GeoMet, Inc.
Form 10-Q
July 27, 2010


# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**WASHINGTON, D.C. 20549**

# FORM 10-Q

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

**For the quarterly period ended June 30, 2010**

**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)**

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

**909 Fannin, Suite 1850**

**Houston, Texas 77010**

**(713) 659-3855**

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

**N/A**

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

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

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

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

| | |
|---|---|
| Large accelerated filer ¨ | Accelerated filer ¨ |
| Non-accelerated filer x (Do not check if a smaller reporting company) | 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 x No

As of July 21, 2010, there were 39,462,762 shares issued and outstanding of GeoMet, Inc. s common stock, par value $0.001 per share.

Table of Contents

## TABLE OF CONTENTS

Table of Contents

**Part I. Financial Information**

**Item 1. Financial Statements**

**GEOMET, INC. AND SUBSIDIARIES**

**Consolidated Balance Sheets**

**(Unaudited)**

| | June 30, 2010 | December 31, 2009 |
|---|---|---|
| **ASSETS** | | |
| Current Assets: | | |
| Cash and cash equivalents | $ 493,701 | $ 973,720 |
| Accounts receivable, both amounts net of allowance of $60,848 | 2,477,084 | 2,909,293 |
| Inventory | 1,533,639 | 2,131,901 |
| Derivative asset | 6,075,383 | 2,563,898 |
| Other current assets | 1,274,080 | 475,025 |
| Total current assets | 11,853,887 | 9,053,837 |
| Gas properties utilizing the full cost method of accounting: | | |
| Proved gas properties | 466,336,932 | 461,003,091 |
| Other property and equipment | 3,341,182 | 3,480,202 |
| Total property and equipment | 469,678,114 | 464,483,293 |
| Less accumulated depreciation, depletion, amortization and impairment of gas properties | (369,147,640) | (365,784,964) |
| Property and equipment net | 100,530,474 | 98,698,329 |
| Other noncurrent assets: | | |
| Derivative asset | 1,917,335 | 761,192 |
| Deferred income taxes | 49,711,842 | 51,804,971 |
| Other | 244,507 | 609,972 |
| Total other noncurrent assets | 51,873,684 | 53,176,135 |
| TOTAL ASSETS | $ 164,258,045 | $ 160,928,301 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current Liabilities: | | |
| Accounts payable | $ 4,967,011 | $ 5,169,174 |
| Accrued liabilities | 4,016,250 | 2,808,227 |
| Deferred income taxes | 1,549,919 | 157,256 |
| Derivative liability | 266,189 | 724,253 |
| Asset retirement liability | 104,739 | 108,111 |
| Current portion of long-term debt | 129,050 | 121,792 |
| Total current liabilities | 11,033,158 | 9,088,813 |

| | | |
|---|---|---|
| Long-term debt | 116,406,256 | 119,996,163 |
| Asset retirement liability | 5,127,043 | 4,862,278 |
| Other long-term accrued liabilities | 57,017 | 73,308 |
| TOTAL LIABILITIES | 132,623,474 | 134,020,562 |
| Commitments and contingencies (Note 11) | | |
| 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 39,457,612 and 39,460,060 at June 30, 2010 and December 31, 2009, respectively | 39,294 | 39,294 |
| Treasury stock 10,432 shares at June 30, 2010 and December 31, 2009 | (94,424) | (94,424) |
| Paid-in capital | 189,860,397 | 189,681,816 |
| Accumulated other comprehensive loss | (1,479,744) | (1,768,521) |
| Retained deficit | (156,445,860) | (160,710,889) |
| Less notes receivable | (245,092) | (239,537) |
| Total stockholders equity | 31,634,571 | 26,907,739 |
| TOTAL LIABILITIES AND STOCKHOLDERS EQUITY | $ 164,258,045 | $ 160,928,301 |

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Consolidated Statements of Operations**

**(Unaudited)**

| | Three Months Ended June 30, 2010 | Three Months Ended June 30, 2009 | Six Months Ended June 30, 2010 | Six Months Ended June 30, 2009 |
|---|---|---|---|---|
| Revenues: | | | | |
| Gas sales | $ 7,661,353 | $ 6,837,910 | $ 17,545,039 | $ 16,290,419 |
| Operating fees | 70,703 | 76,923 | 144,995 | 174,934 |
| Total revenues | 7,732,056 | 6,914,833 | 17,690,034 | 16,465,353 |
| Expenses: | | | | |
| Lease operating expense | 2,812,883 | 3,348,170 | 5,920,254 | 7,917,487 |
| Compression and transportation expense | 1,075,392 | 1,364,841 | 2,079,839 | 2,814,965 |
| Production taxes | 288,039 | 240,593 | 496,268 | 607,655 |
| Depreciation, depletion and amortization | 1,450,238 | 1,981,707 | 3,095,603 | 5,018,438 |
| Impairment of gas properties | | 27,582,106 | | 167,294,577 |
| General and administrative | 1,314,840 | 2,180,889 | 2,792,565 | 5,153,501 |
| Terminated transaction costs | 1,402,534 | | 1,402,534 | |
| Realized gains on derivative contracts | (2,210,850) | (2,733,816) | (3,670,978) | (5,457,120) |
| Unrealized losses (gains) from the change in market value of open derivative contracts | 2,974,026 | 2,144,115 | (4,668,016) | 1,958,232 |
| Total operating expenses | 9,107,102 | 36,108,605 | 7,448,069 | 185,307,735 |
| Operating (loss) income | (1,375,046) | (29,193,772) | 10,241,965 | (168,842,382) |
| Other income (expense): | | | | |
| Interest income | 5,057 | 5,674 | 30,861 | 15,634 |
| Interest expense (net of amounts capitalized) | (1,423,476) | (1,418,402) | (2,667,636) | (2,401,447) |
| Other | 625 | 8,750 | (16,702) | 7,732 |
| Total other income (expense): | (1,417,794) | (1,403,978) | (2,653,477) | (2,378,081) |
| (Loss) income before income taxes | (2,792,840) | (30,597,750) | 7,588,488 | (171,220,463) |
| Income tax benefit (expense) | 1,030,717 | 11,211,554 | (3,323,459) | 64,108,463 |
| Net (loss) income | $ (1,762,123) | $ (19,386,196) | $ 4,265,029 | $ (107,112,000) |
| Earnings per share: | | | | |
| Net (loss) income | | | | |
| Basic | $ (0.04) | $ (0.50) | $ 0.11 | $ (2.75) |
| Diluted | $ (0.04) | $ (0.50) | $ 0.11 | $ (2.75) |
| Weighted average number of common shares: | | | | |
| Basic | 39,240,545 | 39,122,570 | 39,199,990 | 39,024,353 |
| Diluted | 39,240,545 | 39,122,570 | 39,290,788 | 39,024,353 |

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Consolidated Statements of Comprehensive (Loss) Income**

**(Unaudited)**

| | Three Months Ended June 30, 2010 | Three Months Ended June 30, 2009 | Six Months Ended June 30, 2010 | Six Months Ended June 30, 2009 |
|---|---|---|---|---|
| Net (loss) income | $ (1,762,123) | $ (19,386,196) | $ 4,265,029 | $ (107,112,000) |
| (Loss) gain on foreign currency translation adjustment | (2,899) | 85,871 | 5,934 | 181,264 |
| Gain on interest rate swap | 115,891 | 32,138 | 282,844 | 31,199 |
| Other comprehensive (loss) income | $ (1,649,131) | $ (19,268,187) | $ 4,553,807 | $ (106,899,537) |

See accompanying Notes to Consolidated Financial Statements (Unaudited)

**Table of Contents**

**GEOMET, INC. AND SUBSIDIARIES**

**Consolidated Statements of Cash Flows**

**(Unaudited)**

| | Six Months Ended June 30, 2010 | Six Months Ended June 30, 2009 |
|---|---|---|
| Cash flows provided by operating activities: | | |
| Net income (loss) | $ 4,265,029 | $ (107,112,000) |
| Adjustments to reconcile net income (loss) to net cash flows provided by operating activities: | | |
| Depreciation, depletion and amortization | 3,095,603 | 5,018,438 |
| Impairment of gas properties | | 167,294,577 |
| Amortization of debt issuance costs | 189,028 | 102,481 |
| Terminated transaction costs | 666,306 | |
| Deferred income tax expense (benefit) | 3,310,959 | (64,120,962) |
| Unrealized (gains) losses from the change in market value of open derivative contracts | (4,668,016) | 1,958,232 |
| Stock-based compensation | 79,569 | 501,114 |
| Loss on sale of other assets | 23,685 | 31,076 |
| Accretion expense | 241,395 | 212,640 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | 434,118 | 2,881,388 |
| Inventory | 600,555 | (182,207) |
| Other current assets | 322,224 | 349,625 |
| Accounts payable | (1,292,025) | (3,903,241) |
| Other accrued liabilities | 1,206,121 | 211,538 |
| Net cash provided by operating activities | 8,474,551 | 3,242,699 |
| Cash flows used in investing activities: | | |
| Capital expenditures | (4,167,601) | (9,264,458) |
| Proceeds from sale of other property and equipment | 31,838 | 19,165 |
| Other assets | 75,285 | (56,593) |
| Net cash used in investing activities | (4,060,478) | (9,301,886) |
| Cash flows (used in) provided by financing activities: | | |
| Proceeds from exercise of stock options | 46,327 | |
| Proceeds from revolver borrowings | 10,500,000 | 28,550,000 |
| Payments on revolver | (14,000,000) | (23,300,000) |
| Deferred financing costs | (703,245) | |
| Deferred financing costs related to terminated transactions | (666,306) | |
| Purchase of treasury stock | | (613) |
| Payments on other debt | (82,650) | (75,990) |
| Net cash (used in) provided by financing activities | (4,905,874) | 5,173,397 |
| Effect of exchange rate changes on cash | 11,782 | 9,888 |
| Decrease in cash and cash equivalents | (480,019) | (875,902) |
| Cash and cash equivalents at beginning of period | 973,720 | 2,096,561 |
| Cash and cash equivalents at end of period | $ 493,701 | $ 1,220,659 |
| Significant noncash investing activities: | | |
| Accrued capital expenditures | $ 1,650,768 | $ 382,668 |

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements**

**(Unaudited)**

**Note 1 Organization and Our Business**

GeoMet, Inc. ( GeoMet, Company, we, or our ) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coalbed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia, 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 unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America ( GAAP ). Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2009 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 31, 2010.

**Note 2 Recent Pronouncements**

In January 2010, the FASB issued Update No. 2010-06 Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This Update provides amendments to Subtopic 820-10 that require new disclosures for transfers in and out of Levels 1 and 2. This Update also clarifies existing disclosures for level of disaggregation, as well as valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. See additional disclosure provided in Note 6 Derivative Instruments and Hedging Activities.

**Note 3 (Loss) Income Per Share**

***(Loss) Income Per Share of Common Stock*** Basic (loss) income per share is calculated by dividing net (loss) income by the weighted average number of shares of common stock outstanding during the period. Fully diluted (loss) income per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net (loss) income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive (loss) income 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Net (loss) income per share:** | | | | |
| Basic-net (loss) income per share | $ (0.04) | $ (0.50) | $ 0.11 | $ (2.75) |
| Diluted-net (loss) income per share | $ (0.04) | $ (0.50) | $ 0.11 | $ (2.75) |
| **Numerator:** | | | | |
| Net (loss) income available to common stockholders | $ (1,762,123) | $ (19,386,196) | $ 4,265,029 | $ (107,112,000) |
| **Denominator:** | | | | |

| | | | | |
|---|---|---|---|---|
| Weighted average shares outstanding-basic | 39,240,545 | 39,122,570 | 39,199,990 | 39,024,353 |
| Add potentially dilutive securities: | | | | |
| Stock options | | | 90,798 | |
| Dilutive securities | 39,240,545 | 39,122,570 | 39,290,788 | 39,024,353 |

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

Diluted net loss per share for the three months ended June 30, 2010 excluded the effect of outstanding options to purchase 2,206,132 shares and 161,728 shares of restricted stock because we reported a net loss, which caused options to be anti-dilutive. Diluted net income per share for the six months ended June 30, 2010 excluded the effect of outstanding options to purchase 1,661,626 shares because the strike prices of the options were above the average market price of our common stock for the period and would have therefore been anti-dilutive. Diluted net loss per share for the three and six months ended June 30, 2009 excluded the effect of outstanding options to purchase 2,444,333 shares and 329,410 shares of restricted stock because we reported a net loss, which caused options to 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 SEC. Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into United States of America ( U.S. ) and Canadian cost centers. The Canadian cost center was fully impaired in 2009.

Gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved gas reserves. Depletion for the three months ended June 30, 2010 and 2009 was $0.72 and $0.96 per Mcf, respectively. Depletion for the six months ended June 30, 2010 and 2009 was $0.78 and $1.24 per Mcf, respectively.

Estimation of proved gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during future reporting periods. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

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

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. In addition, subsequent to the adoption of Accounting Standards Codification ( ASC ) 410-20-25, formerly Financial Accounting Standard Board ( FASB ) Statement No. 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

No impairments were recorded during the three and six months ended June 30, 2010.

At June 30, 2009, the carrying value of the Company s gas properties in the U.S. and Canada exceeded the full cost ceiling limitation based upon the natural gas prices per Mcf in effect as of the balance sheet date, adjusted for location differentials, which were approximately $4.00 and $3.57, respectively. For the three months ended June 30, 2009, impairments recorded to gas properties were:

| | United States | Canada | Total |
|---|---|---|---|
| Impairment of gas properties | $ 27,082,174 | $ 499,932 | $ 27,582,106 |
| Deferred income tax benefit | (10,345,392) | | (10,345,392) |
| Impairment of gas properties, net of tax | $ 16,736,782 | $ 499,932 | $ 17,236,714 |

For the six months ended June 30, 2009, impairments recorded to gas properties were:

| | United States | Canada | Total |
|---|---|---|---|
| Impairment of gas properties | $ 165,453,805 | $ 1,840,772 | $ 167,294,577 |
| Deferred income tax benefit | (63,203,421) | | (63,203,421) |
| Impairment of gas properties, net of tax | $ 102,250,384 | $ 1,840,772 | $ 104,091,156 |

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

**Note 5 Asset Retirement Liability**

We record an asset retirement obligation ( ARO ) on the consolidated balance sheets and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date we incurred the abandonment obligation using an assumed interest rate. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed interest rate. The following table details the changes to our asset retirement liability for the six months ended June 30, 2010:

| | |
|---|---|
| Current portion of liability at January 1, 2010 | $ 108,111 |
| Add: Long-term asset retirement liability at January 1, 2010 | 4,862,278 |
| Asset retirement liability at January 1, 2010 | 4,970,389 |
| Liabilities incurred | 20,017 |
| Liabilities settled | (3,792) |
| Accretion | 241,395 |
| Foreign currency translation | 3,773 |
| Asset retirement liability at June 30, 2010 | 5,231,782 |
| Less: Current portion of liability | (104,739) |
| Long-term asset retirement liability | $ 5,127,043 |

**Note 6 Derivative Instruments and Hedging Activities**

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

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. 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 (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

***Commodity Price Risk and Related Hedging Activities***

At June 30, 2010, we had the following natural gas collar positions:

| **Period** | **Volume (MMBtu)** | **Sold Ceiling** | **Bought Floor** | **Sold Floor** | **Fair Value** |
|---|---|---|---|---|---|
| July through October 2010 | 492,000 | $ 6.80 | $ 5.50 | $ 3.50 | $ 429,186 |
| July through October 2010 | 492,000 | $ 6.35 | $ 5.50 | | 436,893 |
| November 2010 through March 2011 | 604,000 | $ 7.45 | $ 6.50 | | 815,931 |
| | 1,588,000 | | | | $ 1,682,010 |

At December 31, 2009, we had the following natural gas collar positions:

| Period | Volume (MMBtu) | Sold Ceiling | Bought Floor | Sold Floor | Fair Value |
|---|---|---|---|---|---|
| January 2010 through March 2010 | 540,000 | $ 11.20 | $ 9.50 | $ 7.00 | $ 1,326,724 |
| January 2010 through March 2010 | 360,000 | $ 6.65 | $ 5.50 | $ 3.50 | 65,098 |
| April through October 2010 | 856,000 | $ 6.80 | $ 5.50 | $ 3.50 | 172,072 |
| April through October 2010 | 856,000 | $ 6.35 | $ 5.50 | | 116,559 |
| November 2010 through March 2011 | 604,000 | $ 7.45 | $ 6.50 | | 160,745 |
| | 3,216,000 | | | | $ 1,841,198 |

9

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

At June 30, 2010, we had the following natural gas swap positions:

| Period | Volume (MMBtu) | Price | Fair Value |
|---|---|---|---|
| July through October 2010 | 492,000 | $ 5.70 | $ 499,183 |
| July through October 2010 | 369,000 | $ 6.30 | 595,472 |
| November 2010 through March 2011 | 604,000 | $ 6.67 | 839,421 |
| November 2010 through March 2011 | 906,000 | $ 7.27 | 1,795,809 |
| April 2011 through October 2011 | 856,000 | $ 6.37 | 980,013 |
| April 2011 through October 2011 | 856,000 | $ 5.37 | 131,075 |
| April 2011 through October 2011 | 856,000 | $ 5.43 | 185,981 |
| November 2011 through March 2012 | 608,000 | $ 7.12 | 741,714 |
| November 2011 through March 2012 | 608,000 | $ 6.12 | 143,656 |
| April 2012 through October 2012 | 856,000 | $ 5.73 | 205,565 |
| November 2012 through March 2013 | 604,000 | $ 6.42 | 192,819 |
| | 7,615,000 | | $ 6,310,708 |

At December 31, 2009, we had the following natural gas swap positions:

| Period | Volume (MMBtu) | Price | Fair Value |
|---|---|---|---|
| April through October 2010 | 856,000 | $ 5.70 | $ 5,341 |
| April through October 2010 | 642,000 | $ 6.30 | 387,383 |
| November 2010 through March 2011 | 604,000 | $ 6.67 | 61,493 |
| November 2010 through March 2011 | 906,000 | $ 7.27 | 625,564 |
| April 2011 through October 2011 | 856,000 | $ 6.37 | 236,887 |
| November 2011 through March 2012 | 608,000 | $ 7.12 | 166,836 |
| | 4,472,000 | | $ 1,483,504 |

***Interest Rate Risks and Related Hedging Activities***

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

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 June 30, 2010, we had the following interest rate swaps:

| Description | Effective date | Designated maturity date | Fixed rate (1) | Notional amount | Fair Value |
|---|---|---|---|---|---|
| Floating-to-fixed swap | 12/14/2007 | 12/14/2010 | 3.86% | $ 15,000,000 | $ (243,978) |
| Floating-to-fixed swap | 1/6/2009 | 1/6/2011 | 1.38% | $ 5,000,000 | (22,211) |
| | | | | $ 20,000,000 | $ (266,189) |

At December 31, 2009, we had the following interest rate swaps:

| Description | Effective date | Designated maturity date | Fixed rate (1) | Notional amount | Fair Value |
|---|---|---|---|---|---|
| Floating-to-fixed swap | 12/14/2007 | 12/14/2010 | 3.86% | $ 15,000,000 | $ (479,566) |
| Floating-to-fixed swap | 1/3/2008 | 1/4/2010 | 3.95% | $ 10,000,000 | (87,493) |
| Floating-to-fixed swap | 3/25/2008 | 3/25/2010 | 2.38% | $ 10,000,000 | (50,745) |
| Floating-to-fixed swap | 5/13/2008 | 5/13/2010 | 3.07% | $ 5,000,000 | (67,783) |
| Floating-to-fixed swap | 1/6/2009 | 1/6/2011 | 1.38% | $ 5,000,000 | (38,278) |
| | | | | $ 45,000,000 | $ (723,865) |

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

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

For the three and six months ended June 30, 2010 and 2009, 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 revolving credit facility agreement and the collateral for the outstanding borrowings under our revolving credit facility agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our revolving credit facility agreement.

The application of ASC 820-10-55, formerly SFAS No. 157, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both as of the reporting date. 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 natural gas price curve and volatility estimates were compiled from sources that include NYMEX settlements and observed trading activity in the Over-the-Counter (OTC) markets. Pricing estimates for the theoretical market value of hedge positions were developed using analytical models accepted and employed by a broad cross-section of industry participants. To extrapolate future cash flows, discount factors incorporating our counterparties and our credit standing are used to discount future cash flows.

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

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the three and six months ended June 30, 2010. Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our derivative instruments were as follows:

| | Asset Derivatives | | | | Liability Derivatives | | | |
|---|---|---|---|---|---|---|---|---|
| | June 30, 2010 | | December 31, 2009 | | June 30, 2010 | | December 31, 2009 | |
| | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| **Derivatives designated as hedging instruments under ASC 815-20-25** | | | | | | | | |
| Interest rate swaps | Derivative asset (current) | $ | Derivative asset (current) | $ | Derivative liability (current) | $ 266,189 | Derivative liability (current) | $ 724,253 |
| Interest rate swaps | Derivative asset (non-current) | | Derivative asset (non-current) | 388 | Derivative liability (non-current) | | Derivative liability (non-current) | |
| **Total derivatives designated as hedging instruments under ASC 815-20-25** | | $ | | $ 388 | | $ 266,189 | | $ 724,253 |
| **Derivatives not designated as hedging instruments under ASC 815-20-25** | | | | | | | | |
| Natural gas hedge positions | Derivative asset (current) | $ 6,075,383 | Derivative asset (current) | $ 2,563,898 | Derivative liability (current) | $ | Derivative liability (current) | $ |
| Natural gas hedge positions | Derivative asset (non-current) | 1,917,335 | Derivative asset (non-current) | 760,804 | Derivative liability (non-current) | | Derivative liability (non-current) | |
| **Total derivatives not designated as hedging instruments under ASC 815-20-25** | | $ 7,992,718 | | $ 3,324,702 | | $ | | $ |

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

The following (gains) losses on our hedging instruments included in the Consolidated Statements of Operations for the three and six months ended June 30, 2010 and 2009 and the Consolidated Statements of Comprehensive (Loss) Income ( OCI ) for the three and six months ended June 30, 2010 and 2009 are as follows:

| Derivatives | Location of (Gain) or Loss Recognized in Income on Derivative | Amount of (Gain) or Loss Recognized in Income on Derivative — Three months ended June 30, 2010 | 2009 | Six months ended June 30, 2010 | 2009 |
|---|---|---|---|---|---|
| **Derivatives designated as hedging instruments under ASC 815-20-25** | | | | | |
| Interest rate swaps | Interest expense (net of amounts capitalized) | $ (164,129) | $ 259,293 | $ (403,343) | $ 468,533 |
| Total gain (loss) | | $ (164,129) | $ 259,293 | $ (403,343) | $ 468,533 |
| **Derivatives not designated as hedging instruments under ASC 815-20-25** | | | | | |
| Natural gas collar positions | Realized gains on derivative contracts | $ (2,210,850) | $ (2,733,816) | $ (3,670,978) | $ (5,457,120) |
| Natural gas collar positions | Unrealized losses (gains) from the change in market value of open derivative contracts | 2,974,026 | 2,144,115 | (4,668,016) | 1,958,232 |
| Total loss (gain) | | $ 763,176 | $ (589,701) | $ (8,338,994) | $ (3,498,888) |

| | Three months ended June 30, 2010 | 2009 | Six months ended June 30, 2010 | 2009 |
|---|---|---|---|---|
| **Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships - Interest Rate Swaps** | | | | |
| Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | Interest expense | | | |
| Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) | $ 23,397 | $ (210,329) | $ 54,334 | $ (426,531) |
| Location of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) | Interest expense | | | |
| Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | $ (164,129) | $ (259,293) | $ (403,343) | $ (468,533) |
| | Interest expense | | | |
| | $ | $ | $ | $ |

| |
|---|
| Amount of Gain or (Loss) Recognized in income on Derivative<br>(Ineffective Portion and Amount Excluded from Effectiveness Testing) |

Accumulated comprehensive loss of $1,479,744 as of June 30, 2010 consists of $1,315,239 in foreign currency translation adjustments and a $164,505 loss on interest rate swaps, net of income tax benefit. Accumulated comprehensive loss of $164,505 as of June 30, 2010 is expected to be realized as interest expense in the Consolidated Statement of Operations (Unaudited) in the periods within the 12 months ended June 30, 2011.

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

**Note 7 Terminated Transaction Costs**

Terminated transaction costs consist of payments made related to a terminated financing transaction between the Company and NGP Capital Resources Company ( NGPC ) and North Shore Energy, LLC ( North Shore ), an affiliate of Yorktown Energy Partners IV, L.P. ( Yorktown ) (Yorktown is a related party to the Company) and expenses related to a terminated sale of certain gas properties. The following is a detail of terminated transaction costs and related party amounts for the three and six months ended June 30, 2010:

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

**Note 8 Long-Term Debt**

Our current senior secured revolving credit facility is governed by a credit agreement dated as of June 9, 2006 (the Existing Credit Agreement ) between us and a group of five banks. Effective March 30, 2010, and pursuant to our request, the borrowing base under our revolving credit facility was reduced to $123.0 million, our next borrowing base determination was delayed until June 15, 2010, the maturity date was extended to May 6, 2011 and the LIBOR Rate (defined below) option was increased to the LIBOR Rate, plus a margin of 3.50%. On July 15, 2010, our lenders agreed to extend the maturity date of our revolving credit facility to October 1, 2011 and to delay the next borrowing base determination until October 15, 2010. We currently have limited borrowing availability under our revolving credit facility, which matures on October 1, 2011, and we have no assurances that our lenders will extend the maturity date.

On June 3, 2010 we entered into the Pending Credit Agreement with a group of five banks. The Pending Credit Agreement will become effective only upon the closing of a proposed rights offering and backstop transaction contemplated in the Investment Agreement. At that time, the Existing Credit Agreement will be replaced by the Pending Credit Agreement which will provide for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base will be reviewed each June and December with the next redetermination scheduled to take place by December 2010. All outstanding borrowings under the Pending Credit Agreement will become due and payable three years after it becomes effective. The Pending Credit Agreement provides for interest to accrue at a rate calculated, at the Company s 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) plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate ) plus a margin of 2.75% to 3.25% depending on borrowing base usage. Under the Pending Credit Agreement we will be subject to financial covenants requiring maintenance of a minimum Current Ratio, a maximum Debt Ratio and, depending on our Debt Ratio, either a minimum Interest Coverage Ratio or minimum Fixed Charge Ratio. Our ratio ( Current Ratio ) of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities, less $1.5 million, is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio ( Debt Ratio ) of funded debt to consolidated EBITDA (defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization for the four preceding quarters) at the end of each fiscal quarter ending on or before June 30, 2011 cannot exceed 4.5 to 1. Our Debt Ratio at the end of each fiscal quarter ending after June 30, 2011 cannot exceed 4.0 to 1. If our Debt Ratio is above 3.5 to 1, then our ratio ( Fixed Charge Ratio ) of consolidated EBITDA less capital expenditures to consolidated net interest expense for the four preceding quarters at the end of each fiscal quarter cannot be less than 1.25 to 1. If our Debt Ratio is 3.5 to 1 or less, our ratio ( Interest Coverage Ratio ) of consolidated EBITDA to consolidated net interest expense for the preceding four quarters period plus letter of credit fees accruing during such quarters is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the Pending Credit Agreement excludes non-recurring charges and other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from the change in the market value of open derivative contracts. In addition, we would be subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on the preferred stock will be permitted if our availability under the borrowing base is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.

If the Company does not complete the closing of the proposed rights offering and the backstop transaction contemplated in the Investment Agreement dated June 2, 2010 by and between the Company and Sherwood Energy, LLC (the Investment Agreement ) and described below, the lending commitments in the Pending Credit Agreement will not take effect and that agreement will terminate on October 1, 2010, and the Existing Credit Agreement governing our existing senior revolving credit facility will terminate on October 1, 2011.

**Table of Contents**

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

Under the terms of proposed rights offering and backstop transaction as contemplated in the Investment Agreement, three days after the applicable record date the Company would distribute to the holders of its common stock rights to purchase up to an aggregate of 4,000,000 new shares of preferred stock at a subscription price of $10.00 per share. The preferred stock would be convertible into shares of the Company's common stock at a conversion price of $1.30 per share, subject to customary adjustments. In the event that the Company's stockholders do not subscribe for all 4,000,000 shares of preferred stock offered, the Company is obligated to sell to Sherwood, and Sherwood is obligated to purchase, all remaining shares preferred stock that are not subscribed for in the rights offering , at the offered price of $10.00 per share (the backstop transaction ). As compensation for the backstop transaction, the Company will pay Sherwood a backstop fee of $1,200,000. An initial $250,000 fee already paid to Sherwood will be applied against the backstop fee. If the purchase price for shares of preferred stock purchased by Sherwood is less than $30,000,000, the Company must pay Sherwood an additional fee equal to three percent (3%) of the difference between $30,000,000 and the price paid for the shares of preferred stock purchased by Sherwood. In the event that the Investment Agreement is terminated for any reason other than a breach by Sherwood, the Company will owe Sherwood the remaining $950,000 of the backstop fee plus an additional fee of $900,000, representing three percent (3%) of $30,000,000.

Other terms of the Company s preferred stock to be issued in connection with the proposed rights offering include the following:

- Dividends payable quarterly either in cash at an annual rate of 8.0% for the first three years and thereafter at the annual rate of 9.6% or, until the fifth anniversary of the closing date, in additional shares of preferred stock at an annual rate of 12.5%, at the option of the Company;

- After the third anniversary of the closing date, the Company may elect, subject to certain limitations based on trading volume in the Company's common stock, to convert portions of the preferred stock if the average trading price of the Company's common stock exceeds 225% of the conversion price ($2.93 based on a conversion price of $1.30);

- Redeemable at the option of the holder upon the earlier of (i) a liquidation event or (ii) the eighth anniversary of the closing date, and the redemption price for each share of preferred stock will be equal to the price paid for such share plus any accrued and unpaid dividends on such share; and

A liquidation preference that would entitle the holder of preferred stock to receive an amount equal to the greater of (i) the original purchase price for each share of preferred stock held, including shares issued as dividends, plus any accrued and unpaid dividends; or (ii) a per share amount equal to the liquidation distribution payable with respect to shares of the Company's common stock.

The Investment Agreement contains customary representations, warranties and covenants by the Company and Sherwood. Closing of the backstop transaction by Sherwood is not subject to any financing condition. Additionally, the agreement provides for customary indemnity obligations by each of the Company and Sherwood. The Investment Agreement may be terminated prior to closing under certain circumstances, including termination at Sherwood s election if closing does not occur on or before September 15, 2010, by Sherwood or the Company for material breach or default by the other party that has not been cured within thirty (30) days; or (iv) by Sherwood or the Company in the event a material adverse effect has occurred with regard to the other party that is not curable or that has not been cured within thirty (30) days.

The disclosure regarding the proposed rights offering and Investment Agreement contained in this quarterly report on Form 10-Q does not constitute an offer to sell or the solicitation of an offer to buy any securities of GeoMet, Inc., nor shall there be any sale of such securities in any state or other jurisdiction in which such an offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such state or other jurisdiction.

As of June 30, 2010, we had $116.0 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $7.0 million under our $123.0 million borrowing base. For the three months ended June 30, 2010 we borrowed $4.7 million and made payments of $5.9 million under the revolving credit facility. For the six months ended June 30, 2010 we borrowed $10.5 million and made payments of $14.0 million under the revolving credit facility. For the three months ended June 30, 2009 we borrowed $12.1 million and made payments of $11.3 million under the revolving credit facility. For the six months ended June 30, 2009 we borrowed $28.6 million and made payments of $23.3 million under the revolving credit facility. The rates at June 30, 2010 and December 31, 2009, excluding the effect of our interest rate swaps, were 3.87% and 3.03%, respectively. For the three months ended June 30, 2010 and 2009, interest on the borrowings averaged 3.89% per annum and 3.55% per annum, respectively. For the six months ended June 30, 2010 and 2009, interest on the borrowings averaged 3.51% per annum and 2.99% per annum, respectively.

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

The following is a summary of our long-term debt at June 30, 2010 and December 31, 2009:

| | June 30, 2010 | December 31, 2009 |
|---|---|---|
| Borrowings under revolving credit facility | $ 116,000,000 | $ 119,500,000 |
| Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured | 48,961 | 94,190 |
| Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured | 100,285 | 106,825 |
| 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 | 386,060 | 416,940 |
| Total debt | 116,535,306 | 120,117,955 |
| Less current maturities included in current liabilities | (129,050) | (121,792) |
| Total long-term debt | $ 116,406,256 | $ 119,996,163 |

The fair value of long-term debt at June 30, 2010 and December 31, 2009 was estimated to be approximately $114.5 million and $115.8 million, respectively. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the S&P credit rating of a comparable company to ours and the stated interest rates of the debt instruments included our long-term debt, both at June 30, 2010 and December 31, 2009.

**Note 9 Common Stock**

At June 30, 2010 and December 31, 2009, there were 39,457,612 and 39,460,060 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. Also included in common stock outstanding at June 30, 2010 and December 31, 2009 were 161,728 and 311,684 shares of restricted stock, respectively. For the six months ended June 30, 2010, 66,194 shares of restricted stock were forfeited. On March 24, 2010, 300 shares of common stock were purchased by us from a non-executive employee for the payment of $289 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled. For the six months ended June 30, 2009, we issued 166,668 shares of common stock to our independent directors, representing 50% of their annual retainer.

**Note 10 Share-Based Awards**

As of June 30, 2010, we have two stock-based award plans authorized, which include 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 4,000,000 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 stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards, granted to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the three months ended June 30, 2010, we recorded a compensation expense accrual of $111,177 of which $9,688 was allocated to lease operating expenses, $80,473 was allocated to general and administrative expenses, and $21,017 was capitalized to gas properties. During the six months ended June 30, 2010, we recorded a compensation expense accrual of $127,452 of which $22,196 was allocated to lease operating expenses, $58,090 was allocated to general and administrative expenses, and $47,166 was capitalized to gas properties. The weighted average remaining useful life of the future compensation cost is 0.86 years.

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

During the three months ended June 30, 2009, we recorded a compensation expense accrual of $230,702 which $10,234 was allocated to lease operating expenses, $178,446 was allocated to general and administrative expenses, and $42,022 was capitalized to gas properties. During the six months ended June 30, 2009, we recorded a compensation expense accrual of $606,839 which $36,804 was allocated to lease operating expenses, $464,310 was allocated to general and administrative expenses, and $105,725 was capitalized to gas properties.

The significant assumptions used in determining the compensation costs included an expected volatility of 56.10%, risk-free interest rate of 1.25%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends.

***Incentive Stock Options***

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

| | Number of Options | Weighted Average Exercise Price | Average Remaining Contractual Life | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2009 | 997,786 | $ 3.95 | | |
| Exercised | (64,432) | $ 0.72 | | |
| Forfeited | (117,770) | $ 2.92 | | |
| Outstanding at June 30, 2010 | 815,584 | $ 4.35 | 4.60 | $ 185,097 |
| Options exercisable at June 30, 2010 | 433,240 | $ 6.22 | 3.95 | $ 61,699 |

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

The table below summarizes incentive stock option activity for the six months ended June 30, 2009:

| | Number of Options | Weighted Average Exercise Price | Average Remaining Contractual Life | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2008 | 477,169 | $ 8.09 | | |
| Granted | 606,507 | $ 0.72 | | |
| Transferred | (12,048) | $ 8.30 | | |
| Forfeited | (31,625) | $ 2.13 | | |
| Outstanding at June 30, 2009 | 1,040,003 | $ 3.97 | 5.60 | $ |
| Options exercisable at June 30, 2009 | 254,921 | $ 8.27 | 3.57 | $ |

During the three months ended June 30, 2009, no incentive stock options were granted. During the six months ended June 30, 2009, 606,507 incentive stock options were granted with a weighted average grant-date fair value of $200,147. No incentive stock options were exercised during the three and six months ended June 30, 2009.

***Non-Qualified Stock Options***

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

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

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

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

The table below summarizes non-qualified stock option activity for the six months ended June 30, 2009:

| | Number of Options | Weighted Average Exercise Price | Average Remaining Contractual Life | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2008 | 1,280,087 | $ 3.87 | | |
| Granted | 114,012 | $ 0.72 | | |
| Transferred | 12,048 | $ 8.30 | | |
| Forfeited | (1,817) | $ 13.00 | | |
| Outstanding at June 30, 2009 | 1,404,330 | $ 3.64 | 3.52 | $ |
| Options exercisable at June 30, 2009 | 1,158,512 | $ 3.34 | 3.71 | $ |

During the three months ended June 30, 2009, no non-qualified stock options were granted. During the six months ended June 30, 2009, 114,012 non-qualified stock options were granted with a weighted average grant-date fair value of $38,192. During the three and six months ended June 30, 2009, no non-qualified stock options were exercised.

***Restricted Stock Awards***

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

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

During the three and six months ended June 30, 2010, no shares of restricted stock were granted. During the three months ended June 30, 2010, 14,400 shares of restricted stock vested with a grant date fair value of $109,104. During the six months ended June 30, 2010, 83,762 shares of restricted stock vested with a grant date fair value of $565,899.

The table below summarizes non-vested restricted stock awards activity for the six months ended June 30, 2009:

| | Number of Shares | Weighted Average Value at Grant Date | |
|---|---|---|---|
| Non-vested restricted stock at December 31, 2008 | 401,075 | $ | 6.60 |
| Vested | (68,297) | $ | 6.86 |
| Forfeited | (3,368) | $ | 6.58 |
| Non-vested restricted stock at June 30, 2009 | 329,410 | $ | 6.54 |

During the three months ended June 30, 2009, 19,900 shares of restricted stock vested with a grant date fair value of $152,884. During the six months ended June 30, 2009, 68,297 shares of restricted stock vested with a grant date fair value of $463,109.

**Note 11 Commitments and Contingencies**

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

***CNX Antitrust Action***

In May 2010, we reached a global settlement of all outstanding disputes and litigation with CONSOL Energy, Inc. and certain of its affiliates, including CNX Gas Corporation ( CONSOL/ CNX ). As part of the global settlement, CONSOL/ CNX have agreed to grant us all consents and waivers necessary for permits to drill CBM wells on approximately 5,600 acres in the Virginia portion of our Pond Creek field. We have been limited in our ability to secure drilling permits on this acreage since these disputes and litigation began almost four years ago. As a result, we have dismissed our antitrust litigation against CONSOL/CNX with prejudice. Although a state circuit court decision in 2009 cleared the way for us to proceed with discovery and trial in this matter, continuing this litigation would have been an ongoing drain on our resources with no assurance of a successful outcome.

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

***Environmental and Regulatory***

As of June 30, 2010, 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.

***Investment Agreement With Sherwood Energy, LLC***

Pursuant to the Investment Agreement, the Company is obligated to pay Sherwood a backstop fee of $1,200,000; the initial $250,000 fee the Company has already paid to Sherwood will be applied against the backstop fee. If the purchase price for shares of preferred stock purchased by Sherwood is less than $30,000,000, the Company must pay Sherwood an additional fee equal to three percent (3%) of the difference between $30,000,000 and the amount paid for the shares of preferred stock purchased by Sherwood. In the event that the Investment Agreement is terminated for any reason other than a breach by Sherwood, the Company will owe Sherwood the remaining $950,000 of the backstop fee plus an additional fee of $900,000. The Company has also agreed to reimburse certain out-of-pocket expenses of Sherwood in connection with the Investment Agreement.

**Note 12 Income Taxes**

Our effective tax rate differs from the federal statutory rate primarily due to net operating losses ( NOL s ) in Canada and certain states from which we are currently unable to benefit, as well as state income taxes. The deferred tax asset related to the Canadian and certain state NOL s are fully reserved because it is more likely than not that we will not use those NOL s to offset existing tax liabilities in future years. 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 June 30, 2010. For tax reporting purposes, we have federal and state NOL s of approximately $105.5 million and $115.2 million, respectively, at June 30, 2010 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 NOL s will expire prior to 2022.

Income tax benefit for the three months ended June 30, 2010 was different than the amount computed using the statutory rate as follows:

| | U.S. | | Canada | | Total | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | (911,153) | 34.0% | (29,375) | 26.0% | (940,528) | 33.7% |
| State income taxes net of federal benefit | (110,901) | 4.2% | | 0.0% | (110,901) | 4.0% |
| Valuation Allowance | | 0.0% | 29,375 | -26.0% | 29,375 | -1.1% |
| Nondeductible items and other | (8,663) | 0.3% | | 0.0% | (8,663) | 0.3% |
| Income tax benefit | (1,030,717) | 38.5% | | 0.0% | (1,030,717) | 36.9% |

Income tax benefit for the three months ended June 30, 2009 was different than the amount computed using the statutory rate as follows:

| | U.S. | | Canada | | Total | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | (10,008,686) | 34.0% | (301,714) | 26.0% | (10,310,400) | 33.7% |
| State income taxes net of federal benefit | (1,175,899) | 4.0% | | 0.0% | (1,175,899) | 3.8% |
| Valuation Allowance | | 0.0% | 301,714 | -26.0% | 301,714 | -1.0% |
| Nondeductible items and other | (26,970) | 0.1% | | 0.0% | (26,970) | 0.1% |

| | | | | | | |
|---|---|---|---|---|---|---|
| Income tax benefit | (11,211,555) | 38.1% | | 0.0% | (11,211,555) | 36.6% |

Income tax expense for the six months ended June 30, 2010 was different than the amount computed using the statutory rate as follows:

| | **U.S.** | | **Canada** | | **Total** | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | 2,808,929 | 34.0% | (174,998) | 26.0% | 2,633,931 | 34.7% |
| State income taxes net of federal benefit | 380,810 | 4.6% | | 0.0% | 380,810 | 5.0% |
| Valuation Allowance | | 0.0% | 174,998 | -26.0% | 174,998 | 2.3% |
| Nondeductible items and other | 133,720 | 1.6% | | 0.0% | 133,720 | 1.8% |
| Income tax provision | 3,323,459 | 40.2% | | 0.0% | 3,323,459 | 43.8% |

Table of Contents

**GEOMET, INC. AND SUBSIDIARIES**

**Notes to Consolidated Financial Statements (Continued)**

**(Unaudited)**

Income tax benefit for the six months ended June 30, 2009 was different than the amount computed using the statutory rate as follows:

| | U.S. | | Canada | | Total | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | (57,136,272) | 34.0% | (824,877) | 26.0% | (57,961,149) | 33.9% |
| State income taxes net of federal benefit | (7,154,715) | 4.2% | | 0.0% | (7,154,715) | 4.1% |
| Valuation Allowance | | 0.0% | 824,877 | -26.0% | 824,877 | -0.5% |
| Nondeductible items and other | 182,523 | -0.1% | | 0.0% | 182,523 | -0.1% |
| Income tax benefit | (64,108,464) | 38.1% | | 0.0% | (64,108,464) | 37.4% |

Table of Contents

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

Management s Discussion and Analysis of Financial Condition and Results of Operations and other items in this Quarterly Report on Form 10-Q contain forward-looking statements and information that are based on management s beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words believe, anticipate, estimate, expect, intend, and similar express are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. 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, 2009, which are included in our Annual Report on Form 10-K that we filed with the Securities Exchange Commission on March 31, 2010.

***Overview***

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams ( coalbed methane or CBM ) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of June 30, 2010, we control a total of approximately 162,000 net acres of coalbed methane and oil and gas development rights.

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 above current levels, maintain borrowing capacity at or near current levels under our revolving credit facility, and the availability of future debt and equity financing on satisfactory terms. Our ability to fund new opportunities and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Prolonged weakness in the global economy and in natural gas prices, which may affect both our cash flows and the value of our gas reserves, limitations on 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.

We expect to increase our capital expenditures for 2010 from $7.3 million to $13.1 million and expect to fund such expenditures from our operating cash flows in anticipation of an improvement in our financial position and liquidity. If our operating cash flows are not sufficient to fund our planned capital expenditures or our financial position and liquidity do not improve, we expect to reduce our capital expenditures accordingly.

We currently have limited borrowing availability under our revolving credit facility, which matures on October 1, 2011, and we have no assurances that our lenders will extend the maturity date. Accordingly, because the successful completion of the proposed rights offering and backstop transaction cannot be assured, we will continue to explore alternatives for additional financing for the Company. These alternatives may include private or public offerings of debt or equity securities or the sale of assets. The terms, timing and structure of any such financing or sale will depend on several factors, including market conditions, execution risk, timing, possible dilution of existing shareholders and relative cost of the various financing alternatives. There can be no assurance that we will be able to obtain debt or equity financing, including the proposed rights offering, or complete an asset sale on terms favorable to us, or at all.

Additionally, changes in natural gas prices may significantly affect our revenues, financial condition, cash flows, natural gas reserves and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices may materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Although we will attempt to cure

any non-compliance with covenants in our revolving credit facility in the event they occur, no assurance can be given that we will be able to cure such non-compliance. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

***Recent Developments***

*Revolving Credit Facility*

Our current senior secured revolving credit facility is governed by the Existing Credit Agreement. Effective March 30, 2010, and pursuant to our request, the borrowing base under our revolving credit facility was reduced to $123.0 million, our next borrowing base determination was delayed until June 15, 2010, the maturity date was extended to May 6, 2011 and the LIBOR Rate (defined below) option was increased to the LIBOR Rate, plus a margin of 3.50%. On July 15, 2010, our lenders agreed to extend the maturity date of our revolving credit facility to October 1, 2011 and to delay the next borrowing base determination until October 15, 2010. We currently have limited borrowing availability under our revolving credit facility and we have no assurances that our lenders will extend the maturity date.

During the last quarter of 2008 and throughout 2009, reduced natural gas prices significantly limited our operating cash flow. As a result of these reduced cash flows, a severe contraction of the credit markets and the continued underperformance of our Gurnee field, we initiated efforts in the first quarter of 2009 to lower our cost structure, protect our operating margins and reduce borrowings outstanding. These efforts included personnel reductions and other cost reduction measures, increased natural gas price hedging and initiatives to sell assets. Due to reduced operating cash flow our debt-to-EBITDA ratio rose to levels in excess of the ratio considered conforming by our banks and their regulators. Consequently, we have concluded that it was necessary to take steps to reduce our debt-to-EBITDA ratio to conforming levels in order to secure an extension of our credit facility on a long-term basis. Those steps include our proposed rights offering and the Investment Agreement with Sherwood.

On June 3, 2010 we entered into the Pending Credit Agreement with a group of five banks. The Pending Credit Agreement will become effective only upon the closing of a proposed rights offering and backstop transaction contemplated in the Investment Agreement. At that time, the Existing Credit Agreement will be replaced by the Pending Credit Agreement which will provide for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base will be reviewed each June and December with the next redetermination scheduled to take place by December 2010. All outstanding borrowings under the Pending Credit Agreement will become due and payable three years after it becomes effective. The Pending Credit Agreement provides for interest to accrue at a rate calculated, at the Company s 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) plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate ) plus a margin of 2.75% to 3.25% depending on borrowing base usage. For a more detailed discussion of the material terms of our Pending Credit Agreement, see *Liquidity and Capital Resources Revolving Credit Facility.*

*Proposed Rights Offering and Backstop Transaction*

In light of the limited borrowing availability under our current revolving credit facility and our need to replace the existing credit facility with a three-year revolving credit facility, we explored a variety of alternatives for additional financing for the Company. On June 2, 2010, we entered into the Investment Agreement wherein Sherwood agreed to purchase up to $40 million of the Company s convertible preferred stock in the event that a proposed rights offering of convertible preferred stock is not fully subscribed by our common stockholders.

Under the terms of the proposed rights offering and backstop transaction as contemplated in the Investment Agreement, three days after the applicable record date the Company would distribute to the holders of its common stock rights to purchase up to an aggregate of 4,000,000 new shares of preferred stock at a subscription price of $10.00 per share. The preferred stock would be convertible into shares of the Company s common stock at a conversion price of $1.30 per share, subject to customary adjustments. In the event that the Company s stockholders do not subscribe for all 4,000,000 shares of preferred stock offered, the Company is obligated to sell to Sherwood, and Sherwood is obligated to purchase, all remaining shares preferred stock that are not subscribed for in the rights offering, at the offered price of $10.00 per share (the backstop transaction ). As compensation for the backstop transaction, the Company will pay Sherwood a backstop fee of $1,200,000. An initial $250,000 fee already paid to Sherwood will be applied against the backstop fee. If the purchase price for shares of preferred stock purchased by Sherwood is less than $30,000,000, the Company must pay Sherwood an additional fee equal to three percent (3%) of the difference between $30,000,000 and the price paid for the shares of preferred stock purchased by Sherwood. In the event that the Investment Agreement is terminated for any reason other than a breach by Sherwood, the Company will owe Sherwood the remaining $950,000 of the backstop fee plus an additional fee of $900,000, representing three percent (3%) of $30,000,000. For a more detailed discussion of the proposed rights offering and the Investment Agreement, see *Liquidity and Capital Resources Proposed Rights Offering and Backstop Transaction.*

**Table of Contents**

*Operational Developments*

Pond Creek We connected 3 new wells to sales in the three months ended June 30, 2010. We have a total of 246 net producing wells in the Pond Creek field. Net gas sales were 14.5 MMcf per day for the three months ended June 30, 2010, as compared to 14.4 MMcf per day for the three months ended June 30, 2009. Eight new wells have been drilled in the Virginia portion of the Pond Creek field in 2010 including the 3 wells added to sales in the second quarter.

Lasher No new wells were added to sales in the three months ended June 30, 2010. Net gas sales averaged 0.4 MMcf per day from 18 producing wells for the three months ended June 30, 2010, as compared to 0.2 MMcf per day for the three months ended June 30, 2009.

Gurnee No new wells were added to sales in the three months ended June 30, 2010. Net gas sales were 5.1 MMcf per day from a total of 219 producing wells in the Gurnee field for the three months ended June 30, 2010, as compared to 5.9 MMcf per day from a total of 244 producing wells for the three months ended June 30, 2009. We have no drilling scheduled in Gurnee in 2010. In 2009, we fraced a previously uncompleted coal group in three nearby wells in the Gurnee field to test three new frac techniques. We subsequently fraced one of the test wells a second time using the most effective technique with significantly improved results. We applied this frac technique to all of the coal groups previously completed and produced in an existing well and recently applied this frac technique to a number of coal groups in another well that had been previously completed and produced. The results of these fracs are currently being evaluated. We are planning to spend up to $1.2 million testing this frac technique in 2010.

*Critical Accounting Policies*

The preparation of financial statements in conformity with GAAP requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting policies are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the six months ended June 30, 2010.

**Producing Fields Operations Summary**

The table below presents information on gas sales, net sales volumes, production expenses and per Mcf data for the three and six months ended June 30, 2010 and 2009. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands).

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Gas sales | $ 7,661 | $ 6,838 | $ 17,545 | $ 16,290 |
| Lease operating expenses | $ 2,813 | $ 3,348 | $ 5,920 | $ 7,917 |
| Compression and transportation expenses | 1,075 | 1,365 | 2,080 | 2,815 |
| Production taxes | 288 | 241 | 496 | 608 |
| Total production expenses | $ 4,176 | $ 4,954 | $ 8,496 | $ 11,340 |
| Net sales volumes (MMcf) | 1,824 | 1,903 | 3,644 | 3,790 |
| Pond Creek field | 1,319 | 1,312 | 2,614 | 2,603 |
| Gurnee field | 466 | 537 | 941 | 1,094 |
| Per Mcf data ($/Mcf): | | | | |
| Average natural gas sales price | $ 4.20 | $ 3.59 | $ 4.81 | $ 4.30 |
| Average natural gas sales price realized(1) | $ 5.41 | $ 5.03 | $ 5.82 | $ 5.74 |
| Lease operating expenses | $ 1.54 | $ 1.76 | $ 1.62 | $ 2.09 |
| Pond Creek field | $ 1.27 | $ 1.14 | $ 1.30 | $ 1.44 |
| Gurnee field | $ 2.27 | $ 2.74 | $ 2.21 | $ 2.95 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Compression and transportation expenses | $ | 0.59 | $ | 0.72 | $ | 0.57 | $ | 0.74 |
| Pond Creek field | $ | 0.65 | $ | 0.72 | $ | 0.62 | $ | 0.74 |
| Gurnee field | $ | 0.38 | $ | 0.58 | $ | 0.37 | $ | 0.59 |
| Production taxes | $ | 0.16 | $ | 0.13 | $ | 0.14 | $ | 0.16 |
| Pond Creek field | $ | 0.15 | $ | 0.10 | $ | 0.16 | $ | 0.13 |
| Gurnee field (2) | $ | 0.20 | $ | 0.18 | $ | 0.06 | $ | 0.25 |
| Total production expenses | $ | 2.29 | $ | 2.61 | $ | 2.33 | $ | 2.99 |
| Pond Creek field | $ | 2.07 | $ | 1.96 | $ | 2.08 | $ | 2.31 |
| Gurnee field | $ | 2.85 | $ | 3.50 | $ | 2.64 | $ | 3.79 |
| Depreciation, depletion and amortization | $ | 0.79 | $ | 1.04 | $ | 0.85 | $ | 1.32 |

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

(2) The Company received a production tax refund related to prior production in the Gurnee field in March 2010.

Table of Contents

**Results of Operations**

***Three months ended June 30, 2010 compared with three months ended June 30, 2009***

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

| | Three months ended June 30, 2010 | 2009 | Change |
|---|---|---|---|
| | (In thousands) | | |
| Gas sales | $ 7,661 | $ 6,838 | 12% |
| Lease operating expenses | $ 2,813 | $ 3,348 | -16% |
| Compression expense | $ 757 | $ 949 | -20% |
| Transportation expense | $ 318 | $ 416 | -24% |
| Production taxes | $ 288 | $ 241 | 20% |
| Impairment of gas properties | $ | $ 27,582 | -100% |
| Depreciation, depletion and amortization | $ 1,450 | $ 1,982 | -27% |
| General and administrative | $ 1,315 | $ 2,181 | -40% |
| Terminated transaction costs | $ 1,403 | $ | NM |
| Realized gains on derivative contracts | $ (2,211) | $ (2,734) | -19% |
| Unrealized losses from the change in market value of open derivative contracts | $ 2,974 | $ 2,144 | 39% |
| Interest expense, net of amounts capitalized | $ 1,423 | $ 1,418 | 0% |
| Income tax benefit | $ (1,031) | $ (11,212) | -91% |

NM-Not Meaningful

*Gas sales.* Gas sales increased by $0.82 million, or 12%, to $7.66 million compared to the prior year quarter. The increase in gas sales was a result of increased gas prices partially offset by decreased production. Production decreased 4% and average gas prices increased 17%, excluding hedging transactions. The $0.82 million increase in gas sales consisted of a $1.11 million increase in prices and a $0.29 million decrease in production.

*Lease operating expenses.* Lease operating expenses decreased by $0.54 million, or 16%, to $2.81 million compared to the prior year quarter. The decrease in lease operating expenses consisted of a $0.40 million decrease in costs and a $0.14 million decrease in production. The $0.40 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

*Compression expense.* Compression expense decreased by $0.19 million, or 20%, to $0.76 million compared to the prior year quarter. The $0.19 million decrease was comprised of a $0.15 million decrease in costs and a $0.04 million decrease in production. The $0.15 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

*Transportation expense.* Transportation expense decreased by $0.10 million, or 24%, to $0.32 million compared to the prior year quarter. The $0.10 million decrease was primarily due to the permanent release of excess firm transportation capacity effective May 1, 2009.

*Production taxes*. Production taxes increased by $0.05 million, or 20%, to $0.29 million compared to the prior year quarter. The $0.05 million increase in production taxes was primarily due to the gas sales increase from the prior year quarter and diminishing tax exemptions in West Virginia.

Table of Contents

*Impairment of gas properties.* At June 30, 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the current year period.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization decreased by $0.53 million, or 27%, to $1.45 million compared to the prior year quarter. The depreciation, depletion and amortization decrease consisted of a $0.08 million decrease in production and a $0.45 million decrease in the depletion rate.

*General and administrative.* General and administrative expenses decreased by $0.87 million, or 40%, to $1.31 million compared to the prior year quarter. The decrease in general and administrative expenses was primarily due to a company-wide cost reduction strategy implemented in April 2009.

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

*Realized gains on derivative contracts.* Realized gains on derivative contracts decreased by $0.52 million, or 19%, to $2.21 million compared to the prior year quarter. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

*Unrealized 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 $0.83 million to $2.97 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. The loss was a result of the decreased estimated fair value of our natural gas derivative contracts resulting from increased natural gas prices.

*Interest expense (net of amounts capitalized).* Interest expense (net of amounts capitalized) remained materially unchanged compared to the prior year quarter.

*Income tax benefit*. Income tax benefit was $1.03 million in the current year period. The effective tax rate for the period was 36.9%. Income tax benefit for the three months ended June 30, 2010 was different than the amount computed using the statutory rate as follows:

| | U.S. | | Canada | | Total | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | (911,153) | 34.0% | (29,375) | 26.0% | (940,528) | 33.7% |
| State income taxes net of federal benefit | (110,901) | 4.2% | | 0.0% | (110,901) | 4.0% |
| Valuation Allowance | | 0.0% | 29,375 | -26.0% | 29,375 | -1.1% |
| Nondeductible items and other | (8,663) | 0.3% | | 0.0% | (8,663) | 0.3% |
| Income tax benefit | (1,030,717) | 38.5% | | 0.0% | (1,030,717) | 36.9% |

***Six months ended June 30, 2010 compared with six months ended June 30, 2009***

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

| | Six months ended June 30, 2010 | Six months ended June 30, 2009 | Change |
|---|---|---|---|
| | (In thousands) | | |
| Gas sales | $ 17,545 | $ 16,290 | 8% |
| Lease operating expenses | $ 5,920 | $ 7,917 | -25% |
| Compression expense | $ 1,442 | $ 1,782 | -19% |
| Transportation expense | $ 638 | $ 1,033 | -38% |

| | | | | | |
|---|---|---|---|---|---|
| Production taxes | $ | 496 | $ | 608 | -18% |
| Impairment of gas properties | $ | | $ | 167,295 | -100% |
| Depreciation, depletion and amortization | $ | 3,096 | $ | 5,018 | -38% |
| General and administrative | $ | 2,793 | $ | 5,154 | -46% |
| Terminated transaction costs | $ | 1,403 | $ | | NM |
| Realized gains on derivative contracts | $ | (3,671) | $ | (5,457) | -33% |
| Unrealized (gains) losses from the change in market value of open derivative contracts | $ | (4,668) | $ | 1,958 | NM |
| Interest expense, net of amounts capitalized | $ | 2,668 | $ | 2,401 | 11% |
| Income tax expense (benefit) | $ | 3,323 | $ | (64,108) | NM |

NM-Not Meaningful

**Table of Contents**

*Gas sales.* Gas sales increased by $1.26 million, or 8%, to $17.55 million compared to the prior year period. The increase in gas sales was a result of increased gas prices partially offset by decreased production. Production decreased 4% and average gas prices increased 12%, excluding hedging transactions. The $1.26 million increase in gas sales consisted of a $1.88 million increase in prices and a $0.62 million decrease in production.

*Lease operating expenses.* Lease operating expenses decreased by $2.00 million, or 25%, to $5.92 million compared to the prior year period. The decrease in lease operating expenses consisted of a $1.69 million decrease in costs and a $0.31 million decrease in production. The $1.69 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

*Compression expense.* Compression expense decreased by $0.34 million, or 19%, to $1.44 million compared to the prior year period. The $0.34 million decrease was comprised of a $0.27 million decrease in costs and a $0.07 million decrease in production. The $0.27 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

*Transportation expense.* Transportation expense decreased by $0.40 million, or 38%, to $0.64 million compared to the prior year period. The $0.40 million decrease was due to a $0.36 million decrease in costs resulting from the permanent release of excess firm transportation capacity effective May 1, 2009 and a $0.04 million decrease in production.

*Production taxes*. Production taxes decreased by $0.11 million, or 18%, to $0.50 million compared to the prior year period. The $0.11 million decrease in production taxes was primarily due to a refund received in March 2010 for production taxes related to our Gurnee field partially offset by diminishing tax exemptions in West Virginia.

*Impairment of gas properties.* At June 30, 2009, the carrying value of the Company s gas properties exceeded the full cost ceiling limitation. There was no such impairment recorded in the current year period.

*Depreciation, depletion and amortization.* Depreciation, depletion and amortization decreased by $1.92 million, or 38%, to $3.10 million compared to the prior year period. The depreciation, depletion and amortization decrease consisted of a $0.19 million decrease in production and a $1.73 million decrease in the depletion rate.

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

*General and administrative.* General and administrative expenses decreased by $2.36 million, or 46%, to $2.79 million compared to the prior year period. The decrease in general and administrative expenses was primarily due to a company-wide cost reduction strategy implemented in April 2009.

*Realized gains on derivative contracts.* Realized gains on derivative contracts decreased by $1.79 million, or 33%, to $3.67 million compared to the prior year period. Realized losses represent net cash flow settlements paid to the counterparty, while realized gains represent net cash flow settlements paid to us from the counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

*Unrealized (gains) losses from the change in market value of open derivative contracts.* Unrealized gains from the change in market value of open derivative contracts were $4.67 million in the current period as compared to unrealized losses of $1.96 million in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period. The gain was a result of the increased estimated fair value of our natural gas derivative contracts resulting from decreased natural gas prices.

*Interest expense (net of amounts capitalized).* Interest expense (net of amounts capitalized) increased by $0.27 million, or 11%, to $2.67 million compared to the prior year period. The increase was primarily due to a $0.24 million loss on our interest rate swaps in the first quarter of the current year.

*Income tax benefit*. Income tax expense was $3.32 million in the current year period. The effective tax rate for the period was 43.8%. Income tax expense for the six months ended June 30, 2010 was different than the amount computed using the statutory rate as follows:

| | U.S. | | Canada | | Total | |
|---|---|---|---|---|---|---|
| Amount computed using statutory rates | 2,808,929 | 34.0% | (174,998) | 26.0% | 2,633,931 | 34.7% |
| State income taxes net of federal benefit | 380,810 | 4.6% | | 0.0% | 380,810 | 5.0% |
| Valuation Allowance | | 0.0% | 174,998 | -26.0% | 174,998 | 2.3% |
| Nondeductible items and other | 133,720 | 1.6% | | 0.0% | 133,720 | 1.8% |
| Income tax provision | 3,323,459 | 40.2% | | 0.0% | 3,323,459 | 43.8% |

Table of Contents

**Liquidity and Capital Resources**

*Cash Flows and Liquidity*

Cash flows provided by operations for the six months ended June 30, 2010 and 2009 were $8.5 million and $3.2 million, respectively. Cash on hand and cash flows from operations of $8.5 million for the six months ended June 30, 2010 were sufficient to fund net cash used in investing activities of $4.1 million, which primarily includes capital expenditures for the development of our gas properties, and cash used in financing activities of $4.9 million, primarily related to credit facility net repayment. As of June 30, 2010, we had working capital of approximately $0.8 million. As of December 31, 2009, we had a working capital deficit of less than $0.1 million.

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our revolving credit facility and proceeds from planned financing transactions such as the proposed rights offering and backstop transaction will provide us with sufficient capital resources to develop our existing properties.

*Investment Agreement With Sherwood Energy, LLC* Pursuant to the Investment Agreement, the Company is obligated to pay Sherwood a backstop fee of $1,200,000; the initial $250,000 fee the Company already paid to Sherwood will be applied against the backstop fee. If the purchase price for shares of preferred stock purchased by Sherwood is less than $30,000,000, the Company must pay Sherwood an additional fee equal to three percent (3%) of the difference between $30,000,000 and the amount paid for the shares of preferred stock purchased by Sherwood. In the event that the investment agreement is terminated for any reason other than a breach by Sherwood, the Company will owe Sherwood the remaining $950,000 of the backstop fee plus an additional fee of $900,000. The Company has also agreed to reimburse certain out-of-pocket expenses of Sherwood in connection with the Investment Agreement.

If natural gas prices remain at a depressed level for an extended period, our ability to finance our planned capital expenditures could be affected negatively. Consistent with our intention to keep our capital expenditures in line with our estimated operating cash flows, further reduction in spending may be necessary. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and our lender s expectation of future natural gas prices and cash flows. There is no assurance, absent the completion of new financing such as the proposed rights offering, that our bank group will not decrease the availability under our current revolving credit facility or decline to extend its current maturity. If either our estimated proved reserves or natural gas prices decrease, funding available to us under our revolving credit facility could be further negatively affected. If our cash flows are less than anticipated, amounts available for borrowing under our revolving credit facility are reduced, we are unable to sell equity at acceptable prices, or we are unable to find alternative sources of financing, we may be forced to defer planned capital expenditures.

The ongoing disruption in the credit markets has had a significant adverse impact on a number of financial institutions. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our cash and short-term investments. Thus far, our liquidity and financial position have not been impacted, and we do not expect that it will be materially impacted in the future. However, we cannot predict with any certainty the impact of any further disruption in the credit markets.

***Price Risk Management Activities***

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

We enter into hedging transactions, generally for forward periods of two or more years, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of these hedges during any period to no more than 50% to 70% of the then expected gas production for such future periods. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. 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 (through a sold floor) to a predetermined amount, generally between $2.00 and $3.00 per MMBtu below the bought floor. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our consolidated balance sheets and consolidated statements of operations.

27

Table of Contents

***Commodity Price Risk and Related Hedging Activities***

At June 30, 2010, we had the following natural gas collar positions:

| Period | Volume (MMBtu) | Sold Ceiling | Bought Floor | Sold Floor | Fair Value |
|---|---|---|---|---|---|
| July through October 2010 | 492,000 | $ 6.80 | $ 5.50 | $ 3.50 | $ 429,186 |
| July through October 2010 | 492,000 | $ 6.35 | $ 5.50 | | 436,893 |
| November 2010 through March 2011 | 604,000 | $ 7.45 | $ 6.50 | | 815,931 |
| | 1,588,000 | | | | $ 1,682,010 |

At June 30, 2010, we had the following natural gas swap positions:

| Period | Volume (MMBtu) | Price | Fair Value |
|---|---|---|---|
| July through October 2010 | 492,000 | $ 5.70 | $ 499,183 |
| July through October 2010 | 369,000 | $ 6.30 | 595,472 |
| November 2010 through March 2011 | 604,000 | $ 6.67 | 839,421 |
| November 2010 through March 2011 | 906,000 | $ 7.27 | 1,795,809 |
| April 2011 through October 2011 | 856,000 | $ 6.37 | 980,013 |
| April 2011 through October 2011 | 856,000 | $ 5.37 | 131,075 |
| April 2011 through October 2011 | 856,000 | $ 5.43 | 185,981 |
| November 2011 through March 2012 | 608,000 | $ 7.12 | 741,714 |
| November 2011 through March 2012 | 608,000 | $ 6.12 | 143,656 |
| April 2012 through October 2012 | 856,000 | $ 5.73 | 205,565 |
| November 2012 through March 2013 | 604,000 | $ 6.42 | 192,819 |
| | 7,615,000 | | $ 6,310,708 |

***Interest Rate Risks and Related Hedging Activities***

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

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 June 30, 2010, we had the following interest rate swaps:

| Description | Effective date | Designated maturity date | Fixed rate (1) | Notional amount | Fair Value |
|---|---|---|---|---|---|
| Floating-to-fixed swap | 12/14/2007 | 12/14/2010 | 3.86% | $ 15,000,000 | $ (243,978) |
| Floating-to-fixed swap | 1/6/2009 | 1/6/2011 | 1.38% | $ 5,000,000 | (22,211) |
| | | | | $ 20,000,000 | $ (266,189) |

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

***Capital Expenditures and Capital Resources***

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

| | Three Months Ended June 30, 2010 | Three Months Ended June 30, 2009 | Six Months Ended June 30, 2010 | Six Months Ended June 30, 2009 |
|---|---|---|---|---|
| Capital expenditures: | | | | |
| Leasehold acquisition | $ 64,568 | $ 315,644 | $ 193,727 | $ 955,617 |
| Exploration | 3,115 | 12,270 | 3,115 | 21,877 |
| Development | 2,886,860 | 1,456,141 | 4,250,981 | 3,502,076 |
| Other items (primarily capitalized overhead and interest) | 228,826 | 450,979 | 389,662 | 1,010,310 |
| Total capital expenditures | $ 3,183,369 | $ 2,235,034 | $ 4,837,485 | $ 5,489,880 |

28

Table of Contents

We expect to increase our capital expenditures for 2010 from $7.3 million to $13.1 million and expect to fund such expenditures from our operating cash flows in anticipation of an improvement in our financial position and liquidity. If our operating cash flows are not sufficient to fund our planned capital expenditures or our financial position and liquidity do not improve, we expect to reduce our capital expenditures accordingly.

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

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations and to collect trade receivables. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned operating results.

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

Based upon current expectations, we believe that our cash flow from operations and other financial resources such as borrowings under our revolving credit facility and proceeds from planned financing transactions such as the proposed rights offering and backstop transaction as contemplated in the Investment Agreement will provide us with sufficient capital resources to develop our existing properties.

Beginning in early 2009, we began implementing countermeasures in response to the above referenced trends in order to enhance our ability to execute our business strategy. These countermeasures included reducing costs, increasing hedging to reduce exposure to volatile natural gas prices and limiting capital spending. We have evaluated additional measures in light of the current credit and commodity markets including the proposed rights offering, selling assets, entering into joint venture agreements with industry partners to reduce our capital outlays, and alternate forms of financing.

***Proposed Rights Offering and Backstop Transaction***

In light of the limited borrowing availability under our current revolving credit facility and our need to replace the existing facility with a three-year revolving credit facility, we explored a variety of alternatives for additional financing for the Company. On June 2, 2010, we entered into the Investment Agreement wherein Sherwood agreed to purchase up to $40 million of the Company s convertible preferred stock in the event that a proposed rights offering of convertible preferred stock is not fully subscribed by our common stockholders.

Under the terms of proposed rights offering and backstop transaction as contemplated in the Investment Agreement, three days after the applicable record date the Company would distribute to the holders of its common stock rights to purchase up to an aggregate of 4,000,000 new shares of preferred stock at a subscription price of $10.00 per share. The preferred stock would be convertible into shares of the Company s common stock at a conversion price of $1.30 per share, subject to customary adjustments. In the event that the Company s stockholders do not subscribe for all 4,000,000 shares of preferred stock offered, the Company is obligated to sell to Sherwood, and Sherwood is obligated to purchase, all remaining shares preferred stock that are not subscribed for in the rights offering, at the offered price of $10.00 per share. As compensation for the backstop transaction, the Company will pay Sherwood a backstop fee of $1,200,000. An initial $250,000 fee already paid to Sherwood will be applied against the backstop fee. If the purchase price for shares of preferred stock purchased by Sherwood is less than $30,000,000, the Company must pay Sherwood an additional fee equal to three percent (3%) of the difference between $30,000,000 and the price paid for the shares of preferred stock purchased by Sherwood. In the event that the Investment Agreement is terminated for any reason other than a breach by Sherwood, the Company will owe Sherwood the remaining $950,000 of the backstop fee plus an additional fee of $900,000, representing three percent (3%) of $30,000,000.

Table of Contents

Other terms of the Company s preferred stock to be issued in connection with the proposed rights offering include the following:

Dividends payable quarterly either in cash at an annual rate of 8.0% for the first three years and thereafter at the annual rate of 9.6% or, until the fifth anniversary of the closing date, in additional shares of preferred stock at an annual rate of 12.5%, at the option of the Company;

After the third anniversary of the closing date, the Company may elect, subject to certain limitations based on trading volume in the Company s common stock, to convert portions of the preferred stock if the average trading price of the Company s common stock exceeds 225% of the conversion price ($2.93 based on a conversion price of $1.30);

Redeemable at the option of the holder upon the earlier of (i) a liquidation event or (ii) the eighth anniversary of the closing date, and the redemption price for each share of preferred stock will be equal to the price paid for such share plus any accrued and unpaid dividends on such share; and

A liquidation preference that would entitle the holder of preferred stock to receive an amount equal to the greater of (i) the original purchase price for each share of preferred stock held, including shares issued as dividends, plus any accrued and unpaid dividends; or (ii) a per share amount equal to the liquidation distribution payable with respect to shares of the Company s common stock.

The Investment Agreement contains customary representations, warranties and covenants by the Company and Sherwood. Closing of the backstop transaction by Sherwood is not subject to any financing condition. Additionally, the agreement provides for customary indemnity obligations by each of the Company and Sherwood. The Investment Agreement may be terminated prior to closing under certain circumstances, including termination at Sherwood s election if closing does not occur on or before September 15, 2010, by Sherwood or the Company for material breach or default by the other party that has not been cured within thirty (30) days; or (iv) by Sherwood or the Company in the event a material adverse effect has occurred with regard to the other party that is not curable or that has not been cured within thirty (30) days.

The disclosure regarding the proposed rights offering and Investment Agreement contained in this quarterly report on Form 10-Q does not constitute an offer to sell or the solicitation of an offer to buy any securities of GeoMet, Inc., nor shall there be any sale of such securities in any state or other jurisdiction in which such an offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such state or other jurisdiction.

***Revolving Credit Facility***

Our current senior secured revolving credit facility is governed by the Existing Credit Agreement. Effective March 30, 2010, and pursuant to our request, the borrowing base under our revolving credit facility was reduced to $123.0 million, our next borrowing base determination was delayed until June 15, 2010, the maturity date was extended to May 6, 2011 and the LIBOR Rate (defined below) option was increased to the LIBOR Rate, plus a margin of 3.50%. On July 15, 2010, our lenders agreed to extend the maturity date of our revolving credit facility to October 1, 2011 and to delay the next borrowing base determination until October 15, 2010. We currently have limited borrowing availability under our revolving credit facility and we have no assurances that our lenders will extend the maturity date.

During the last quarter of 2008 and throughout 2009, reduced natural gas prices significantly limited our operating cash flow. As a result of these reduced cash flows, a severe contraction of the credit markets and the continued underperformance of our Gurnee field, we initiated efforts in the first quarter of 2009 to lower our cost structure, protect our operating margins and reduce borrowings outstanding. These efforts included personnel reductions and other cost reduction measures, increased natural gas price hedging and initiatives to sell assets. Due to reduced operating cash flow our debt-to-EBITDA ratio rose to levels in excess of the ratio considered conforming by our banks and their regulators. Consequently, we have concluded that it is necessary to take steps to reduce our debt-to-EBITDA ratio to conforming levels in order to secure an extension of our credit facility on a long-term basis. Those steps include our proposed rights offering and the Investment Agreement with Sherwood.

On June 3, 2010 we entered into the Pending Credit Agreement with a group of five banks. The Pending Credit Agreement will become effective only upon the closing of a proposed rights offering and backstop transaction contemplated in the Investment Agreement. At that time, the Existing Credit Agreement will be replaced by the Pending Credit Agreement which will provide for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base will be reviewed each June and December with the next redetermination scheduled to take place by December 2010. All outstanding borrowings under the Pending Credit Agreement will become due and payable three years after it becomes effective. The Pending Credit Agreement provides for interest to accrue at a rate calculated, at the Company s 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) plus a margin of 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate ) plus a margin of 2.75% to 3.25% depending on borrowing base usage. Under the Pending Credit Agreement we will be subject to financial covenants requiring maintenance of a minimum Current Ratio, a maximum Debt Ratio and, depending on our Debt Ratio, either a minimum Interest Coverage Ratio or minimum Fixed Charge Ratio. Our ratio ( Current Ratio ) of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities, less $1.5 million, is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio ( Debt Ratio ) of funded debt to consolidated EBITDA (defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization for the four preceding quarters) at the end of each fiscal quarter ending on or before June 30, 2011 cannot exceed 4.5 to 1. Our Debt Ratio at the end of each fiscal quarter ending after June 30, 2011 cannot exceed 4.0 to 1. If our Debt Ratio is above 3.5 to 1, then our ratio ( Fixed Charge Ratio ) of consolidated EBITDA less capital expenditures to consolidated net interest expense for the four preceding quarters at the end of each fiscal quarter cannot be less than 1.25 to 1. If our Debt Ratio is 3.5 to 1 or less, our ratio ( Interest Coverage Ratio ) of consolidated EBITDA to consolidated net interest expense for the preceding four quarters period plus letter of credit fees accruing during such quarters is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the Pending Credit Agreement excludes non-recurring charges and other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from the change in the market value of open derivative contracts. In addition, we would be subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on the preferred stock will be permitted if our availability under the borrowing base is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.

If the Company does not complete the closing of the proposed rights offering and the backstop transaction contemplated in the Investment Agreement dated June 2, 2010 by and between the Company and Sherwood Energy, LLC (the Investment Agreement ) and described below, the lending commitments in the Pending Credit Agreement will not take effect and that agreement will terminate on October 1, 2010, and the Existing Credit Agreement governing our existing senior revolving credit facility will terminate on October 1, 2011.

***Contractual Commitments***

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

***Recent Pronouncements***

In January 2010, the FASB issued Update No. 2010-06 Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This Update provides amendments to Subtopic 820-10 that require new disclosures for transfers in and out of Levels 1 and 2. This Update also clarifies existing disclosures for level of disaggregation, as well as valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009. See additional disclosure provided in Note 6 Derivative Instruments and Hedging Activities within Notes to Consolidated Financial Statements (Unaudited).

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

*Commodity Price Risk.* Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the three months ended June 30, 2010, a 10% decrease in the prices received for natural gas production would have had an approximate $0.77 million impact on our revenues, which would be partially offset by gas hedging gains. For the six months ended June 30, 2010, a 10% decrease in the prices received for natural gas production would have had an approximate $1.75 million impact on our revenues, which would be partially offset by gas hedging gains.

*Interest Rate Risk.* We have long-term debt subject to the risk of loss associated with movements in interest rates. At June 30, 2010, we had $116 million outstanding under our revolving credit facility. The rates at June 30, 2010 and December 31, 2009, excluding the effect of our interest rate swaps, were 3.87% and 3.03%, respectively. For the three months ended June 30, 2010 and 2009, interest on the borrowings averaged 3.89% per annum and 3.55% per annum, respectively. For the six months ended June 30, 2010 and 2009, interest on the borrowings averaged 3.51% per annum and 2.99% per annum, respectively. Borrowing availability at June 30, 2010 was $7 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 June 30, 2010, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.96 million. $20 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

Table of Contents

*Foreign Currency Exchange Rate Risk.* We have operations in Canada and do not have operations in any other foreign countries. We do not hedge our foreign currency risk and are exposed to foreign currency exchange rate risk in the Canadian dollar. Our Canadian prospect is temporarily shut in and, therefore, the impact on our Consolidated Financial Statements (Unaudited) is not significant. We will continue to monitor the foreign currency exchange rate in Canada and may implement measures to protect against the foreign currency exchange rate risk in the future.

**Item 4. Controls and Procedures**

***Evaluation of Disclosure Controls and Procedures***

In accordance with Exchange Act Rules 13a-15(e) and 15d-15(e), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2010 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 and 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 Control Over Financial Reporting***

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

Table of Contents

## Part II. Other Information

### Item 1. Legal Proceedings

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

***CNX Antitrust Action***

In May 2010, we reached a global settlement of all outstanding disputes and litigation with CONSOL Energy, Inc. and certain of its affiliates including CNX Gas Corporation ( CONSOL/ CNX ). As part of the global settlement, CONSOL/ CNX have agreed to grant us all consents and waivers necessary for permits to drill CBM wells on approximately 5,600 acres in the Virginia portion of our Pond Creek field. We have been limited in our ability to secure drilling permits on this acreage since these disputes and litigation began almost four years ago. As a result, we have dismissed our antitrust litigation against CONSOL/CNX with prejudice. Although a state circuit court decision in 2009 cleared the way for us to proceed with discovery and trial in this matter, continuing this litigation would have been an ongoing drain on our resources with no assurance of a successful outcome.

***Environmental and Regulatory***

As of June 30, 2010, 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 the following updates to the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2009.

***We have indebtedness, which makes us more vulnerable to economic downturns and adverse developments in our business.***

We have incurred bank debt amounting to approximately $116.0 million as of June 30, 2010. As a result of our indebtedness, we must use a portion of our cash flow to pay interest, which reduces the amount we have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our revolving credit facility is at a variable interest rate. As such, an increase in interest rates will generate greater interest expense. The amount of our debt makes us more vulnerable to economic downturns and adverse developments in our business.

Additionally, our existing senior secured revolving credit facility is scheduled to mature in October 2011. We have entered into a pending senior secured revolving credit facility with our five-bank group, which will become effective on the closing date of the rights offering and the backstop transaction. The pending credit facility has an initial borrowing base of $90 million and has a term of three years from the closing date of the rights offering and the backstop transaction. If we are unable to close the rights offering and the backstop transaction and we are unable to extend the maturity date under our revolving credit facility, or are unable to refinance or restructure our existing indebtedness prior to maturity, we could be in default of our bank credit agreement, which could adversely affect our business, financial condition and results of operations and could require us to pursue a restructuring of our indebtedness or file for protection under the U.S. Bankruptcy Code.

If we are unable to close the rights offering and backstop transaction, the next regular borrowing base determination is scheduled to be complete on or before October 15, 2010. Our lenders have the ability to reduce our borrowing base on the basis of subjective factors. If natural gas prices remain low for an extended period of time, our lenders will likely redetermine our borrowing base by evaluating our reserves in light of such lower natural gas prices. Such determination could result in a lower value of our proved reserves and a reduction of our borrowing base, which could result in a default by the Company under the terms of our credit facility.

***If the closing of the proposed rights offering and the backstop transaction is delayed or prevented, our liquidity and operations may be adversely affected and the market price of our common stock may decline.***

If the closing of the proposed rights offering or the backstop transaction is delayed, or if the rights offering and the backstop transaction are not consummated, our liquidity position may be constricted and we may be unable to reduce or refinance our existing indebtedness when it becomes due. In addition, we will have incurred significant costs, including the diversion of management resources, from which we will have received little or no benefit. Moreover, we may experience negative reactions from the financial markets and from our suppliers, customers, and employees. Each of these factors may adversely affect the trading price of our common stock and financial results and operations.

Table of Contents

***The proposed United States federal budgets for fiscal years 2010 and 2011 and other pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.***

In February 2009, the Obama administration released its budget proposals for the fiscal year 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives and in February 2010, the Obama administration released similar budget proposals for the fiscal year 2011. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Although these proposals initially were made approximately one year ago, none have been voted on or become law. However, it is still the Obama administration s stated intention to enact these provisions in 2010. We do not know the ultimate impact these proposed changes may have on our business.

***The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business.***

The United States Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act ). The Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. The Act requires the Commodities Futures and Trading Commission (the CFTC ) to promulgate rules to define these terms in detail, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

We enter into natural gas derivative contracts from time to time with respect to a portion of our expected production of natural gas in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from the sale of our production. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions. Posting of cash collateral could cause significant liquidity issues for us by reducing our ability to use our cash for capital expenditures or other corporate purposes. A requirement to post cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our derivative hedging contracts. In addition, even if we ourselves are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act s new requirements, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

***Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.***

Congress is currently considering legislation to amend the federal Safe Drinking Water Act (SDWA) to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. We employ hydraulic fracturing techniques in all of the wells we drill. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. These bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. Thus, even if the pending bills are not adopted, the EPA study, depending on its results, could spur further initiatives to regulate hydraulic fracturing under the SDWA.

Table of Contents

***We may face unanticipated water disposal costs.***

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities, or upgrade facilities. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- our wells produce excess water; or
- new laws and regulations require water to be disposed of in a different manner.

All National Pollutant Discharge Elimination System ( NPDES ) permits for the discharge of produced water from coalbed methane fields in Alabama are issued for five-year terms by the Alabama Department of Environmental Management ( ADEM ) and are subject to renewal every five years. We were granted an NPDES permit for the discharge of produced water from the Gurnee field into the Black Warrior River in 2004. We have submitted a timely and complete renewal application to ADEM for a five-year renewal of our NPDES permit. No five-year renewal NPDES permits for the discharge of produced water from coalbed methane fields into streams or rivers have been granted by ADEM since our renewal application was submitted. ADEM is currently administratively extending all existing NPDES permits for disposal of produced water from coalbed methane fields into streams or rivers for which timely and complete renewal applications are received, including our NPDES permit.

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

| Period | Total Number of Shares Purchased(1) | Average Price Paid Per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| 04/01/10 04/30/10 | | | | |
| 05/01/10 05/31/10 | | | | |
| 06/01/10 06/30/10 | 386 | $ 1.28 | | |

(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on vested shares of restricted stock issued under stock-based compensation plans.

**Item 3. Defaults Upon Senior Securities**

None.

**Item 4. [Removed and Reserved]**

**Item 5. Other Information**

None.

**Item 6. Exhibits**

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

**Table of Contents**

## 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: July 27, 2010 | By /S/ William C. Rankin<br>**William C. Rankin, Executive Vice President and Chief Financial Officer**<br>**(Principal Financial Officer)** |

36

Table of Contents

**INDEX TO EXHIBITS**

| Exhibit Number | Exhibits |
|---|---|
| 10.1* | Fourth Amended and Restated Credit Agreement, dated as of June 3, 2010 by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. National Bank Association, and Sterling Bank. |
| 10.2* | Letter Amendment (to Fourth Amended and Restated Credit Agreement) dated as of July 15, 2010 by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. National Bank Association, and Sterling Bank. |
| 10.3* | Letter Amendment (to Third Amended and Restated Credit Agreement) dated as of July 15, 2010 by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. National Bank Association, and Sterling Bank. |
| 10.4* | Settlement, Release and Confidentiality Agreement dated April 16, 2010, by and among Consol Energy Inc. and certain of its affiliates, CNX Gas Corporation and certain of its affiliates, and GeoMet, Inc. and certain of its affiliates. |
| 10.5* | Investment Agreement dated June 2, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC. |
| 10.6 | Commitment Letter dated May 3, 2010 by and between Sherwood Energy, LLC and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on May 7, 2010). |
| 31.1* | Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241). |
| 31.2* | Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241). |
| 32* | Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350). |

* Attached hereto