008 to $3.748 million, for the six months ended June 30, 2009. This 56% decrease is due primarily to (1) a decrease in non-cash compensation of $4.595 million, as only costs associated with restricted stock awards were incurred in 2009 (no LTIP tranches are deemed probable to be achieved as of June 30, 2009, and accordingly no costs related thereto were incurred); (2) a $215,000 decrease in professional fees, and (3) a decrease of $203,000 in corporate communications due to a reduction in investor relations activities and annual report/meeting costs as a result of successful cost-cutting measures we implemented. There were no other individually significant increases or decreases.

Surrendered lease expense related to oil and gas properties increased from $0 for the six months ended June 30, 2008 to $3.292 million for the six months ended June 30, 2009. This increase is due to lease expirations in the second quarter of 2009 of $2.620 million in CKU, $330,000 in Big Horn, $250,000 in South Frenchman Creek, and $90,000 in Washco.

DD&A expense related to oil and gas properties increased from $1.789 million for the six months ended June 30, 2008 to $2.943 million for the six months ended June 30, 2009. This increase is due to the new productive area of the CKU for a full six months in 2009 offset by a decrease in the 2009 DD&A rate in Washco. The decrease in DD&A rate in Washco is primarily the result of an increase in the proved developed producing reserves in the area.

During the six months ended June 30, 2009, we recorded a realized gain on oil and gas derivative contracts of $7.241 million and a net unrealized loss (non-cash) on derivative contracts of $10.917 million. The realized gain results from the hedged value of the contracts for the first half of 2009 being higher than the actual price received for the product and the fact that we liquidated our future contracts for the period from January 2010 through April 30, 2013 for net proceeds of $4.316 million. The unrealized loss represents marking the derivative contracts to market at June 30, 2009, based on the future expected prices of the related commodities (see discussion on fair value measurement above).

Net interest expense for the six months ended June 30, 2009 was $2.674 million compared to $9.634 million for the same prior year period. The 2009 interest expense reflects the actual interest incurred on the Amended Credit Facility and the Debentures of $2.056 million, as well as related amortization of $282,000 of debt issuance costs on those facilities and the amortization of the deferred debt discount related to the Debentures of $242,000. The 2008 interest expense reflects the actual interest incurred on the Credit Facility and the Convertible Notes, as well as the amortization of $8.789 million of debt issuance discount and costs on the Convertible Notes.

FAIR VALUE MEASUREMENT

Effective January 1, 2008, we adopted the provisions of SFAS No. 157 for all financial instruments. The valuation techniques required by SFAS No. 157 are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent resources, while unobservable inputs reflect our market assumptions. The standard established the following fair value hierarchy:

Level 1 Quoted prices for identical assets or liabilities in active markets.

Level 2 Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

The following describes the valuation methodologies we use to measure financial instruments at fair value.

Debt and Equity Securities

The recorded value of our long-term debt approximates its fair value as it bears interest at a floating rate. Our Debentures were a negotiated instrument and are therefore recorded at fair value. We evaluated the Debentures and determined that, upon adoption of EITF 07-5 on January 1, 2009, embedded conversion features existed which were required to be bifurcated and accounted for separately as a derivative instrument. See discussion below on the embedded conversion features.

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Derivative Instruments

We use derivative financial instruments to mitigate exposures to oil and gas production cash flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, we recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At June 30, 2009, we did not have any derivative contracts that qualify as cash flow hedges.

Derivative assets in Level 2 include costless collars for the sale of oil hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through the end of 2009 for a total of approximately 68,407 Bbls of oil production. During the six months ended June 30, 2009, we recognized a realized gain of $7.241 million related to hedging settlements and to the sale of our open positions for the first quarter of 2010 through April 2013. A loss of $10.917 million is included under unrealized loss on oil and gas derivative contracts, and relates to the change in fair value of the open hedging positions.

We also use various types of financing arrangements to fund our business capital requirements, including convertible debt and other financial instruments indexed to the market price of our common stock. We evaluate these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants), whether certain conditions for equity classification have been achieved.

On April 2, 2008, in conjunction with the purchase of production and reserves related to certain oil and gas producing properties in the Central Kansas Uplift, we issued 625,000 warrants to acquire shares of our common stock. Each warrant is exercisable on or after July 2, 2008 at an exercise price of $6.00 per share, and expires on April 1, 2010. We evaluated these instruments in accordance with SFAS No. 133 and EITF 00-19 and determined, based on the facts and circumstances, that these instruments qualify for classification in stockholders equity and therefore are not reported as a liability or measured at fair value on a recurring basis.

We adopted the provisions of EITF 07-5 on January 1, 2009. We evaluated our Debentures under the provisions of this EITF and determined that the embedded conversion features constitute embedded derivatives which are not linked to our equity. These embedded features, which include provisions to protect the investor in the event we issue stock dividends, go through a subsequent rights offering or enter into a fundamental or change of control transaction, were valued using the Black-Scholes-Merton valuation technique. The inputs to this model include significant unobservable inputs which require management s judgment and are considered to be Level 3 inputs within the meaning of FAS 157. As of June 30, 2009, the fair value of the embedded conversion features was $0. The initial adoption was recorded as a debt discount and a cumulative effect of a change in accounting principle and recorded in retained earnings. The embedded derivative conversion features are re-measured at each reporting period with subsequent changes in the fair value being recorded under the other income and expense caption in the consolidated statements of operations.

Additionally, we have freestanding warrants which were evaluated and determined to meet the scope exceptions in SFAS No. 133. Accordingly, these warrants are not measured at fair value.

Assets Measured at Fair Value on a Non-Recurring Basis

The fair value of long-lived assets is determined using, to the extent possible, Level 2 inputs which may include, third-party valuations of the PV10 value of reserves, and Level 1 inputs, which may include, public information regarding the sales price of like assets in an orderly transaction between willing market participants. In the absence of available information, we use significant unobservable Level 3 inputs to assess the fair value of long-lived assets.

In accordance with the provisions of SFAS No. 144, long-lived assets held for sale are recorded at their fair value. As a result of the sale of our non-operated working interest in the Goliath project acreage located in the Williston Basin which was effective July 1, 2009, an impairment charge of approximately $6.691 million was taken, and is included in discontinued operations. The fair value of the assets held for sale was valued using level 2 inputs. The fair value is the cash received and agrees to the quoted price for the sale of these assets.

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Our undeveloped properties are subject to impairment under the provisions of SFAS No. 19. The recoverability of the carrying value of the properties is compared to the expected future cash flows, or the fair value of the asset. For the period ended June 30, 2009, we used level 2 and level 3 inputs to determine the fair value of our undeveloped properties. The current economic state and lack of market activity constitutes an inactive market under the provisions of SFAS No. 157. Accordingly, we applied judgment to adjust level 2 inputs, including Q4 2008 sales of similar assets and its knowledge of transactions between private companies, as current and relevant observable data is unavailable. As a result, for the six months ended June 30, 2009, an impairment of approximately $837,000 and $406,000 was recorded related to the undeveloped properties in the Williston Basin and Central Kansas Uplift, respectively.

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 risks. The term market risk refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future gains or losses, but rather indicators of reasonably possible gains or losses depending on market dynamics. This forward-looking information provides indicators of how we view and manage (or anticipate managing) our ongoing market risk exposures.

Commodity Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas commodity prices have been volatile and unpredictable for several years. The prices we receive for our production depend on numerous factors beyond our control. Based on our production for the six months ended June 30, 2009, our income before income taxes for the period would have moved up or down approximately $5,600 for every $1.00 change in oil prices and $9,300 for every $0.10 change in natural gas prices.

We have entered into derivative contracts to manage our exposure to oil price volatility. We have a Company hedging policy in place to protect a portion of our production against future price fluctuations. Refer to Contractual Obligations under Item 2 above for a breakout of our outstanding hedge positions at June 30, 2009.

Interest Rate Risk

At June 30, 2009, we had $22.5 million outstanding on our Credit Facility. Under the Amended Credit Facility, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 2.50% to 4.25% or a base rate (the higher of the Prime Rate, the Federal Funds Rate plus 0.5%, or the adjusted LIBO rate for a one month interest period on such day plus 1%) plus applicable margins of 1.50% to 3.25%, at our request. We are also required to pay a commitment fee of 0.5% per annum, based on the average daily amount of the unused amount of the commitment. Based on the $22.5 million outstanding under our Credit Facility at June 30, 2009, a one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate would result in an additional interest expense to us of approximately $56,250 per quarter.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities and Exchange Commission (SEC) reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applied its judgment in assessing the costs and benefits of such controls and procedures, which, by their nature, can provide only reasonable assurance regarding management s control objectives.

In accordance with the Securities Exchange Act of 1934, as amended (the Exchange Act), Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of June 30, 2009. Based upon this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in ensuring that material information required to be disclosed in the reports that we file with or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and is effective in ensuring that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings.

ITEM 1A. RISK FACTORS

The following is the only material change in our Risk Factors from those reported in Item 1A of Part I of our 2008 Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 5, 2009.

As noted in Note 2 to our financial statements, our ability to continue as a going concern is dependent on obtaining sufficient resources to fund our current working capital requirements and to service our existing debt.

Historically, our primary sources of liquidity have been cash provided by debt and equity offerings as well as borrowings under our Amended Credit Facility. However, the adverse developments in financial and credit markets during the last quarter of 2008 and the first half of fiscal 2009 have made it difficult and expensive to access capital markets. Depending on the timing and amounts of our capital projects and future developments in the capital markets, we will likely be required to seek additional sources of capital through alternative financing arrangements with third parties and the sale of assets. Due to the uncertain state of the current capital markets, securing additional financing is likely to be much more difficult than it has been in the past, and, if secured, will likely contain more onerous terms. Effective May 1, 2009, the Senior Lenders redetermined our borrowing base downward from $32.5 million to $20.0 million. At that time, we had drawn $31.4 million on the credit facility. After divesting our non-operated working interests in the Piceance Basin and selling certain long term hedge positions, the borrowing base was further reduced to $14.0 million and we had drawn $22.5 million. The outstanding excess, or borrowing base deficiency, is due to the Senior Lenders on August 25, 2009, and we do not have adequate funds available to repay it at this time. In addition to our plan to seek additional sources of capital, our management continues to re-examine all aspects of our business for areas of improvement and continues to focus on our fixed cost base to better align our expenses with our current operating levels. However, we can provide no assurance that our plans can be consummated on acceptable terms or at all. As a result, there is substantial doubt as to our ability to continue as a going concern. Should we be unable to continue as a going concern, we may be unable to realize the carrying value of our assets and to meet our liabilities as they become due, which could adversely affect our business, financial condition and results of operations.

We are currently unable to repay our borrowing base deficiency, and upon redetermination, our borrowing base may be further reduced to a materially lower level relative to our current limit.

We currently finance our operations through borrowings under the Amended Credit Facility and through cash generated by operating activities. As described above, we currently have a borrowing base deficiency of $8.5 million, which is due to the banks on August 25, 2009, and we do not have adequate funds available to repay it at this time. In addition, the Amended Credit Agreement contains provisions to redetermine the borrowing base at least every six months. The next redetermination of the borrowing base will be effective on August 1, 2009, and we expect the banks to communicate their results to us during mid to late August 2009. We have not been notified by the Senior Lenders of the amount of the redetermined borrowing base as of the filing date of this Quarterly Report. If, upon redetermination, the borrowing base is further reduced, or otherwise continues to create a deficiency larger than we can repay, our Senior Lenders could accelerate our indebtedness under the Amended Credit Facility and exercise any available rights and remedies.

We are currently unable to repay our borrowing base deficiency, which is due on August 25, 2009, and we do not have a forbearance agreement in place with the group of participating banks.

We currently have a borrowing base deficiency of $8.5 million, which is due to the banks on August 25, 2009, and we do not have adequate funds available to repay it at this time. We are actively engaged in discussions with our Senior Lenders to amend certain terms of our Amended Credit Agreement to allow for greater operating flexibility although we currently do not have a forbearance agreement in place. We can provide no assurance that current discussions will result in a forbearance agreement or any amendments to the Amended Credit Agreement. Even if we were able to successfully negotiate a forbearance agreement, we may be required to pay significant amounts to our Senior Lenders to obtain their agreement to forbear exercising their rights and remedies. In addition, any forbearance agreement would have a limited duration and any future failures to comply with the covenants under the Amended Credit

Agreement could result in further events of default which, if not cured or waived, could trigger prepayment obligations, which could adversely affect our business, financial condition and results of operations.

There can be no assurance that the forbearance period granted by the holders of our Debentures will be extended further than August 25, 2009.

Our first interest payment on our Debentures was due on July 1, 2009. Due to our strained financial condition, we were unable to make such payment. We have successfully negotiated a forbearance period with the holders of the Debentures, which is currently scheduled to expire on August 25, 2009. We intend to continue to work with the holders of the Debentures, however, there can be no assurance that the holders will agree to extend such forbearance period further than the current expiration date, or a more permanent solution. Our failure successfully to negotiate with the holders of the Debentures for an extended forbearance period, and our continued inability to make any payments due on the Debentures, will result in a default under the Debentures, and we may be required to seek protection under the United States Bankruptcy Code.

The current constraints on our liquidity impose significant risks to our operations.

Our liquidity position will likely adversely affect our relationships with our creditors, suppliers, customers and employees. Further, as a result of the public disclosure of our liquidity constraints, our ability to maintain normal credit terms with our suppliers may become impaired. Customers perception of our financial position may adversely affect their business dealings with us. We may also have difficulty maintaining our ability to attract, motivate and retain management and other key employees. Failure to maintain any of these important relationships could adversely affect our business, financial condition and results of operations.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

On May 5, 2009, we held our annual stockholders meeting. The Board proposed, and the shareholders approved, the election of each of our Directors for an additional term of one year to expire at our next Annual Meeting, tentatively scheduled for May 5, 2010, or until his successor is elected and qualified or until his earlier resignation or removal. The number of votes cast for and the number withheld, as to each Director, were as follows:

	James J. Woodcock	Karl F. Arleth	Dominic J. Bazile II	Thomas F. Conroy	Bill I. Pennington	Robert F. Bailey	Marc MacAluso
Shares in Favor	13,918,809	13,455,257	16,343,582	13,953,516	11,877,852	13,969,176	15,293,820
Shares Withheld	5,749,176	6,212,728	3,324,403	5,714,469	7,790,133	5,698,809	4,374,165

Subsequent to the annual meeting, as previously disclosed, on May 5, 2009, Mr. Arleth resigned from his positions as an officer and director of the Company.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this report:

Exhibit Number and Description:

4.1 Secured Subordinated Convertible Debenture Indenture dated September 19, 2008 among Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.2 Form of 10.75% Secured Convertible Debenture dated June 18, 2008 issued by Teton Energy Corporation (incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.3 Form of Global 10.75% Secured Subordinated Convertible Debenture (included in Exhibit 4.1).

4.4 Form of Securities Purchase Agreement dated June 9, 2008, entered into by and between Teton Energy Corporation and the investors (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.5 Letter Agreement dated September 19, 2008 amending and supplementing the Securities Purchase Agreement dated June 9, 2008 (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.6 Form of Registration Rights Agreement (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.7 Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and Whitebox Advisors LLC (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.8 Form of Amended and Restated Subordinated Guaranty and Pledge Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.9 Form of Intercreditor and Subordination Agreement dated June 9, 2008, entered into by and between, Teton Energy Corporation, JPMorgan Chase Bank, N.A. as administrative agent and the representative for the subordinated holders (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.10 Amended and Restated Intercreditor and Subordination Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on September 23, 2008).

10.1 Purchase and Sale Agreement between Teton DJ LLC and Noble Energy, Inc. dated effective February 1, 2009 (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on April 3, 2009).

10.2 Second Amendment to Second Amended and Restated Credit Agreement dated as of May 21, 2009 among Teton Energy Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders to the Credit Agreement (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on May 27, 2009).

10.3 Pledge and Security Agreement dated as of May 21, 2009 between Teton Energy Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders to the Credit Agreement (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on May 27, 2009).

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10.4	Employment Agreement between the Company and Jonathan Bloomfield, effective as of July 1, 2009 (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on July 6, 2009)
10.5	Executive Severance and Mutual Release Agreement between the Company and Karl F. Arleth, filed herewith.
31.1	Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
32	Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, 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.

TETON ENERGY CORPORATION
(Registrant)

Date: August 14, 2009

By: /s/ James J. Woodcock
James J. Woodcock
Interim Chief Executive Officer

Date: August 14, 2009

By: /s/ Jonathan Bloomfield
Jonathan Bloomfield
Executive Vice President and
Chief Financial Officer

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