GeoMet, Inc.
Form 10-Q
May 15, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2012

OR

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

For the transition period from to

Commission File Number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of	(I.R.S. Employer
incorporation or organization)	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 o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 o 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 o	Accelerated filer o
Non-accelerated filer o	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). o Yes x No

As of May 1, 2012, 40,071,320 shares and 4,838,181 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. **Financial Statements**

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	March 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 791,175	$ 457,865
Accounts receivable, net of allowance of $17,634 at March 31, 2012 and December 31, 2011	4,352,049	4,402,065
Inventory	596,750	597,197
Derivative asset natural gas contracts	24,037,749	20,685,187
Other current assets	1,077,438	1,141,310
Total current assets	30,855,161	27,283,624
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	562,271,607	561,451,504
Other property and equipment	3,706,034	3,671,123
Total property and equipment	565,977,641	565,122,627
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(408,726,740)	(388,730,093)
Property and equipment net	157,250,901	176,392,534
Other noncurrent assets:		
Derivative asset natural gas contracts	1,092,869	1,765,450
Deferred income taxes	6,665,414	48,171,298
Other	3,350,435	3,532,882
Total other noncurrent assets	11,108,718	53,469,630
TOTAL ASSETS	$ 199,214,780	$ 257,145,788
LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY		
Current Liabilities:		
Accounts payable	$ 7,942,589	$ 7,500,768
Accrued liabilities	3,817,686	3,936,070
Deferred income taxes	6,665,414	4,153,099
Asset retirement liability	31,127	32,028
Current portion of long-term debt	93,860	91,757
Total current liabilities	18,550,676	15,713,722

Long-term debt		149,747,394		158,171,662
Asset retirement liability		8,347,851		8,138,551
Other long-term accrued liabilities				8,145
TOTAL LIABILITIES		176,645,921		182,032,080
Commitments and contingencies (Note 12)				
Mezzanine equity:				
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $46,916,320; $.001 par value; 7,401,832 shares authorized, 4,691,632 and 4,549,537 shares were issued and outstanding at March 31, 2012 and December 31, 2011, respectively.		30,466,675		28,482,624
Stockholders (Deficit) 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 40,071,320 and 40,010,188 at March 31, 2012 and December 31, 2011, respectively		40,071		40,010
Treasury stock 10,432 shares at March 31, 2012 and December 31, 2011		(94,424)		(94,424)
Paid-in capital		198,771,087		200,344,209
Accumulated other comprehensive loss		(1,317,376)		(1,309,926)
Retained deficit		(205,052,333)		(152,104,329)
Less notes receivable		(244,841)		(244,456)
Total stockholders (deficit) equity		(7,897,816)		46,631,084
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY	$	119,214,780	$	257,145,788

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

	Three Months Ended March 31, 2012		2011	
Revenues:				
Gas sales	$	10,143,174	$	7,851,048
Operating fees and other		75,765		72,772
Total revenues		10,218,939		7,923,820
Expenses:				
Lease operating expense		4,460,759		2,972,755
Compression and transportation expense		2,241,116		916,231
Production taxes		469,649		322,388
Depreciation, depletion and amortization		3,629,341		1,632,968
Impairment of gas properties		15,779,441		
General and administrative		1,302,749		1,439,190
Realized gains on derivative contracts		(4,792,869)		(3,497,062)
Unrealized (gains) losses from the change in market value of open derivative contracts		(5,224,211)		2,850,168
Total operating expenses		17,865,975		6,636,638
Operating (loss) income		(7,647,036)		1,287,182
Other income (expense):				
Interest income		3,702		4,474
Interest expense		(1,275,868)		(840,069)
Other income (expense)		(4,352)		4,682
Total other income (expense):		(1,276,518)		(830,913)
(Loss) income before income taxes		(8,923,554)		456,269
Income tax expense		(44,024,450)		(5,190)
Net (loss) income	$	52,948,004	$	451,079
Accretion of Series A Convertible Redeemable Preferred Stock		(462,016)		(423,143)
Dividends paid on Series A Convertible Redeemable Preferred Stock		(1,241,365)		(1,296,418)
Net loss available to common stockholders	$	54,651,385	$	(1,268,482)
Loss per common share:				
Net loss available to common stockholders				
Basic	$	(1.37)	$	(0.03)
Diluted	$	(1.37)	$	(0.03)
Weighted average number of common shares:				
Basic		39,748,005		39,470,284

Diluted	39,748,005	39,470,284

See accompanying Notes to Consolidated Financial Statements (Unaudited).

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive (Loss) Income

(Unaudited)

	Three Months Ended March 31, 2012		2011	
Net (loss) income	$	(52,948,004)	$	451,079
(Loss) gain on foreign currency translation adjustment		(7,451)		447
Gain on interest rate swap, net of tax				10,862
Other comprehensive (loss) income	$	(52,955,455)	$	462,388

See accompanying Notes to Consolidated Financial Statements (Unaudited)

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended March 31, 2012	2011
Cash flows provided by operating activities:		
Net (loss) income	$ (52,948,004)	$ 451,079
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	3,629,341	1,632,968
Impairment of gas properties	15,779,441	
Amortization of debt issuance costs	161,606	142,218
Deferred income tax expense (benefit)	44,018,200	(1,060)
Unrealized (gains) losses from the change in market value of open derivative contracts	(5,224,211)	2,863,152
Stock-based compensation	114,756	133,899
Loss on sale of other assets	5,200	
Accretion expense	196,210	135,170
Changes in operating assets and liabilities:		
Accounts receivable	50,145	268,540
Other current assets	56,512	111,157
Accounts payable	543,641	(1,327,362)
Other accrued liabilities	142,019	(508,023)
Net cash provided by operating activities	6,524,856	3,901,738
Cash flows provided by (used in) investing activities:		
Capital expenditures	(292,316)	(1,760,475)
Return of original basis through the settlement of natural gas derivative contracts	2,544,230	
Proceeds from sale of other assets	3,500	
Other assets	10,049	9,306
Net cash provided by (used in) investing activities	2,265,463	(1,751,169)
Cash flows used in financing activities:		
Proceeds from borrowings under our Credit Agreement	7,400,000	7,200,000
Payments on borrowings under our Credit Agreement	(15,800,000)	(9,200,000)
Proceeds from exercise of stock options		1,389
Deferred financing costs	(32,843)	2,885
Payments on other debt	(22,166)	(69,203)
Dividends paid	(645)	(558)
Treasury stock	(1,862)	
Net cash used in financing activities	(8,457,516)	(2,065,487)
Effect of exchange rate changes on cash	507	3,807
Increase in cash and cash equivalents	333,310	88,889
Cash and cash equivalents at beginning of period	457,865	536,533

Cash and cash equivalents at end of period	$	791,175	$	625,422
Supplemental disclosure of cash flow information:				
Cash paid during the period for:				
Interest expense	$	1,369,617	$	866,096
Income taxes	$	6,250	$	6,250
Significant noncash investing and financing activities:				
Accrued capital expenditures	$	840,226	$	2,306,636

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, 2011 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 March 30, 2012.

Note 2 Liquidity and Going Concern Considerations

As of May 11, 2012, we had $148.6 million outstanding under our Fifth Amended and Restated Credit Agreement (the Credit Agreement). As of March 31, 2012, we were in compliance with all of the covenants in our Credit Agreement. The Credit Agreement provides, however, that if the amount outstanding at any time exceeds the borrowing base , we must provide additional collateral to the lenders or repay the excess as provided in the Credit Agreement. The borrowing base is set in the sole discretion of our lenders in June and December of each year based, in part, on the value of our estimated reserves as determined by the lenders using natural gas prices forecasted by the lenders.

Due to the decline in the bank group s price projections, we expect our outstanding loan balance at the June determination date will exceed the new borrowing base, resulting in a borrowing base deficiency. We do not have additional collateral to provide to the lenders and we expect that our operating cash flows would be insufficient to repay the expected borrowing base deficiency, as required under the Credit Agreement. As such, unless we amend the Credit Agreement, we may be in default under the agreement when the borrowing base is determined in June 2012. In addition, the elimination of the unused availability under the borrowing base, which is a factor in our working capital covenant, may result in a future default of that covenant under the Credit Agreement. We have begun discussions with our bank group; however, until the borrowing base for June 2012 has been determined, we will not know the amount of the deficiency. As of March 31, 2012, the debt is classified as long-term as we are not in violation of any debt covenants. Should we be in violation of any covenants which have not been waived or have a borrowing base deficiency as of June 30, 2012, some or all of the debt will be reclassified to current. There are no assurances that we will be able to amend our Credit Agreement or obtain a waiver. If we do obtain a waiver or an amendment, there can be no assurance as to the cost or terms of such an amendment.

These conditions raise substantial doubt about our ability to continue as a going concern for the next twelve months. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. Accordingly, the consolidated financial statements do not include any adjustments relating to the recoverability of assets and classification of liabilities that might be necessary should the Company be unable to continue as a going concern.

The liquidity issues discussed above were also considered in assessing the recoverability of our deferred tax asset. See Note 13 Income Taxes for further discussion.

Note 3 Recent Pronouncements

On June 16, 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. The Company has adopted and applied the provisions of this update for the three months ended March 31, 2012.

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 has adopted and applied the provisions of this update for the three months ended March 31, 2012. See disclosure provided in Note 8 Long-Term Debt and Note 10 Series A Convertible Redeemable Preferred Stock.

Note 4 Loss Per Common Share

Net loss per common share basic is calculated by dividing Net loss available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Net loss per common share diluted assumes the conversion of all potentially dilutive securities and is calculated by dividing net loss available to common stockholders by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Net loss 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 Loss per common share is as follows:

		2012		2011
Net (loss) income	$	(52,948,004)	$	451,079
Accretion of Series A Convertible Redeemable Preferred Stock		(462,016)		(423,143)
Dividends paid on Series A Convertible Redeemable Preferred Stock		(1,241,365)		(1,296,418)
Net loss available to common stockholders	$	(54,651,385)	$	(1,268,482)

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		2012		2011
Loss per common share:				
Net loss available to common stockholders				
Basic	$	(1.37)	$	(0.03)
Diluted	$	(1.37)	$	(0.03)
Weighted average number of common shares:				
Basic		39,748,005		39,470,284
Add potentially dilutive securities:				
Stock options and non-vested restricted stock				
Diluted		39,748,005		39,470,284

Loss per common share diluted for the three months ended March 31, 2012 excluded the effect of outstanding exercisable options to purchase 1,384,398 shares, 262,896 weighted average restricted shares outstanding, and 4,549,537 shares of Series A Convertible Redeemable Preferred Stock (34,996,440 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 and restricted shares to be anti-dilutive. Additionally, in computing the dilutive effect of convertible securities, Net loss 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 available to common stockholders for the three months ended March 31, 2012 for Accretion of and dividends paid for Series A Convertible Redeemable Preferred Stock of $462,016 and $1,241,365, respectively, in computing Loss per common share diluted as the preferred shares were anti-dilutive.

Loss per common share diluted for the three months ended March 31, 2011 excluded the effect of outstanding exercisable options to purchase 1,125,318 shares, 383,222 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 and restricted shares to be anti-dilutive. There was no add back to Net loss available to common stockholders for the three months ended March 31, 2011 for Accretion of and dividends paid for Series A Convertible Redeemable Preferred Stock of $423,143 and $1,296,418, respectively, in computing Loss per common share diluted as the preferred shares were anti-dilutive.

Note 5 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 March 31, 2012.

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 March 31, 2012 and 2011 was $0.97 and $0.83 per Mcf, respectively.

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 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 (deficit) 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 twelve-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

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ASC 410-20-25, 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.

For the twelve months ended March 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.75 per Mcf, resulting in a natural gas price of $3.90 per Mcf when adjusted for regional price differentials. Based on the ceiling test performed utilizing the aforementioned prices, we recorded a $15.8 million write-down of the carrying value of our U.S. full cost pool at March 31, 2012.

Note 6 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 three months ended March 31, 2012:

Current portion of liability at January 1, 2012	$	32,028
Add: Long-term asset retirement liability at January 1, 2012		8,138,551
Asset retirement liability at January 1, 2012		8,170,579
Liabilities incurred		14,252
Settlements		(9,655)
Accretion		196,210
Foreign currency translation		7,592
Asset retirement liability at March 31, 2012		8,378,978
Less: Current portion of liability		(31,127)
Long-term asset retirement liability	$	8,347,851

The following table details the changes to our asset retirement liability for the three months ended March 31, 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		8,773
Accretion		135,170

Foreign currency translation		9,269
Asset retirement liability at March 31, 2011		5,651,903
Less: Current portion of liability		(33,832)
Long-term asset retirement liability	$	5,618,071

Note 7 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 our natural gas derivative contracts during any period to no more than 50% to 80% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future

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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 March 31, 2012, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
April through December 2012	414,000	$	5.11	$	1,078,163
April through December 2012	171,000	$	5.12		447,032
April through December 2012	795,275	$	6.85		3,454,561
April through December 2012	382,691	$	6.99		1,719,285
April through December 2012	623,158	$	7.05		2,845,530
April through October 2012	856,000	$	5.73		2,881,780
April through October 2012	1,712,000	$	4.94		4,405,671
April through October 2012	3,210,000	$	2.89		1,711,377
November 2012 through March 2013	604,000	$	6.42		1,928,929
November 2012 through March 2013	906,000	$	5.50		2,070,308
November 2012 through March 2013	4,128,000	$	3.81		1,265,468
November 2012 through March 2013	4,128,000	$	3.82		1,306,244
	17,930,124			$	25,114,348

At December 31, 2011, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
January through March 2012	364,000	$	7.12	$	1,487,299
January through March 2012	364,000	$	6.12		1,121,787
January through March 2012	546,000	$	5.08		1,118,044
January through December 2012	552,000	$	5.11		1,028,519
January through December 2012	228,000	$	5.12		427,089
January through December 2012	1,070,715	$	6.85		3,851,739
January through December 2012	528,995	$	6.99		1,977,837
January through December 2012	859,269	$	7.05		3,239,221
April through October 2012	856,000	$	5.73		2,137,811
April through October 2012	1,712,000	$	4.94		2,923,067
November 2012 through March 2013	604,000	$	6.42		1,575,321
November 2012 through March 2013	906,000	$	5.50		1,544,680
	8,590,979			$	22,432,414

At March 31, 2012, we had the following natural gas basis swap position:

Period	Volume (MMBtu)		Fixed Basis		Fair Value
April through December 2012	414,000	$	0.04	$	16,270

At December 31, 2011, we had the following natural gas basis swap position:

Period	Volume (MMBtu)		Fixed Basis		Fair Value
April through December 2012	552,000	$	0.04	$	18,223

Subsequent to March 31, 2012, we added the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price
January through December 2013	2,190,000	$	3.60
April through December 2013	2,750,000	$	3.25

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Subsequent to March 31, 2012, we added the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor
January 2014 through December 2015	3,650,000	$	4.20	$	3.50
January 2014 through December 2015	3,650,000	$	4.30	$	3.60

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 New York Mercantile Exchange ("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. There were no remaining volumes at March 31, 2012. As of December 31, 2011, we had 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
January through March 2012	273,000	$	5.20	$	0.130	$	5.330	$	1,419,600

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

Period	Volume (MMBtu)		Fixed Basis Differential
January through March 2012	1,183,000	$	0.130

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.

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 Existing Credit Agreement and the collateral for the outstanding borrowings under our Existing 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 Existing 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 derivative contracts using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. 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 in our long-term debt.

In order to estimate the fair value of our natural gas derivative contracts, 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.

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 months ended March 31, 2012. 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 was as follows:

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	Asset Derivatives				Liability Derivatives			
	March 31, 2012		December 31, 2011		March 31, 2012		December 31, 2011	
	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)	$
Natural gas hedge positions	Derivative asset (current)	24,037,749	Derivative asset (current)	20,685,187	Derivative liability (current)		Derivative liability (current)	
Natural gas hedge positions	Derivative asset (non- current)	1,092,869	Derivative asset (non- current)	1,765,450	Derivative liability (non- current)		Derivative liability (non- current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 25,130,618		$ 22,450,637		$		$

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

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

Other Comprehensive (Loss) Income for the Three Months Ended March 31, 2011 and 2010

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative 2012	2011
Derivatives designated as hedging instruments under ASC 815-20-25			
Interest rate swaps	Interest expense	$	$ 17,782
Total loss		$	$ 17,782
Derivatives not designated as hedging instruments under ASC 815-20-25			
Natural gas swap positions	Realized gains on derivative contracts	$ (4,792,869)	$ (3,497,062)
Natural gas swap positions	Unrealized (gains) losses from the change in market value of open derivative contracts	(5,224,211)	2,850,168

Total gain	$	(10,017,080)	$	(646,894)

Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) 2012		2011	
Interest rate contracts	Interest expense	$		$	(17,782)
Total		$		$	(17,782)

Accumulated comprehensive loss of $1,317,376 as of March 31, 2012 consists entirely of foreign currency translation adjustment. Accumulated comprehensive loss of $1,309,926 as of December 31, 2011 consists entirely of foreign currency translation adjustment.

Note 8 Long-Term Debt

On November 18, 2011, our Fifth Amended and Restated Credit Agreement (the Credit Agreement) with a group of six banks became effective. The Credit Agreement replaced our Fourth Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $250 million with an initial borrowing base of $180 million. The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by June 2012. All outstanding borrowings under the

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Credit Agreement become due and payable on November 18, 2015. In the event that the outstanding borrowings at any borrowing base determination date exceed the borrowing base (a borrowing base deficiency) the Company has three options in order to remain in compliance with the Credit Agreement, (i) to immediately reduce the outstanding borrowing by the amount of the borrowing base deficiency, (ii) provide additional collateral equal to the amount of the borrowing base deficiency, or (iii) make six equal monthly payments in an aggregate amount equal to the borrowing base deficiency. 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 1.25% to 1.75% or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 2.25% to 2.75%. 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) depending on our Debt Ratio, either (a) a minimum Interest Coverage Ratio or (b) a minimum Fixed Charge 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) 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 4.25 to 1.0 through the quarter ending December 31, 2012 and 4.0 to 1.0 thereafter. If our Debt Ratio at the end of each fiscal quarter is above 3.5 to 1.0, then the Fixed Charge Ratio (defined as consolidated EBITDA less capital expenditures to consolidated net cash interest expense for the four preceding quarters) is applicable and cannot be less than 1.25 to 1.0. If our Debt Ratio at the end of each fiscal quarter is 3.5 to 1.0 or less, 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) is applicable and cannot be less than 2.75. 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 and non-cash gains, losses or adjustments and charges on any oil and gas hedge transaction, including those resulting from the requirements of ASC Topic 815, as a result of changes in the fair market value of oil and gas hedge transactions. 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 above the $2 million discretionary amount allowable under the Credit Agreement 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 the payment of PIK dividends on our preferred stock. At March 31, 2012, we are in compliance with the aforementioned Credit Agreement covenants. We are currently in the process of completing the June borrowing base determination which is discussed in Note 2 Liquidity and Going Concern Considerations.

As of March 31, 2012 and December 31, 2011, we had $149.5 million and $157.9 million, respectively, of borrowings outstanding under our Credit Agreement, resulting in a borrowing availability of $30.5 million and $22.1 million, respectively, under our $180 million borrowing base, subject to compliance with covenants. For the three months ended March 31, 2012 we borrowed $7.4 million and made payments of $15.8 million under the Credit Agreement. For the three months ended March 31, 2011 we borrowed $7.2 million and made payments of $9.2 million under the Credit Agreement. The rates at March 31, 2012 and December 31, 2011 were 2.79% and 2.84% per annum, respectively. For the three months ended March 31, 2012 and 2011, interest on the borrowings averaged 2.90% and 3.41% per annum, respectively.

The following is a summary of our long-term debt at March 31, 2012 and December 31, 2011:

	March 31, 2012	**December 31, 2011**
Borrowings under Credit Agreement	$ 149,500,000	$ 157,900,000
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	73,876	78,012
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	267,378	285,407
Total debt	149,841,254	158,263,419

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		March 31, 2012		December 31, 2011
Less current maturities included in current liabilities		(93,860)		(91,757)
Total long-term debt	$	149,747,394	$	158,171,662

We record our debt instruments based on contractual terms. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities. On January 1, 2012, we adopted ASU 2011-04 Fair Value Measurement which requires the categorization by level of the fair value hierarchy for items not measured at fair value on our Consolidated Balance Sheets but for which fair value is required to be disclosed. We measure the fair value of our debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 or 2 within the fair value hierarchy. 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 equity capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included in our long-term debt. The fair value of long-term debt at March 31, 2012 and December 31, 2011 was estimated to be approximately $131.4 million and $131.1 million, respectively.

Note 9 Common Stock

At March 31, 2012 and December 31, 2011, there were 40,071,320 and 40,010,188 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 March 31, 2012 and December 31, 2011 were 260,562 and 293,166 shares of restricted stock, respectively.

On January 5, 2012, 1,981 shares of common stock were purchased by us from three employees for the payment of $1,862 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 March 24, 2011, 819 shares of common stock were purchased by us from two employees for the payment of $1,335 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 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.

Note 10 Series A Convertible Redeemable Preferred Stock

At March 31, 2012 and December 31, 2011, 4,691,632 and 4,549,537 shares of preferred stock were issued and outstanding, respectively. At March 31, 2012, an additional 2,710,200 shares of our preferred stock are reserved exclusively for the payment of paid-in-kind dividends (PIK dividends). During the three months ended March 31, 2012, the Company issued PIK dividends of 142,095 shares to the holders of preferred stock. Additionally, during the three months ended March 31, 2012, cash dividends of $645 were paid for fractional share dividends not paid-in-kind. During the three months ended March 31, 2011, the Company issued PIK dividends of 129,586 shares to the holders of Preferred Stock. Additionally, during the three months ended March 31, 2011, cash dividends of $558 were paid for fractional share dividends not paid-in-kind.

The following table details the activity related to the preferred stock for the three months ended March 31, 2012:

Balance at December 31, 2011	$	28,482,624
Accretion of Series A Convertible Redeemable Preferred Stock		462,016
PIK Dividends for Series A Convertible Redeemable Preferred Stock		1,522,035
Balance At March 31, 2012	$	30,466,675

The following table details the activity related to the Preferred Stock for the three months ended March 31, 2011:

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Balance at December 31, 2010	$	22,074,320
Accretion of Series A Convertible Redeemable Preferred Stock		423,143
PIK Dividends for Series A Convertible Redeemable Preferred Stock		1,295,860
Other		3,667
Balance at March 31, 2011	$	23,796,990

The PIK dividends of 142,095 shares issued during the three months ended March 31, 2012 to the holders of preferred stock were recorded at a fair value of $1,522,035. We measure the fair value of PIK dividends using a discounted cash flow analysis based on our current borrowing rates (categorized as level 3).

Note 11 Share-Based Awards

As of March 31, 2012, 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 authorizes 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 which are granted solely 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 March 31, 2012, we recorded a compensation expense accrual of $131,799 which was allocated as an addition of $9,861 to lease operating expenses, an addition of $104,896 to general and administrative expense, and $17,042 was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is $705,182 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.04 years.

During the three months ended March 31, 2011, we recorded a compensation expense accrual of $162,867 which was allocated as an addition of $11,787 to lease operating expenses, an addition of $122,112 to general and administrative expense, and $28,968 was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is $545,797 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.16 years.

For the three months ended March 31, 2012, no share-based awards were granted to our executive officers and 64,284 shares of common stock were issued under the 2006 Plan to our independent directors, representing 12.5% of their annual retainer. For the three months ended March 31, 2011, no share-based awards were granted to our five executive officers and no shares of common stock were issued to our independent directors.

For the share based awards granted in the three months ended March 31, 2011, 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 to be granted under the 2006 Plan (Option Exchange). Options eligible for exchange, or eligible options, included 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.

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

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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 three months ended March 31, 2012:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2011	1,574,886	$	1.11			
Forfeited	(20,412)	$	1.24			
Outstanding at March 31, 2012	1,554,474	$	1.10	5.2	$	
Options exercisable at March 31, 2012	576,398	$	0.77	4.5	$	

The table below summarizes incentive stock option activity for the three months ended March 31, 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			
Exercised	(1,932)	$	0.72			
Forfeited	(39,941)	$	9.24			
Outstanding at March 31, 2011	1,021,518	$	0.81	5.9	$	846,688
Options exercisable at March 31, 2011	280,546	$	0.72	5.0	$	258,102

The total intrinsic value of incentive stock options exercised during the three months ended March 31, 2011 was $1,526.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended March 31, 2012:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2011	992,272	$	2.32			
Outstanding at March 31, 2012	992,272	$	2.32	2.1	$	
Options exercisable at March 31, 2012	808,000	$	2.60	1.5	$	

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The table below summarizes non-qualified stock option activity for the three months ended March 31, 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			
Outstanding at March 31, 2011	911,800	$	2.39	2.8	$	95,496
Options exercisable at March 31, 2011	808,000	$	2.60	2.5	$	

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2012:

	Number of Shares		Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2011	293,166	$	3.03
Vested	(31,433)	$	1.32
Forfeited	(1,171)	$	4.16
Non-vested restricted stock at March 31, 2012	260,562	$	3.23

During the three months ended March 31, 2012, 31,433 shares of restricted stock vested with a vesting date fair value of $0.94 per share.

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2011:

	Number of Shares		Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2010	292,512	$	3.95
Vested	(37,490)	$	6.41
Granted in Option Exchange	98,416	$	1.32
Non-vested restricted stock at March 31, 2011	353,438	$	2.96

During the three months ended March 31, 2011, 37,490 shares of restricted stock vested with a vesting date fair value of $1.63 per share.

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 Company s achievement of certain performance targets, but no earlier than ratably over the three year period following the grant date, at which time one common share will be issued and exchanged 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. There have been no grants, vestings nor forfeitures of restricted stock units subsequent to the aforementioned grant.

Note 12 Commitments and Contingencies

From time to time we are a party to litigation in the normal course of business. Management does not believe that the outcome of lawsuits or other proceedings against us will have an adverse effect on our financial condition, results of operations or cash flows.

Lease Revenue Audit The lessor from one of our leases recently completed a five year revenue audit where the examiner claims to have identified an exception related to compressor fuel deductions. We have accrued a $356,147 liability in the Consolidated Balance Sheet (Unaudited) as of March 31, 2011 related to this matter.

Environmental and Regulatory

As of March 31, 2012, 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.

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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.

For tax reporting purposes, we have federal and state net operating losses (NOL s) of approximately $127.6 million and $133.7 million, respectively, at March 31, 2012 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $126.0 million and $132.3 million, respectively, at December 31, 2011 that were available to reduce future taxable income. Our first material NOL carryforward expires in 2022 and the last one expires in 2031.

In determining the carrying value of a deferred tax asset, ASC 740 provides for the weighing of all available 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 March 31, 2012 and December 31, 2011, the Company considered all available negative and positive evidence. The Company had incurred a cumulative pre-tax loss of $117.6 million, including ceiling impairment charges of $141.3 million, over the three year period ended March 31, 2012. The Company evaluated all available evidence including historical operating results, historical pricing, natural gas reserves as estimated and appraised by an independent third party engineer, the forward natural gas price curve, and the length of the carryforward period available.

The liquidity issues discussed in Note 2 Liquidity and Going Concern Considerations which cause uncertainty about our ability to forecast, combined with recent cumulative net losses and the forward natural gas price curve, represented sufficient negative evidence to outweigh the positive evidence to overcome under the evaluation guidance of ASC 740. As a result, we established a full valuation allowance for our net deferred tax assets at March 31, 2012 of $47.3 million. These tax benefits will be available, prior to the expiration of carryforwards, to reduce future income tax expense resulting from earnings or increases in deferred tax liabilities.

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, may, will, p forecast, plan, and similar expressions 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 2011 Annual Report on Form 10-K that we filed with the SEC on March 30, 2012, 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, 2011, which are included in our 2011 Annual Report on Form 10-K that we filed with the SEC on March 30, 2012.

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, developer and producer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba and Black Warrior Basins in Alabama and the central Appalachian Basin in Virginia and West Virginia. We also own additional coalbed methane and oil and

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gas development rights, principally in Alabama, Virginia, West Virginia, and British Columbia. As of March 31, 2012, we own a total of approximately 192,000 net acres of coalbed methane and oil and gas development rights.

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. Our capital expenditures have been financed primarily with internally generated cash from operations and proceeds from bank borrowings. 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, the existence of hedging opportunities, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets.

Natural gas prices continue to adversely affect the natural gas industry and GeoMet by reducing our cash flows, capital expenditures and debt capacity.

Current Business Plan

During 2011 and the first quarter of 2012, prices received for natural gas in the United States declined significantly which we believe is due to over-supply, primarily from shale drilling, and reduced demand due to milder weather. In addition, the current 2012 NYMEX strip price for natural gas is at a decade low. The forward natural gas price curve has declined significantly over the last six months. The forward natural gas price curve as of May 11, 2012 shows an average gas price of $3.08 for the next twelve months. Consistent with actions we have taken in past low price environments, we currently intend to defer or limit additional drilling activity until gas prices rise from their current level. Our focus will be the reduction of costs and the optimization of production volumes to maintain maximum cash flow and liquidity. In response to low natural gas prices we plan to take the following steps during 2012:

- limit capital spending to maintenance levels,
- reduce operating and administrative costs with particular attention to the properties acquired in November of 2011,
- reduce bank debt,
- monitor the natural gas futures markets and enter into hedging transactions opportunistically, and
- seek transactional opportunities to expand our natural gas reserves in order to increase economies of scale.

Budgeted capital expenditures for 2012 are less than $2 million; however, we may increase our capital budget later in the year if prices for natural gas improve. Cost reduction initiatives implemented or currently planned are expected to total between $2.5 million to $3 million on an annual basis. We have hedged approximately 82% of our estimated natural gas sales volumes for the last nine months of 2012 at an average hedged price of $4.66 per Mcf. We have hedged approximately 80% of our estimated natural gas sales volumes for 2013 at an average hedged price of $3.80 per Mcf. We are pursuing smaller acquisitions and divestitures which enhance operational efficiencies in our existing properties without materially impairing our liquidity. We may also consider more strategic transactions that would provide more critical mass and spread fixed costs over a larger base. Please read Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations for additional information about the negative effects of low natural gas prices on our results of operations and liquidity.

Liquidity and Going Concern Considerations

As of May 11, 2012, we had $148.6 million outstanding under our Fifth Amended and Restated Credit Agreement (the Credit Agreement). As of March 31, 2012, we were in compliance with all of the covenants in our Credit Agreement. The Credit Agreement provides, however, that if the amount outstanding at any time exceeds the borrowing base , we must provide additional collateral to the lenders or repay the excess as provided in the Credit Agreement. The borrowing base is set in the sole discretion of our lenders in June and December of each year based, in part, on the value of our estimated reserves as determined by the lenders using natural gas prices forecasted by the lenders.

Due to the decline in the bank group s price projections, we expect our outstanding loan balance at the June determination date will exceed the new borrowing base, resulting in a borrowing base deficiency. We do not have additional collateral to provide to the lenders and we expect that our operating cash flows would be insufficient to repay the expected borrowing base deficiency, as required under the Credit Agreement. As such, unless we amend the Credit Agreement, we may be in default under the agreement when the borrowing base is determined in June 2012. In addition, the elimination of the unused availability under the borrowing base, which is a factor in our working capital covenant, may result in a future default of that covenant under the Credit Agreement. We have begun discussions with our bank group; however, until the borrowing base for June 2012 has been determined, we will not know the amount of the deficiency. As of March 31, 2012, the debt is classified as long-term as we are not in violation of any debt covenants. Should we be in violation of any covenants which have not been waived or have a borrowing base deficiency as of June 30, 2012, some or all of the debt will be reclassified to current. There are no assurances that we will be able to amend our Credit Agreement or obtain a waiver. If we do obtain a waiver or an amendment, there can be no assurance as to the cost or terms of such an amendment.

These conditions raise substantial doubt about our ability to continue as a going concern for the next twelve months. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. Accordingly, the consolidated financial statements do not include any adjustments relating to the recoverability of assets and classification of liabilities that might be necessary should the Company be unable to continue as a going concern.

The liquidity issues discussed above were also considered in assessing the recoverability of our deferred tax asset. See Other Developments Deferred Tax Asset below for further discussion.

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NASDAQ Capital Market

On May 10, 2012, we received approval from NASDAQ to transfer the listing of our common stock and preferred stock from The NASDAQ Global Market to The NASDAQ Capital Market. Our common stock and preferred stock began trading on The NASDAQ Capital Market at the opening of the market on May 14, 2012. Our common stock and preferred stock continues to trade under the symbols GMET and GMETP . We have been advised by NASDAQ that we have until August, 1, 2012 to regain compliance with the minimum bid price rule for our common stock while listed on The NASDAQ Capital Market. On, or prior to this date, the bid price of our common stock must close at $1.00 per share or more for a minimum of ten consecutive business days. If compliance is not regained, and we do not receive an extension of the deadline for compliance, our common and preferred shares will be subject to delisting.

Other Developments

On April 30, 2012, J. Darby Seré resigned from the positions of Chairman of the Board, President and Chief Executive Officer of the Company. The Company and Mr. Seré entered into a separation agreement that provides for certain payments to Mr. Seré, including a lump sum payment of $499,500, $2,000 per month for 18 months and $30,000 per month as a consulting fee for up to nine months. The separation agreement further provided for certain adjustments to equity awards owned by Mr. Seré. The Board of Directors of the Company appointed Michael Y. McGovern as the Company s Chairman of the Board; William C. Rankin, as a new Board member and as its new President and Chief Executive Officer; and Tony Oviedo, as the Company s Senior Vice President, Chief Financial Officer, Chief Accounting Officer and Controller.

The Company has retained FBR Capital Markets & Co. (FBR) as its advisor to review strategic alternatives, primarily focused on identifying potential merger partners. The Company believes a merger transaction would be beneficial during the current natural gas price environment, allowing it to spread fixed costs over a larger production and reserve base. The Company will continue to pursue its long range plans pending identification of a suitable transaction. The initial retainer paid to FBR was $50,000 and there are no additional future financial commitments currently in place unless we enter into a transaction.

Ceiling Write-Down

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the twelve-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. For the twelve months ended March 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.75 per Mcf, resulting in a natural gas price of $3.90 per Mcf when adjusted for regional price differentials. Based on the ceiling test performed utilizing the aforementioned prices, we recorded a $15.8 million write-down of the carrying value of our U.S. full cost pool at March 31, 2012. Based on current forward natural gas price curve, we expect additional ceiling write-downs during 2012 which will be significant to our gas properties, statements of operations and shareholders (deficit) equity.

Deferred Tax Asset

In order to assess the realization of our net deferred tax asset as of March 31, 2012 and December 31, 2011, we considered all available negative and positive evidence. We had incurred a cumulative pre-tax loss of $117.6 million, including ceiling impairment charges of $141.3 million, over the three year period ended March 31, 2012. We evaluated all available evidence including historical operating results, historical pricing, natural gas reserves as estimated and appraised by an independent third party engineer, the forward natural gas price curve, and the length of the carryforward period available. The liquidity issues discussed in Liquidity and Going Concern Considerations above which causes uncertainty about our ability to forecast, combined with recent cumulative net losses and the forward natural gas price curve, represented sufficient negative evidence to outweigh the positive evidence to overcome under the evaluation guidance. As a result, we established a full valuation allowance for our net deferred tax assets at March 31, 2012 of $47.3 million. These tax benefits will be available, prior to the expiration of carryforwards, to reduce future income tax expense resulting from earnings or increases in deferred tax liabilities.

Operational Update

Our core areas of operations are in the Central Appalachian Basin of Virginia and West Virginia and the Black Warrior and Cahaba Basins in Alabama. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. The Black Warrior and Cahaba Basins are hilly, gently rolling regions and coal mining is also present but less active. In addition to the areas listed below, we have non-producing properties in Canada which we are not currently operating or developing.

Central Appalachia - In the Central Appalachian Basin, we are the operator of 300 vertical wells in which we own a 99.0% average working interest. Additionally, we are the operator of 89 horizontal wells in which we own a 66.0% average working interest. We also have a 33.0% average working interest in 67 non-operated horizontal wells. In Central Appalachia, we are party to six firm transportation agreements with total maximum daily quantities of approximately 54,000 MMBtu per day and primary terms expiring from April 2012 through November 2024 which can be automatically extended from time to time at the maximum tariff rate. In some cases, our gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

On December 25th, 2011 we had a separator rupture at our Crab Orchard compressor station in West Virginia. The station was out of service until January 24th, 2012. Net gas sales lost during this period were approximately 127 MMcf. The production from the wells affected during this downtime is still recovering with net gas sales currently down about 500 Mcf/day.

Black Warrior and Cahaba Basins - In the Cahaba Basin in Alabama, we are the operator of 252 vertical wells for which we own a 100.0% working interest. Our gas sales volumes from the Cahaba Basin are delivered and sold into the Southern Natural Gas pipeline system. In the Black Warrior Basin, we own working, overriding royalty or royalty interests in 1,103 non-operated vertical

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wells. Of these non-operated vertical wells, we own an average working interest of 15.4% in 542 wells, and we own an average royalty or overriding royalty interest of 7.9% in the remaining 561 wells. Our gas sales volumes from the Black Warrior Basin are delivered and sold into the Southern Natural Gas pipeline system under transportation arrangements controlled by the operators of the properties.

In accordance with our business plan described above, we have not drilled any new wells to date and we have continued to reduce operating expenses and apply the majority of our cash flows to the reduction of bank debt. If no new wells are drilled, we expect production to decline during 2012 by approximately 10% to 15% from year end levels.

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 three months ended March 31, 2012.

Natural Gas Production Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the three months ended March 31, 2012 and 2011. This table should be read with the discussion of the results of operations for the periods presented below (in thousands, except per Mcf amounts).

	Three Months Ended March 31,			
		2012		**2011**
Gas sales	$	10,143	$	7,851
Lease operating expenses	$	4,461	$	2,973
Compression and transportation expenses		2,241		916
Production taxes		470		322
Total production expenses	$	7,172	$	4,211
Net sales volumes (Consolidated) (MMcf)		3,629		1,840
Pond Creek field (Central Appalachian Basin) (MMcf)		1,465		1,362
Other Central Appalachian Basin fields (MMcf)		1,050		39
Gurnee field (Cahaba Basin) (MMcf)		457		436
Black Warrior Basin fields (MMcf)		657		3
Per Mcf data ($/Mcf):				
Average natural gas sales price realized (Consolidated)(1)	$	4.12	$	6.17
Average natural gas sales price (Consolidated)	$	2.79	$	4.27

Pond Creek field (Central Appalachian Basin)	$	2.95	$	4.29
Other Central Appalachian Basin fields	$	2.61	$	4.21
Gurnee field (Cahaba Basin)	$	2.77	$	4.20
Black Warrior Basin fields	$	2.76	$	4.22
Lease operating expenses (Consolidated)	$	1.23	$	1.62
Pond Creek field (Central Appalachian Basin)	$	1.03	$	1.23
Other Central Appalachian Basin fields	$	1.43	$	1.50
Gurnee field (Cahaba Basin)	$	2.46	$	2.74
Black Warrior Basin fields	$	0.45	$	0.04
Compression and transportation expenses (Consolidated)	$	0.60	$	0.50
Pond Creek field (Central Appalachian Basin)	$	0.52	$	0.53
Other Central Appalachian Basin fields	$	1.17	$	1.25
Gurnee field (Cahaba Basin)	$	0.28	$	0.32
Black Warrior Basin fields	$	0.18	$	0.05
Production taxes (Consolidated)	$	0.13	$	0.17
Pond Creek field (Central Appalachian Basin)	$	0.17	$	0.17
Other Central Appalachian Basin fields	$	0.06	$	0.00
Gurnee field (Cahaba Basin)	$	0.12	$	0.21
Black Warrior Basin fields	$	0.16	$	0.26
Total production expenses (Consolidated)	$	1.96	$	2.29

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	Three Months Ended March 31, 2012	2011
Pond Creek field (Central Appalachian Basin)	$ 1.72	$ 1.93
Other Central Appalachian Basin fields	$ 2.66	$ 2.75
Gurnee field (Cahaba Basin)	$ 2.86	$ 3.27
Black Warrior Basin fields	$ 0.79	$ 0.35
Depletion (Consolidated)	$ 0.97	$ 0.83

(1) Average realized price includes the effects of realized gains and losses on derivative contracts.

Results of Operations

Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011

Selected items derived from our Consolidating Statement of Operations and their percentage changes from the comparable period are presented below.

	Three Months Ended March 31, 2012	2011 (In thousands)	Change
Gas sales	$ 10,143	$ 7,851	29%
Lease operating expenses	$ 4,461	$ 2,973	50%
Compression expense	$ 1,198	$ 608	97%
Transportation expense	$ 1,043	$ 308	238%
Production taxes	$ 469	$ 322	46%
Depreciation, depletion and amortization	$ 3,629	$ 1,633	122%
Impairment of gas properties	$ 15,779	$	NM
General and administrative	$ 1,303	$ 1,439	-9%
Realized gains on derivative contracts	$ (4,793)	$ (3,497)	37%
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (5,224)	$ 2,850	NM
Interest expense, net of amounts capitalized	$ (1,276)	$ (840)	52%
Income tax expense	$ 44,024	$ 5	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $2.3 million, or 29%, to $10.1 million compared to the prior year quarter. The increase in gas sales was primarily the result of higher production volumes, of which 1.7 Bcf was due to our November 18, 2011 acquisition of coalbed methane gas properties, while 0.1 Bcf was due to increased production in our previously existing properties, partially offset by a 34% decrease in natural gas prices, excluding hedging transactions.

Lease operating expenses. Lease operating expenses increased by $1.5 million, or 50%, to $4.5 million compared to the prior year quarter. The $1.5 million increase in lease operating expenses consisted of $1.7 million increase due to our recent acquisition of coalbed methane gas properties partially offset by a $0.2 million decrease in our previously existing properties.

Compression expense. Compression expense increased by $0.6 million, or 97%, to $1.2 million compared to the prior year quarter. The increase was primarily attributable to the $0.55 million of expenses related to our recently purchased gas combined with an increase of $0.05 million related to our previously existing properties. The increase in compression expenses in our previously existing properties was due to increased production.

Transportation expense. Transportation expense increased by $0.7 million, or 238%, to $1.0 million compared to the prior year quarter. The increase was due to the recent acquisition of coalbed methane gas properties. Transportation expenses remained relatively flat in our previously existing gas properties.

Production taxes. Production taxes increased by $0.1 million, or 46%, to $0.5 million compared to the prior year quarter. The increase in production taxes was primarily due to our recent acquisition of gas properties. Production taxes remained relatively flat in our previously existing gas properties.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $2.0 million, or 122%, to $3.6 million compared to the prior year quarter. This increase was primarily due to the $1.7 million of expenses related to the natural gas properties recently acquired in combination with an increase of $0.3 million related to our previously existing natural gas properties.

The increase in depreciation, depletion, and amortization at our pre-acquisition properties consisted of a $0.1 million increase related to production and a $0.1 million increase in the depletion rate.

Impairment of gas properties. During the first quarter of 2012, the gross carrying value of the Company s gas properties exceeded the full cost ceiling limitation and, as such, a $15.8 million ($9.8 million net of tax of $6.0 million) impairment of gas properties was recorded.

General and administrative. General and administrative expenses decreased by $0.1 million, or 9%, to $1.3 million compared to the prior year quarter. This decrease was primarily due the suspension of bonus accruals for senior management.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $1.3 million, or 37%, to $4.8 million compared to the prior year quarter. The increase was due to the $0.7 million of realized gains on derivative contracts acquired as part of our recent natural gas property acquisition combined with an increase of $0.6 million in realized gains on previously existing derivative contracts. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract 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 on open derivative contracts were $5.2 million in the current quarter as compared to unrealized losses of $2.9 million in the prior year quarter. The current quarter unrealized gain position was made up of $4.3 million in unrealized gains on derivative contracts executed during the first quarter of 2012 combined with $1.6 million of unrealized gains on derivative contracts recently acquired as part of our coalbed methane gas property acquisition, partially offset by unrealized losses of $0.7 million on pre-acquisition derivative contracts. Unrealized gains and losses 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.

Interest expense. Interest expense increased by $0.4 million, or 52%, to $1.3 million compared to the prior year quarter. The increase was primarily due to a higher average outstanding balance under our Credit Agreement in the current year quarter, partially offset by a lower average interest rate under our Credit Agreement in the current year quarter.

Income tax expense. Our income tax expense was $44.0 million in the current quarter as compared to income tax expense of $0.01 million the prior year quarter. The income tax expense for the three months ended March 31, 2012 was different than the amount computed using the statutory rate primarily due to a $47.3 million valuation allowance. A reconciliation of the effective tax rate to the statutory rate is as follows:

	U.S.			Canada			Total		
Amount computed using statutory rates	$	(3,027,014)	34.00%	$	(5,143)	25.00%	$	(3,032,157)	33.98%
State income taxes net of federal benefit		(310,553)	3.49%			0.00%		(310,553)	3.48%
Valuation Allowance		47,349,918	-531.84%		5,143	-25.00%		47,355,061	-530.67%
Nondeductible items and other		12,099	-0.14%			0.00%		12,099	-0.14%
Income tax provision	$	44,024,450	-494.49%	$		0.00%	$	44,024,450	-493.35%

Liquidity and Capital Resources

Cash Flows and Liquidity

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. Accordingly, the consolidated financial statements do not include any adjustments, other that the valuation of the net deferred tax asset discussed in Note 13-Income Taxes of the notes to the consolidated financial statements, relating to the recoverability of assets and classification of liabilities that might be necessary should the Company be unable to continue as a going concern.

Cash flows provided by operating activities for the three months ended March 31, 2012 and 2011 were $6.5 million and $3.9 million, respectively. As of March 31, 2012, we had working capital of approximately $12.3 million as compared to working capital of $11.6 million as of December 31, 2011.

On November 18, 2011, our Fifth Amended and Restated Credit Agreement (the Credit Agreement) with a group of six banks became effective. The Credit Agreement replaced our Fourth Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $250 million with an initial borrowing base of $180 million. The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by June 2012. All outstanding borrowings under the Credit Agreement become due and payable on November 18, 2015. In the event that the outstanding borrowings at any borrowing base determination date exceed the borrowing base (a borrowing base deficiency) the Company has three options in order to remain in compliance with the Credit Agreement, (i) to immediately reduce the outstanding borrowing by the amount of the borrowing base deficiency, (ii) provide additional collateral equal to the amount of the borrowing base deficiency, or (iii) make six equal monthly

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payments in an aggregate amount equal to the borrowing base deficiency. 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 1.25% to 1.75% or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 2.25% to 2.75%. 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) depending on our Debt Ratio, either (a) a minimum Interest Coverage Ratio or (b) a minimum Fixed Charge 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) 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 4.25 to 1.0 through the quarter ending December 31, 2012 and 4.0 to 1.0 thereafter. If our Debt Ratio at the end of each fiscal quarter is above 3.5 to 1.0, then the Fixed Charge Ratio (defined as consolidated EBITDA less capital expenditures to consolidated net cash interest expense for the four preceding quarters) is applicable and cannot be less than 1.25 to 1.0. If our Debt Ratio at the end of each fiscal quarter is 3.5 to 1.0 or less, 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) is applicable and cannot be less than 2.75. 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 and non-cash gains, losses or adjustments and charges on any oil and gas hedge transaction, including those resulting from the requirements of ASC Topic 815, as a result of changes in the fair market value of oil and gas hedge transactions. 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 above the $2 million discretionary amount allowable under the Credit Agreement 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 the payment of PIK dividends on our preferred stock. At March 31, 2012, we are in compliance with the aforementioned Credit Agreement covenants. We are currently in the process of completing the June borrowing base determination which is discussed above in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Going Concern Considerations.

Natural Gas Price Risk and Related 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 our natural gas derivative contracts during any period to no more than 50% to 80% 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 March 31, 2012, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
April through December 2012	414,000	$	5.11	$	1,078,163
April through December 2012	171,000	$	5.12		447,032
April through December 2012	795,275	$	6.85		3,454,561
April through December 2012	382,691	$	6.99		1,719,285
April through December 2012	623,158	$	7.05		2,845,530

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Period	Volume (MMBtu)		Fixed Price		Fair Value
April through October 2012	856,000	$	5.73		2,881,780
April through October 2012	1,712,000	$	4.94		4,405,671
April through October 2012	3,210,000	$	2.89		1,711,377
November 2012 through March 2013	604,000	$	6.42		1,928,929
November 2012 through March 2013	906,000	$	5.50		2,070,308
November 2012 through March 2013	4,128,000	$	3.81		1,265,468
November 2012 through March 2013	4,128,000	$	3.82		1,306,244
	17,930,124			$	25,114,348

At March 31, 2012, we had the following natural gas basis swap position:

Period	Volume (MMBtu)		Fixed Basis		Fair Value
April through December 2012	414,000	$	0.04	$	16,270

Subsequent to March 31, 2012, we added the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price
January through December 2013	2,190,000	$	3.60
April through December 2013	2,750,000	$	3.25

Subsequent to March 31, 2012, we added the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor
January 2014 through December 2015	3,650,000	$	4.20	$	3.50
January 2014 through December 2015	3,650,000	$	4.30	$	3.60

Capital Expenditures and Capital Resources

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

	Three Months Ended March 31,			
		2012		2011
Capital expenditures:				
Leasehold acquisition	$	148,619	$	350,564

Exploration				3,000
Development		(63,206)		2,499,765
Other items (primarily capitalized overhead)		131,025		273,158
Total capital expenditures	$	216,438	$	3,126,487

Based on the prevailing low prices for natural gas, our Board of Directors has established a limited capital budget for 2012. We expect to spend $1.5 million in capital in 2012 primarily for maintenance operations associated with our existing properties.

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 2011 Annual Report on Form 10-K that we filed with the SEC on March 30, 2012.

Recent Pronouncements

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 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. The Company has adopted and applied the provisions of this update for the three months ended March 31, 2012.

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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 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 has adopted and applied the provisions of this update for the three months ended March 31, 2012. See disclosure provided in Note 8 Long-Term Debt and Note 10 Series A Convertible Redeemable Preferred Stock in the Notes to Consolidated Financial Statements (Unaudited).

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 months ended March 31, 2012, a 10% decrease in the prices received for natural gas production would have had an approximate $1.0 million impact on our revenues, which would have been offset by approximately $0.4 million realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of March 31, 2012, we had $149.5 million of borrowings outstanding under our Credit Agreement. The rate at March 31, 2012 was 2.79%. For the three months ended March 31, 2012, interest on the borrowings averaged 2.90% per annum. 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 balance outstanding under our Credit Agreement for the three months ended March 31, 2012, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.4 million.

Foreign Currency Exchange Rate Risk. We have 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. Our Canadian prospect is temporarily shut-in and, therefore, the impact on our Consolidated Financial Statements is not significant. We will 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

Management s Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified by the SEC s rules and forms and include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act) as of March 31, 2012, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and are effective at the reasonable assurance level that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC s rules and forms.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the three months ended March 31, 2012 and found no change that has materially affected, or is reasonably likely to materially affect, 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. Management does not believe that the outcome of lawsuits or other proceedings against us will have an adverse effect on our financial condition, results of operations or cash flows.

Lease Revenue Audit The lessor from one of our leases recently completed a five year revenue audit where the examiner claims to have identified an exception related to compressor fuel deductions. We have accrued a $356,147 liability in the Consolidated Balance Sheet (Unaudited) as of March 31, 2011 related to this matter.

Environmental and Regulatory

As of March 31, 2012, 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 have 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, 2011, except as follows.

Natural gas prices have been depressed recently and have the potential to remain depressed for the foreseeable future, which may have an adverse effect on our financial condition and results of operations

Natural gas prices have fallen substantially since late 2011 as a result of over-supply caused by, among other things, increased drilling in unconventional reservoirs, reduced economic activity associated with a recession and weather conditions. We expect natural gas prices to be depressed during the foreseeable future. All of our estimated net proved reserves and production are natural gas. A sustained reduction in natural gas prices will have an adverse effect on our results of operation and financial condition.

Our Credit Agreement provides for the determination of our borrowing base each June and December, and we expect that the borrowing base to be determined in June 2012 will be less than the amounts outstanding under the Credit Agreement. The Credit Agreement also contains a number of financial and other covenants, and our obligations under the Credit Agreement are secured by substantially all of our assets. If the borrowing base is less than the amounts outstanding or we are unable to comply with these covenants, we could default under

the agreement and our lenders could accelerate the repayment of our indebtedness.

Our Credit Agreement provides for determinations of our borrowing base in June and December of each year. Based on discussions with the lenders under the Credit Agreement, while we do not currently know what amount the lenders will set as the borrowing base for June 2012, we believe that our outstanding loan balance at that time will exceed the new borrowing base. If a deficiency exists, we will be required to provide additional collateral or repay the deficiency as provided in the Credit Agreement. We do not have additional collateral to provide the lenders and we believe that our cash flows will not be sufficient to repay the deficiency as required by the Credit Agreement. In addition, the excess of the outstanding loan balance over the borrowing base may cause us to be in default under a covenant in the Credit Agreement requiring that we have positive working capital. We have begun discussions with our lenders regarding the likely borrowing base deficiency, and have made a proposal to our lenders which would amend our Credit Agreement to allow us to remain in compliance.

Our Credit Agreement subjects us to a number of other covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends. We are also required by the terms of our Credit Agreement to comply with certain financial ratios. Our Credit Agreement is secured by a lien on substantially all of our assets, including equity interests in our subsidiaries.

A failure to remedy the borrowing base deficiency as required under the Credit Agreement, or a breach of any of the covenants imposed on us by the terms of our Credit Agreement, including the financial covenants, will result in a default under the Credit Agreement. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the Credit Agreement. Any acceleration in the repayment of our indebtedness or related foreclosure would materially and adversely affect our business, financial condition and results of operations.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

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: May 15, 2012	By	/S/ TONY OVIEDO **Tony Oviedo, Senior Vice President, Chief Financial Officer,** **Chief Accounting Officer and Controller** **(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.