TETON ENERGY CORP
Form 10-Q
August 07, 2008

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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, 2008

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.)
410 Seventeenth Street, Suite 1850, Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip code)

(303) 565-4600

(Registrant s telephone number, including area code)

NONE

(Former name, former address, and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

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 o

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

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 1, 2008
Common stock, $.001 par value	21,938,002

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

TETON ENERGY CORPORATION
CONSOLIDATED BALANCE SHEET
(000s except share data)

	June 30, 2008 (Unaudited)	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 13,977	$ 24,616
Trade accounts receivable	7,003	2,686
Advances to operator	1,019	
Tubular inventory	465	149
Prepaid expenses and other assets	412	131
Deferred debt issuance costs net	454	1,419
Total current assets	23,330	29,001
Oil and gas properties, successful efforts method:		
Developed properties	88,253	35,708
Wells and facilities in progress	9,718	3,230
Undeveloped properties	24,033	13,411
Corporate and other assets	832	485
Total property and equipment	122,836	52,834
Less accumulated depreciation and depletion	(8,977)	(3,695)
Net property and equipment	113,859	49,139
Deferred debt issuance costs net	1,941	159
Total assets	$ 139,130	$ 78,299
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 1,944	$ 400
Accrued liabilities	7,346	7,833
Accrued payroll	1,699	902
8% senior subordinated convertible notes, net of discount of $7,370 at December 31, 2007		1,630
Short-term debt	10,000	
Fair value of oil and gas derivative contracts	9,403	455
Derivative warrant liabilities	8,646	9,522

Total current liabilities	39,038	20,742
Long-term liabilities:		
Long-term debt	51,867	8,000
Asset retirement obligations	985	529
Fair value of oil and gas derivative contracts	14,518	
Total liabilities	106,408	29,271
Commitments and contingencies (see Note 10)		
Stockholders equity:		
Preferred stock, $.001 par value; 25,000,000 shares authorized; none outstanding as of June 30, 2008 and December 31, 2007		
Common stock, $.001 par value; 250,000,000 shares authorized; 21,938,002 and 17,652,889 shares issued and outstanding as of June 30, 2008 and December 31, 2007, respectively	22	18
Additional paid-in capital	98,798	76,857
Accumulated deficit	(66,098)	(27,847)
Total stockholders equity	32,722	49,028
Total liabilities and stockholders equity	$ 139,130	$ 78,299

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

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Operating revenues:				
Oil and gas sales	$ 10,121	$ 990	$ 13,761	$ 2,188
Operating expenses:				
Lease operating expense	1,302	64	1,651	107
Transportation expense	477	158	600	287
Production taxes	425	89	627	153
Exploration expense	762	309	1,088	615
General and administrative	4,756	2,180	8,575	4,060
Depreciation, depletion and accretion expense	3,099	594	5,298	1,149
Total operating expenses	10,821	3,394	17,839	6,371
Operating loss	(700)	(2,404)	(4,078)	(4,183)
Other income (expense):				
Realized gain (loss) on oil and gas derivative contracts	(1,715)	201	(1,936)	256
Unrealized loss on oil and gas derivative contracts	(22,246)	(105)	(23,479)	(198)
Gain (loss) on derivative warrant liabilities	51	(4,629)	876	(4,629)
Interest expense, net	(5,418)	(308)	(9,634)	(292)
Total other expense	(29,328)	(4,841)	(34,173)	(4,863)
Net loss	$ (30,028)	$ (7,245)	$ (38,251)	$ (9,046)
Basic loss per common share	$ (1.40)	$ (0.45)	$ (1.95)	$ (0.57)
Fully diluted loss per common share	$ (1.40)	$ (0.45)	$ (1.95)	$ (0.57)
Basic weighted-average common shares outstanding	21,477,811	16,125,492	19,625,383	15,846,748
	21,477,811	16,125,492	19,625,383	15,846,748

Fully diluted weighted-average common shares outstanding		

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

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

	Six Months Ended	
	June 30, 2008	**June 30, 2007**
Operating activities:		
Net loss	$ (38,251)	$ (9,046)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and accretion	5,298	1,150
Amortization of debt issuance costs	1,439	57
Amortization of debt discount	7,370	163
Stock-based compensation expense, exclusive of cash withheld for payroll taxes of $1,107 and $0, respectively	4,129	1,792
Non-cash (gain) loss on derivative warrant liabilities	(876)	4,629
Unrealized loss oil and gas derivative contracts	23,479	198
Changes in current assets and liabilities:		
Trade accounts receivable	(4,317)	51
Prepaid expenses, tubular inventory and other current assets	(597)	(42)
Accounts payable and accrued liabilities	3,629	224
Accrued payroll	797	(794)
Net cash provided by (used in) operating activities	2,100	(1,618)
Investing activities:		
Acquisition of corporate fixed assets	(347)	(9)
Acquisition and development of oil and gas properties	(59,308)	(14,933)
Net cash used in investing activities	(59,655)	(14,942)
Financing activities:		
Proceeds from exercise of options/warrants	1,905	2,019
Proceeds from 10.75% Convertible debt, including $10 million classified as S-T debt (Note 5)	40,000	9,000
Net borrowings (repayments) on senior bank credit facility	13,867	
Net payments on subordinated convertible debt	(6,600)	6,000
Debt issuance costs	(2,256)	(744)
Net cash provided by financing activities	46,916	16,275
Increase (decrease) in cash and cash equivalents	(10,639)	(285)
Cash and cash equivalents beginning of period	24,616	4,325

Cash and cash equivalents end of period	$	13,977	$	4,040
Supplemental disclosure of cash and non-cash transactions:				
Cash paid for interest, net of amounts capitalized	$	887	$	
Capitalized interest	$	155	$	
Placement agent warrants recorded as debt issuance costs	$		$	1,022
Capital expenditures included in accounts payable and accrued liabilities	$	3,083	$	7,367
Stock-based compensation expense included in capital expenditures	$	88	$	
ARO additions and revisions	$	440	$	141
Sale of Frenchman Creek undevloped leasehold interest	$		$	111
Reclassification of derivative liabilities to stockholder s equity	$		$	3,124
Conversion of Subordinated Debt into Common Stock	$	2,400	$	
Common Stock and Warrants issued in connection with the acqusition of oil and gas properties	$	13,423	$	

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

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TETON ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollar amounts in thousands except per share data)
(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.

Certain amounts in the 2007 financial statements were reclassified to conform to the 2008 unaudited consolidated financial statement presentation, including, but not limited to, presenting revenues on a gross basis before gathering and transportation expenses which are now included in transportation expense on the Consolidated Statement of Operations.

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, 2007 (the 2007 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, 2007 included in the 2007 Form 10-K filed with the SEC.

Recently adopted accounting pronouncements

On January 1, 2008, we adopted the provisions of SFAS No. 157, Fair Value Measurements (SFAS No. 157) related to assets and liabilities, which primarily affect the valuation of our derivative contracts (see Note 4). In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Beginning January 1, 2009, we will adopt the provisions for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of SFAS No. 157 did not have a material effect on our financial condition or results of operations. The Company does not believe that the implementation of this standard, with respect to its effect on nonfinancial assets and liabilities, will have a material impact on its consolidated financial position or results of operations.

On January 1, 2008, we adopted the provision of SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) which permits an entity to measure certain financial assets and financial liabilities at fair value. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report

unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. The adoption of SFAS No. 159 did not have a material effect on our financial condition or results of operations as we did not make any such elections under this fair value option.

New accounting pronouncements

In December 2007, the FASB issued 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. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

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In March 2008, the FASB issued 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. This Statement will be effective for the Company s interim and annual financial statements beginning in fiscal year 2010. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements presented in conformity with GAAP. SFAS No. 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board (the PCAOB) amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles . The Company does not believe that the implementation of this standard will have a material impact on its consolidated financial position or results of operations.

In May 2008, the FASB issued 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. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past period presented. Early adoption is prohibited. The Company is in the process of evaluating the impacts, if any, of adopting this FSP.

In June 2008, the FASB ratified the consensus reached by the Task Force, EITF Issue No. 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-5). EITF 07-5 addresses how an entity should evaluate whether an instrument is indexed to its own stock. The consensus is effective for fiscal years (and interim periods) beginning after December 15, 2008 (fiscal 2009 for the Company). The consensus must be applied to outstanding instruments as of the beginning of the fiscal year in which the consensus is adopted and should be treated as a cumulative-effect adjustment to the opening balance of retained earnings. Early adoption is not permitted. The Company is in the process of evaluating the impacts, if any, of adopting this EITF.

2. Earnings per share of common stock

Basic income (loss) per common share is computed by dividing net income (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 8) are considered issued and outstanding at June 30, 2008 and 2007, respectively, and are included in the calculation of the weighted average basic common shares outstanding. Diluted income (loss) per common share reflects the potential dilution that would occur if contracts to issue common stock were exercised or converted into common stock.

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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:

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Net income (loss)	$ (30,028)	$ (7,245)	$ (38,251)	$ (9,046)
Weighted average common shares outstanding basic	21,477,811	16,125,492	19,625,383	15,846,748
Dilution effect of restricted stock, performance share units, stock options and warrants				
Weighted average common shares outstanding fully diluted	21,477,811	16,125,492	19,625,383	15,846,748
Earnings (loss) per share of common stock:				
Basic	$ (1.40)	$ (0.45)	$ (1.95)	$ (0.57)
Fully diluted	$ (1.40)	$ (0.45)	$ (1.95)	$ (0.57)

The following securities, which could be potentially dilutive in future periods, were not included in the computation of diluted net income per share because the effect would have been anti-dilutive for the periods indicated:

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Convertible Notes	1,101,018		550,509	
Warrants	1,392,428	4,827,819	1,276,118	4,827,819
Stock options	474,717	1,523,067	425,596	1,523,067
LTIP Performance Units	202,229	1,911,000	69,758	1,911,000
Restricted Common Stock	138,350	237,332	135,139	237,332
Total	3,308,742	8,499,218	2,457,120	8,499,218

The above amounts are calculated using the treasury stock method, whereby a company uses the proceeds from the exercise or purchase of shares to repurchase common stock at the average market price during the period. This is the prescribed method used to calculate the dilutive shares in a fully diluted earnings per share calculation. 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 16,500,374 shares.

3. Oil and Gas Properties

Acquisitions

On April 2, 2008, the Company completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from Shelby Resources, LLC, a private oil and gas company and a group of approximately 14 other working interest owners, (Shelby) for approximately $53.6 million, after post closing

adjustments. Terms also included warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The effective date of the transaction is March 1, 2008.

The purchase price was funded with $40.2 million of cash and borrowing capacity available under Teton s revolving credit facility with JPMorgan Chase (see Note 6), $13.0 million of Teton common stock, or 2,746,124 common shares and 625,000 warrants valued at $434. Effective April 2, 2008, Teton amended its bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million. The available borrowing base under Teton s bank credit facility was increased from $10 million to $50 million as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new hedging positions. The Company has hedged 80 percent of the oil proved developed producing (PDP) production and 80 percent of the natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition (see Note 10).

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The purchase price was allocated using the purchase method of accounting with Teton treated as the acquirer. Under this method of accounting, the assets and assumed liabilities of Shelby are recorded by Teton at their estimated fair values as of the respective dates the acquisition was deemed to have occurred.

The following table shows the allocation of the purchase price to the assets acquired and liabilities assumed from Shelby Resources on April 2, 2008.

Allocation of Purchase Price

Undeveloped properties	$	11,371
Oil and gas properties and related facilities	$	42,057
Asset retirement obligations	$	193
	$	53,621

The following unaudited summarized pro forma information gives effect to the acquisition of the interests of Shelby by Teton as if the assets had been acquired as of January 1, 2008.

Proforma Supplemental Information:

	For the Six Months Ended June 30,			
		2008		2007
Revenues	$	16,911	$	6,969
Net income	$	(37,555)	$	(8,890)
Earnings per share	$	(1.91)	$	(0.48)

The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had Teton and Shelby always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the acquisition occurred in the past or the future financial results that Teton will achieve after the acquisition.

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 has not incurred any impairment expense during the three months ended June 30, 2008 or 2007.

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, 2008 or 2007.

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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, 2008
Asset retirement obligation beginning of period	$ 529
Additional liabilities incurred	342
Revisions in estimated cash flows	98
Accretion expense	16
Asset retirement obligation end of period	$ 985

4. 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 we use 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 Company s Secured Convertible Notes (Convertible Notes) were a negotiated instrument and are therefore recorded at fair value. The Company evaluated the Convertible Notes and determined that there were no embedded features which would require derivative accounting.

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, 2008, the Company did not have any derivative contracts that qualify as cash flow hedges.

Derivative assets and liabilities included in Level 2 include fixed rate swap arrangements for the sale of oil and natural gas and hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through 2013 for a total of approximately 531,790 Bbls of oil production and 2,429,277 MMbtu of natural gas production. The Company previously included swap agreements in Level 1, however, has determined that based on the nature of the agreements swaps are more appropriately classified as Level 2.

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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. In instances where derivative financial instruments require liability classification, the Company initially and subsequently measures such instruments at estimated fair value using Level 2 inputs. Accordingly, the Company adjusts the estimated fair value of these derivative components at each reporting period through earnings until such time as the instruments are exercised, expired or permitted to be classified in stockholders equity.

As of June 30, 2008, the fair value of financing warrants included as a component of current liabilities consisted of warrants to purchase 3,600,000 shares of the Company s common stock that do not achieve all of the requisite conditions for equity classification. These free-standing derivative financial instruments arose in connection with the Company s financing transaction in May 2007 which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years as more fully discussed in Note 5.

On April 2, 2008, in conjunction with the purchase of production, reserves and 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 following table summarizes Teton s assets and liabilities measured at fair value on a recurring basis at June 30, 2008.

	Level 1	Level 2	Level 3	Total
Assets:				
Oil and gas derivative contracts	$	$	$	$
Liabilities:				
Oil and gas derivative contracts	$	$ 23,921	$	$ 23,921
Derivative contracts Warrants		8,646		8,646
	$	$ 32,567	$	$ 32,567

5. Convertible Notes

8% Senior Subordinated Convertible Notes

On May 16, 2008, the Company repaid, to the extent not converted, its $9.0 million face value of 8% Senior Subordinated Convertible Notes that closed on May 16, 2007 (the Notes). $6.6 million was repaid in cash and $2.4 million was converted to 480,000 shares of common stock at a conversion price of $5.00 per share.

The $9.0 million debt component of the Notes was initially recorded net of debt issuance discount of $9.0 million. The debt issuance discount was amortized to interest expense over the life of the Notes using the effective interest method. The Company recorded $3,845 and $7,370 of debt issuance discount amortization during the three and six months ended June 30, 2008, respectively.

Additionally, the Company recorded $740 and $1,419 of amortization of deferred debt issuance costs during the three and six months ended June 30, 2008, respectively, related to the Notes.

The warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years issued in connection with the Notes include a cashless exercise feature. In addition, on May 18, 2007, the Company issued to the placement agent for this offering warrants to purchase 360,000 shares of the Company s common stock at a $5.00 strike price with a term of five years. The Warrants continue to require classification as derivative contract liabilities in the Company s consolidated balance sheet.

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10.75% Secured Convertible Debentures

On June 18, 2008, the Company closed the private placement of $40 million aggregate principal amount of 10.75% Secured Convertible Debentures due on June 18, 2013 (the Debentures). 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 lender maintains a 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 have a 90-day put option, expiring September 18, 2008, whereby they may elect to reduce their investment in the Debentures by a total of up to 25% of the face amount, or up to a total of $10 million. The Company has classified the amount subject to the 90-day put option as short term debt on the face of the Consolidated Balance Sheet. Any portion of the $10 million not called by the end of the 90 day period will be reclassified to long-term debt and will be due on June 18, 2013.

The net proceeds from the issuance of the Debentures, after fees and related expenses (and excluding the 90-day 25% put option) were approximately $28 million. These funds were used to pay down the Company s outstanding indebtedness on its revolving credit facility (see Note 6). At the end of the 90-day put period, if the holders do not elect to call the aggregate $10 million in Debentures, the Company will incur approximately $600,000 of additional debt issuance fees related to the $10 million.

Deferred debt issuance costs of $2,256 associated with the Convertible Notes are included in assets as of June 30, 2008 and will be amortized to interest expense over the life of the related Debenture. Additionally, the Company recorded $20 of amortization of deferred debt issuance costs during the three and six months ended June 30, 2008, respectively, related to the Notes.

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6. Senior Bank Facility

On August 9, 2007, the Company s $50 million revolving credit facility with BNP Paribas (the Credit Facility) was replaced by an amended and restated $50 million revolving credit facility with JPMorgan Chase, as administrative agent. JPMorgan Chase assumed the Company s previous Credit Facility with BNP Paribas. The amended Credit Facility originally was scheduled to mature on August 9, 2011. On April 2, 2008, the Company again amended its Credit Facility (the Amended Credit Facility) to a $150 million revolving credit facility ($50 million borrowing base). There will be a re-determination of the borrowing base on August 1, 2008 and November 1, 2008.

In connection with the privately placed 10.75% Secured Convertible Debenture, the borrowing base on the Company s $150 million revolving credit facility was reduced to $32.5 million, bringing the Company s total available borrowings from $50 million to $70 million, including the $10 million related to the 90-day put option as discussed in Note 5 and an additional $2.5 million reduction in the borrowing base that will occur should no holders exercise the put option. If the put option is exercised, the Company s total available borrowings will be $62.5 million.

Under the Amended Credit Facility, at the option of the Company, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 1.25% to 3.0% or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to 1.5%, 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 0.375% to 0.5% 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.

The Company borrowed on its Amended Credit Facility during the second quarter of 2008 to fund the acquisition of certain oil and gas properties in the Central Kansas Uplift and to repay $6.6 million of the 8% Senior Secured Convertible Notes. With the gross proceeds of the $30 million privately placed 10.75% Secured Convertible Debentures which are not subject to the holders put option (see Note 5 above), on June 18, 2008, the Company repaid approximately $28 million on its credit facility.

The balance outstanding at June 30, 2008 was approximately $22 million. For the three and six months ended June 30, 2008, cash interest expense with respect to the above credit lines and the Convertible Notes described in Note 5 totaled $687 and $1,042, respectively and capitalized interest totaled $77 and $155, respectively.

7. Stockholders Equity

Warrants

The following table presents the composition of warrants outstanding and exercisable as of June 30, 2008:

Range of Exercise Prices	Number	Weighted Average Remaining Contractual Life (years)
$3.24	232,904	4.5
$4.35	200	0.3
$5.00	3,960,000	3.9
$6.00	625,000	1.8
$6.06	414,547	4.1
Total warrants outstanding and exercisable	5,232,651	3.7

On April 2, 2008, in conjunction with the purchase of production, reserves and 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.

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8. Stock-Based Compensation

During 2008, 2,974,500 performance share units 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 measure 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 372,750 shares of restricted common stock, granted pursuant to the Company s LTIP, were awarded during the six months ended June 30, 2008. 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 three and six months ended June 30, 2008, the Company recorded $3.6 million and $5.2 million for stock-based compensation expense applicable to the vesting of LTIP performance-vesting (including the first tranche of the 2008 LTIP awards) and restricted stock grants, respectively. The Company expects to recognize approximately an additional $3.0 million during the twelve months ending December 31, 2008 related to the LTIP performance-vesting and restricted stock grants outstanding at June 30, 2008.

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9. Income Taxes

For each of the three and six months ended June 30, 2008 and 2007, the current and deferred provision for income taxes was $0.

At December 31, 2007, the Company had net operating loss carryforwards (NOLs), for federal income tax purposes, of approximately $32.5 million. These NOLs, if not utilized to reduce taxable income in future periods, will expire in various amounts from 2018 through 2027. Approximately $5.8 million of such NOLs is subject to U.S. Internal Revenue Code Section 382 limitations. As a result of these limitations, utilization of this portion of the NOLs is limited to approximately $3.6 million and $2.2 million for the years ending December 31, 2008 and 2009, respectively plus any loss attributable to any built-in gain on assets sold within five years of the ownership change.

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, 2008.

10. Commitments and Contingencies

To mitigate a portion of the potential exposure to adverse market changes in the prices of oil and natural gas, the Company has entered into various derivative contracts. The outstanding commodity hedges as of June 30, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price (1)	Price Index (2)	Remaining Period	
Oil Fixed Price Swap	11,040	$80.70	WTI	11/01/07	12/31/08
Oil Costless Collar	77,606	$95.80 Floor/$103.00 Ceiling	WTI	07/01/08	12/31/08
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09	12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10	12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11	12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12	12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13	04/30/13
Total Bbl	531,790				
Natural Gas Fixed Price Swap	120,000	$5.78	CIGRM	08/01/07	10/31/08
Natural Gas Costless Collar	368,000	$6.00 Floor/$7.10 Ceiling	CIGRM	07/01/08	12/31/08
Natural Gas Costless Collar	62,000	$6.00 Floor/$7.10 Ceiling	CIGRM	01/01/09	01/31/09
Natural Gas Costless Collar	473,867	$6.50 Floor/$7.75 Ceiling	CIGRM	02/01/09	12/31/09
Natural Gas Costless Collar	417,405	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/10	12/31/10
Natural Gas Costless Collar	355,399	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/11	12/31/11

Natural Gas Costless Collar	310,702	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/12	12/31/12
Natural Gas Costless Collar	95,200	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/13	04/30/13
Natural Gas Costless Collar	57,280	$9.10 Floor/$9.75 Ceiling	NYMEX	07/01/08	12/31/08
Natural Gas Costless Collar	77,630	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/09	12/31/09
Natural Gas Costless Collar	46,274	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/10	12/31/10
Natural Gas Costless Collar	26,158	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/11	12/31/11
Natural Gas Costless Collar	15,258	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/12	12/31/12
Natural Gas Costless Collar	4,104	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/13	04/30/13
Total MMBtu	2,429,277				

(1) Fixed price is per Bbl for oil swaps and collars and per MMBtu for natural gas swaps and collars.

(2) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platts for Inside FERC on the first business day of each month. NYMEX refers to quoted prices on the New York Mercantile Exchange. 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. As of June 30, 2008, the start of the new lease agreement has been delayed to November 1, 2008. Rental payments, before expenses, under the lease are $32,509 for the remainder of 2008, $224,148 for 2009 and $1,283,374 thereafter, for the remaining 55 months of the agreement. After November 1, 2008, the Company has no further obligations under its current lease agreement.

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

($ amounts in thousands, except amounts per unit of production)

The terms Teton , Company , we , our and us refer to Teton Energy Corporation and its 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:

- General economic and political conditions, including governmental energy policies, tax rates or policies and inflation rates;
- The market price of, and demand for, oil and natural gas;
- Our ability to service current and future indebtedness;
- Our success in completing development and exploration activities;
- Reliance on outside operating companies for drilling and development of our non-operated oil and gas properties;
- 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 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 2007 Form 10-K.

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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. The Company s current operations are concentrated in the prolific Midcontinent and Rocky Mountain regions of the U.S. We have leasehold interest in the Central Kansas Uplift, the Piceance Basin in western Colorado, the eastern Denver-Julesburg Basin in Colorado, Kansas and Nebraska, the Williston Basin in North Dakota and the Big Horn Basin in Wyoming.

Teton was formed in November 1996 and is incorporated in the State of Delaware. Our common shares are publicly traded on the American Stock Exchange under the symbol TEC.

Our principal executive offices are located at 410 Seventeenth Street, Suite 1850, Denver, CO 80202, and our telephone number is (303) 565-4600. Our web site is *www.teton-energy.com*.

Our objective is to increase stockholder value by pursuing our corporate strategy of:

- economically growing reserves and production, by 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;
- seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories; and
- selectively pursuing strategic acquisitions that may expand or complement our existing operations.

The pursuit of our strategy includes the following key elements:

Pursue Attractive Reserve and Leasehold Acquisitions

To date, acquisitions have been critical in establishing our asset base. We believe that we are well positioned, given our initial success in identifying and quickly closing on attractive opportunities in the Central Kansas Uplift, Piceance, DJ, Williston and Big Horn Basins, to effect opportunistic acquisitions that can provide upside potential, including long-term drilling inventories and undeveloped leasehold positions with attractive return characteristics. Our focus is to acquire assets that provide the opportunity for developmental drilling and/or the drilling of extensional step-out wells, which we believe will provide us with significant upside potential while not exposing us to the risks associated with drilling new field wildcat wells in frontier basins.

Drive Growth through Drilling

We plan to supplement our long-term reserve and production growth through drilling operations. In 2007, we participated in the drilling of 41 gross wells in connection with our Piceance Basin project where we have a 12.5% non-operated working interest and 81 gross wells in the DJ Basin under the Noble Earning Agreement where we have a 25% non-operated working interest in the AMI. In 2008, we anticipate that we will participate in the drilling of approximately 52 gross wells in the Berry Petroleum Company (Berry) operated properties in the Piceance Basin, in the drilling of approximately 150 gross wells in the Noble-operated properties in the Teton Noble AMI, and in the drilling of up to 4 gross wells in the Evertson-operated properties in the Williston Basin. During 2008, we also anticipate that we will drill up to 17 gross wells in the DJ Basin (Frenchman Creek, South Frenchman Creek and Washco), up to 4 gross wells in the Big Horn Basin properties and up to 40 gross wells in the Central Kansas Uplift properties (see further discussion below).

Maximize Operational Control

It is strategically important to our future growth and maturation as an independent exploration and production company to be able to serve as operator of our properties when possible in order to be able to exert greater control over costs and timing in, and the manner of, our exploration, development and production activities. In 2007, we acquired 499,904 gross acres (413,786 net) in the DJ Basin Washco properties, including about 1.0 MMcfed of production, 111,872 gross acres (109,688 net) in the DJ Basin South Frenchman Creek properties, 28,204 gross acres (11,689 net) in the DJ Basin Frenchman Creek properties and 16,417 gross acres (15,132 net) in the Big Horn Basin properties, all of which are properties operated by us. On April 2, 2008, we acquired an additional 48,100 gross acres (31,650 net) in the Central Kansas Uplift, all of which is also operated by us (see further discussion below). The Company currently has eight projects; five operated by the Company and three operated by other companies.

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Operate Efficiently and Effectively, and Maximize Economies of Scale Where Practical

Our objective is to generate profitable growth and high returns for our stockholders, and we expect that our unit cost structure will benefit from economies of scale as we grow and from our continuing cost management initiatives. As we manage our growth, we are actively focusing on reducing lease operating expenses and finding and development costs. In addition, our acquisition efforts are geared toward pursuing opportunities that fit well within existing operations, in areas where we are establishing new operations or in areas where we believe that a base of existing production will produce an adequate foundation for economies of scale.

Pursuit of Selective Complementary Acquisitions

We seek to acquire long-lived producing properties with a high degree of operating control, or oil and gas concerns that enjoy good business reputations and that offer economical opportunities to increase our natural gas and crude oil reserves.

As an example of this strategy, on April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from Shelby Resources, LLC, a private oil and gas company and a group of approximately 14 other working interest owners, collectively (the Sellers) for approximately $53.6 million. Terms also include warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The effective date of the transaction was March 1, 2008.

The purchase price was funded with $40.2 million of cash, $13.0 million of Teton common stock, or 2,746,124 common shares and 625,000 warrants valued at $434. Effective April 2, 2008, we amended our bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million (the Amended Credit Facility). The available borrowing base under the Amended Credit Facility was increased from $10 million to $50 million ($32.5 million at June 30, 2008 as discussed in Note 6 of the Notes to the Consolidated Financial Statements) as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new hedging positions. We have hedged 80 percent of the oil proved developed producing (PDP) production and 80 percent of the natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition.

Following are summary comments of our performance in several key areas during the three and six month periods ended June 30, 2008:

Net income (loss)

During the three and six month periods ended June 30, 2008, our net loss increased from $7,245 (or $0.45 per share) for the three months ended June 30, 2007, to $30,028 (or $1.40 per share) for the three months ended June 30, 2008 and from $9,046 (or $0.57 per share) for the six months ended June 30, 2007 to $38,251 (or $1.95 per share) for the six months ended June 30, 2008. The increases in net loss of $22,783 for the three month period and $29,205 for the six month period are due largely to an increase in the unrealized loss on oil and gas derivative contracts, a non-cash item required by SFAS No. 133, of $22,141 and $23,281, respectively; an increase in realized loss on oil and gas derivative contracts of $1,916 and $2,192, respectively; an increase in general and administrative expenses of $2,576 and $4,515, respectively (largely due to an increase in non-cash compensation of $2,558 and $3,443, respectively); and an increase in non-cash interest expense related to the amortization of deferred debt discount and issuance costs of $4,391 and $8,595, respectively; and less significantly to an increase in lease operating and related production expenses (due primarily to increased production and production in new locations with heavy oil productions and resultant per unit LOE that is slightly higher). These increases were somewhat offset by an increase in oil and gas revenues, from $990 to $10,121 during the three months ended June 30, 2008 and from $2,188 to $13,761 for the six months ended June 30, 2008.

Production

During the three and six month periods ended June 30, 2008, average company-wide daily production increased 156% to 7,520 Mcfed, and increased 135% to 6,080 Mcfed, respectively, as compared to average daily production of 2,942 Mcfed and 2,591 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 the Company began recognizing its share of production from the 50

producing wells at that time. Average daily production, net to the Company, from the 50 wells in the area was 3,527 Mcfed for the three months ended June 30, 2008. The second quarter 2008 was the first production from the Central Kansas properties. We closed on April 2 and physically took over operations at the end of April. We intend to drill up to an additional 40 gross wells in the Central Kansas Uplift in 2008 (see additional discussion under Results of Operations below).

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Piceance. Average daily production, net to the Company, in the area decreased to 2,707 Mcfed and increased to 2,801 Mcfed for the three and six months ended June 30, 2008, respectively, compared to 2,817 Mcfed and 2,502 Mcfed for the same prior year periods. The increase during the six month period ended June 30, 2008 is due primarily to an increase in producing well count, offset slightly by the normal production decline of existing wells and more so by the fact that we sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million in the fourth quarter 2007. Twelve new wells came on-line during the first half of 2008, bringing the total producing well count to 65 wells, with 23 additional wells waiting on completion as of June 30, 2008. Berry has informed us that they expect to complete the 23 wells by the end of September and intend to drill a total of 52 wells, approximately 6.5 net to our interest, in 2008.

Teton Noble AMI. As of June 30, 2008, there were 94 gross producing non-operated wells in the DJ Noble area of the DJ Basin with an additional 19 waiting on completion. This producing well count is compared to 18 producing wells at June 30, 2007. Production, net to the Company, increased to 495 Mcfed and 549 Mcfed for the three and six months ended June 30, 2008, respectively, from 70 Mcfed and 48 Mcfed for the same prior year periods. Noble commenced its 2008 drilling program on March 23, 2008, and we have been informed by the operator that it intends to drill approximately 150 gross wells, approximately 41 net to our interest, during 2008.

Washco. As of June 30, 2008, there were 27 gross producing wells in the Washco area of the DJ Basin, operated by the Company, that produced an average of 774 Mcfed and 904 Mcfed, net to the Company, during the three and six months ended June 30, 2008, respectively. The Company recognized its first production in the area during the fourth quarter of 2007.

Williston. For the three and six months ended June 30, 2008, production, net to the Company, in the area averaged 16 Mcfed and 63 Mcfed, respectively, as compared to 6 Mcfed and 7 Mcfed during the same prior year periods. Teton holds an interest in five producing wells in the Williston Basin, and has one well in process of workover and one drilling. There are three additional wells approved which are waiting on equipment and/or permits to begin drilling.

Oil and Gas Sales

Oil and gas sales increased from $990 for the three months ended June 30, 2007 to $10,121 for the three months ended June 30, 2008 and from $2,188 for the six months ended June 30, 2007 to $13,761 for the six months ended June 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by operating area, and an increase in the average price per Mcfe. The average price per Mcfe increased $10.31 per Mcfe, from $4.48 to $14.79 per Mcfe and $7.77 per Mcfe from $4.67 to $12.44 per Mcfe for the three and six months ended June 30, 2008, respectively, when compared to the prior year periods. The increases in price per Mcfe is largely impacted by an increase in oil volumes as a percentage of total volumes, as well as higher average spot prices, for both oil and natural gas in 2008 compared to 2007.

LIQUIDITY AND CAPITAL RESOURCES

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 the needs of the business. As a result of our development drilling program in 2007, the continued development drilling in 2008 and the additional producing well count added from the April 2, 2008 acquisition in the Central Kansas Uplift, we expect that cash flow from operating activities will begin to contribute more significantly to our cash requirements for the remainder of 2008 and thereafter. We believe that cash on hand and amounts available under our $150 million credit facility ($32.5 million borrowing base at June 30, 2008), together with anticipated net cash provided by operating activities during 2008, will provide us with sufficient funds to develop new reserves, maintain our current facilities and complete our current capital expenditure program through 2008. Depending on the timing and amount of future projects, we may be required to seek additional sources of capital. While we believe that we would be able to secure additional financing if required, we can provide no assurance that we will be able to do so or as to the terms of any additional financing.

We may also receive proceeds from the exercise of outstanding warrants and/or options as we did during previous years. At June 30, 2008 warrants to purchase 5,232,651 shares of common stock were outstanding. These warrants have a weighted average exercise price of $5.13 per share and expire between October 2008 and December 2012. At

June 30, 2008, 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. During the three and six months ended June 30, 2008, we received proceeds of approximately $927 and $1,905, respectively, from the exercise of warrants.

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Credit Facility

On August 9, 2007, the $50 million revolving credit facility with BNP Paribas (the Credit Facility) was replaced by an amended and restated Credit Facility with JP Morgan Chase Bank, N.A. The Amended Credit Facility had an initial borrowing capacity of $50 million, and was amended on April 2, 2008 to a $150 million revolving credit facility ($50 million borrowing base) as a result of adding the additional reserves related to the acquisition of the Central Kansas Uplift properties previously discussed.

In connection with the privately placed 10.75% Secured Convertible Debentures, the borrowing base on the Company s $150 million Amended Credit Facility was reduced to $32.5 million, which, when combined with the $30 million convertible debenture (assuming the put option is exercised by the holders of the convertible debentures as discussed in Note 5 of the Notes to the Consolidated Financial Statements), brought our total available borrowing capacity from the prior borrowing base of $50 million to a combined $62.5 million. Including the $10 million related to the 90-day put option would result in a further reduction of the borrowing base to $30 million, for a total borrowing capacity of $70 million.

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

	June 30, 2008	December 31, 2007
Financial Position Summary		
Cash and cash equivalents	$ 13,977	$ 24,616
Working capital	$ (15,708)	$ 8,259
Debt outstanding	$ 61,867	$ 9,630
Stockholders equity	$ 32,722	$ 49,028
Ratios		
Long-term debt to total capital ratio	61.3%	14.0%
Total debt to equity ratio	189.1%	19.6%

During the six months ended June 30, 2008, we had negative working capital of $15,708, due primarily to cash expenditures for our share of drilling and completion expenses in the non-operated properties of the Piceance Basin and our operated properties in the DJ Basin and the Central Kansas Uplift, the Central Kansas Uplift acquisition, and the increase in the balance sheet amount related to the unrealized loss on oil and gas derivatives. Additionally, in accordance with SFAS 133, we have taken a $23.5 million charge to income for unrealized losses on oil and gas derivative contracts, resulting in a significant increase to our accumulated deficit at June 30, 2008. The accumulated deficit is a component of stockholders equity and is reflected in that line above. The lower stockholders equity, in turn, results in a much inflated total debt to equity ratio, as noted above. If the oil and gas commodity prices used to value the unrealized gains (losses) on the related derivative contracts continue to increase from their June 30, 2008 levels, this effect will increase. However, if those commodity prices decrease from their June 30, 2008 levels, this effect will decrease.

Cash Flows and Capital Requirements

The following table summarizes our cash flows for the periods indicated:

	Six months ended June 30, 2008	2007
Cash provided by (used in):		
Operating Activities	$ 2,100	$ (1,618)
Investing Activities	(59,655)	(14,942)
Financing Activities	46,916	16,275
Net change in cash	$ (10,639)	$ (285)

During the six months ended June 30, 2008, net cash provided by operating activities was $2,100 as compared to net cash used in operating activities of $1,618 during the same prior year period. Our net loss increased by $29,205 during the six months ended June 30, 2008 as compared to the same prior year period. This increase in net loss included several large non-cash items: an increase in the unrealized loss related to oil and gas derivatives of $23,281, an increase in non-cash charges related to depreciation, depletion and amortization of $4,149, an increase in the amortization of deferred debt discount and issuance costs of $8,589 and an increase in non-cash compensation of $2,337. These increases in amounts added back to net income to arrive at operating cash flow were slightly offset by a decrease in the net change of current assets and current liabilities of $488 and a change in the non-cash item related to the derivative contracts (warrants) of $5,505.

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During the six months ended June 30, 2008, net cash used in investing activities was $59,655 as compared to $14,942 in the same prior year period. Cash expenditures during the six month period ended June 30, 2008 relate largely to the acquisition of producing properties and undeveloped acreage in the Central Kansas Uplift (as previously discussed), as well as development of our non-operated properties in the Piceance Basin and the Teton-Noble AMI, and of our operated properties in the DJ Basin and Central Kansas Uplift. Amounts were funded primarily from borrowings on our Amended Credit Facility and cash on hand.

During the six months ended June 30, 2008, net cash provided by financing activities was $46,916 as compared to $16,275 in the same prior year period. During the six months ended June 30, 2008, we repaid the $8.0 million outstanding as of December 31, 2007 under our Amended Credit Facility and repaid $6.6 million of the $9.0 million in Senior Secured Convertible Notes (the remaining $2.4 million converted into common stock prior to maturity). Net borrowings on our Amended Credit Facility were approximately $22 million and the Company raised $40 million related to the privately placed 10.75% Secured Convertible Debentures.

Our revised capital budget for 2008 of up to $49.2 million includes planned drilling in the Central Kansas Uplift, the Piceance, DJ, Williston and Big Horn Basins. Of that amount approximately $16.0 million has been accrued or expended in the six months ended June 30, 2008, primarily for our share of drilling and completion expenses in the non-operated properties of the Piceance and DJ Basins. Our planned 2008 development and exploration expenses could also increase if any of the operations associated with our properties experience cost overruns.

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, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price (1)	Price Index (2)	Remaining Period	
Oil Fixed Price Swap	11,040	$80.70	WTI	11/01/07	12/31/08
Oil Costless Collar	77,606	$95.80 Floor/$103.00 Ceiling	WTI	07/01/08	12/31/08
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09	12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10	12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11	12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12	12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13	04/30/13
Total Bbl	531,790				
Natural Gas Fixed Price Swap	120,000	$5.78	CIGRM	08/01/07	10/31/08
Natural Gas Costless Collar	368,000	$6.00 Floor/$7.10 Ceiling	CIGRM	07/01/08	12/31/08
Natural Gas Costless Collar	62,000	$6.00 Floor/$7.10 Ceiling	CIGRM	01/01/09	01/31/09
Natural Gas Costless Collar	473,867	$6.50 Floor/$7.75 Ceiling	CIGRM	02/01/09	12/31/09
Natural Gas Costless Collar	417,405	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/10	12/31/10
Natural Gas Costless Collar	355,399	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/11	12/31/11
Natural Gas Costless Collar	310,702	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/12	12/31/12

Natural Gas Costless Collar	95,200	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/13	04/30/13
Natural Gas Costless Collar	57,280	$9.10 Floor/$9.75 Ceiling	NYMEX	07/01/08	12/31/08
Natural Gas Costless Collar	77,630	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/09	12/31/09
Natural Gas Costless Collar	46,274	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/10	12/31/10
Natural Gas Costless Collar	26,158	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/11	12/31/11
Natural Gas Costless Collar	15,258	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/12	12/31/12
Natural Gas Costless Collar	4,104	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/13	04/30/13
Total MMBtu	2,429,277				

(1) Fixed price is per Bbl for oil swaps and collars and per MMBtu for natural gas swaps and collars.

(2) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platts for Inside FERC on the first business day of each month. NYMEX refers to quoted prices on the New York Mercantile Exchange. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

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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 natural gas contracts listed above, a $0.10 hypothetical change in the CIGRM or NYMEX 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 2008 of $243. For the oil contracts listed above, a $1.00 hypothetical change in the WTI price above the ceiling price or below the floor price applies to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $532. The Company plans 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.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

On January 1, 2008, we adopted the provisions of SFAS No. 157, Fair Value Measurements (SFAS No. 157) related to assets and liabilities, which primarily affects the valuation of our derivative contracts (see Note 4 to the Notes to the Consolidated Financial Statements included in this Form 10-Q). In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Beginning January 1, 2009, we will adopt the provisions for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of SFAS No. 157 did not have a material effect on our financial condition or results of operations. We do not believe that the implementation of this standard, with respect to its effect on nonfinancial assets and liabilities, will have a material impact on its consolidated financial position or results of operations.

On January 1, 2008, we adopted, but did not elect to apply, the provision of SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) which permits an entity to measure certain financial assets and financial liabilities at fair value. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. The adoption of SFAS No. 159 had no effect on our financial condition or results of operations as we did not make any such elections under this fair value option.

New accounting pronouncements

In December 2007, the FASB issued 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. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. We are in the process of evaluating the impacts, if any, of adopting this pronouncement.

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In March 2008, the FASB issued 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. This Statement will be effective for our interim and annual financial statements beginning in fiscal year 2010. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We do not believe adopting this pronouncement will have a material impact on the us. The pronouncement will impact reporting only.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements presented in conformity with GAAP. SFAS No. 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board (the PCAOB) amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles . We do not believe that the implementation of this standard will have a material impact on our consolidated financial position or results of operations.

In May 2008, the FASB issued 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. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past periods presented. Early adoption is prohibited. We are in the process of evaluating the impacts, if any, of adopting this FSP.

In June 2008, the FASB ratified the consensus reached by the Task Force, EITF Issue No. 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-5). EITF 07-5 addresses how an entity should evaluate whether an instrument is indexed to its own stock. The consensus is effective for fiscal years (and interim periods) beginning after December 15, 2008 (fiscal 2009 for the Company). The consensus must be applied to outstanding instruments as of the beginning of the fiscal year in which the consensus is adopted and should be treated as a cumulative-effect adjustment to the opening balance of retained earnings. Early adoption is not permitted. We are in the process of evaluating the impacts, if any, of adopting this EITF.

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 Secured Convertible Notes (Convertible Notes) were a negotiated instrument and are therefore recorded at fair value. We evaluated the Convertible Notes and determined that there were no embedded features which would require derivative accounting.

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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 (we have no cash flow hedges at, or for the periods ended, June 30, 2008), changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in our Consolidated Statement of Operations. When oil and gas derivative contracts are settled, we recognize realized gains and losses under the other income and expense caption in our consolidated statement of operations.

Derivative assets and liabilities included in Level 2 include fixed rate swap arrangements for the sale of oil and natural gas and hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through 2013 for a total of approximately 531,790 Bbls of oil production and 2,429,277 MMbtu of natural gas production. The Company previously included swap agreements in Level 1, however, has determined that based on the nature of the agreements swaps are more appropriately classified as Level 2.

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. In instances where derivative financial instruments require liability classification, we initially and subsequently measure such instruments at estimated fair value using Level 2 inputs in the Black-Scholes-Merton Pricing Model. Accordingly, we adjust the estimated fair value of these derivative components at each reporting period through a charge to earnings until such time as the instruments are exercised, expire or are permitted to be classified in stockholders equity.

RESULTS OF OPERATIONS

Three months ended June 30, 2008 compared to the three months ended June 30, 2007

Sales volume and price comparisons

	Three months ended June 30,					
	2008			2007		
	Volume		Average Price (1)	Volume		Average Price (1)
Product:						
Gas (Mcf)	332,046	$	7.47	262,717	$	4.96
Oil (Bbls)	58,710	$	101.98	565	$	59.75
Mcfe	684,306	$	12.37	266,107	$	5.03

(1) Average price is net of the impact of hedging activity.

For the three months ended June 30, 2008, we had net loss from continuing operations of $30,028 as compared to $7,245 in the same prior year period. Factors contributing to the $22,783 increase in net loss include the following:

Oil and gas production for the three months ended June 30, 2008 increased 157% to 684,306 Mcfe as compared to 266,107 Mcfe in the same prior year period. The increase in production is largely attributable to the recognition of our first production in the Central Kansas Uplift, acquired in April of 2008, and to increased production in the Teton Noble AMI and the Washco operating area. Production in the Central Kansas Uplift was 320,972 Mcfe for the three months ended June 30, 2008 and is expected to increase throughout the remainder of the year as newly drilled wells are brought on line and identified recompletions are performed. We drilled six new wells in Kansas by June 30, 2008, with three of those wells coming on line late in the quarter, one waiting on completion and two that were not

commercially viable. We will begin to see measurable results from the four new wells, and three additional successful wells that have been drilled since June 30, in the third quarter. Drilling of up to an additional 31 wells is planned for the remainder of 2008. Production in the Piceance decreased to 246,306 Mcfe for the three months ended June 30, 2008, as compared to 256,316 Mcfe for the same prior year period. The decrease is due primarily to an increase in producing well count, more than offset by the normal production decline of existing wells and more so by the fact that we sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million in the fourth quarter 2007. Twelve new wells came on-line during the first half of 2008, bringing the total producing well count to 65 wells, with 23 additional wells waiting on completion as of June 30, 2008.

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Berry has informed us that they expect to complete the 23 wells by the end of September and intend to drill a total of 52 wells, approximately 6.5 net to our interest, in 2008. Management of the REX pipeline, which is a major conduit moving natural gas east from the Rockies, has informed the public that they intend to curtail transportation capacity on the pipeline during the month of September by 45% to perform maintenance procedures. Berry has further informed us that it will shut in some production in the Piceance Basin during the REX pipeline maintenance but, as of yet, has not determined how much will be shut in on properties in which we participate. Production in the Teton Noble AMI increased from 6,401 Mcfe for the three months ended June 30, 2007 to 45,083 Mcfe for the three months ended June 30, 2008, due to increased drilling activity. Washco production for the three months ended June 30, 2008 was 70,470 Mcfe. We recognized our first production in Washco during the fourth quarter of 2007. Williston Basin production decreased to 1,475 Mcfe for the three months ended June 30, 2008, from 3,390 Mcfe for the same prior year period. Current plans are to drill at least one additional Bakken well and one additional Red River well in the Williston Basin this year, with the possibility of drilling up to two in each formation.

Oil and gas sales increased 922% from $990 for the three months ended June 30, 2007 to $10,121 for the three months ended June 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by operating area, and an increase in the average price per Mcfe. The average price per Mcfe increased $7.34 per Mcfe, from $5.03 to $12.37 per Mcfe, after the effect of hedging gains/losses. More typical winter weather contributed to the spring s lower average natural gas storage volumes which produced higher average second quarter prices for natural gas in 2008 compared to 2007. Additionally, we added significant oil production during the second quarter of 2008 as a part of the acquisition in the Central Kansas Uplift. When converted to a per Mcfe basis, oil prices are currently significantly higher than that of natural gas, also contributing to an increase in our price per Mcfe over the same prior year period.

Oil and gas production expenses

	Three Months Ended June 30,	
	2008	2007
	(in dollars per Mcfe)	
Average price	$ 12.37	$ 5.03
Production costs	2.60	0.83
Production taxes	0.62	0.34
Total operating costs	3.22	1.17
Gross margin before DD&A	$ 9.15	$ 3.86
Gross margin percentage	74%	77%

Our production costs (lease operating expenses and transportation costs) and production taxes for the three months ended June 30, 2008 increased $1,893, due primarily to adding new operating areas and to increased production as discussed above. LOE per Mcfe increased from $0.83 to $2.60 per Mcfe primarily due to the addition of new operating areas with higher oil production which results in higher LOE costs, as well as an increase in transportation costs related to oil in the Central Kansas Uplift.

General and administrative expenses increased $2,576, from $2,180 to $4,756 for the three months ended June 30, 2008. The increase is due primarily to an increase in compensation expense of $3,111 related to (1) cash compensation related to additional headcount over the same prior year period ($553) and (2) the increase in non-cash compensation charges ($2,558) for presumed vesting of the 2006 LTIP and restricted stock awards ($174) and the actual vesting of the 2007 LTIP awards and 2008 LTIP Tranche 1 awards ($2,384). These increases were partially offset by a decrease in professional fees of $103 related to the use of financial consultants who have been replaced with additional full-time headcount and an increase in the reclassification of billable G&A costs and G&A costs

related to exploration activities of $370. There were no other individually significant increases or decreases.

Depletion, depreciation and amortization expense increased from $594 for the three months ended June 30, 2007 to $3,099 for the three months ended June 30, 2008. This increase is due primarily to the increased production, new productive areas and higher capitalized costs over the same prior year period.

During the three months ended June 30, 2008, we recorded a net unrealized loss (non-cash) on derivative contracts of $22,246. The loss represents marking the derivative contracts to market at June 30, 2008, 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, 2008 was $5,418 and included $3,845 and $740 of amortization of debt issuance discount and debt issuance costs (non-cash), respectively related to the 8% Senior Subordinated Convertible Notes. The remaining interest expense relates to net borrowings on our Amended Credit Facility and the convertible notes that were outstanding during the quarter.

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Six months ended June 30, 2008 compared to the six months ended June 30, 2007

Sales volume and price comparisons

	Six months ended June 30,					
	2008			2007		
	Volume	Average Price (1)		Volume	Average Price (1)	
Product:						
Gas (Mcf)	670,232	$	7.19	454,762	$	4.97
Oil (Bbls)	72,722	$	97.14	2,372	$	53.98
Mcfe	1,106,564	$	10.74	468,994	$	5.09

(1) Average price is net of the impact of hedging activity.

For the six months ended June 30, 2008, we had a net loss from continuing operations of $38,251 as compared to $9,046 in the same prior year period. Factors contributing to the $29,205 increase in net loss include the following:

Oil and gas production for the six months ended June 30, 2008 increased 136% to 1,106,564 Mcfe as compared to 468,994 Mcfe in the same prior year period. The increase in production is largely attributable to the recognition of our first production in the Central Kansas Uplift, acquired in April of 2008, and to increased production in the Piceance Basin, the Teton Noble AMI and the Washco operating area. Production in the Central Kansas Uplift was 320,972 Mcfe for the six months ended June 30, 2008 and is expected to increase throughout the remainder of the year as newly drilled wells are brought on line and identified recompletions are performed. We drilled six new wells in Kansas by June 30, 2008, with three of those wells coming on line late in the quarter, one waiting on completion and two that were not commercially viable. We will begin to see measurable results from the four new wells, and three additional successful wells that have been drilled since June 30, in the third quarter. Drilling of up to an additional 31 wells is planned for the remainder of 2008. Production in the Piceance increased to 509,868 Mcfe for the six months ended June 30, 2008 as compared to 452,805 Mcfe for the same prior year period. The increase is due primarily to an increase in producing well count offset slightly by the normal production decline of existing wells, and more so by the fact that we sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million in the fourth quarter 2007. Twelve new wells came on-line during the first half of 2008, bringing the total producing well count to 65 wells, with 23 additional wells waiting on completion as of June 30, 2008. Berry has informed us that they expect to complete the 23 wells by the end of September and intend to drill a total of 52 wells, approximately 6.5 net to our interest, in 2008. Management of the REX pipeline, which is a major conduit moving natural gas east from the Rockies, has informed the public that they intend to curtail transportation capacity on the pipeline during the month of September by 45% to perform maintenance procedures. Berry has further informed us that it will shut in some production in the Piceance Basin during the REX pipeline maintenance but, as of yet, has not determined how much will be shut in on properties in which we participate. Production in the Teton Noble AMI increased from 8,761 Mcfe for the six months ended June 30, 2007 to 99,871 Mcfe for the six months ended June 30, 2008, due to increased drilling activity. Washco production for the six months ended June 30, 2008 was 164,464 Mcfe. We recognized our first production in the area during the fourth quarter of 2007. Williston Basin production increased to 11,389 Mcfe for the six months ended June 30, 2008, from 7,428 Mcfe for the same prior year period. Current plans are to drill at least one additional Bakken well and one additional Red River well in the Williston Basin this year, with the possibility of drilling up to two in each formation.

Oil and gas sales increased 529% from $2,188 for the six months ended June 30, 2007 to $13,761 for the six months ended June 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by

operating area, and an increase in the average price per Mcfe. The average price per Mcfe increased $5.65 per Mcfe, from $5.09 to $10.74 per Mcfe, after the effect of hedging gains/losses. More typical winter weather and lower average natural gas storage volumes combined to produce higher average first and second quarter prices for natural gas in 2008 compared to 2007. Additionally, we added significant oil production during the second quarter of 2008 as a part of the acquisition in the Central Kansas Uplift. When converted to a per Mcfe basis, oil prices are currently significantly higher than that of natural gas, also contributing to an increase in our price per Mcfe over the same prior year period.

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Oil and gas production expenses

	Six Months Ended June 30,	
	2008	2007
	(in dollars per Mcfe)	
Average price	$ 10.74	$ 5.09
Production costs	2.04	0.84
Production taxes	0.57	0.33
Total operating costs	2.61	1.17
Gross margin before DD&A	$ 8.13	$ 3.92
Gross margin percentage	76%	77%

Our production costs (lease operating expenses and transportation costs) and production taxes for the six month ended June 30, 2008 increased $2,332, due primarily to adding new operating areas and to increased production as discussed above. LOE per Mcfe increased from $0.84 to $2.04 per Mcfe primarily due to the addition of new operating areas with higher oil production which results in higher LOE costs as well as an increase in transportation costs related to oil in the Central Kansas Uplift.

General and administrative expenses increased $4,515, from $4,060 to $8,575 for the six months ended June 30, 2008. The increase is due primarily to an increase in compensation expense of $4,320 related to (1) cash compensation related to additional headcount over the same prior year period ($877) and (2) the increase in non-cash compensation charges ($3,443) for presumed vesting of the 2006 LTIP and restricted stock awards ($699) and the actual vesting of the 2007 LTIP awards and 2008 LTIP Tranche 1 awards ($2,744), an increase in professional fees of $436 related to Sarbanes Oxley and financial consultant work performed in the first quarter of 2008 and an increase of $111 for office rent and related expenses due to the additional headcount and related office space. These increases were partially offset by an increase in the reclassification of billable G&A costs and G&A costs related to exploration activities of $402. There were no other individually significant increases or decreases.

Depletion, depreciation and amortization expense increased from $1,149 for the six months ended June 30, 2007 to $5,298 for the six months ended June 30, 2008. This increase is due primarily to the increased production and higher capitalized costs over the same prior year period.

During the six months ended June 30, 2008, we recorded a net unrealized loss (non-cash) on derivative contracts of $23,479. The loss represents marking the derivative contracts to market at June 30, 2008, 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, 2008 was $9,634 and included $7,370 and $1,419 of amortization of debt issuance discount and debt issuance costs (non-cash), respectively related to the 8% Senior Subordinated Convertible Notes. The remaining interest expense relates to net borrowings on our Amended Credit Facility and the convertible notes that were outstanding during the first half of 2008.

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 nature gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible 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, 2008, our income before income taxes for the period would have moved up or down approximately $15.00 for every $1.00 change in oil prices and $14.00 for every $0.10 change in natural gas prices.

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We have entered into derivative contracts to manage our exposure to oil and natural gas 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 above for a breakout of our outstanding hedge positions at June 30, 2008.

Interest Rate Risk

At June 30, 2008, we had $21,867 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 1.25% to 3.0% or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to 1.5%, at our request. We are also required to pay a commitment fee of 0.375% or 0.5% per annum, based on the average daily amount of the unused amount of the commitment. Based on the $21,867 outstanding under our Credit Facility at June 30, 2008, 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 $55 per quarter.

ITEM 4. CONTROLS AND PROCEDURES

In accordance with the Securities Exchange Act of 1934, as amended, Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that as of June 30, 2008, our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

There has been no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings.

ITEM 1A. RISK FACTORS

There were no material changes in our Risk Factors from those reported in Item 1A of Part I of our 2007 Annual Report on Form 10-K filed with the Securities and Exchange Commission, on March 13, 2008.

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

On June 18, 2008, the Company closed on the private placement of $40 million in 10.75% Secured Convertible Debentures due June 18, 2013 (the Debentures). The Debentures accrue interest at the rate of 10.75% per year, payable semi-annually in arrears. In addition, the Debentures will be convertible into shares of common stock at $6.50 per share. If investors convert into the common stock or if the Debentures are called by the Company before the three-year anniversary of the original issuance date, or June 18, 2011, the holders of the Debentures will be entitled to a payment in an amount equal to all interest that would have accrued if the principal amount subject to such conversion had remained outstanding through such three-year anniversary (the Interest Make Whole). The Company may, at its option, pay the Interest Make Whole amount in cash or shares of common stock. The value of the common stock will be determined based on ninety-percent (90%) of the lower of (i) the volume weighted average price (the VWAP) for the common stock for the ten (10) trading days immediately prior to the date the payment is due; and the closing price of the common stock on the date immediately preceding the conversion date; provided, however, that the Company may not issue the shares at a price below the $5.47, which was the closing price of the Company s common stock on June 6, 2008. The Debentures also provide for customary dividend protection and anti-dilution protection in the event of, among other things, stock splits and dividends.

The Debentures are convertible into a maximum of 8,411,937 shares of the Company s common stock, assuming the payment of the maximum Interest Make Whole amount in shares. Excluding the Interest Make Whole amount, the Debentures are convertible into 6,153,847 shares of common stock.

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Net proceeds to the Company are approximately $37,400,000, after fees and related expenses. RBC Capital Markets Corporation (RBC) served as the sole placement agent for the transaction. RBC receives a total placement fee of $2,400,000 for the $40 million offering.

No advertising or general solicitation was employed in offering the securities. This transaction was not registered under the Securities Act of 1933, as amended (the Act), in reliance on an exemption from registration under Section 4(2) of the Securities Act, and Rule 506 promulgated thereunder, based on the limited number of purchasers, their sophistication in financial matters and their access to information concerning the Company.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

None.

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

On April 24, 2008, the Company held its annual stockholders meeting. The Board proposed, and the shareholders approved, the election of each of the Company s Directors for an additional term of one year to expire at the Company s next Annual Meeting, tentatively scheduled for May 7, 2009. The number or votes cast for and against, or withheld, as to each Director were as follows:

	Karl F. Arleth	Robert F. Bailey	John T. Connor, Jr.	Thomas F. Conroy	Bill I. Pennington	James J. Woodcock
Shares in Favor	12,868,002	12,933,090	12,933,090	12,933,590	10,163,252	12,914,590
Shares Withheld	2,030,254	1,965,166	1,965,166	1,964,666	4,735,004	1,983,666

ITEM 5. OTHER INFORMATION.

None.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this report:

Exhibit Number and Description:

3.1.1 Certificate of Incorporation of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.2 Certificate of Domestication of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.3 Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company, incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.4 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.5 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.6 Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.

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3.2	Bylaws, as amended, of Teton Petroleum Company, incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed on August 20, 2002.
4.1	Form of 10.75% Secured Convertible Debentures dated June 18, 2008, issued by Teton Energy Corporation, incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed on June 19, 2008.
10.1	Second Amended and Restated Credit Agreement dated as of April 2, 2008 among Teton Energy Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto, incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed on April 3, 2008.
10.2	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 on June 19, 2008.
10.3	Form of Registration Rights Agreement, incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed on June 19, 2008.
10.4	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 on June 19, 2008.
10.5	Form of Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between, Teton Energy Corporation and the representative for the subordinated holders, incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed on June 19, 2008.
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.

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 7, 2008

By: /s/ Karl F. Arleth
Karl F. Arleth
President and Chief Executive Officer

Date: August 7, 2008

By: /s/ Lonnie R. Brock
Lonnie R. Brock
Executive Vice President and
Chief Financial Officer

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