GeoMet, Inc.
Form 10-Q
August 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from to

Commission File Number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

(Address of principal executive offices and telephone number, including area code)

N/A

(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. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	x

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

As of August 1, 2011, 39,973,810 shares and 4,411,749 shares, respectively, of the registrant s common stock and preferred stock, par value $0.001 per share, were outstanding.

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Part I. Financial Information

Item 1. Consolidated Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 783,777	$ 536,533
Accounts receivable, both amounts net of allowance of $60,848	2,666,387	2,600,319
Inventory	867,215	1,002,207
Derivative asset natural gas hedges	5,059,982	7,087,775
Other current assets	830,660	951,622
Total current assets	10,208,021	12,178,456
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	485,200,730	475,917,727
Other property and equipment	3,387,229	3,405,502
Total property and equipment	488,587,959	479,323,229
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(377,156,357)	(373,235,875)
Property and equipment net	111,431,602	106,087,354
Other noncurrent assets:		
Derivative asset natural gas hedges	1,561,546	2,186,767
Deferred income taxes	46,783,892	48,202,861
Other	1,138,069	1,430,584
Total other noncurrent assets	49,483,507	51,820,212
TOTAL ASSETS	$ 171,123,130	$ 170,086,022
LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 6,258,686	$ 5,950,861
Accrued liabilities	2,540,868	2,306,020
Deferred income taxes	1,689,073	2,206,531
Derivative liability interest rate swaps		4,592
Asset retirement liability	33,684	32,893
Current portion of long-term debt	87,677	132,743
Total current liabilities	10,609,988	10,633,640

Long-term debt	79,718,579	80,863,419
Asset retirement liability	5,763,357	5,465,798
Other long-term accrued liabilities	24,436	40,728
TOTAL LIABILITIES	96,116,360	97,003,585
Commitments and contingencies (Note 12)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,658,718; redemption amount $44,117,490; $.001 par value; 7,401,832 shares authorized, 4,411,749 and 4,148,538 shares were issued and outstanding at June 30, 2011 and December 31, 2010, respectively.	25,437,209	22,074,320
Stockholders Equity:		
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,973,810 and 39,758,484 at June 30, 2011 and December 31, 2010, respectively	39,974	39,744
Treasury stock 10,432 shares at June 30, 2011 and December 31, 2010	(94,424)	(94,424)
Paid-in capital	204,576,159	207,548,596
Accumulated other comprehensive loss	(1,312,553)	(1,324,154)
Retained deficit	(153,395,919)	(154,918,736)
Less notes receivable	(243,676)	(242,909)
Total stockholders equity	49,569,561	51,008,117
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY	$ 171,123,130	$ 170,086,022

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues:				
Gas sales	$ 8,330,680	$ 7,661,353	$ 16,181,728	$ 17,545,039
Operating fees	72,914	70,703	145,686	144,995
Total revenues	8,403,594	7,732,056	16,327,414	17,690,034
Expenses:				
Lease operating expense	2,879,695	2,812,883	5,852,450	5,920,254
Compression and transportation expense	964,825	1,075,392	1,881,056	2,079,839
Production taxes	365,321	288,039	687,709	496,268
Depreciation, depletion and amortization	1,621,546	1,450,238	3,254,514	3,095,603
General and administrative	1,503,149	1,314,840	2,942,339	2,792,565
Terminated transaction costs		1,402,534		1,402,534
Realized gains on derivative contracts	(1,536,056)	(2,210,850)	(5,033,118)	(3,670,978)
Unrealized (gains) losses from the change in market value of open derivative contracts	(197,154)	2,974,026	2,653,014	(4,668,016)
Total operating expenses	5,601,326	9,107,102	12,237,964	7,448,069
Operating income (loss)	2,802,268	(1,375,046)	4,089,450	10,241,965
Other income (expense):				
Interest income	4,287	5,057	8,761	30,861
Interest expense (net of amounts capitalized)	(823,703)	(1,423,476)	(1,663,772)	(2,667,636)
Other	(9,007)	625	(4,325)	(16,702)
Total other income (expense):	(828,423)	(1,417,794)	(1,659,336)	(2,653,477)
Income (loss) before income taxes	1,973,845	(2,792,840)	2,430,114	7,588,488
Income tax (expense) benefit	(902,107)	1,030,717	(907,297)	(3,323,459)
Net income (loss)	$ 1,071,738	$ (1,762,123)	$ 1,522,817	$ 4,265,029
Accretion of Series A Convertible Redeemable Preferred Stock	(436,029)		(859,172)	
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock	(1,336,250)		(2,632,110)	
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(664)		(1,222)	
Net (loss) income available to common stockholders	$ (701,205)	$ (1,762,123)	$ (1,969,687)	$ 4,265,029
Net (loss) income per share:				
Net (loss) income per common share				
Basic	$ (0.02)	$ (0.04)	$ (0.05)	$ 0.11
Diluted	$ (0.02)	$ (0.04)	$ (0.05)	$ 0.11
Weighted average number of common shares:				
Basic	39,617,625	39,240,545	39,544,361	39,199,990

Diluted	39,617,625	39,240,545	39,544,361	39,290,788

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive Income (Loss)

(Unaudited)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net income (loss)	$ 1,071,738	$ (1,762,123)	$ 1,522,817	$ 4,265,029
Gain (loss) on foreign currency translation adjustment	293	$ (2,899)	740	5,934
Gain on interest rate swap		115,891	10,862	282,844
Other comprehensive income (loss)	$ 1,072,031	$ (1,649,131)	$ 1,534,419	$ 4,553,807

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash flows provided by operating activities:		
Net income	$ 1,522,817	$ 4,265,029
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	3,254,514	3,095,603
Amortization of debt issuance costs	287,309	189,028
Terminated transaction costs		666,306
Deferred income tax expense	894,797	3,310,959
Unrealized losses (gains) from the change in market value of open derivative contracts	2,665,998	(4,668,016)
Stock-based compensation	451,853	79,569
Loss on sale of other assets	12,086	23,685
Accretion expense asset retirement obligation	270,913	241,395
Changes in operating assets and liabilities:		
Accounts receivable	(66,033)	434,118
Inventory	(347,100)	600,555
Other current assets	127,183	322,224
Accounts payable	(1,159,720)	(1,292,025)
Other accrued liabilities	237,329	1,206,121
Net cash provided by operating activities	8,151,946	8,474,551
Cash flows used in investing activities:		
Capital expenditures	(6,595,291)	(4,167,601)
Proceeds from sale of other property and equipment		31,838
Other assets	18,816	75,285
Net cash used in investing activities	(6,576,475)	(4,060,478)
Cash flows used in financing activities:		
Proceeds from revolving credit facility borrowings	15,800,000	10,500,000
Payments on revolving credit facility	(16,900,000)	(14,000,000)
Proceeds from exercise of stock options	3,791	46,327
Deferred financing costs	(142,153)	(703,245)
Deferred financing costs related to terminated transaction costs		(666,306)
Payments on other debt	(89,907)	(82,650)
Purchase and cancellation of treasury stock	(2,145)	
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(1,222)	
Net cash used in financing activities	(1,331,636)	(4,905,874)
Effect of exchange rate changes on cash	3,409	11,782
Increase (decrease) in cash and cash equivalents	247,244	(480,019)
Cash and cash equivalents at beginning of period	536,533	973,720
Cash and cash equivalents at end of period	$ 783,777	$ 493,701

Significant noncash investing and financing activities:

Accrued capital expenditures	$ 2,603,369	$ 1,650,768

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coalbed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia and Virginia.

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2010 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the SEC) on April 6, 2011.

Note 2 Recent Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, Improving Disclosures about Fair Value Measurements. This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are now applicable to interim and annual reporting periods. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 6 Derivative Instruments and Hedging Activities.

On June 16, 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in Accounting Standards Codification (ASC) 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Early adoption is permitted. The Company has not elected to early adopt and is still evaluating the effect on its disclosures. The amendments do not require incremental disclosures in addition to those required by ASC 250 or any transition guidance.

On May 12, 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework that is, converged guidance on how (not when) to measure fair value and on what disclosures to provide about fair value measurements. Thus, there are few differences between the ASU and its international counterpart, IFRS 13. While the ASU is largely consistent with existing fair value measurement principles in U.S. GAAP, it expands ASC 820 s existing disclosure requirements for fair value measurements and makes other amendments. Many of these amendments were made to eliminate unnecessary wording differences between U.S. GAAP and IFRS. However, some could change how the fair value measurement guidance in ASC 820 is applied. The ASU is effective for interim and annual periods beginning after December 15, 2011. The Company is still evaluating the effect on its disclosures.

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Note 3 Net (Loss) Income Per Common Share

Net (loss) income per common share basic is calculated by dividing Net (loss) income available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Net (loss) income per common share diluted assumes the conversion of all potentially dilutive securities and is calculated by dividing net (loss) income available to common stockholders by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Net (loss) income per common share diluted considers the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares would have an anti-dilutive effect. A reconciliation of Net (loss) income per common share is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income (loss)	$ 1,071,738	$ (1,762,123)	$ 1,522,817	$ 4,265,029
Accretion of Series A Convertible Redeemable Preferred Stock	(436,029)		(859,172)	
PIK dividends on Series A Convertible Redeemable Preferred Stock	(1,336,250)		(2,632,110)	
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(664)		(1,222)	
Net (loss) income available to common stockholders	$ (701,205)	$ (1,762,123)	$ (1,969,687)	$ 4,265,029
Net (loss) income per share:				
Net (loss) income available to common stockholders				
Basic	$ (0.02)	$ (0.04)	$ (0.05)	$ 0.11
Diluted	$ (0.02)	$ (0.04)	$ (0.05)	$ 0.11
Weighted average number of common shares:				
Basic	39,617,625	39,240,545	39,544,361	39,199,990
Add potentially dilutive securities:				
Stock options and non-vested restricted stock				90,798
Diluted	39,617,625	39,240,545	39,544,361	39,290,788

Net (loss) income per common share diluted for the three months ended June 30, 2011 excluded the effect of outstanding exercisable options to purchase 2,603,536 shares, 232,089 restricted stock units for which common shares are distributed upon achievement of certain performance targets, 350,906 weighted average restricted shares outstanding, and 4,278,124 shares of Series A Convertible Redeemable Preferred Stock (32,908,646 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive.

Net (loss) income per common share diluted for the six months ended June 30, 2011 excluded the effect of outstanding exercisable options to purchase 2,603,536 shares, 232,089 restricted stock units for which common shares are distributed upon achievement of certain performance targets, 366,975 weighted average restricted shares outstanding, and 4,148,538 shares of Series A Convertible Redeemable Preferred Stock (31,911,830 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive.

Additionally, in accordance with ASC 260, in computing the dilutive effect of convertible securities, Net (loss) income available to common stockholders is also adjusted to add back any convertible preferred dividends and accretion unless the preferred shares are anti-dilutive. As such, there was no add back to Net (loss) income available to common stockholders for the three months ended June 30, 2011 for accretion of, and dividends paid for, Series A Convertible Redeemable Preferred Stock (cash and PIK) of $436,029 and $1,336,914, respectively, in computing

Net (loss) income per common share diluted as the preferred shares were anti-dilutive. Additionally, there was no add back to Net (loss) income available to common stockholders for the six months ended June 30, 2011 for accretion of, and dividends paid for, Series A Convertible Redeemable Preferred Stock (cash and PIK) of $859,172 and $2,633,332, respectively, in computing Net (loss) income per common share diluted as the preferred shares were anti-dilutive.

Note 4 Gas Properties

The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the SEC. Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into United States of America (U.S.) and Canadian cost centers. The Canadian cost center was fully impaired in 2009 and remains fully impaired at June 30, 2011.

Gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved gas reserves. Depletion for the three months ended June 30, 2011 and 2010 was $0.83 and $0.72 per Mcf, respectively. Depletion for the six months ended June 30, 2011 and 2010 was $0.83 and $0.78 per Mcf, respectively. For both of the aforementioned periods, the increase in the depletion rate was primarily due to the impact of current year to date capital expenditures.

Estimation of proved gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion

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expense recognized during future reporting periods. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of estimated future net revenues, discounted at 10% per annum, plus cost of properties not being amortized plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. The ceiling test is performed separately for our U.S. and Canadian cost centers. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. In addition, subsequent to the adoption of ASC 410-20-25, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

No impairments were recorded during the three and six months ended June 30, 2011 and 2010. Future adverse changes could lead to an impairment of all or a portion of our full cost pool in future periods which could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to the full cost pool and stockholders equity.

Note 5 Asset Retirement Liability

We record an asset retirement obligation (ARO) on the consolidated balance sheets and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date we incurred the abandonment obligation using an assumed interest rate. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed interest rate.

The following table details the changes to our asset retirement liability for the six months ended June 30, 2011:

Current portion of liability at January 1, 2011	$ 32,893
Add: Long-term asset retirement liability at January 1, 2011	5,465,798
Asset retirement liability at January 1, 2011	5,498,691
Liabilities incurred	19,714
Accretion	270,913
Foreign currency translation	7,723
Asset retirement liability at June 30, 2011	5,797,041
Less: Current portion of liability	(33,684)
Long-term asset retirement liability	$ 5,763,357

The following table details the changes to our asset retirement liability for the six months ended June 30, 2010:

Current portion of liability at January 1, 2010	$ 108,111
Add: Long-term asset retirement liability at January 1, 2010	4,862,278

Asset retirement liability at January 1, 2010	4,970,389
Liabilities incurred	20,017
Liabilities settled	(3,792)
Accretion	241,395
Foreign currency translation	3,773
Asset retirement liability at June 30, 2010	5,231,782
Less: Current portion of liability	(104,739)
Long-term asset retirement liability	$ 5,127,043

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Note 6 Derivative Instruments and Hedging Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily using derivative instruments in the form of three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

Commodity Price Risk and Related Hedging Activities

At June 30, 2011, we had no natural gas collar positions.

At December 31, 2010, we had the following natural gas collar position:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2011	360,000	$ 7.45	$ 6.50		775,853

At June 30, 2011, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
July through October 2011	492,000	$ 6.37	973,840
July through October 2011	492,000	$ 5.37	479,805
July through October 2011	492,000	$ 5.43	511,757
November 2011 through March 2012	608,000	$ 7.12	1,433,590
November 2011 through March 2012	608,000	$ 6.12	824,878
November 2011 through March 2012	912,000	$ 5.08	296,992
April through October 2012	856,000	$ 5.73	818,627
April through October 2012	1,712,000	$ 4.94	287,694
November 2012 through March 2013	604,000	$ 6.42	724,543
November 2012 through March 2013	906,000	$ 5.50	269,802
	7,682,000		$ 6,621,528

At December 31, 2010, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
January through March 2011	360,000	$ 6.67	836,287
January through March 2011	540,000	$ 7.27	1,576,095

April through October 2011	856,000	$ 6.37	1,572,738
April through October 2011	856,000	$ 5.37	715,726
April through October 2011	856,000	$ 5.43	771,155
November 2011 through March 2012	608,000	$ 7.12	1,216,885
November 2011 through March 2012	608,000	$ 6.12	611,002
November 2011 through March 2012	912,000	$ 5.08	(19,449)
April through October 2012	856,000	$ 5.73	653,211
April through October 2012	1,712,000	$ 4.94	(34,286)
November 2012 through March 2013	604,000	$ 6.42	563,413
November 2012 through March 2013	906,000	$ 5.50	35,912
	9,674,000		$ 8,498,689

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Forward Physical Sale Contract

Our production is sold at an all-in price which includes the market price for natural gas plus a basis differential . In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus a basis differential of $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. As of June 30, 2011, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows:

Period	Volume (MMBtu)	Fixed Market Price	Fixed Basis Differential	All-In Price	Gross Sale
July through October 2011	492,000	$ 4.80	$ 0.115	$ 4.915	$ 2,418,180
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	948,000				$ 4,848,660

The remaining volumes giving effect for the fixed amounts denoted above are as follows:

Period	Volume (MMBtu)	Fixed Basis Differential
July through October 2011	1,476,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	3,452,000	

The aforementioned forward physical sale contract meets the definition of a derivative contract under ASC 815. However, it qualifies for normal purchase and sale exemption and, as such, we have elected not to record it on the Consolidated Balance Sheets (Unaudited) using mark-to-market accounting.

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under ASC 815-20-25. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

At June 30, 2011, we had no interest rate swaps. At December 31, 2010, we had the following interest rate swap:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	$ (4,592)

(1) The floating rate paid by the counterparty is the British Bankers Association LIBOR rate.

On September 14, 2010, we de-designated the remaining two interest rate swaps which we had previously designated as cash flow hedges under ASC 815-20-25. The de-designation resulted from entering into the Fourth Amended and Restated Credit Agreement (Credit Agreement) which replaced our Third Amended and Restated Credit Agreement. In the new agreement, the notional and interest rates no longer match, and therefore, these two interest rate swaps were no longer effective hedges under ASC 815-20-25. Subsequently, we accounted for the remaining interest rate swaps on a mark-to-market basis which gave rise to both realized and unrealized gains and losses recorded in Interest expense (net of amounts capitalized) in the Consolidated Statements of Operations. Amounts in accumulated other comprehensive income were frozen and reclassified into earnings as the forecasted transactions impacted earnings. For the three and six months ended June 30, 2010, we recognized no ineffective portion of our cash flow hedges.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our Credit Agreement and the collateral for the outstanding borrowings under our Credit Agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our Credit Agreement.

The application of ASC 820-10-55, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value.

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ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of credit risk on the fair value of the assets and liabilities related to the items stated below. The consideration for discounting our counterparties liabilities (our assets) was based on the difference between the S&P credit rating of a comparable company to our counterparties and the 13-week Treasury bill rate, both at the reporting date. The consideration for discounting our liabilities was based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

Natural Gas Hedges In order to estimate the fair value of our natural gas hedge positions, a forward price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

Interest Rate Swaps In order to estimate the fair value of our interest rate swaps, we use a yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available Money Market rates and Interest Rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the three and six months ended June 30, 2011. Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	June 30, 2011		December 31, 2010		June 30, 2011		December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments under ASC 815-20-25								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$	Derivative liability (current)	$ 4,592
Natural gas hedge positions	Derivative asset (current)	5,059,982	Derivative asset (current)	7,087,775	Derivative liability (current)		Derivative liability (current)	
Natural gas hedge positions	Derivative asset (non-current)	1,561,546	Derivative asset (non-current)	2,186,767	Derivative liability (non-current)		Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 6,621,528		$ 9,274,542		$		$ 4,592

The following (gains) losses on our hedging instruments included in the consolidated statements of operations and other comprehensive income (OCI) are as follows:

The Effect of Derivative Instruments on the Consolidated Statements of Operations and

Other Comprehensive Income for the Three Months Ended June 30, 2011 and 2010

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative			
		Three months ended June 30,		Six months ended June 30,	
		2011	2010	2011	2010
Derivatives designated as hedging instruments under ASC 815-20-25					
Interest rate swaps	Interest expense	$	$ 164,129	$	$ 403,343
Total loss		$	$ 164,129	$	$ 403,343
Derivatives not designated as hedging instruments under ASC 815-20-25					
Natural gas collar positions	Realized gains on derivative contracts	$ (1,536,056)	$ (2,210,850)	$ (5,033,118)	$ (3,670,978)
Natural gas collar positions	Unrealized (gains) losses from the change in market value of open derivative contracts	(197,154)	2,974,026	2,653,014	(4,668,016)
Total (gain) loss		$ (1,733,210)	$ 763,176	$ (2,380,104)	$ (8,338,994)

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships Interest Rate Swaps				
Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		Interest expense		
Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)	$	$ 23,397	$ (206)	$ 54,334
Location of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)		Interest expense		
Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	$	$ (164,129)	$ (17,782)	$ (403,343)

Accumulated comprehensive loss of $1,312,553 as of June 30, 2011 consisted entirely of foreign currency translation adjustments.

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Note 7 Terminated Transaction Costs

Terminated transaction costs consist of payments made related to a terminated financing transaction between the Company and NGP Capital Resources Company (NGPC) and North Shore Energy, LLC (North Shore), an affiliate of Yorktown Energy Partners IV, L.P. (Yorktown) (Yorktown is a related party to the Company) and expenses related to a terminated sale of certain gas properties. There were no terminated transaction costs for the three and six months ended June 30, 2011. The following is a detail of terminated transaction costs and related party amounts for the three and six months ended June 30, 2010:

	(Related Party) North Shore	NGPC	Other	Total Payments
Initial backstop fees	$ 250,000	$ 250,000	$	$ 500,000
Additional fees upon termination	220,000	350,000		570,000
Out-of-pocket expenses	49,187	117,041		166,228
Legal fees			102,252	102,252
Costs associated with potential asset sale			64,054	64,054
Total payments	$ 519,187	$ 717,041	$ 166,306	$ 1,402,534

Note 8 Long-Term Debt

On September 14, 2010, our Fourth Amended and Restated Credit Agreement (the Credit Agreement) with a group of five banks became effective. The Credit Agreement replaced our Third Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base is determined as of each June and December. The June 2011 borrowing base determination was completed on April 15, 2011 and the borrowing base remains at $90 million. Also on April 15, 2011, the Credit Agreement was amended to remove the minimum Fixed Charge Ratio covenant which was described in our Annual Report on Form 10-K. All outstanding borrowings under the Credit Agreement become due and payable on September 14, 2013. The Credit Agreement provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.75% to 3.25%. Adjusted Base Rate is defined to be the greater of (i) the agent s base rate or (ii) the federal funds rate plus one half of one percent or (iii) the LIBOR Rate plus a margin of 1.00%. In all cases the applicable margin is dependent on the percentage of borrowing base usage. Under the Credit Agreement we are subject to certain financial covenants requiring maintenance of (i) a minimum Current Ratio, (ii) a maximum Debt Ratio, and (iii) a minimum Interest Coverage Ratio. The Current Ratio of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities (defined to exclude up to $1.5 million in accrued and unpaid preferred dividends and the effects, including associated deferred taxes, of unrealized derivative gains and losses) is not permitted to be less than 1.0 to 1.0 as of the end of any fiscal quarter. The Debt Ratio (defined as funded debt at the end of each fiscal quarter to trailing four quarter consolidated EBITDA) at the end of each fiscal quarter cannot exceed 4.5 to 1.0 through the quarter ending June 30, 2011 and 4.0 to 1.0 thereafter. The Interest Coverage Ratio (defined as consolidated EBITDA to consolidated net cash interest expense plus letter of credit fees accruing during the preceding four quarters) cannot be less than 2.75 to 1. Consolidated EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization and also excludes non-recurring charges and other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from a change in the market value of open derivative contracts. We are also subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on our preferred stock are permitted if, following any such cash payment our availability is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.0. There are no restrictions associated with dividends paid-in-kind on our preferred stock. At June 30, 2011, we are in compliance with the aforementioned Credit Agreement covenants and expect to continue to be in compliance for at least the next 12 months.

As of June 30, 2011, we had $79.4 million of borrowings outstanding under our Credit Agreement, resulting in a borrowing availability of $10.6 million under our $90.0 million borrowing base, subject to compliance with covenants. For the three months ended June 30, 2011 we borrowed $8.6 million and made payments of $7.7 million under the Credit Agreement. For the three months ended June 30, 2010 we borrowed $4.7 million and made payments of $5.9 million under the revolving credit facility. For the six months ended June 30, 2011 we borrowed $15.8 million and made payments of $16.9 million under the Credit Agreement. For the six months ended June 30, 2010 we borrowed $10.5 million and made payments of $14.0 million under the revolving credit facility. The rates at June 30, 2011 and December 31, 2010, excluding the effect of our interest rate swaps, were 3.25% and 3.30% per annum, respectively.

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For the three months ended June 30, 2011 and 2010, interest on the borrowings averaged 3.39% and 3.89% per annum, respectively. For the six months ended June 30, 2011 and 2010, interest on the borrowings averaged 3.40% and 3.51% per annum, respectively.

The following is a summary of our long-term debt at June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
Borrowings under Credit Agreement	$ 79,400,000	$ 80,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured		48,961
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	85,908	93,321
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	320,348	353,880
Total debt	79,806,256	80,996,162
Less current maturities included in current liabilities	(87,677)	(132,743)
Total long-term debt	$ 79,718,579	$ 80,863,419

The fair value of long-term debt at June 30, 2011 and December 31, 2010 was approximately $72.1 million and $68.4 million, respectively. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt.

Note 9 Common Stock

At June 30, 2011 and December 31, 2010, there were 39,973,810 and 39,758,484 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. Also included in common stock outstanding at June 30, 2011 and December 31, 2010 were 339,038 and 292,512 shares of restricted stock, respectively.

On January 5, 2011, 98,416 shares of restricted stock were granted in exchange for 566,968 options. For the details related to the Option Exchange , see Note 11 Share-Based Awards.

On March 24, 2011 and June 15, 2011, 819 shares and 744 shares of common stock, respectively, were purchased by us from two non-executive employees for the payment of $1,335 and $811, respectively, in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

On April 5, 2011, we issued 113,208 shares of common stock to our independent directors, representing 50% of their 2011 annual retainer.

For the six months ended June 30, 2011 and 2010, no shares and 66,194 shares, respectively, of restricted stock were forfeited. For the six months ended June 30, 2011 and 2010, 5,265 shares and 64,432 shares of common stock, respectively, were issued upon the exercise of incentive stock options.

On March 24, 2010 and June 15, 2010, 300 shares and 386 shares of common stock, respectively, were purchased by us from two non-executive employees for the payment of $289 and $494, respectively, in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

Note 10 Series A Convertible Redeemable Preferred Stock

At June 30, 2011 and December 31, 2010, 4,411,749 and 4,148,538 shares of Preferred Stock were issued and outstanding, respectively. At June 30, 2011, an additional 2,990,083 shares of our Preferred Stock are reserved exclusively for the payment of paid-in-kind dividends (PIK dividends). During the three months ended June 30, 2011, the Company declared and issued PIK dividends of 133,625 shares to the holders of Preferred Stock. Additionally, during the three months ended June 30, 2011, cash dividends of $664 were paid for fractional share dividends not paid-in-kind. During the six months ended June 30, 2011, the Company declared and issued PIK dividends of 263,211 shares to the holders of Preferred Stock. Additionally, during the six months ended June 30, 2011, cash dividends of $1,222 were paid for fractional share dividends not paid-in-kind.

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The following table details the activity related to the Preferred Stock for the six months ended June 30, 2011:

Balance at December 31, 2010	$ 22,074,320
Accretion of Series A Convertible Redeemable Preferred Stock	859,172
PIK Dividends for Series A Convertible Redeemable Preferred Stock	2,632,110
Issuance costs and other	(128,393)
Balance at June 30, 2011	$ 25,437,209

There was no Preferred Stock outstanding during the six months ended June 30, 2010.

Note 11 Share-Based Awards

As of June 30, 2011, our 2006 Long-Term Incentive Plan (the 2006 Plan) is our only authorized stock-based award plan. Our 2005 Stock Option Plan was terminated on March 11, 2011 as no options granted under the plan remained outstanding at that time. Our 2006 Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are available for grant under this plan. The 2006 Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards, granted to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the three months ended June 30, 2011, we recorded a compensation expense accrual of $354,287 which was allocated as an addition of $8,376 to lease operating expenses, an addition of $309,579 to general and administrative expense, and $36,332 was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is $1,143,423 which will be amortized over the vesting period of such stock options and restricted stock. During the six months ended June 30, 2011, we recorded a compensation expense accrual of $517,154 of which $20,163 was allocated to lease operating expenses, $431,692 was allocated to general and administrative expenses, and $65,300 was capitalized to gas properties. The weighted average remaining useful life of the future compensation cost is 1.29 years.

During the three months ended June 30, 2010, we recorded a compensation expense accrual of $111,177 of which $9,688 was allocated to lease operating expenses, $80,473 was allocated to general and administrative expenses, and $21,017 was capitalized to gas properties. During the six months ended June 30, 2010, we recorded a compensation expense accrual of $127,452 of which $22,196 was allocated to lease operating expenses, $58,090 was allocated to general and administrative expenses, and $47,166 was capitalized to gas properties.

For the three and six months ended June 30, 2011, we granted 673,551 stock options with time vesting criteria to certain key employees, including our five executive officers, 232, 089 restricted stock units with performance vesting criteria to our five executive officers and 113,208 shares of common stock to our independent directors, representing 50% of their annual retainer.

The significant assumptions used in determining the compensation costs included an expected volatility of 87.2%, risk-free interest rate of 2.28%, an expected term from 4.38 to 4.83 years, forfeiture rates from 5% to 15%, and no expected dividends.

Option Exchange

On December 7, 2010, we offered our eligible employees the opportunity to exchange certain outstanding stock options for new restricted shares of GeoMet common stock (Restricted Stock), to be granted under the 2006 Plan (Option Exchange). Options eligible for exchange, or eligible options, were those options, whether vested or unvested, that met all of the following requirements:

the options had a per share exercise price greater than $5.00;

the options were granted under one of our existing equity incentive plans;

the options were outstanding and unexercised as of January 5, 2010;

the options were not granted within the twelve-month period immediately preceding the commencement of this offer, December 7, 2010; and

the options did not have a remaining term of less than 12 months immediately following January 5, 2010.

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On January 5, 2011, 98,416 shares of restricted stock were granted to those eligible employees as follows:

Exercise Price Per Share	Number of Eligible Options	Number of New Restricted Shares To Be Granted in Exchange
$5.04	85,122	32,391
$6.98	65,244	993
$7.64	16,000	244
$8.30	247,359	57,287
$10.88	8,265	881
$13.00	144,978	6,620
	566,968	98,416

The Option Exchange was accounted for as a modification of an award in accordance with ASC 718-20-35-3. We recognize the incremental compensation expense of $102,348 over the remaining requisite service period. The incremental compensation expense is the excess of the fair value of the shares of restricted stock granted (using the closing market price) over the fair value of the cancelled options (using the black-scholes model) on January 5, 2011.

Incentive Stock Options

The table below summarizes incentive stock option activity for the six months ended June 30, 2011:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2010	1,391,611	$ 2.85		
Exchanged in Option Exchange	(328,220)	$ 8.41		
Granted	593,079	$ 1.59		
Exercised	(5,265)	$ 0.72		
Forfeited	(39,941)	$ 9.24		
Outstanding at June 30, 2011	1,611,264	$ 1.10	3.6	$ 873,276
Options exercisable at June 30, 2011	278,324	$ 0.72	4.7	$ 256,058

During the three and six months ended June 30, 2011, 3,333 and 5,265 incentive stock options, respectively, were exercised with an intrinsic value of $2,266 and $3,793, respectively.

The table below summarizes incentive stock option activity for the six months ended June 30, 2010:

	Number of Options	Weighted Average Exercise	Average Remaining Contractual	Aggregate Intrinsic Value

		Price	Life	
Outstanding at December 31, 2009	997,786	$ 3.95		
Exercised	(64,432)	$ 0.72		
Forfeited	(117,770)	$ 2.92		
Outstanding at June 30, 2010	815,584	$ 4.35	4.60	$ 185,097
Options exercisable at June 30, 2010	433,240	$ 6.22	3.95	$ 61,699

During the three and six months ended June 30, 2010, no incentive stock options were granted. The total intrinsic values of the 64,432 incentive stock options exercised during the three and six months ended June 30, 2010 was $24,252.

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Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2011:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2010	1,150,548	$ 3.87		
Exchanged in Option Exchange	(238,748)	$ 9.52		
Granted	80,472	$ 1.59		
Outstanding at June 30, 2011	992,272	$ 2.32	2.9	$ 99,520
Options exercisable at June 30, 2011	808,000	$ 2.60	2.3	$

During the three and six months ended June 30, 2011, no non-qualified stock options were exercised.

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2010:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2009	1,400,760	$ 3.61		
Forfeited	(10,212)	$ 0.72		
Outstanding at June 30, 2010	1,390,548	$ 3.63	3.05	$ 43,596
Options exercisable at June 30, 2010	1,114,196	$ 3.05	2.69	$

During the three and six months ended June 30, 2010, no non-qualified stock options were granted or exercised.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2011:

	Number of Shares	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2010	292,512	$ 3.95
Vested	(51,890)	$ 6.80
Granted in Option Exchange	98,416	$ 1.32
Non-vested restricted stock at June 30, 2011	339,038	$ 2.75

During the three and six months ended June 30, 2011, 14,400 and 51,890 shares of restricted stock, respectively, vested with a vesting date fair value of $1.09 and $1.48 per share, respectively.

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2010:

	Number of Shares	Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2009	311,684	$ 6.57
Vested	(83,762)	$ 6.76
Forfeited	(66,194)	$ 6.50
Non-vested restricted stock at June 30, 2010	161,728	$ 6.50

During the three and six months ended June 30, 2010, no shares of restricted stock were granted. During the three and six months ended June 30, 2010, 14,400 and 83,762 shares of restricted stock, respectively, vested with a vesting date fair value of $1.28 and $1.02 per share, respectively.

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Restricted Stock Unit Awards

On April 5, 2011, we granted 232,089 restricted stock units to our five executive officers. These restricted stock units vest upon the completion of certain performance targets, at which time one common share will be distributed for each restricted stock unit held. The restricted stock units are included in the calculation of diluted earnings per share utilizing the treasury stock method.

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2011:

	Number of Shares	Weighted Average Value at Grant Date
Non-vested restricted stock units at December 31, 2010		$
Granted	232,089	$ 1.59
Non-vested restricted stock units at June 30, 2011	232,089	$ 1.59

Note 12 Commitments and Contingencies

From time to time we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

Environmental and Regulatory

As of June 30, 2011, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Note 13 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

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As of June 30, 2011 and December 31, 2010, the Company had available, to reduce future taxable income, a United States federal regular net operating loss (NOL) carryforward of approximately $119.4 million and $113.6 million, respectively. As of June 30, 2011 and December 31, 2010, the Company also had available, to reduce future taxable income, various state NOL carryforwards totaling approximately $128.1 million and 123.0 million, respectively.

ASC 740 requires the Company to recognize income tax benefits for loss carry forwards that have not previously been recorded. The tax benefits recognized must be reduced by a valuation allowance when it is more likely than not that the deferred tax asset will not be realized. The Company has a net deferred tax asset of $45.1 million and $46.0 million, respectively, as of June 30, 2011 and December 31, 2010, which includes recorded valuation allowances of $3.2 million and $3.1 million, respectively. Our valuation allowances primarily relate to our Canadian operations where we do not believe it is more likely than not that we will recover our net deferred tax asset prior to expiration and have recorded a full valuation allowance as we currently have no proved reserves in Canada. In addition, we have recorded a valuation allowance for certain immaterial state net operating losses where the Company has ceased operations.

Our first material NOL carryforward expires in 2022 and the last one expires in 2030. We also consider the lengthy carryforward period in the overall evaluation of our ability to realize our NOLs as it substantially increases the likelihood of utilization.

In determining the carrying value of a deferred tax asset, ASC 740 provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. In order to assess the realization of our net deferred tax asset as of June 30, 2011 and December 31, 2010, the Company considered all available negative and positive evidence. While the Company has incurred a cumulative loss over the three year period ended June 30, 2011, after evaluating all available evidence including historical operating results, historical pricing, current operating income, consideration of the full cost ceiling test impairments in 2009 and 2008 that resulted in the cumulative losses, our reserves level as estimated and appraised by an independent third party engineer, future pricing as indicated on the New York Mercantile Exchange, and the length of the carryforward period available, the Company concluded that it is more likely than not the deferred tax asset, net of the $3.2 million valuation allowance related to our Canadian operations and state NOLs, will be realized. The Company will continue to assess the need for additional valuation allowances in the future. If future results are less than projected using either our historical results or our forecast based on the reserve report and future market pricing, then additional valuation allowances may be required to reduce the deferred tax assets which could have a material impact on the Company s results of operations in the period in which it is recorded.

For the three months ended June 30, 2011 and 2010, our effective tax rate was 45.7% and 36.9%, respectively. Our effective tax rate for the three months ended June 30, 2011 was more than the combined estimated federal and state statutory rate of 38% primarily due to a permanent difference associated with a difference in the grant date and vesting date fair values of restricted stock that vested in the current period, a permanent difference related to current incentive stock option book expense, and the recording of a valuation allowance against the income tax benefit related to our Canadian operations.

For the six months ended June 30, 2011 and 2010, our effective tax rate was 37.3% and 43.8%, respectively. Our effective tax rate for the six months ended June 30, 2011 was less than the combined estimated federal and state statutory rate of 38% primarily due to an income tax benefit associated with the tender offer exchange of restricted stock for incentive stock options, partially offset by a permanent difference associated with a difference in the grant date and vesting date fair values of restricted stock that vested in the current period, a permanent difference related to current incentive stock option book expense, and the recording of a valuation allowance against the income tax benefit related to our Canadian operations.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Statement Regarding Forward-Looking Information

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, and similar express are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Certain of these risks are summarized under Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011, which you should read carefully in connection with our forward looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2010, which are included in our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011.

Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also own additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of June 30, 2011, we own a total of approximately 145,000 net acres of coalbed methane and oil and gas development rights.

Current Business Plan

The natural gas industry is capital intensive. We have historically made substantial capital expenditures in the exploration for, development and acquisition of natural gas reserves. Historically, our capital expenditures have been financed primarily with internally generated cash from operations, proceeds from bank borrowings, and industry joint venture arrangements. The continued availability of these capital sources depends upon a number of variables, including proved reserves, production from existing wells, the sales prices for natural gas, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets. In the current natural gas pricing environment, the Company intends to limit capital spending to its internally generated cash flows from operations. Accordingly, it is unlikely to consider any significant exploration activities until conditions improve and, as such, investments would likely not produce an acceptable return. We currently intend to drill our proved undeveloped locations in the Pond Creek field and on a limited basis in the Gurnee field to continue conducting hydraulic fracturing in new infill wells and in shallow behind pipe coal groups. Our current focus is to complete the developmental drilling program in the Pond Creek field and, in the Gurnee field, improve production and determine the commerciality of future development through improved hydraulic fracturing techniques. The Company will consider strategic acquisition opportunities should they arise. At June 30, 2011 and December 31, 2010, we had $10.6 million and $9.5 million, respectively, in available borrowing capacity. This business plan is consistent with our past actions taken in unfavorable pricing environments. For example, when the price of natural gas declined precipitously at the end of 2008, we stopped substantially all of our development activities, and in 2009 did not drill any new wells.

Operational Developments

Pond Creek Four new wells were added to sales in the three months ended June 30, 2011. We have a total of 266 net producing wells in the Pond Creek field. Net gas sales were 14.8 MMcf per day for the three months ended June 30, 2011. Net sales volumes in Pond Creek were reduced during the quarter by approximately 500 Mcf per day as a result of the temporary loss of pipeline delivery capacity due to a mechanical problem at one of our compressor stations. Delivery capacity was fully restored by the end of the second quarter. For the three months ended June 30, 2010, net gas sales volumes were 14.5 MMcf per day. We have revised the number of wells we plan to drill in the Pond Creek field during 2011 from 20 to 16, which will reduce our budgeted expenditures in the field by $2.0 million. We plan to allocate this $2.0 million to operations in our Gurnee field, as discussed below.

In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the

NYMEX contract for the month of sale plus $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. Additionally, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows: (1) 4,000 MMBtu /day for the period April 2011 through October 2011 was fixed at a total price for physical gas sales, including the aforementioned basis, of $4.915/ MMBtu and (2) 3,000 MMBtu /day for the period November 2011 through March 2012 was fixed at a total price for physical gas sales, including the aforementioned basis, of $5.33/ MMBtu. If we are unable to fulfill our commitment, or a portion thereof, we are obligated to reimburse our counterparty for any price paid to replace the

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quantity of natural gas we failed to deliver which is in excess of the contract price. This obligation is limited to the spot price for natural gas at the delivery point on the day we fail to deliver. The reduction in delivery capacity caused by the aforementioned compressor problem did not impact our ability to meet our obligation under our forward sale described above.

Lasher No new wells were added to sales in the three months ended June 30, 2011. Net gas sales averaged 0.43 MMcf per day from 18 producing wells for the three months ended June 30, 2011, as compared to 0.39 MMcf per day for the three months ended June 30, 2010.

Gurnee Net gas sales were 4.8 MMcf per day from a total of 221 producing wells in the Gurnee field for the three months ended June 30, 2011, as compared to 5.1 MMcf per day for the three months ended June 30, 2010. Gurnee field production has continually performed below our expectations. We believe this underperformance is because fracture conductivity is lost after commencement of initial production and, as a result, our Gurnee wells are draining only a small area around each wellbore. We have tried various techniques in an attempt to resolve this underperformance and have had encouraging results using a new shale-like frac in adjacent strata. Although it is too early to determine if this technique can be economically applied broadly throughout the field, based on results to date we have reallocated approximately $2.0 million of our planned capital expenditures for the current year from the Pond Creek field to the Gurnee Field in order to further test this technique.

Garden City We recently put our two horizontal wells back on production and reinstalled a compressor to sell the produced gas. We plan to complete a longer term production test of these wells while temporarily and economically disposing of produced water. We will concurrently be exploring long term solutions to dispose of produced water.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting policies are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the six months ended June 30, 2011.

Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2011 and 2010. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Gas sales	$ 8,331	$ 7,661	$ 16,182	$ 17,545
Lease operating expenses	$ 2,880	$ 2,813	$ 5,852	$ 5,920
Compression and transportation expenses	965	1,075	1,881	2,080
Production taxes	365	288	688	496
Total production expenses	$ 4,210	$ 4,176	$ 8,421	$ 8,496
Net sales volumes (MMcf)	1,840	1,824	3,679	3,644
Pond Creek field	1,347	1,319	2,709	2,614
Gurnee field	441	466	877	941
Per Mcf data ($/Mcf):				
Average natural gas sales price	$ 4.53	$ 4.20	$ 4.40	$ 4.81
Average natural gas sales price realized(1)	$ 5.36	$ 5.41	$ 5.77	$ 5.82
Lease operating expenses	$ 1.57	$ 1.54	$ 1.59	$ 1.62
Pond Creek field	$ 1.14	$ 1.27	$ 1.19	$ 1.30

Gurnee field	$ 2.72	$ 2.27	$ 2.73	$ 2.21
Compression and transportation expenses	$ 0.52	$ 0.59	$ 0.51	$ 0.57

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	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Pond Creek field	$ 0.55	$ 0.65	$ 0.54	$ 0.62
Gurnee field	$ 0.38	$ 0.38	$ 0.35	$ 0.37
Production taxes	$ 0.20	$ 0.16	$ 0.19	$ 0.14
Pond Creek field	$ 0.20	$ 0.15	$ 0.18	$ 0.16
Gurnee field(2)	$ 0.22	$ 0.20	$ 0.21	$ 0.06
Total production expenses	$ 2.29	$ 2.29	$ 2.29	$ 2.33
Pond Creek field	$ 1.89	$ 2.07	$ 1.91	$ 2.08
Gurnee field	$ 3.32	$ 2.85	$ 3.29	$ 2.64
Depreciation, depletion and amortization	$ 0.88	$ 0.79	$ 0.88	$ 0.85

(1) Average realized price includes the effects of realized gains on derivative contracts.
(2) The Company received a production tax refund related to prior production in the Gurnee field in March 2010.

Results of Operations

Three months ended June 30, 2011 compared with three months ended June 30, 2010

The following are selected items derived from our Consolidated Statement of Operations and their percentage changes from the comparable period are presented below.

	Three months ended June 30, 2011	Three months ended June 30, 2010	Change
	(In thousands)		
Gas sales	$ 8,331	$ 7,661	9%
Lease operating expenses	$ 2,880	$ 2,813	2%
Compression expense	$ 643	$ 757	-15%
Transportation expense	$ 322	$ 318	1%
Production taxes	$ 365	$ 288	27%
Depreciation, depletion and amortization	$ 1,622	$ 1,450	12%
General and administrative	$ 1,503	$ 1,315	14%
Terminated transaction costs	$	$ 1,403	NM
Realized gains on derivative contracts	$ (1,536)	$ (2,211)	-31%
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (197)	$ 2,974	NM
Interest expense, net of amounts capitalized	$ 824	$ 1,423	-42%
Income tax expense (benefit)	$ 902	$ (1,031)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $0.67 million, or 9%, to $8.33 million compared to the prior year quarter. The increase in gas sales was a result of increased gas prices and production volumes. Average gas prices increased 8%, excluding hedging transactions. Production increased 1% from the prior year quarter despite net gas sales volumes for the quarter being reduced by approximately 0.5 MMcf per day as a result of a temporary reduction in pipeline delivery capacity resulting from a mechanical accident at one of our compressor stations in our Pond Creek field.

Lease operating expenses. Lease operating expenses remained flat relative to gas sales compared to the prior year quarter.

Compression expense. Compression expense decreased by $0.11 million, or 15%, to $0.64 million compared to the prior year quarter. The $0.11 million decrease was comprised of a $0.12 million decrease in costs partially offset by a $0.01 million increase in production. The decrease in compression expense was primarily due to the exercise of early buyout options on two leased compressors in November 2010.

Transportation expense. Transportation expense remained relatively unchanged compared to the prior year quarter.

Production taxes. Production taxes increased by $0.08 million, or 27%, to $0.37 million compared to the prior year quarter. The $0.08 million increase in production taxes was primarily due to diminishing tax exemptions in West Virginia.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.17 million, or 12%, to $1.62 million compared to the prior year quarter. Depletion for the three months ended June 30, 2011 and 2010 was $0.83 and $0.72 per Mcf, respectively. The increase in the depletion rate was due to the impact of current year to date capital expenditures.

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General and administrative. General and administrative expenses increased by $0.19 million, or 14%, to $1.50 million compared to the prior year quarter. The increase in general and administrative expenses was primarily due to stock compensation expense related to both employees and directors of the Company, as well as professional fees.

Terminated transaction costs. During the prior year quarter, we incurred $1.34 million of costs related to a proposed financing transaction with certain parties and $0.06 million related to a potential sale of certain assets. Negotiations with those parties ceased and the related costs were expensed as terminated transaction costs. No such expenses were incurred in the current year quarter.

Realized gains on derivative contracts. Realized gains on derivative contracts decreased by $0.67 million, or 31%, to $1.54 million compared to the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized (gains) losses from the change in market value of open derivative contracts. Unrealized gains from the change in market value of open derivative contracts were $0.20 million in the current period as compared to unrealized losses of $2.97 million in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. The gain was a result of the increased estimated fair value of our natural gas derivative contracts resulting from decreased natural gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.60 million, or 42%, to $0.82 million compared to the prior year period. The decrease was primarily due to a lower average outstanding revolver balance in the current year quarter.

Income tax expense (benefit). For the three months ended June 30, 2011 and 2010, our effective tax rate was 45.7% and 36.9%, respectively. Our effective tax rate for the three months ended June 30, 2011 was more than the combined estimated federal and state statutory rate of 38% primarily due to a $25,000 net permanent difference associated with a shortfall related to the vesting of 14,400 shares of restricted stock with a vesting date fair value of $1.09 per share and a weighted average grant date fair value of $7.58 per share, a $28,000 net permanent difference related to current incentive stock option book expense, and the recording of a valuation allowance against the $48,000 net income tax benefit related to our Canadian operations.

Six months ended June 30, 2011 compared with six months ended June 30, 2010

The following are selected items derived from our Consolidated Statement of Operations and their percentage changes from the comparable period are presented below.

	Six months ended June 30,		
	2011	2010	Change
	(In thousands)		
Gas sales	$ 16,182	$ 17,545	-8%
Lease operating expenses	$ 5,852	$ 5,920	-1%
Compression expense	$ 1,251	$ 1,442	-13%
Transportation expense	$ 630	$ 638	-1%
Production taxes	$ 688	$ 496	39%
Depreciation, depletion and amortization	$ 3,255	$ 3,096	5%
General and administrative	$ 2,942	$ 2,793	5%
Terminated transaction costs	$	$ 1,403	NM
Realized gains on derivative contracts	$ (5,033)	$ (3,671)	37%
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 2,653	$ (4,668)	NM
Interest expense, net of amounts capitalized	$ 1,664	$ 2,668	-38%
Income tax expense	$ 907	$ 3,323	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $1.36 million, or 8%, to $16.18 million compared to the prior year period. The decrease in gas sales was a result of decreased gas prices partially offset by increased production. Average gas prices decreased 9%, excluding hedging transactions. Production increased 1% from the prior year period despite net gas sales volumes for the period being reduced by approximately 0.2 MMcf per day as a result of a temporary reduction in pipeline delivery capacity resulting from a mechanical accident at one of our compressor stations in our Pond Creek field.

Lease operating expenses. Lease operating expenses remained flat relative to gas sales compared to the prior year period.

Compression expense. Compression expense decreased by $0.19 million, or 13%, to $1.25 million compared to the prior year period. The $0.19 million decrease was comprised of a $0.20 million decrease in costs partially offset by a $0.01 million increase in production. The $0.20 million decrease in costs was primarily due to the exercise of early buyout options on two leased compressors in November 2010.

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Transportation expense. Transportation expense decreased by 0.01 million, or 1%, to $0.63 million compared to the prior year period. The $0.01 million decrease was primarily due to a refund of over-charged pipeline fees.

Production taxes. Production taxes increased by $0.19 million, or 39%, to $0.69 million compared to the prior year period. The $0.19 million increase in production taxes was primarily due to a refund received in March 2010 for production taxes related to our Gurnee field offset by diminishing tax exemptions in West Virginia.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.16 million, or 5%, to $3.26 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of a $0.03 million increase in production and a $0.13 million increase in the depletion rate. Depletion for the six months ended June 30, 2011 and 2010 was $0.83 and $0.78 per Mcf, respectively. The increase in the depletion rate was due to the impact of current year to date capital expenditures.

Terminated transaction costs. During the prior year period, we incurred $1.34 million of costs related to a proposed financing transaction with certain parties and $0.06 million related to a potential sale of certain assets. Negotiations with those parties ceased and the related costs were expensed as terminated transaction costs. No such expenses were incurred in the current year period.

General and administrative. General and administrative expenses increased by $0.15 million, or 5%, to $2.94 million compared to the prior year period. The increase in general and administrative expenses was primarily due to stock compensation expense related to both employees and directors of the Company, as well as professional fees.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $1.36 million, or 37%, to $5.03 million compared to the prior year period. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts were $2.65 million in the current period as compared to unrealized gains of $4.67 million in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. The loss was a result of the decreased estimated fair value of our natural gas derivative contracts resulting from increased natural gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $1.00 million, or 38%, to $1.66 million compared to the prior year period. The decrease was primarily due to a lower average outstanding revolver balance in the current year period combined with a $0.40 million loss on our interest rate swaps in the prior year period, partially offset by a higher average interest rate on our revolving credit facility in the current year period.

Income tax expense (benefit). For the six months ended June 30, 2011 and 2010, our effective tax rate was 37.3% and 43.8%, respectively. Our effective tax rate for the six months ended June 30, 2011 was less than the combined estimated federal and state statutory rate of 38% primarily due to a $294,000 net income tax benefit associated with the tender offer exchange of restricted stock for incentive stock options, partially offset by a $87,000 net permanent difference associated with a shortfall related to the vesting of 51,890 shares of restricted stock with a weighted average vesting date fair value of $1.48 per share and a weighted average grant date fair value of $6.80 per share, a $42,000 net permanent difference related to current incentive stock option book expense, and the recording of a valuation allowance against the $94,000 net income tax benefit related to our Canadian operations.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the six months ended June 30, 2011 and 2010 were $8.2 million and $8.5 million, respectively. Cash flows from operations of $8.2 million for the six months ended June 30, 2011 were sufficient to fund net cash used in investing activities of $6.6 million, which primarily includes capital expenditures for the development of our gas properties, and cash used in financing activities of $1.3 million, primarily related to credit facility net repayment.

As of June 30, 2011, we had a working capital deficit of approximately $0.4 million as the result of the change in the mark-to-market valuation of our natural gas swaps from December 31, 2010. As of December 31, 2010, we had working capital of approximately $1.5 million. At June 30, 2011, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficit. Additionally, based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our Credit Agreement will provide us with sufficient capital resources to meet our projected operational and capital expenditure needs for the next twelve months.

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We expect our remaining capital expenditure budget for 2011 to be approximately $5.3 million. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, results of operations and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and changes in borrowing capacity under our Credit Agreement.

The development of coalbed methane fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, the transportation alternatives, and the timing and rate of initial and subsequent natural gas production volumes.

Changes in natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Continued or prolonged low natural gas prices may also result in non-compliance with the covenants in our Credit Agreement and could result in a lower determination of our borrowing base. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

On September 14, 2010, our Fourth Amended and Restated Credit Agreement (the Credit Agreement) with a group of five banks became effective. The Credit Agreement replaced our Third Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base is determined as of each June and December. The June 2011 borrowing base determination was completed on April 15, 2011 and the borrowing base remains at $90 million. Also on April 15, 2011, the Credit Agreement was amended to remove the minimum Fixed Charge Ratio covenant which was described in our Annual Report on Form 10-K. All outstanding borrowings under the Credit Agreement become due and payable on September 14, 2013. The Credit Agreement provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.75% to 3.25%. Adjusted Base Rate is defined to be the greater of (i) the agent s base rate or (ii) the federal funds rate plus one half of one percent or (iii) the LIBOR Rate plus a margin of 1.00%. In all cases the applicable margin is dependent on the percentage of borrowing base usage. Under the Credit Agreement we are subject to certain financial covenants requiring maintenance of (i) a minimum Current Ratio, (ii) a maximum Debt Ratio, and (iii) a minimum Interest Coverage Ratio. The Current Ratio of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities (defined to exclude up to $1.5 million in accrued and unpaid preferred dividends and the effects, including associated deferred taxes, of unrealized derivative gains and losses) is not permitted to be less than 1.0 to 1.0 as of the end of any fiscal quarter. The Debt Ratio (defined as funded debt at the end of each fiscal quarter to trailing four quarter consolidated EBITDA) at the end of each fiscal quarter cannot exceed 4.5 to 1.0 through the quarter ending June 30, 2011 and 4.0 to 1.0 thereafter. The Interest Coverage Ratio (defined as consolidated EBITDA to consolidated net cash interest expense plus letter of credit fees accruing during the preceding four quarters) cannot be less than 2.75 to 1. Consolidated EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization and also excludes non-recurring charges and other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from a change in the market value of open derivative contracts. We are also subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on our preferred stock are permitted if, following any such cash payment our availability is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.0. There are no restrictions associated with dividends paid-in-kind on our preferred stock. At June 30, 2011, we are in compliance with the aforementioned Credit Agreement covenants and expect to continue to be in compliance for at least the next 12 months.

As of June 30, 2011, we had $79.4 million of borrowings outstanding under our Credit Agreement, resulting in a borrowing availability of $10.6 million under our $90.0 million borrowing base, subject to compliance with covenants. For the three months ended June 30, 2011 we borrowed $8.6 million and made payments of $7.7 million under the Credit Agreement. For the three months ended June 30, 2010 we borrowed $4.7 million and made payments of $5.9 million under the revolving credit facility. For the six months ended June 30, 2011 we borrowed $15.8 million and made payments of $16.9 million under the Credit Agreement. For the six months ended June 30, 2010 we borrowed $10.5 million and made payments of $14.0 million under the revolving credit facility. The rates at June 30, 2011 and December 31, 2010, excluding the effect of our interest rate swaps, were 3.25% and 3.30% per annum, respectively.

Price Risk Management Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily using derivative instruments in the form of three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

At June 30, 2011, we had no natural gas collar positions.

At June 30, 2011, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
July through October 2011	492,000	$ 6.37	973,840
July through October 2011	492,000	$ 5.37	479,805
July through October 2011	492,000	$ 5.43	511,757
November 2011 through March 2012	608,000	$ 7.12	1,433,590
November 2011 through March 2012	608,000	$ 6.12	824,878
November 2011 through March 2012	912,000	$ 5.08	296,992
April through October 2012	856,000	$ 5.73	818,627
April through October 2012	1,712,000	$ 4.94	287,694
November 2012 through March 2013	604,000	$ 6.42	724,543
November 2012 through March 2013	906,000	$ 5.50	269,802
	7,682,000		$ 6,621,528

Forward Physical Sale Contract

Our production is sold at an all-in price which includes the market price for natural gas plus a basis differential . In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus a basis differential of $0.15, $0.115, and

$0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. As of June 30, 2011, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows:

Period	Volume (MMBtu)	Fixed Market Price	Fixed Basis Differential	All-In Price	Gross Sale
July through October 2011	492,000	$ 4.80	$ 0.115	$ 4.915	$ 2,418,180
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	948,000				$ 4,848,660

The remaining volumes giving effect for the fixed amounts denoted above are as follows:

Period	Volume (MMBtu)	Fixed Basis Differential
July through October 2011	1,476,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	3,452,000	

The aforementioned forward physical sale contract meets the definition of a derivative contract under ASC 815. However, it qualifies for normal purchase and sale exemption and, as such, we have elected not to record it on the Consolidated Balance Sheet (Unaudited) using mark-to-market accounting.

Capital Expenditures and Capital Resources

The following table is a summary of our capital expenditures on an accrual basis by category:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Capital expenditures:				
Leasehold acquisition	$ 185,154	$ 64,568	$ 535,718	$ 193,727
Exploration		3,115	3,000	3,115
Development	5,003,966	2,886,860	7,503,731	4,250,981
Other items (primarily capitalized overhead and interest)	267,222	228,826	540,380	389,662
Total capital expenditures	$ 5,456,342	$ 3,183,369	$ 8,582,829	$ 4,837,485

Our capital budget remains at $13.9 million for the year. However, we have reallocated $2.0 million from the Pond Creek field to the Gurnee field to increase our hydraulic fracturing testing activities in Gurnee. We expect our remaining capital expenditure budget for 2011 of $5.3 million to be funded from our estimated operating cash flows. If the amount and timing of cash flows are reduced, we will reduce our capital budget. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, results of expenditures and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and borrowing base redeterminations under our Credit Agreement.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. There has been no material changes in those commitments disclosed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Commitments of our 2010 Annual Report on Form 10-K that we filed with the SEC on April 6, 2011.

Recent Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, Improving Disclosures about Fair Value Measurements. This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are now applicable to interim and annual reporting periods. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 6 Derivative Instruments and Hedging Activities.

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On June 16, 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in Accounting Standards Codification (ASC) 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Early adoption is permitted. The Company has not elected to early adopt and is still evaluating the effect on its disclosures. The amendments do not require incremental disclosures in addition to those required by ASC 250 or any transition guidance.

On May 12, 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework that is, converged guidance on how (not when) to measure fair value and on what disclosures to provide about fair value measurements. Thus, there are few differences between the ASU and its international counterpart, IFRS 13. While the ASU is largely consistent with existing fair value measurement principles in U.S. GAAP, it expands ASC 820 s existing disclosure requirements for fair value measurements and makes other amendments. Many of these amendments were made to eliminate unnecessary wording differences between U.S. GAAP and IFRS. However, some could change how the fair value measurement guidance in ASC 820 is applied. The ASU is effective for interim and annual periods beginning after December 15, 2011. The Company is still evaluating the effect on its disclosures.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the three and six months ended June 30, 2011, a 10% decrease in the prices received for natural gas production would have decreased our gas revenues by approximately $0.8 million and $1.6 million, respectively, which would have been offset approximately $0.5 million and $1.0 million, respectively, by realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At June 30, 2011, we had $79.4 million outstanding under our Credit Agreement. For the three months ended June 30, 2011 and 2010, interest on the borrowings averaged 3.39% and 3.89% per annum, respectively. For the six months ended June 30, 2011 and 2010, interest on the borrowings averaged 3.40% and 3.51% per annum, respectively. Borrowing availability at June 30, 2011 was $10.6 million. All of the debt outstanding under our Credit Agreement accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the weighted average balance outstanding under our Credit Agreement, a 1% increase in market interest rates would have increased interest expense and negatively impacted our cash flows for the three and six months ended June 30, 2011 by approximately $0.2 million and $0.4 million, respectively.

Foreign Currency Exchange Rate Risk. We have exploratory operations in Canada and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15(e) and 15d-15(e), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2011 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us cannot be predicted with certainty, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

Environmental and Regulatory

As of June 30, 2011, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 1A. Risk Factors

There has been no changes from the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Reserved

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	GeoMet, Inc.
Date: August 9, 2011	By /S/ William C. Rankin
	William C. Rankin, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS

Exhibit Number	Exhibits
31.1*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32*	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
101**	Interactive Data Files.

* Attached hereto

** Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability.