

GeoMet, Inc.
Form 10-Q
May 09, 2008
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2008

OR

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

For the transition period from _____ to _____

Commission File Number 000-52155

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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Delaware (State or other jurisdiction of incorporation or organization)	76-0662382 (I.R.S. Employer Identification Number)
909 Fannin, Suite 1850 Houston, Texas 77010 (713) 659-3855	
(Address of principal executive offices and telephone number, including area code)	
N/A	
(Former name, former address and former fiscal year, if changed since last report)	

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

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

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

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

As of April 1, 2008 there were 39,270,331 shares issued and outstanding of GeoMet, Inc.'s common stock, par value \$0.001 per share.

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Table of Contents**Item 1. Financial Statements****GEOMET, INC. AND SUBSIDIARIES****Consolidated Balance Sheets****(Unaudited)**

	March 31, 2008	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 2,834,925	\$ 1,540,516
Accounts receivable	6,016,512	4,881,397
Inventory	2,209,842	2,355,595
Derivative asset		2,247,248
Deferred income taxes	2,012,714	
Other current assets	309,237	484,341
Total current assets	13,383,230	11,509,097
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	375,899,790	370,404,336
Unevaluated gas properties, not subject to amortization	26,851,716	25,174,764
Other property and equipment	2,752,953	2,536,619
Total property and equipment	405,504,459	398,115,719
Less accumulated depreciation, depletion, and amortization	(34,295,977)	(31,886,633)
Property and equipment net	371,208,482	366,229,086
Other noncurrent assets:		
Derivative asset	12,861	90,427
Other	799,860	848,816
Total other noncurrent assets	812,721	939,243
TOTAL ASSETS	\$ 385,404,433	\$ 378,677,426
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	\$ 6,719,609	\$ 7,536,274
Accrued liabilities	2,524,279	5,087,871
Deferred income taxes		770,675
Derivative liability	5,389,130	
Asset retirement liability	72,397	74,387
Current portion of long-term debt	107,218	102,586
Total current liabilities	14,812,633	13,571,793
Long-term debt	101,171,027	96,729,722
Derivative liability	1,693,038	
Asset retirement liability	3,977,578	2,915,855
Other long-term accrued liabilities	130,326	138,471
Deferred income taxes	48,141,392	46,645,879

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TOTAL LIABILITIES	169,925,994	160,001,720
Commitments and contingencies (Note 10)		
Stockholders' Equity:		
Preferred stock, \$0.001 par value authorized 10,000,000, none issued		
Common stock, \$0.001 par value authorized 125,000,000 shares; issued and outstanding 39,270,331 and 38,962,359 at March 31, 2008 and December 31, 2007, respectively	39,270	38,962
Paid-in capital	187,937,443	187,550,484
Accumulated other comprehensive income	954,202	2,394,001
Retained earnings	26,767,420	28,909,363
Less notes receivable	(219,896)	(217,104)
TOTAL STOCKHOLDERS' EQUITY	215,478,439	218,675,706
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 385,404,433	\$ 378,677,426

See accompanying Notes to Consolidated Financial Statements.

Table of Contents**GEOMET, INC. AND SUBSIDIARIES****Consolidated Statements of Operations****(Unaudited)**

	Three Months Ended March 31,	
	2008	2007
Revenues:		
Gas sales	\$ 15,581,178	\$ 11,848,202
Operating fees and other	297,629	291,753
Total revenues	15,878,807	12,139,955
Expenses:		
Lease operating expense	3,751,326	3,369,235
Compression and transportation expense	1,042,809	1,512,418
Production taxes	421,936	280,313
Depreciation, depletion and amortization	2,459,329	2,075,323
General and administrative	2,492,470	2,276,264
Realized gains on derivative contracts	(861,828)	(1,246,126)
Unrealized losses from the change in market value of open derivative contracts	8,646,663	4,574,216
Total operating expenses	17,952,705	12,841,643
Operating loss from continuing operations	(2,073,898)	(701,688)
Other income (expense):		
Interest income	6,777	6,973
Interest expense (net of amounts capitalized)	(1,303,193)	(875,005)
Other	(5,549)	(28,668)
Total other income (expense):	(1,301,965)	(896,700)
Loss before income taxes and discontinued operations	(3,375,863)	(1,598,388)
Income tax benefit	1,233,920	496,584
Loss from continuing operations	(2,141,943)	(1,101,804)
Discontinued operations, net of tax		75,941
Net loss	\$ (2,141,943)	\$ (1,025,863)
Earnings per share:		
Loss from continuing operations		
Basic	\$ (0.05)	\$ (0.03)
Diluted	\$ (0.05)	\$ (0.03)
Discontinued operations		
Basic	\$	\$
Diluted	\$	\$

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Net loss per common share			
Basic	\$	(0.05)	\$ (0.03)
Diluted	\$	(0.05)	\$ (0.03)
Weighted average number of common shares:			
Basic		39,004,402	38,682,235
Diluted		39,004,402	38,682,235

See accompanying Notes to Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive Loss

(Unaudited)

	Three Months Ended March 31,	
	2008	2007
Net loss	\$ (2,141,943)	\$ (1,025,863)
(Loss) gain on foreign currency translation adjustment	(679,480)	93,962
Loss on interest rate swap	(760,319)	
Other comprehensive loss	\$ (3,581,742)	\$ (931,901)

See accompanying Notes to Consolidated Financial Statements.

Table of Contents**GEOMET, INC. AND SUBSIDIARIES****Consolidated Statements of Cash Flows****(Unaudited)**

	Three Months Ended March 31,	
	2008	2007
Cash flows provided by operating activities:		
Net loss	\$ (2,141,943)	\$ (1,025,863)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	2,459,329	2,121,213
Amortization of debt issuance costs	42,991	34,764
Deferred income taxes	(1,233,920)	(462,358)
Unrealized losses from the change in market value of open derivative contracts	8,646,663	4,574,216
Stock-based compensation	188,306	80,780
(Gain) loss on sale of other assets	17,084	(15,954)
Accretion expense	83,797	50,718
Changes in operating assets and liabilities:		
Accounts receivable	(1,143,381)	1,548,445
Inventory	142,265	
Other current assets	175,104	211,319
Accounts payable	(790,605)	(2,877,238)
Other accrued liabilities	(2,599,613)	(257,773)
Net cash provided by operating activities	3,846,077	3,982,269
Cash flows used in investing activities:		
Capital expenditures	(7,234,087)	(18,032,955)
Proceeds from sale of other property and equipment	18,500	22,159
Other assets	5,754	(67,621)
Net cash used in investing activities	(7,209,833)	(18,078,417)
Cash flows provided by financing activities:		
Treasury stock		(4,380)
Proceeds from exercise of stock options	67,880	66,057
Net proceeds from revolving credit agreement	4,500,000	14,000,000
Payments on other debt	(54,063)	(49,802)
Net cash provided by financing activities	4,513,817	14,011,875
Effect of exchange rate changes on cash	144,348	(33,186)
Increase (decrease) in cash and cash equivalents	1,294,409	(117,459)
Cash and cash equivalents at beginning of period	1,540,516	1,414,476
Cash and cash equivalents at end of period	\$ 2,834,925	\$ 1,297,017

See accompanying Notes to Consolidated Financial Statements.

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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 (coal bed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia, Virginia and Canada.

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 financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for year-end financial statements prepared in conformity with accounting principles generally accepted in the United States of America. 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 financial statements for the fiscal year ended December 31, 2007 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 14, 2008.

On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our discontinued gas marketing subsidiary (see Note 11 Discontinued Operations). Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC was a low margin business and as a result it did not have a significant impact on our results of operations. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, Business Combinations, whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price approximated the fair value of the net assets acquired.

Note 2 Recent Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (the FASB) issued Statement of Financial Accounting Standard No. 157, Fair Value Measurements (SFAS 157). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, GeoMet, Inc. adopted SFAS 157, which provides a framework for measuring fair value under accounting principles generally accepted in the United States. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are observed from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 Derivative Instruments and Hedging Activities.

On February 15, 2007, the FASB issued SFAS Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115 (SFAS 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

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In March 2008, the FASB issued SFAS Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities" an amendment of FASB Statement No. 133 (SFAS 161). This standard changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosures relating to derivative instruments and hedging activities.

Table of Contents**Note 3 Net Loss Per Share**

Basic loss per share is calculated by dividing net loss by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted net loss per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net loss by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive loss per share 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 the numerator and denominator is as follows:

	Three Months Ended March 31,	
	2008	2007
Loss from continuing operations:		
Basic-net loss per share	\$ (0.05)	\$ (0.03)
Diluted-net loss per share	\$ (0.05)	\$ (0.03)
Discontinued operations:		
Basic-net income per share	\$	\$
Diluted-net income per share	\$	\$
Net loss per share:		
Basic-net loss per share	\$ (0.05)	\$ (0.03)
Diluted-net loss per share	\$ (0.05)	\$ (0.03)
Numerator:		
Loss from continuing operations	\$ (2,141,943)	\$ (1,101,804)
Discontinued operations	\$	\$ 75,941
Net loss available to common stockholders	\$ (2,141,943)	\$ (1,025,863)
Denominator:		
Weighted average shares outstanding-basic	39,004,402	38,682,235
Add potentially dilutive securities:		
Stock options		
Dilutive securities	39,004,402	38,682,235

We reported a net loss for the three months ended March 31, 2008 and 2007, respectively, and, as a result, outstanding dilutive securities to purchase 664,491 and 683,561 shares for the three months ended March 31, 2008 and 2007, respectively, were excluded from the calculation because the effect of including them would be anti-dilutive.

Note 4 Gas Properties

The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the United States Securities and Exchange Commission (SEC). Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into U.S. and Canadian cost centers.

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.

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

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The ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC, significant changes in gas prices subsequent to quarter end are used in the ceiling limitation test. In addition, subsequent to the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143), the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

Table of Contents**Note 5 Asset Retirement Liability**

We record an asset retirement obligation (ARO) on the consolidated balance sheet 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, 2008:

Current portion of obligation at January 1, 2008	\$ 74,387
Add: Long-term asset retirement obligation at January 1, 2008	2,915,855
Asset retirement obligation at January 1, 2008	2,990,242
Liabilities incurred	54,714
Liabilities settled	(13,939)
Accretion	92,637
Revisions in estimates	934,924
Foreign currency translation	(8,603)
Asset retirement obligation at March 31, 2008	4,049,975
Less: Current portion of obligation	(72,397)
Long-term asset retirement obligation	\$ 3,977,578

ARO revisions in estimates of \$934,924 were due to specific lease agreement requirements related to plug and abandonment of our wells.

Note 6 Derivative Instruments and Hedging Activities

The energy markets have historically been very volatile, and there can be no assurance that natural gas prices will not be subject to wide fluctuations in the future. 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 that increase our statistical probability of achieving our targeted level of cash flows and at times hedge forward for periods of more than two years. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. 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. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (a sold floor) to a predetermined amount, generally between \$2.00 and \$3.00 per MMBtu. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices rise above the level of our hedges and gains during periods where prices drop below the level of our hedges causing significant fluctuations in our statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments does materially affect our financial position and results of operations as a result of changes in the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our liquidity.

During the three months ended March 31, 2008, we had losses on derivative contracts of \$7,784,835, which consisted of \$861,828 in realized gains on derivative contracts offset by \$8,646,663 in unrealized losses on derivative contracts. During the three months ended March 31, 2007, we had losses on derivative contracts of \$3,328,090, which consisted of \$1,246,126 in realized gains on derivative contracts offset by \$4,574,216 in unrealized losses on derivative contracts.

Commodity Price Risk and Related Hedging Activities.

At March 31, 2008, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
Summer 2008	1,712,000	\$ 10.50	\$ 7.00	\$ 5.00
Winter 2008/2009	906,000	\$ 11.00	\$ 8.50	\$ 6.25
Winter 2008/2009	906,000	\$ 11.00	\$ 8.84	\$ 6.00
Summer 2009	1,284,000	\$ 10.00	\$ 7.50	\$ 5.25
Summer 2009	1,284,000	\$ 10.00	\$ 8.50	\$ 6.50
Winter 2009/2010	906,000	\$ 11.20	\$ 9.50	\$ 7.00

At March 31, 2008, the Company had the following natural gas swap position:

Period	Volume in MMBtu s	Price
Summer 2008	736,000	\$ 8.00

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When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under SFAS No. 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At March 31, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%(1)	\$ 15,000,000
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%(1)	\$ 10,000,000
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%(1)	\$ 10,000,000

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

For the three months ended March 31, 2008, we recognized no ineffective portion of our cash flow hedges.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

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

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

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our natural gas hedge asset was \$12,861 at March 31, 2008. The fair value of our natural gas hedge liabilities and interest rate swap liabilities were \$6,319,872 and \$749,435 at March 31, 2008, respectively. As of December 31, 2007, our natural gas hedges and interest rate swaps represented only assets in our consolidated balance sheets. The fair value of our natural gas hedge assets and interest rate swap assets were \$2,326,791 and \$10,884 at December 31, 2007, respectively.

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Note 7 Long-Term Debt

We have a revolving credit facility with a current borrowing base of \$180 million, maturing January 6, 2011. Our revolving credit facility permits us to borrow amounts from time to time based on the available borrowing base as determined in the credit agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of March 31, 2008, we had \$100.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of \$79.5 million under our \$180 million borrowing base. For the three months ended March 31, 2008 we borrowed \$20.5 million and made payments of \$16.0 million under the revolving credit facility. As of March 31, 2008 the outstanding balances on the revolving credit facility bear interest at either the bank's adjusted base rate, which is the bank's base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage. The rates at March 31, 2008 and December 31, 2007 were 4.28% and 6.29%, respectively.

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The following is a summary of our long-term debt at March 31, 2008 and December 31, 2007:

	March 31, 2008	December 31, 2007
Borrowings under revolving credit facility	\$ 100,500,000	\$ 96,000,000
Note payable to a third party, annual installments of \$53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	135,972	174,570
Note payable to an individual, semi-monthly installments of \$644, through September 2015, interest-bearing at 12.6% annually, unsecured	126,736	129,240
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	515,536	528,498
Total debt	101,278,245	96,832,308
Less current maturities included in current liabilities	(107,218)	(102,586)
Total long-term debt	\$ 101,171,027	\$ 96,729,722

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio of 1.0 to 1.0, and a rate of EBITDA to interest expense of up to 2.75 to 1.0, both as defined in the credit agreement. As of March 31, 2008, we were in compliance with all of the covenants in the credit agreement.

Note 8 Common Stock

At March 31, 2008 and December 31, 2007, there were 39,270,331 shares and 38,962,359 shares, respectively, of common stock outstanding. For the three months ended March 31, 2008, we issued a total of 40,337 shares of common stock upon the exercise of stock options and 253,806 shares of restricted stock. We also issued 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. The shares of common stock were issued upon the exercise of stock options pursuant to the 2005 Stock Option Plan. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. Additionally, 4,891 shares of restricted stock were forfeited.

Note 9 Share-Based Awards

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123R, Share-Based Payment, using the prospective transition method. For share-based awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

As of March 31, 2008, we have two stock-based award plans authorized, our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan, although we will continue to issue shares of our common stock upon exercise of awards previously granted under the 2005 Stock Option Plan.

Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 2,000,000 shares is available for grant under this plan. The 2006 Long-Term Incentive 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 a stock option 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, vest evenly over three years, except performance based awards 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 issued to our directors vest immediately.

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For the three months ended March 31, 2008, we granted 164,604 restricted stock awards with time vesting criteria to certain key employees, including our four executive officers, 89,202 restricted stock awards with performance vesting criteria to our four executive officers and two other officers and 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. The restricted stock awards will vest as a result of a triggering event such as a corporate change of control or merger. During the three months ended March 31, 2008, 4,891 shares of restricted stock were forfeited. During the three months ended March 31, 2008, we recorded a compensation expense accrual of \$344,554 of which \$7,580 was allocated to lease operating expenses, \$262,640 to general and administrative expenses, and \$74,334 was capitalized to unevaluated gas properties. The future compensation cost of all the outstanding awards is \$1.7 million, 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 2.5 years.

Significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 40%, risk-free interest rate of 3.15%, an expected term of 4.5 years, and forfeiture rates from 5% to 15%.

Incentive Stock Options

The table below summarizes incentive stock option activity for the three months ended March 31, 2008:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007	682,277	\$ 6.77		
Forfeited	(17,806)	\$ 9.26		
Exercised	(40,337)	\$ 1.69		
Outstanding at March 31, 2008	624,134	\$ 7.03	4.57	\$ 712,145
Options exercisable at March 31, 2008	167,115	\$ 2.40	2.73	\$ 712,145

The total intrinsic value of incentive stock options exercised during the three months ended March 31, 2008 was \$157,308.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended March 31, 2008:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2007	1,311,055	\$ 4.02		
Forfeited	(12,889)	\$ 9.63		
Outstanding at March 31, 2008	1,298,166	\$ 3.96	5.08	\$ 4,391,458
Options exercisable at March 31, 2008	1,080,159	\$ 2.59	4.94	\$ 4,391,458

During the three months ended March 31, 2008, no non-qualified stock options were exercised nor granted.

Table of Contents*Restricted Stock Awards*

The table below summarizes non-vested restricted stock awards activity for the three months ended March 31, 2008:

	Non-Vested Restricted Stock Awards	Weighted Average Value Per Share At Grant Date
Non-vested restricted stock at December 31, 2007	173,998	\$ 7.21
Granted	253,806	6.41
Forfeited	(4,891)	7.21
Non-vested restricted stock at March 31, 2008	422,913	\$ 6.73

Note 10 Commitments and Contingencies

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

CNX Surface Use Disputes

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company (PMC) in Buchanan County, Virginia. Our Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC (CNX), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We expect to present oral arguments before the Virginia Supreme Court in early June, 2008. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the property. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. If such an alternative is unavailable, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

Table of Contents**CNX Antitrust Action**

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX's alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX's intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX's position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of \$385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

As of March 31, 2008, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Note 11 Discontinued Operations

As of September 30, 2007, we discontinued the third-party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting the third-party marketing business, we are treating these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations were as follows:

Statement of Operations Data:

	Three months ended March 31,	
	2008	2007
Gas marketing revenues	\$	\$ 8,542,486
Purchased gas		(8,432,319)
Income before tax		110,167
Income tax expense		(34,226)
Discontinued operations	\$	\$ 75,941

Balance Sheet Data:

	March 31,	December 31,
	2008	2007
Current Assets:		
Cash and cash equivalents	\$	\$ 175,398
Accounts receivable		15,530
Other		14,945
Total assets	\$	\$ 205,873
Current Liabilities:		
Accounts payable	\$	\$ 86,510
Stockholder's equity		119,363

Total liabilities and stockholder's equity	\$	\$	205,873
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Note 12 Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB Statement No. 109, *Accounting for Income Taxes*, as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities using enacted tax rates at the end of the period. Under FASB No. 109, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Section 382 of the Internal Revenue Code. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use the NOLs in the U.S. to offset current tax liabilities in future years.

Our effective tax rate differs from the federal statutory rate primarily due to losses in Canada that we are unable to benefit from and state income taxes. The Canadian losses are fully reserved because it is more likely than not that we will not use those NOLs to offset current tax liabilities in future years. The effective tax rate increased to 36.6% for the quarter ended March 31, 2008 from 31.1% in the same quarter in the prior year. The increase in the effective tax rate of 5.5% to 36.6% from the prior year quarter was due to state tax rate increases and state apportionment adjustments.

Uncertain Tax Positions

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified \$269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48 principally due to the size of our NOLs. An additional \$2,700 was recorded during 2007 based on tax positions related to 2007. There was no change in the amounts of unrecognized tax benefits for the three months ended March 31, 2008.

It is expected that the amount of unrecognized tax benefits may change in the next 12 months; however, we do not expect the change to have a significant impact on our results of operations or the financial position.

We file a consolidated federal income tax return in the U.S. and various combined and separate filings in Canada and several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2002.

Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. As of the date of adoption of FIN 48, we did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the three months ended March 31, 2008.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to March 31, 2009.

For tax reporting purposes, we have federal and state NOLs of approximately \$76.7 million and \$5.7 million, respectively, at March 31, 2008 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOLs will expire prior to 2022.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations Statement Regarding Forward-Looking Information

Management's Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management's beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, and similar 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. 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, 2007, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 14, 2008.

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. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of March 31, 2008, we control a total of approximately 237,000 net acres of coalbed methane and oil and gas development rights.

We primarily explore for, develop, and produce CBM and non-conventional shallow gas. Our objective is to create the premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the efficient investment of capital to increase reserves, production, cash flow and earnings. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane and non-conventional shallow gas fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane and non-conventional shallow gas offer significant operational advantages compared to conventional gas production.

Our ability to successfully leverage our competitive strengths and execute our strategy depends upon many factors and is subject to a variety of risks. For example, our ability to drill on our properties and fund our capital budgets depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels and maintain borrowing capacity at or near current levels under our revolving credit facility, or the availability of future debt and equity financing at attractive prices. Our ability to fund CBM property acquisitions and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Changes in natural gas prices, which may affect both our cash flows and the value of our gas reserves, our ability to replace production through drilling activities, a material adverse change in our gas reserves due to factors other than gas pricing changes, our ability to transport our gas to markets, drilling costs, lower than expected production rates and other factors, many of which are beyond our control, may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel, among other things.

Net gas sales volumes for the three months ended March 31, 2008 were 1.9 Bcf, an increase of 9.7% over the same period in 2007. The increase in sales volume was related to the continued development of our Pond Creek and Gurnee fields. Average gas sales price for the three months ended March 31, 2008 increased by \$1.38 per Mcf from the comparable prior period to \$8.33 per Mcf. As a result of both the increased gas volumes and price, gas sales revenue is up 31.5% from the comparable prior period to \$15.6 million.

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Recent Developments

Operational activity during the three months ended March 31, 2008, include the following:

Gurnee - We did not add any new wells into sales during the first quarter of 2008 with the total productive wells remaining at 234. However, we did complete a second test well west of the Cahaba River. Production testing of this well along with a well completed in the fourth quarter of 2007 is currently in progress and initial production rates are encouraging. Five additional new wells are planned to be drilled in 2008. At least three of these wells will be drilled on the east side of the Cahaba River with drilling having already begun in the second quarter of 2008. Net gas sales were 6.1 MMcf per day for the three months ended March 31, 2008, as compared to 6.4 MMcf per day for the quarter ended March 31, 2007, and will probably remain relatively flat until the wells that we drill in 2008 are placed into production.

Pond Creek - We drilled three wells and added two of these into sales. We also added two wells that were completed at the end of 2007 giving us a total of 220 productive wells in the Pond Creek field. Subject to the completion of required permitting and acquisition of certain right-of-way agreements, 21 additional new wells are planned to be drilled in 2008, three of which were drilled in the first quarter of 2008. Net gas sales increased to 13.4 MMcf per day for the three months ended March 31, 2008, as compared to 11.9 MMcf per day for the quarter ended March 31, 2007.

Lasher - Production testing continued on three previously drilled wells. Additionally, the permitting is in process for 15 wells that are planned to be drilled in 2008. We have initiated the construction of the new well locations, water and gas gathering systems and the high-pressure pipeline that will be used to transport the natural gas to the market.

Garden City - At our Garden City Chattanooga Shale prospect, we had drilled five coreholes and three production wells at the end of 2007. Since then we have drilled our first horizontal well in the prospect area and plan to drill at least one additional horizontal well and one additional vertical well in 2008. We will connect at least 3 wells to sales this quarter in order to facilitate longer term testing. We are continuing to expand our 59,000 acre leasehold position in this area. Similar to the west side of Cahaba, if further data supports our initial results, and gas prices remain strong, we would expect to expand our budgeted activity at Garden City in 2008.

Peace River - We have begun facilities and location construction, and have made progress in our permitting process. We expect to commence drilling this summer, have 8 wells on production by year-end, and book initial proved reserves at this project. Adequate water disposal capacity was confirmed from an injection test on an existing well.

We have concluded our previously announced review of strategic opportunities or alternatives. We believe that the prospect of higher natural gas prices and the existing opportunities within the Company to grow reserves, production and cash flow as an independent company offer the greatest potential to maximize value for our stockholders.

Table of Contents**Critical Accounting Policies**

The preparation of financial statements in conformity with generally accepted accounting principles in the United States 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, 2008.

Producing Fields Operations Summary

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three months ended March 31, 2008 and 2007. This table should be read with the discussion of the results of operations for the periods presented below (in thousands).

	Three Months Ended March 31,	
	2008	2007
Gas sales	\$ 15,581	\$ 11,848
Lease operating expenses	\$ 3,751	\$ 3,369
Compression and transportation expenses	1,043	1,512
Production taxes	422	280
Total production expenses	\$ 5,216	\$ 5,161
Net sales volumes (MMcf)	1,871	1,706
Pond Creek field	1,223	1,066
Gurnee field	559	540
Per Mcf data (\$/Mcf):		
Average natural gas sales price	\$ 8.33	\$ 6.95
Average natural gas sales price realized(1)	\$ 8.79	\$ 7.68
Lease operating expenses	\$ 2.00	\$ 1.97
Pond Creek field	\$ 1.61	\$ 1.67
Gurnee field	\$ 3.18	\$ 2.93
Compression and transportation expenses	\$ 0.56	\$ 0.88
Pond Creek field	\$ 0.63	\$ 1.18
Gurnee field	\$ 0.48	\$ 0.47
Production taxes	\$ 0.23	\$ 0.16
Pond Creek field	\$ 0.08	\$ 0.02
Gurnee field	\$ 0.51	\$ 0.41
Total production expenses	\$ 2.79	\$ 3.03
Pond Creek field	\$ 2.32	\$ 2.87
Gurnee field	\$ 4.17	\$ 3.82
Depreciation, depletion and amortization	\$ 1.31	\$ 1.22

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

Table of Contents**Results of Operations*****Three Months Ended March 31, 2008 compared with Three Months Ended March 31, 2007***

The following are 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,		
	2008	2007	Change
	(In thousands)		
Gas sales	\$ 15,581	\$ 11,848	31.51%
Lease operating expenses	\$ 3,751	\$ 3,369	11.34%
Compression and transportation expenses	\$ 1,043	\$ 1,512	-31.02%
Production taxes	\$ 422	\$ 280	50.71%
Depreciation, depletion and amortization	\$ 2,459	\$ 2,075	18.51%
General and administrative	\$ 2,493	\$ 2,276	9.53%
Realized gains on derivative contracts	\$ 862	\$ 1,246	NM
Unrealized losses from the change in market value of open derivative contracts	\$ 8,647	\$ 4,574	NM
Interest expense, net of amounts capitalized	\$ 1,303	\$ 875	48.91%
Income tax benefit	\$ 1,234	\$ 497	NM
Discontinued operations	\$	\$ 76	NM

NM-Not Meaningful

Gas sales. Gas sales increased by \$3.7 million, or 31.5%, to \$15.6 million compared to the prior year quarter. The increase in gas sales was a result of both increased gas prices and production. Production increased 10% and average gas prices increased 20%, excluding hedging transactions. The \$3.7 million increase in gas sales consisted of a \$2.5 million increase in prices and a \$1.2 million increase in production. The increase in production was principally attributable to the continued development activities at our Pond Creek and Gurnee fields.

Lease operating expenses. Lease operating expenses increased by \$0.38 million, or 11%, to \$3.75 million compared to the prior year quarter. The increase in lease operating expenses consisted of \$0.32 million increase in production and \$0.06 million increase in costs. The increase in costs is due to well treatments, and well servicing.

Compression and transportation expenses. Compression and transportation expenses decreased by \$0.47 million, or 31%, to \$1.04 million compared to the prior year quarter. The \$0.47 million decrease was primarily comprised of a decrease in transportation expenses resulting from the commencement of transportation on our own system and the temporary release of a portion of our firm capacity commitments. Compression remained flat compared the same period in the prior year.

Production taxes. Production taxes increased by \$0.14 million, or 51%, to \$0.42 million compared to the prior year quarter. The increase in production taxes consisted of \$0.03 million increase in production and a \$0.11 million increase in prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by \$0.38 million, or 18%, to \$2.46 million compared to the prior year quarter. The depreciation, depletion and amortization increase consisted of a \$0.20 million increase in production and a \$0.18 million decrease in the depletion rate.

General and administrative. General and administrative expenses increased by \$0.22 million, or 9.5%, to \$2.5 million compared to the prior year quarter. The primary drivers for the increased general and administrative expenses were professional services and employee expenses. Professional services consisted of increased audit fees, Sarbanes-Oxley compliance costs, tax services and legal services. Employee expenses increased as a result of increased personnel and higher costs of salary and wages.

Realized gains on derivative contracts. Realized gains on derivative contracts decreased by \$0.38 million to \$0.86 million compared to the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlement

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paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

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Unrealized losses from the change in market value of open derivative contracts. Unrealized losses from the change in market value of open derivative contracts increased by \$4.07 million to \$8.65 million compared to the prior year quarter. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair value of derivative liabilities increase. The loss was a result of increased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by \$0.43 million to \$1.30 million compared to the prior year quarter. The increase was primarily due to higher outstanding debt and higher interest rates partially offset by our interest rate swaps.

Income tax benefit. Income tax benefit increased by \$0.74 million to \$1.23 million compared to the prior year quarter. The increase in income tax benefit was due to increased pretax loss compared to the prior year quarter. In addition, the effective tax rate for the current quarter increased to 36.6% from 31.1% in the comparable prior year quarter. The increase in the effective tax rate of 5.5% to 36.6% from the prior year quarter was due to state tax rate increases and state apportionment adjustments.

Discontinued operations. In September 2007, we discontinued the third party marketing business and second reportable segment that had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows from operations for the three months ended March 31, 2008 and 2007 were \$3.8 million and \$4.0 million, respectively. Cash flows from operations of \$3.8 million for the three months ended March 31, 2008, combined together with net cash provided by financing activities of \$4.5 million, were sufficient to fund net cash used in investing activities of \$7.2 million, which primarily includes capital expenditures for the exploration and development of our gas properties. Net cash provided by financing activities was related to the credit facility net borrowings.

As of March 31, 2008 and December 31, 2007, we had a working capital deficit of approximately \$1.4 million and \$2.1 million, respectively. At March 31, 2008, we had adequate cash flows from operating activities and adequate credit availability to fund our working capital deficits.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our credit facility and proceeds from future equity offerings will provide us with the ability to develop our existing properties and conduct exploration on our unevaluated properties.

If natural gas commodity prices decrease from their current levels for an extended period, our ability to finance our planned capital expenditures could be negatively affected. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and current natural gas prices. If either our estimated proved reserves or natural gas prices decrease, the amount available for us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated, if the amounts available for borrowing under our revolving credit facility are reduced, or if we are unable to sell equity at acceptable prices, we may be forced to defer planned capital expenditures.

Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that natural gas prices will not be subject to wide fluctuations in the future. 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.

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We enter into hedging transactions that increase our statistical probability of achieving our targeted level of cash flows and at times hedge forward for periods of more than two years. We generally limit the amount of these hedges during any period to no more than 50% to 60% of the then expected gas production for such future periods. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. 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. Three-way costless collars are similar to regular costless collars except that, in order to increase the ceiling price, we agree to limit the amount of the floor price protection (a sold floor) to a predetermined amount, generally between \$2.00 and \$3.00 per MMBtu. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices rise above the level of our hedges and gains during periods where prices drop below the level of our hedges causing significant fluctuations in our statement of operations.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments does materially affect our results of operations as a result of changes in the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

Table of Contents*Commodity Price Risk and Related Hedging Activities*

At March 31, 2008, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
Summer 2008	1,712,000	\$ 10.50	\$ 7.00	\$ 5.00
Winter 2008/2009	906,000	\$ 11.00	\$ 8.50	\$ 6.25
Winter 2008/2009	906,000	\$ 11.00	\$ 8.84	\$ 6.00
Summer 2009	1,284,000	\$ 10.00	\$ 7.50	\$ 5.25
Summer 2009	1,284,000	\$ 10.00	\$ 8.50	\$ 6.50
Winter 2009/2010	906,000	\$ 11.20	\$ 9.50	\$ 7.00

At March 31, 2008, we had the following natural gas swap position:

Period	Volume in MMBtu s	Price
Summer 2008	736,000	\$ 8.00

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market of natural gas may have on the fair value of our natural gas derivative instruments. At March 31, 2008, the potential change in the fair value of our derivative contracts assuming a 10% increase in the underlying commodity price would be a \$5.4 million decrease in the unrealized gain on derivative contracts reported on our unaudited consolidated statements of operations and comprehensive income for the three months ended March 31, 2008.

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge at the time we prepare the documentation required under SFAS No. 133. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At March 31, 2008, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%(1)	\$ 15,000,000
Floating-to-fixed swap	1/3/2008	1/4/2010	3.95%(1)	\$ 10,000,000
Floating-to-fixed swap	3/25/2008	3/25/2010	2.38%(1)	\$ 10,000,000

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

For the three months ended March 31, 2008, we recognized no ineffective portion of our cash flow hedges.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

The application of SFAS 157 currently applies to our derivative instruments. Under the provisions of SFAS 157, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

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

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

Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for SFAS 157 reporting purposes. The fair value of our natural gas hedge asset was \$12,861 at March 31, 2008. The fair value of our natural gas hedge liabilities and interest rate swap liabilities were \$6,319,872 and \$749,435 at March 31, 2008, respectively. As of December 31, 2007, our natural gas hedges and interest rate swaps represented only assets in our consolidated balance sheets. The fair value of our natural gas hedge assets and interest rate swap assets were \$2,326,791 and \$10,884 at December 31, 2007, respectively.

Table of Contents***Capital Expenditures and Capital Resources***

The development of CBM fields requires substantial initial investment before meaningful production and resulting cash flows are realized. Among the factors that can be expected to affect our cash flows and liquidity are the characteristics of the field, the amount of water produced, the methods utilized to dispose of produced water, and the timing and volume of initial and subsequent natural gas production. We estimate total capital expenditures in 2008 will be approximately \$48.8 million as compared to \$59.8 million expended in 2007. The current year budget includes approximately \$34.3 million for development, \$4.7 million for exploration and evaluation, \$1.5 million for leasehold and \$5.3 million for other capitalized costs. Approximately \$21.6 million of the 2008 capital budget is allocated to the Pond Creek and Lasher fields in Virginia and West Virginia; \$9.7 million is allocated to the Gurnee field and the Garden City Chattanooga Shale prospect in Alabama; and \$9.1 million is allocated to the Peace River field in British Columbia. As of March 31, 2008, we had approximately \$79.5 million of available borrowing capacity under our revolving credit facility.

The following represents total capital expenditures for the three months ended March 31, 2008 (in millions):

Gurnee	\$ 2.1
Pond Creek	2.4
Lasher	0.6
Garden City	1.2
Peace River	0.6
Other	0.6
Total	\$ 7.5

Revolving Credit Facility

In June 2006, we entered into a \$180 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under our credit agreement is subject to a borrowing base, which is currently set at \$180 million. Our credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent's base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the same period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA, as defined in the amended credit agreement, excludes other non-cash charges deducted in determining net income (loss), which would include unrealized losses from the change in the market value of open derivative contracts. In addition, we are 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. A breach of any of the covenants imposed on us by the terms of our revolving credit facility, including the financial covenants, could result in a default under such indebtedness. 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 facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business. As of March 31, 2008, we were in compliance with all of the covenants in the credit agreement.

In addition, the borrowing base under our revolving credit facility is redetermined semi-annually and may be redetermined at other times upon request by the lenders under certain circumstances. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. Using our December 31, 2007 reserve report, the borrowing base was reaffirmed at \$180 million as of February 29, 2008. The next scheduled redetermination is to occur as of June 30, 2008. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the revolving credit facility and an acceleration of our indebtedness. At March 31, 2008, we had \$100.5 million outstanding under our revolving credit facility. Interest on the borrowings averaged 4.28% per annum. Borrowing availability at March 31, 2008 was \$79.5 million.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments.

Discontinued Operations

As of September 30, 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46(R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result, we are treating our third party marketing activities as a discontinued operation for all the periods presented.

The marketing activities of Shamrock Energy LLC have been transitioned to GeoMet, Inc without disruption in the marketing of our gas, and we do not expect to incur significant liabilities or sell any assets in connection with discontinuing this business. As a result, the discontinued operations have an insignificant impact on our cash flows.

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Recent Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard No. 157, Fair Value Measurements (SFAS 157). SFAS 157 is effective for fiscal years beginning after November 15, 2007. Effective January 1, 2008, GeoMet, Inc. adopted SFAS 157, which provides a framework for measuring fair value under accounting principles generally accepted in the United States. SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are observed from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of SFAS 157 in Note 6 Derivative Instruments and Hedging Activities.

On February 15, 2007, the FASB issued SFAS Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB 115 (SFAS 159). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of SFAS 159 are elective; however, the amendment to FASB 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities that own trading and available-for-sale securities. The fair value option created by SFAS 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. SFAS 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Effective January 1, 2008, we adopted SFAS 159. We did not elect the fair value option for any of our assets or liabilities that did not already require such treatment under other authoritative literature.

In March 2008, the FASB issued SFAS Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). This standard changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact of SFAS 161 on our disclosure relating to derivative instruments and hedging activities.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity 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 year ended March 31, 2008, a 10% fluctuation in the prices received for natural gas production would have had an approximate \$5.1 million impact on our revenues.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At March 31, 2008, we had \$100.5 million outstanding under our revolving credit facility. Interest on the borrowings averaged 4.28% per annum. Borrowing availability at March 31, 2008 was \$79.5 million. All of the debt outstanding under our revolving credit facility 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 revolving credit facility at March 31, 2008, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately \$0.8 million. \$35 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swap discussed above.

Foreign Currency Exchange Rate Risk. We have exploratory operations in Canada and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. Because our Canadian project is exploratory, the effect of changes in the exchange rate does not impact our revenues or expenses but primarily affects the costs of unevaluated properties. We continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2008 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls Over Financial Reporting

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

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

CNX Surface Use Disputes

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company (PMC) in Buchanan County, Virginia. Our Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC (CNX), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

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On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We expect to present oral arguments before the Virginia Supreme Court in early June, 2008. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the property. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. If such an alternative is unavailable, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company (Island Creek), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, in which we sought damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit sought compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX's alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleged CNX's intentional interference with our existing and prospective third-party business relationships in an attempt to harm us and improve CNX's position and corporate and financial interests. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we have filed an amended petition that restates with specificity our claims against CNX and Island Creek, names Cardinal States Gathering Company and CONSOL Energy Inc., the ultimate parent of the other defendants, as additional defendants, and seeks actual damages of \$385.6 million. We are seeking treble damages for the alleged violations of the Virginia Antitrust Act, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities.

As of March 31, 2008, 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 material 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, 2007.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information.

None.

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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 9, 2008

By /s/ William C. Rankin
William C. Rankin, Executive Vice President and Chief Financial
Officer
(Principal Financial Officer)

INDEX TO EXHIBITS

Exhibit Number	Exhibits
31.1*	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).
31.2*	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).
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).

* Attached hereto