GeoMet, Inc.
Form 10-Q
August 14, 2013
Table of Contents

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, 2013

OR

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

For the transition period from to

Commission File Number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

909 Fannin, Suite 1850

Houston, Texas 77010

(713) 659-3855

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

N/A

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

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

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

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

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

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

As of August 1, 2013, 40,662,749 shares and 5,642,541 shares, respectively, of the registrant s common stock and preferred stock, par value $0.001 per share, were outstanding.

Table of Contents

TABLE OF CONTENTS

Part I. Financial Information		
Item 1.	Consolidated Financial Statements (Unaudited)	
	Consolidated Balance Sheets as of June 30, 2013 and December 31, 2012	3
	Consolidated Statements of Operations for the three and six months ended June 30, 2013 and 2012	4
	Consolidated Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2013 and 2012	5
	Consolidated Statements of Cash Flows for the six months ended June 30, 2013 and 2012	6
	Notes to Consolidated Financial Statements (Unaudited)	7
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	19
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	28
Item 4.	Controls and Procedures	29
Part II. Other Information		
Item 1.	Legal Proceedings	29
Item 1A.	Risk Factors	29
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	29
Item 3.	Defaults Upon Senior Securities	29
Item 4.	Mine Safety Disclosures	29
Item 5.	Other Information	29
Item 6.	Exhibits	29

Table of Contents

Part I. FINANCIAL INFORMATION

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,533,406	$ 7,234,225
Accounts receivable, net of allowance of $14,744 and $17,634 at June 30, 2013 and December 31, 2012, respectively	4,817,473	6,248,819
Inventory	106,974	262,885
Derivative asset natural gas contracts	360,679	3,929,767
Other current assets	847,772	1,437,819
Total current assets	17,666,304	19,113,515
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	333,524,433	539,077,119
Other property and equipment	3,332,394	3,749,621
Total property and equipment	336,856,827	542,826,740
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(292,324,195)	(467,702,053)
Property and equipment net	44,532,632	75,124,687
Other noncurrent assets:		
Deferred income taxes	99,365	1,125,804
Other	840,799	962,451
Total other noncurrent assets	940,164	2,088,255
TOTAL ASSETS	$ 63,139,100	$ 96,326,457
LIABILITIES, MEZZANINE AND STOCKHOLDERS DEFICIT		
Current Liabilities:		
Accounts payable	$ 3,972,380	$ 5,728,879
Royalties payable	3,621,726	3,830,904
Accrued liabilities	2,870,771	1,793,946
Paid in-kind dividend payable on Series A Convertible Redeemable Preferred Stock	1,367,488	
Deferred income taxes	99,365	1,125,804
Derivative liability natural gas contracts		919,572
Asset retirement obligations	11,983	73,706
Current portion of long-term debt	77,000,000	10,300,000
Total current liabilities	88,943,713	23,772,811
Long-term debt		129,000,000
Asset retirement obligations	9,387,734	13,235,318
Derivative liability natural gas contracts	824,920	1,636,348
Other long-term accrued liabilities	128,558	143,682
TOTAL LIABILITIES	99,284,925	167,788,159
Commitments and contingencies (Note 16)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $53,058,650; $.001 par value; 7,401,832 shares authorized,	37,953,945	35,851,887

5,471,610 and 5,305,865 shares were issued and outstanding at June 30, 2013 and December 31, 2012, respectively				
Stockholders Deficit:				
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued				
Common stock, $0.001 par value authorized 125,000,000 shares; 40,663,554 and 40,690,077 issued and outstanding at June 30, 2013 and December 31, 2012, respectively		40,664		40,690
Treasury stock 10,432 shares at June 30, 2013 and December 31, 2012		(94,424)		(94,424)
Paid-in capital		191,499,298		195,033,585
Accumulated other comprehensive loss		(102,547)		(53,020)
Retained deficit		(265,442,761)		(302,057,496)
Less notes receivable				(182,924)
Total stockholders deficit		(74,099,770)		(107,313,589)
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS DEFICIT	$	63,139,100	$	96,326,457

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,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Revenues:				
Gas sales	$ 12,053,170	$ 7,711,969	$ 22,932,434	$ 17,855,143
Operating fees	38,113	59,446	83,069	135,211
Total revenues	12,091,283	7,771,415	23,015,503	17,990,354
Operating expenses:				
Lease operating expense	4,122,868	4,491,593	8,592,107	8,933,027
Compression and transportation expense	1,868,165	2,300,765	3,706,801	4,540,254
Production taxes	647,371	364,437	1,197,917	834,086
Depreciation, depletion and amortization	1,370,777	3,290,420	2,877,143	6,920,889
Impairment of gas properties		42,255,847		58,035,288
General and administrative	1,408,521	1,366,142	2,406,754	2,668,167
Restructuring costs	17,396	765,233	87,584	765,233
(Gains) losses on natural gas derivatives	(4,149,649)	4,891,613	1,385,470	(5,125,467)
Total operating expenses	5,285,449	59,726,050	20,253,776	77,571,477
Gain on the sale of Properties in Alabama	37,135,611		37,135,611	
Operating income (loss)	43,941,445	(51,954,635)	39,897,338	(59,581,123)
Other income (expense):				
Interest income	428	597	848	4,299
Interest expense	(1,559,276)	(1,268,399)	(3,235,605)	(2,544,243)
Other	(6,698)	253	(35,346)	(4,099)
Total other income (expense):	(1,565,546)	(1,267,549)	(3,270,103)	(2,544,043)
Income (loss) before income taxes from continuing operations	42,375,899	(53,222,184)	36,627,235	(62,125,166)
Income tax expense	(6,250)	(6,250)	(12,500)	(44,030,700)
Income (loss) from continuing operations	42,369,649	(53,228,434)	36,614,735	(106,155,866)
Discontinued operations, net of tax		(675,809)		(696,381)
Net income (loss)	$ 42,369,649	$ (53,904,243)	$ 36,614,735	$ (106,852,247)
Accretion of Series A Convertible Redeemable Preferred Stock	(532,836)	(470,953)	(1,026,373)	(932,969)
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock	(1,367,488)	(619,625)	(2,443,173)	(1,860,345)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(568)	(651)	(1,201)	(1,296)
Net income (loss) available to common stockholders	$ 40,468,757	$ (54,995,472)	$ 33,143,988	$ (109,646,857)
Net income (loss) per common share basic:				
Net income (loss) per common share from continuing operations	$ 1.00	$ (1.36)	$ 0.82	$ (2.74)
		(0.01)		(0.01)

Net loss per common share from discontinued operations				
Net income (loss) per common share basic	$ 1.00	$ (1.37)	$ 0.82	$ (2.75)
Net income (loss) per common share diluted:				
Net income (loss) per common share from continuing operations	$ 0.51	$ (1.36)	$ 0.45	$ (2.74)
Net loss per common share from discontinued operations		(0.01)		(0.01)
Net income (loss) per common share diluted	$ 0.51	$ (1.37)	$ 0.45	$ (2.75)
Weighted average number of common shares:				
Basic	40,477,411	40,003,977	40,467,149	39,883,409
Diluted	82,683,271	40,003,977	82,039,050	39,883,409

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive Income (Loss)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Net income (loss)	$ 42,369,649	$ (53,904,243)	$ 36,614,735	$ (106,852,247)
(Loss) gain on foreign currency translation adjustment	(10,350)	9,470	(9,118)	2,019
Unrealized (loss) gain on available for sale securities	(60,472)	36,952	(40,409)	36,952
Other comprehensive income (loss)	$ 42,298,827	$ (53,857,821)	$ 36,565,208	$ (106,813,276)

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,	
	2013	**2012**
Cash flows provided by operating activities:		
Net income (loss)	$ 36,614,735	$ (106,852,247)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	2,877,143	6,919,168
Impairment of gas properties		58,035,288
Amortization of debt issuance costs	454,340	316,671
Deferred income tax expense		44,018,200
Unrealized losses from the change in market value of open derivative contracts	1,838,088	4,978,668
Stock-based compensation	119,374	393,536
Gain on the sale of Properties in Alabama	(37,135,611)	
Loss on sale of Hudson s Hope Gas, Ltd		683,154
Loss on sale of other assets	35,348	5,200
Accretion expense asset retirement obligation	612,553	391,687
Changes in operating assets and liabilities:		
Accounts receivable	2,100,139	810,421
Other assets	99,190	477,654
Accounts payable	(2,408,500)	(675,844)
Other accrued liabilities	1,139,382	912,190
Net cash provided by operating activities	6,346,181	10,413,746
Cash flows provided by investing activities:		
Capital expenditures	(494,031)	(508,657)
Return of original basis through the settlement of natural gas derivative contracts		4,925,738
Net proceeds from the sale of Properties in Alabama	60,732,775	
Proceeds from sale of other property and equipment	19,276	3,500
Net cash provided by investing activities	60,258,020	4,420,581
Cash flows used in financing activities:		
Proceeds from revolving credit facility borrowings		10,500,000
Payments on revolving credit facility	(62,300,000)	(19,800,000)
Deferred financing costs	(3,801)	(403,383)
Payments on other debt		(167,087)
Purchase and cancellation of treasury stock	(586)	(2,037)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(633)	(1,296)
Net cash used in financing activities	(62,305,020)	(9,873,803)
Effect of exchange rate changes on cash		5,115
Increase in cash and cash equivalents	4,299,181	4,965,639
Cash and cash equivalents at beginning of period	7,234,225	457,865

Cash and cash equivalents at end of period	$	11,533,406	$	5,423,504
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	$	1,664,956	$	2,509,404
Cash paid during the period for income taxes	$	12,500	$	12,500
Significant noncash investing and financing activities:				
Accrued capital expenditures	$	444,102	$	817,015

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 primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. Subsequent to the asset sale, our core area of operations is the Central Appalachian Basin of Virginia and West Virginia. We also own additional coalbed methane development rights, principally in Virginia and West Virginia.

Note 2 Sale of Coalbed Methane Properties in Alabama

On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama. The sale resulted in proceeds of approximately $62.0 million after normal and customary purchase price adjustments of $1.2 million to account for net cash flows from the effective date to the closing date. Simultaneously with the close of the property sale, approximately $57.0 million was used to repay outstanding borrowings under the Company s Credit Agreement and $5.0 million was held in reserve to pay transaction related costs and expenses, including the liquidation of certain natural gas hedge positions. After this repayment, borrowings outstanding under the Credit Agreement totaled $77.0 million and such amount has been established as the new borrowing base. In connection with this repayment the non-conforming Tranche B portion of total outstanding borrowings, which has existed since August 2012, has been eliminated and the Company no longer has a borrowing base deficiency under the Credit Agreement. The next scheduled borrowing base determination is expected to occur on or around December 15, 2013 and will be based on the Company s reserves at June 30, 2013. The Credit Agreement continues to have a maturity date of April 1, 2014.

GeoMet s net interest in the sold properties produced approximately 9,700 Mcf of natural gas per day during the month of March 2013 (the effective date of the sale was April 1, 2013), or approximately 29% of GeoMet s total production for this time period. As of April 1, 2013 and based on Securities and Exchange Commission guidelines, GeoMet s net proved reserves attributable to the coalbed methane properties in Alabama being sold were estimated to be approximately 43 Bcf, all classified as proved developed reserves.

Total gain on the sale included the following:

Cash proceeds	$	62,007,639

Buyer s assumption of asset retirement obligations		4,411,201
Buyer s assumption of other liabilities		164,108
Net book value of sold gas properties		(27,998,835)
Net book value of sold inventory		(133,732)
Net book value of sold equipment		(108,642)
Transaction costs		(1,206,128)
Total gain on sale	$	37,135,611

No current federal or state income taxes payable were recorded in conjunction with the sale of the Alabama properties which is the result of 2013 tax basis operating losses generated in the normal course of business that are estimated to be available to offset the taxable gain. Additionally, under GAAP, our pre-gain net deferred tax asset of $97.4 million and the offsetting $97.4 valuation allowance recorded against it were both reduced by $14.2 million as a result of recording the gain. At June 30, 2013, the remaining net deferred tax asset is $83.2 million for which a full valuation allowance remains recorded against it.

Pro forma adjustments related to the unaudited pro forma financial information presented below were computed assuming the transaction was consummated on January 1, 2012 and include adjustments which give effect to events that are (i) directly attributable to the transaction, (ii) expected to have a continuing impact on the registrant, and (iii) factually supportable. As such, included in Net income (loss), Net income (loss) available to common stockholders and Net income (loss) per common share (basic and diluted) is the Total gain on sale disclosed above of $37,135,611.

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenue	$ 8,969,890	$ 5,452,801	$ 16,770,976	$ 12,535,769
Income (loss) from continuing operations	$ 41,421,377	$ (39,469,009)	$ 34,960,777	$ (86,907,781)
Net income (loss)	$ 41,421,377	$ (40,144,818)	$ 34,960,777	$ (87,604,162)
Net income (loss) available to common stockholders	$ 39,520,485	$ (41,236,047)	$ 31,490,030	$ (90,398,772)
Net income (loss) per common share basic	$ 0.98	$ (1.03)	$ 0.78	$ (2.27)
Net income (loss) per common share diluted	$ 0.50	$ (1.03)	$ 0.43	$ (2.27)

Note 3 Going Concern and Management s Plans

The accompanying consolidated financial statements (unaudited) have been prepared in conformity with accounting principles generally accepted in the United States which contemplate continuation of the Company as a going concern. In 2012, the amounts outstanding under the Company s Fifth Amended and Restated Credit Agreement (Credit Agreement) exceeded the borrowing base as determined by the lenders under the Credit Agreement. Although the recent sale of gas properties by the Company caused the Company to be in conformity with its borrowing base, the Company remains highly leveraged. In addition, the Credit Agreement matures on April 1, 2014, and no assurances can be made that the Company will be able to refinance, repay or further extend the maturity date of the Credit Agreement. Also, as of June 30, 2013, the Company had a working capital deficit of $71.3 million, a retained deficit of $265.4 million and stockholders deficit of $74.1 million. Depressed natural gas prices in 2012 resulted in significant property impairments and full valuation of our deferred tax assets during 2012. On April 2, 2013, all the indebtedness under the Company s Credit Agreement was reclassified to current liabilities. These and other factors raise substantial doubt about the Company s ability to continue as a going concern for the next twelve months.

Management s current business plan is to continue to evaluate its strategic alternatives. Additionally, management is seeking to divest properties with limited value and will consider additional asset sale opportunities as they arise. Management also remains focused on maintaining compliance with the Credit Agreement, as amended, maintaining production levels, and keeping costs under control.

The ability of the Company to continue as a going concern is dependent upon its ability to generate sufficient cash flows and sales proceeds or other sources of capital sufficient to repay or refinance its indebtedness, continue its operations and fund its long-term capital needs. The accompanying consolidated financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

Note 4 Recent Pronouncements

In July 2013, the FASB, issued ASU, No. 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. The amendments in ASU 2013-10 permit the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to UST and LIBOR. The amendments also remove the restriction on using different benchmark rates for similar hedges. The amendments are effective prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We are presently assessing the potential impact of ASU 2013-11.

In February 2013, the FASB issued ASU No. 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date. ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations addressed within existing guidance. The update is effective for interim and annual periods beginning after December 15, 2013 and is required to be applied retrospectively to all prior periods presented for those obligations that existed upon adoption of ASU 2013-04. We are presently assessing the potential impact of ASU 2013-04.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under accounting principles generally accepted in the United States (GAAP) to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. The amendments are effective prospectively for reporting periods beginning after December 15, 2012. The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

Table of Contents

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company has adopted and applied the provisions of ASU 2013-01. See disclosure provided in Note 9 Derivative Instruments and Hedging Activities.

Note 5 Net Income (Loss) Per Common Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss) available to common stockholders basic	$ 40,468,757	$ (54,995,472)	$ 33,143,988	$ (109,646,857)
Dilutive related add back:				
Accretion of Preferred Stock	532,836	470,953	1,026,373	932,969
Paid-in-kind dividends on Preferred Stock	1,367,488	619,625	2,443,173	1,860,345
Cash dividends paid on Preferred Stock	568	651	1,201	1,296
Net income (loss) available to common stockholders diluted	$ 42,369,649	$ (53,904,243)	$ 36,614,735	$ (106,852,247)
Net income (loss) per common share basic:				
Net income (loss) per common share from continuing operations	$ 1.00	$ (1.36)	$ 0.82	$ (2.74)
Net loss per common share from discontinued operations		(0.01)		(0.01)
Net income (loss) per common share basic	$ 1.00	$ (1.37)	$ 0.82	$ (2.75)
Net income (loss) per common share diluted:				
Net income (loss) per common share from continuing operations	$ 0.51	$ (1.36)	$ 0.45	$ (2.74)
Net loss per common share from discontinued operations		(0.01)		(0.01)
Net income (loss) per common share diluted	$ 0.51	$ (1.37)	$ 0.45	$ (2.75)
Weighted average number of common shares:				
Basic	40,477,411	40,003,977	40,467,149	39,883,409
Potentially dilutive securities:				
Preferred stock	42,089,307		41,455,348	
Restricted stock units	116,553		116,553	
Diluted	82,683,271	40,003,977	82,039,050	39,883,409

Net income (loss) per common share basic for both the three and six months ended June 30, 2013 included $0.92 per common share, net of $0 tax, resulting from the Gain on the sale of Properties in Alabama. Net income (loss) per common share diluted for both the three and six months ended June 30, 2013 included $0.45 per common share, net of $0 tax, resulting from the Gain on the sale of Properties in Alabama.

Net income per common share diluted for the three months ended June 30, 2013 excluded the effect of outstanding exercisable options to purchase 2,099,658 shares and 231,457 weighted average restricted shares outstanding because they were assumed reacquired under the treasury stock method.

Net income per common share diluted for the six months ended June 30, 2013 excluded the effect of outstanding exercisable options to purchase 2,099,658 shares and 232,274 weighted average restricted shares outstanding because they were assumed reacquired under the treasury stock method.

Table of Contents

Net loss per common share diluted for the three months ended June 30, 2012 excluded the effect of outstanding exercisable options to purchase 2,490,558 shares, 164,565 weighted average restricted stock units for which common shares are distributed upon achievement of certain performance targets, 268,739 weighted average restricted shares outstanding, and 4,691,632 shares of Series A Convertible Redeemable Preferred Stock (36,089,476 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive.

Net loss per common share diluted for the six months ended June 30, 2012 excluded the effect of outstanding exercisable options to purchase 2,490,558 shares, 198,327 restricted stock units for which common shares are distributed upon achievement of certain performance targets, 258,399 weighted average restricted shares outstanding, and 4,549,537 shares of Series A Convertible Redeemable Preferred Stock (34,996,440 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive.

Note 6 Discontinued Operations

On June 20, 2012, we disposed of Hudson s Hope Gas, Ltd., a subsidiary which held our Canadian gas properties, in exchange for two million shares of Canada Energy Partners, Inc. (CEP Shares) which we are restricted from selling before June 20, 2013. We recognized a loss on the disposition in the amount of $0.7 million, which was made up of a $1.3 million loss related to the currency translation adjustment, offset by $0.3 million in asset retirement obligations conveyed to the buyer and the proceeds consisting of the $0.3 million in estimated fair value of the CEP shares received. The loss on this disposition has been included in Discontinued operations, net of tax, in the Consolidated Statements of Operations (Unaudited). Additionally, all historical operating results related to the disposed company have been removed from Operating (loss) income and included in Discontinued operations, net of tax, in the Consolidated Statements of Operations (Unaudited) for the periods presented.

As a result of the disposition, we are classifying these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations for the three and six months ended June 30, 2013 and 2012 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues	$	$	$	$
Total operating benefit (expenses)		7,426		(13,123)
Operating income (loss)		7,426		(13,123)
Loss on sale of Hudson s Hope, Ltd.		(683,154)		(683,154)
Other income (expense)		(81)		(104)
Income tax expense				
Net loss	$	$ (675,809)	$	$ (696,381)

Note 7 Gas Properties

The method of accounting for oil and gas producing activities determines which costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for our gas properties. Under this method, all direct costs and certain

indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized.

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.

Estimation of proved gas reserves involves 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

Table of Contents

of our full cost pool exceeds the ceiling limitation. 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 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 twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. In addition, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

For the twelve months ended June 30, 2013, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.47 per Mcf, resulting in a natural gas price of $3.53 per Mcf when adjusted for regional price differentials. Based on the ceiling test performed utilizing the aforementioned prices, no write-down of the carrying value of our U.S. full cost pool was required at June 30, 2013.

For the twelve months ended June 30, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.17 per Mcf, resulting in a natural gas price of $3.34 per Mcf when adjusted for regional price differentials. For the three and six months ended June 30, 2012, we recorded a $42.3 million and a $58.0 million write-downs, respectively, of the carrying value of our U.S. full cost pool.

In accordance with the full cost method of accounting for gas properties as prescribed by the SEC, sales of oil and gas reserves in place are generally accounted for as adjustments of capitalized cost, with no gain or loss recognized, unless such adjustments significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center (i.e. depletion rate). A significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. The sale of the Alabama gas properties, as disclosed in Note 2 Sale of Coalbed Methane Properties in Alabama, would have significantly altered the depletion rate. As such, a gain on the sale was recorded in the Consolidated Statements of Operations for the three and six months ended June 30, 2013.

Note 8 Asset Retirement Liability

We record an asset retirement obligation (ARO) on the Consolidated Balance Sheets (Unaudited) 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, 2013:

Current portion of liability at January 1, 2013	$	73,706
Add: Long-term asset retirement liability at January 1, 2013		13,235,318
Asset retirement liability at January 1, 2013		13,309,024
Buyer s assumption of asset retirement obligations		(4,411,201)
Settlements		(110,659)
Accretion		612,553
Asset retirement liability at June 30, 2013		9,399,717
Less: Current portion of liability		(11,983)
Long-term asset retirement liability	$	9,387,734

Note 9 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. At June 30, 2013, we do not have the ability to enter into natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

Table of Contents

In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has historically hedged natural gas prices 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. We entered into hedging transactions, generally for forward periods up to two years or more, which increased the probability of achieving our targeted level of cash flows. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our Consolidated Balance Sheets (Unaudited) and Consolidated Statements of Operations (Unaudited).

Commodity Price Risk and Related Hedging Activities

At June 30, 2013, we had the following natural gas derivative contracts:

Contract Type	Period	Volume (MMBtu)	Fixed Price or Sold Ceiling/ Bought Floor	Derivative asset current	Derivative liability non-current	Total Fair Value of Contract
Collar	January 2014 through December 2015	3,650,000	$4.30/$3.60	$ 25,275	$ (327,599)	$ (302,324)
Collar	January 2014 through December 2015	3,650,000	$4.20/$3.50	(32,176)	(497,321)	(529,497)
Swap	July 2013 through December 2013	1,104,000	$3.60	(47,156)		(47,156)
Swap	July 2013 through March 2014	2,192,000	$3.81	184,627		184,627
Swap	July 2013 through March 2014	1,832,000	$3.82	230,109		230,109
		12,428,000		$ 360,679	$ (824,920)	$ (464,241)

At December 31, 2012, we had the following natural gas derivative contracts:

Contract Type	Period	Volume (MMBtu)	Fixed Price or Sold Ceiling/ Bought Floor	Derivative asset current	Derivative liability current	Derivative liability non-current	Total Fair Value of Contract
Collar	January 2014 through December 2015	3,650,000	$4.30/$3.60	$	$	$ (556,636)	$ (556,636)
Collar	January 2014 through December 2015	3,650,000	$4.20/$3.50			(796,266)	(796,266)
Swap	January 2013 through March 2013	360,000	$6.42	1,100,395			1,100,395
Swap	January 2013 through March 2013	540,000	$6.50	1,156,734			1,156,734
Swap	January 2013 through December 2013	2,190,000	$3.60	127,253			127,253
Swap	January 2013 through March 2014	3,640,000	$3.81	758,669		(144,994)	613,675

Swap	January 2013 through March 2014	3,640,000	$3.82	786,716		(138,452)	648,264
Swap	April 2013 through December 2013	2,750,000	$3.25		(919,572)		(919,572)
		20,420,000		$ 3,929,767	$ (919,572)	$ (1,636,348)	$ 1,373,847

At December 31, 2012, we had the following forward sales at NYMEX plus a fixed basis:

Period	Volume (MMBtu)		Fixed Basis
January 2013 through March 2013	450,000	$	0.19
January 2013 through March 2013	918,000	$	0.22
	1,368,000		

The aforementioned forward physical sale contracts qualified for normal purchase and sale exemption and, as such, we have elected not to record it on the Consolidated Balance Sheets (Unaudited) using mark-to-market accounting.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants or affiliates of the participants in our Credit Agreement and the collateral for the outstanding

Table of Contents

borrowings under our Credit Agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our Credit Agreement.

We estimate the fair value of our natural gas derivative contracts and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. Fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of credit risk on the fair value of the assets and liabilities related to the items stated below. The consideration for discounting our counterparties liabilities (our assets) was based on the difference between the S&P credit rating of a comparable company to our counterparties and the 13-week Treasury bill rate, both at the reporting date. The consideration for discounting our liabilities was based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt.

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

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the three and six months ended June 30, 2013. Based on the use of observable market inputs, we have designated these types of instruments designated below as Level 2. The fair value of our Level 2 derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	June 30, 2013		December 31, 2012		June 30, 2013		December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments								
Natural gas hedge positions	Derivative asset (current)	$ 360,679	Derivative asset (current)	$ 3,929,767	Derivative liability (current)	$	Derivative liability (current)	$ 919,572
Natural gas hedge positions	Derivative asset (non-current)		Derivative asset (non-current)		Derivative liability (non-current)	824,920	Derivative liability (non-current)	1,636,348
Total derivatives not designated as hedging instruments		$ 360,679		$ 3,929,767		$ 824,920		$ 2,555,920

The following (gains) losses on our hedging instruments included in the unaudited Consolidated Statements of Operations and Other Comprehensive Income (Loss) (OCI) are as follows:

The Effect of Derivative Instruments on the Unaudited Consolidated Statements of Operations and Other Comprehensive Income for the Three and six months ended June 30, 2013 and 2012

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
Derivatives not designated as hedging instruments under ASC 815-20-25					
Natural gas collar/swap settled positions	(Gains) losses on natural gas derivatives	$ 1,440,084	$ (5,311,266)	$ (1,659,668)	$ (10,104,135)
Natural gas swap positions terminated (1)	(Gains) losses on natural gas derivatives	1,207,050		1,207,050	
Natural gas collar/swap unsettled positions	(Gains) losses on natural gas derivatives	(6,796,783)	10,202,879	1,838,088	4,978,668
Total (gain) loss		$ (4,149,649)	$ 4,891,613	$ 1,385,470	$ (5,125,467)

(1) The natural gas swap positions were terminated in order to prevent the Company from being over-hedged after the closing of the sale of its coalbed methane properties in Alabama.

Table of Contents

Note 10 Investment in Canada Energy Partners

At June 30, 2013 and December 31, 2012, we own two million shares of Canada Energy Partners (CEP), discussed in Note 6 Discontinued Operations, which we classify as available for sale and record at fair value in Other noncurrent assets on the Consolidated Balance Sheets (Unaudited) based on the closing price of the shares on the TSX Venture Exchange on that date. Gains or losses related to both market price fluctuation and currency translation adjustment on the shares of CEP are held in Accumulated other comprehensive loss in the Consolidated Balance Sheets (Unaudited). At June 30, 2013 and December 31, 2012, the value of the shares recorded in Other noncurrent assets was $191,222 and $240,749, respectively, using a Level 1 input. Accumulated other comprehensive loss of $102,547 in the Consolidated Balance Sheets (Unaudited) as of June 30, 2013 consisted of a $102,070 cumulative decrease in market value and a $477 cumulative loss related to currency translation on the CEP shares. Accumulated other comprehensive loss of $53,020 in the Consolidated Balance Sheets (Unaudited) as of December 31, 2012 consisted of a $61,661 cumulative decrease in market value offset by a $8,641 cumulative gain related to currency translation on the CEP shares.

Note 11 Long-Term Debt

Under our Credit Agreement, outstanding borrowings may not exceed a borrowing base determined by the lenders. During 2012, the amounts borrowed under our Credit Agreement exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Credit Agreement, as amended, provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the borrowing base deficiency.

On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama. Simultaneously with the close of the property sale, approximately $57.0 million was used to repay outstanding borrowings under the Company s Credit Agreement, which eliminated the borrowing base deficiency. After this repayment, borrowings outstanding under the Credit Agreement totaled $77.0 million. The new borrowing base will be the lesser of the total amount of outstanding borrowings under the Credit Agreement and the current balance of $77.0 million. The next scheduled borrowing base determination is expected to occur on or around December 15, 2013 and will be based on the Company s reserves at June 30, 2013.

With the closing of the sale of its coalbed methane properties in Alabama, the Company retained a $5.0 million reserve to be disbursed from time to time solely to pay transaction related costs as defined in the Credit Agreement, as amended, until the final settlement date of December 31, 2013, at which time, any remaining reserve shall be used to repay the outstanding principal balance of the Tranche A Loans until repaid in full. At June 30, 2013, a reserve of $2.1 million remained in Cash and cash equivalents in the Consolidated Balance Sheets (Unaudited).

The Credit Agreement no longer provides for loans to be available on a revolving basis up to the amount of the borrowing base. As a result, the current outstanding loans, once repaid, may not be re-borrowed by the Company. All outstanding borrowings under the Credit Agreement are due and payable on April 1, 2014. The Credit Agreement provides for interest to accrue at a rate calculated, at our option, at the Adjusted Base Rate plus a margin of 2.00% or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00%. Adjusted Base Rate is defined to be the greater of (i) the agent s base rate or (ii) the federal funds rate plus one half of one percent or (iii) the LIBOR Rate plus a margin of 1.00%. All financial covenants were deleted by the Amendment and were replaced with a capital expenditure covenant (a maximum of $1.5 million in 2012 and $1.5 million in 2013). As of June 30, 2013, we had $77.0 million of borrowings outstanding under our Credit Agreement. As of June 30, 2013, the interest rates applied to borrowings were 3.24%.

For the three months ended June 30, 2013, we had no borrowings and made payments of $57.8 million under the Credit Agreement. For the three months ended June 30, 2012 we borrowed $3.1 million and made payments of $4.0 million under the Credit Agreement. For the three months ended June 30, 2013 and 2012, interest on the borrowings averaged 3.83% and 2.99% per annum, respectively.

For the six months ended June 30, 2013, we had no borrowings and made payments of $62.3 million under the Credit Agreement. For the six months ended June 30, 2012 we borrowed $10.5 million and made payments of $19.8 million under the Credit Agreement. For the six months ended June 30, 2013 and 2012, interest on the borrowings averaged 4.06% and 2.94% per annum, respectively.

Table of Contents

The following is a summary of our long-term debt at June 30, 2013 and December 31, 2012:

	June 30, 2013	December 31, 2012
Borrowings under Credit Agreement	$ 77,000,000	$ 139,300,000
Less current maturities included in current liabilities	(77,000,000)	(10,300,000)
Total long-term debt	$	$ 129,000,000

We record our debt instruments based on contractual terms. We did not elect to apply the fair value option for recording financial assets and financial liabilities. We measure the fair value of our debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 or 2 within the fair value hierarchy. Fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the market weighted average cost of equity capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included in our long-term debt. The fair value of long-term debt at June 30, 2013 and December 31, 2012 was estimated to be approximately $73.7 million and $121.6 million, respectively.

Note 12 Income Taxes

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

For tax reporting purposes, we have federal and state net operating losses (NOL s) of approximately $138.1 million and $143.4 million, respectively, at June 30, 2013 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $137.8 million and $127.0 million, respectively, at December 31, 2012 that were available to reduce future taxable income. Our first material federal NOL carryforward expires in 2022 and the last one expires in 2032.

Additionally, for tax reporting purposes, we have a federal capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 6 Discontinued Operations, of approximately $34.9 million at June 30, 2013 that is available to reduce future taxable capital gains and expiring in 2017.

At June 30, 2013, we have a valuation allowance of $83.2 million recorded against our net deferred tax asset which includes $69.8 million related to our U.S. operations and $13.4 million related to the capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 6 Discontinued Operations.

A reconciliation of the effective tax rate to the statutory rate for the three months ended June 30, 2013 is as follows:

		Total	
Amount computed using statutory rates	$	14,407,806	34.00%
State income taxes net of federal benefit		1,084,723	2.56%
Reduction of valuation allowance		(15,629,252)	-36.88%
Nondeductible items and other		142,973	0.33%
Income tax provision	$	6,250	0.01%

A reconciliation of the effective tax rate to the statutory rate for the six months ended June 30, 2013 is as follows:

		Total	
Amount computed using statutory rates	$	12,453,260	34.00%
State income taxes net of federal benefit		876,006	2.39%
Reduction of valuation allowance		(13,472,543)	-36.78%
Nondeductible items and other		155,777	0.42%
Income tax provision	$	12,500	0.03%

Table of Contents

Note 13 Common Stock

At June 30, 2013 and December 31, 2012, there were 40,663,554 and 40,690,077 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, 2013 and December 31, 2012 were 180,233 and 254,260 shares of restricted stock, respectively. The following table details the activity related to our common stock for the three months ended June 30, 2013:

	Date	Shares
Common stock outstanding at January 1, 2013		40,690,077
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	01/07/2013	(121)
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	03/15/2013	(470)
Forfeited upon default of shareholder loans	06/06/2013	(24,428)
Shares of restricted stock forfeited upon termination of employment	06/14/2013	(1,504)
Common stock outstanding at June 30, 2013		40,663,554

Note 14 Series A Convertible Redeemable Preferred Stock

At June 30, 2013 and December 31, 2012, 5,471,610 and 5,305,865 shares of preferred stock were issued and outstanding, respectively. At June 30, 2013, an additional 1,930,222 shares of our Series A Convertible Redeemable Preferred Stock (Preferred Stock) are reserved exclusively for the payment of paid-in-kind dividends (PIK dividends). We measure the fair value of PIK dividends using the closing quoted NASDAQ market price on the dividend date (categorized as level 1). The following table details the activity related to the Preferred Stock for the six months ended June 30, 2013:

	Dividend Period (Three Months Ended)	Date Issued	Number of Shares		Balance
Balance at January 1, 2013			5,305,865	$	35,851,887
Accretion of Preferred Stock					1,026,373
PIK Dividend Issued for Preferred Stock	3/31/13	4/1/13	165,745		1,075,685
Balance At June 30, 2013			5,471,610	$	37,953,945

On June 5, 2013, we declared a quarterly dividend of 170,931 shares of Preferred Stock covering the period April 1, 2013 through June 30, 2013. As those shares were not issued until July 1, 2013, they were not included in the Preferred Stock balance at June 30, 2013. As such, we recorded a dividend payable in Current liabilities in the Consolidated Balance Sheets (Unaudited) at June 30, 2013 at an estimated fair value of $1,367,488.

Note 15 Share-Based Awards

As of June 30, 2013, our 2006 Long-Term Incentive Plan (the 2006 Plan) is our only authorized stock-based award plan. Our 2005 Stock Option Plan was terminated on March 11, 2011 as no options granted under the plan remained outstanding at that time. Our 2006 Plan authorizes the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are available for grant under this plan. The 2006 Plan is available to our employees and independent directors. However, the Company does not anticipate any additional grants will be awarded under the 2006 Plan in the immediate future. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards which are granted solely to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the three months ended June 30, 2013, we recorded a compensation expense accrual of $60,650 which was allocated as an addition of $6,759 to lease operating expenses and an addition of $53,891 to general and administrative expense. During the six months ended June 30, 2013, we recorded a compensation expense accrual of $119,374 which was allocated as an addition of $13,511 to lease operating expenses and an addition of $105,863 to general and administrative expense. The future compensation cost of all the outstanding awards is $172,100 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 0.61 years.

Table of Contents

During the three months ended June 30, 2012, we recorded a compensation expense accrual of $282,350 of which $12,433 was allocated to lease operating expenses, $135,220 was allocated to general and administrative expenses, $131,127 was allocated to restructuring costs, and $3,570 was capitalized to gas properties. During the six months ended June 30, 2012, we recorded a compensation expense accrual of $414,149 of which $22,294 was allocated to lease operating expenses, $240,116 was allocated to general and administrative expenses, $131,127 was allocated to restructuring costs, and $20,612 was capitalized to gas properties.

Incentive Stock Options

The table below summarizes incentive stock option activity for the three months ended June 30, 2013:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2012	1,412,739	$ 1.11		
Forfeited	(87,846)	$ 1.18		
Outstanding at June 30, 2013	1,324,893	$ 1.11	3.4	$
Options exercisable at June 30, 2013	909,208	$ 0.99	3.8	$

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three months ended June 30, 2013:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2012	974,765	$ 2.33		
Expired	(200,000)	$ 2.50		
Outstanding at June 30, 2013	774,765	$ 2.28	0.9	$
Options exercisable at June 30, 2013	733,242	$ 2.37	1.1	$

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three months ended June 30, 2013:

	Number of Shares	Weighted Average

			Grant Date Fair Value
Non-vested restricted stock at December 31, 2012	254,260	$	1.43
Vested	(72,053)	$	0.70
Forfeited	(1,974)	$	1.32
Non-vested restricted stock at June 30, 2013	180,233	$	1.72

Restricted Stock Unit Awards

On April 5, 2011, we granted 232,089 restricted stock units to our five executive officers. These restricted stock units vest upon the Company s achievement of certain performance targets, but no earlier than ratably over the three year period following the grant date, at which time one common share will be issued and exchanged for each restricted stock unit held. If the requisite performance targets are not achieved in the seven year period ended April 5, 2018, the restricted stock units will expire. Restricted stock units are included in the calculation of diluted earnings per share utilizing the treasury stock method. On April 30, 2012, 99,108 restricted stock units vested with a vesting date fair value of $0.53 per share. On June 25, 2012, 16,428 restricted stock units were forfeited. There have been no grants of restricted stock units subsequent to the aforementioned grant. Unrecognized compensation cost related the restricted stock units is $116,553 at June 30, 2013.

Table of Contents

Note 16 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 are not possible to reasonably predict, management does not believe that the adverse effect on our financial condition, results of operations or cash flows, if any, will be material.

Environmental and Regulatory

As of June 30, 2013, 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.

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, may, will, p forecast, plan, and similar expressions are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to certain risks, uncertainties and assumptions. Certain of these risks are summarized in our 2012 Annual Report on Form 10-K that we filed with the SEC on March 28, 2013, which you should read carefully in connection with our forward-looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

You should read Management s Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the corresponding sections and our audited consolidated financial statements for the fiscal year ended December 31, 2012, which are included in our 2012 Annual Report on Form 10-K.

Overview

GeoMet, Inc. is primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993.

Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The low natural gas prices in 2012 had pervasive adverse consequences to our business. A borrowing base deficiency under our Credit Agreement was caused by the then low natural gas prices. On August 8, 2012, we amended our Credit Agreement to include a conforming tranche equal to the borrowing base, and a non-conforming tranche in the amount of outstanding loans in excess of the borrowing base. The amendment required that we use all of our excess cash flows, as defined, to reduce outstanding borrowings under the Credit Agreement and significantly limited our capital expenditures. On June 14, 2013, we closed the sale of the Alabama properties and used approximately $57.0 million of the proceeds to repay outstanding borrowings under our Credit Agreement. After this repayment, borrowings outstanding under the Credit Agreement totaled $77.0 million. The new borrowing base was set at the lesser of the total amount of outstanding borrowings under the Credit Agreement and $77.0 million. In connection with this repayment the non-conforming Tranche B portion of total outstanding borrowings has been repaid and the Company no longer has a borrowing base deficiency under the Credit Agreement. The next scheduled borrowing base determination is expected to occur on or around December 15, 2013 and will be based on the Company s reserves at June 30, 2013. As of June 30, 2013, the interest rates applied to borrowings was 3.24%. The Credit Agreement continues to have a maturity date of April 1, 2014.

Additionally, depressed natural gas prices resulted in significant property impairments and full valuation of our net deferred tax asset during 2012. We believe that low natural gas prices and our indebtedness contributed to our common stock being delisted by NASDAQ as we had no remaining equity and the market price of our common stock had diminished.

Management s current business plan is to continue to evaluate its strategic alternatives. Additionally, management is seeking to divest properties with limited value and will consider additional asset sale opportunities as they arise. Management also remains focused on maintaining compliance with the Credit Agreement, as amended, maintaining production levels, and keeping costs under control.

During 2011 and the first five months of 2012, prices received for natural gas in the United States continued to decline significantly which we believe, among other things, was due to an over-supply of natural gas, primarily resulting from shale drilling and reduced demand due to a much warmer winter than normal. On April 21, 2012, the Henry Hub spot price closed at $1.825/ MMBtu, its lowest in over ten years. Presented below are the NYMEX Settle Prices for the period January 2011 through August 2013 and the NYMEX Forward Curve Prices (as of August 7, 2013) for natural gas for the period September 2013 through December 2013.

Table of Contents

Recent Developments

On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama. The sale resulted in proceeds of approximately $62.0 million after normal and customary purchase price adjustments of $1.2 million to account for net cash flows from the effective date to the closing date. Simultaneously with the close of the property sale, approximately $57.0 million was used to repay outstanding borrowings under the Company s Credit Agreement and $5.0 million was held in reserve to pay transaction related costs and expenses, including the liquidation of certain natural gas hedge positions.

GeoMet s net interest in the coalbed methane properties in Alabama sold produced approximately 9,700 Mcf of natural gas per day during the month of March 2013, or approximately 29% of GeoMet s total production for this time period. As of March 31, 2013 and based on Securities and Exchange Commission guidelines, GeoMet s net proved reserves attributable to the coalbed methane properties in Alabama sold were estimated to be approximately 43 Bcf, all classified as proved developed reserves.

Areas of Operation

Subsequent to the asset sale, our core area of operations is the Central Appalachian Basin of Virginia and West Virginia. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. We also own additional coalbed methane and oil and gas development rights, principally in Virginia and West Virginia. As of June 30, 2013, we own a total of approximately 93,000 net acres of coalbed methane and oil and gas development rights.

Central Appalachia

Pond Creek and Lasher Fields We are the operator of 298 producing vertical CBM wells in which we own a 99.0% average working interest in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia. Net daily sales of gas averaged 16.0 MMcf per day for the three and six months ended June 30, 2013. Our natural gas production from the Pond Creek field is delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). We have two long-term transportation agreements with ETNG which went into effect in April 2007 with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. Our gas from the Lasher field is delivered into the Columbia Gas Transmission pipeline with firm transportation for 500 MMBtu s per day. We also own and operate a 12 mile, 8 inch high-pressure steel pipeline and gas treatment and compression facilities through which the Pond Creek field natural gas production is gathered, dehydrated, and compressed for delivery into the Jewell Ridge Lateral of the East Tennessee pipeline system.

Pinnate Horizontal Wells We are the operator of 44 producing pinnate horizontal CBM wells in which we own a 71.6% average working interest in central and northern West Virginia. We also have a 33.7% average working interest in 67 non-operated pinnate horizontal wells in central West Virginia. Net daily sales of natural gas averaged 7.7 MMcf per day and 8.0 MMcf per day for the three and six months ended June 30, 2013, respectively. We are party to two firm transportation agreements with total maximum daily capacity of 18,500 MMBtu per day and primary terms expiring from April 2013 through November 2024 which can be automatically extended at GeoMet s option at the maximum tariff rate. We are also party to a 10,000 MMBtu per day gathering

Table of Contents

contract that is currently in a month-to-month evergreen term. In some cases, our natural gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our natural gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires us to use our judgment to make estimates and assumptions that affect certain amounts reported in our financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Critical accounting policies are those accounting policies that involve judgment and uncertainties affecting the application of those policies and the likelihood that materially different amounts would be reported under different conditions or using differing assumptions. We periodically update our estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. There have been no significant changes to our critical accounting policies during the three months ended June 30, 2013.

Table of Contents

Natural Gas Production 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, 2013 and 2012. This table should be read in conjunction with the discussion of the results of operations for the periods presented below (in thousands, except per Mcf amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Gas sales	$ 12,053	$ 7,712	$ 22,932	$ 17,855
Lease operating expenses	$ 4,123	$ 4,492	$ 8,592	$ 8,933
Compression and transportation expenses	1,868	2,301	3,707	4,540
Production taxes	647	364	1,198	834
Total production expenses	$ 6,638	$ 7,157	$ 13,497	$ 14,307
Net sales volumes (Consolidated) (MMcf)	2,908	3,448	6,016	7,078
Pond Creek field (Central Appalachian Basin) (MMcf)	1,411	1,459	2,822	2,925
Other Central Appalachian Basin fields (MMcf)	744	996	1,539	2,045
Gurnee field (Cahaba Basin) (MMcf)	328	438	723	895
Black Warrior Basin fields (MMcf)	425	555	932	1,213
Per Mcf data ($/Mcf):				
Average natural gas sales price (Consolidated)	$ 4.14	$ 2.24	$ 3.81	$ 2.52
Pond Creek field (Central Appalachian Basin)	$ 4.14	$ 2.26	$ 3.87	$ 2.61
Other Central Appalachian Basin fields	$ 4.18	$ 2.14	$ 3.77	$ 2.38
Gurnee field (Cahaba Basin)	$ 4.16	$ 2.25	$ 3.77	$ 2.52
Black Warrior Basin fields	$ 4.09	$ 2.32	$ 3.73	$ 2.56
Average natural gas sales price realized (Consolidated)(1) (2)	$ 3.23	$ 3.78	$ 3.89	$ 3.95
Lease operating expenses (Consolidated)	$ 1.42	$ 1.29	$ 1.43	$ 1.26
Pond Creek field (Central Appalachian Basin)	$ 1.11	$ 1.05	$ 1.15	$ 1.04
Other Central Appalachian Basin fields	$ 1.68	$ 1.41	$ 1.69	$ 1.42
Gurnee field (Cahaba Basin)	$ 2.93	$ 2.75	$ 2.84	$ 2.60
Black Warrior Basin fields	$ 0.80	$ 0.59	$ 0.74	$ 0.52
Compression and transportation expenses (Consolidated)	$ 0.64	$ 0.67	$ 0.61	$ 0.64
Pond Creek field (Central Appalachian Basin)	$ 0.67	$ 0.64	$ 0.62	$ 0.58
Other Central Appalachian Basin fields	$ 1.02	$ 1.14	$ 1.02	$ 1.16
Gurnee field (Cahaba Basin)	$ 0.26	$ 0.23	$ 0.29	$ 0.26
Black Warrior Basin fields	$ 0.18	$ 0.21	$ 0.18	$ 0.19
Production taxes (Consolidated)	$ 0.22	$ 0.10	$ 0.20	$ 0.12
Pond Creek field (Central Appalachian Basin)	$ 0.22	$ 0.13	$ 0.21	$ 0.15
Other Central Appalachian Basin fields	$ 0.22	$ 0.06	$ 0.18	$ 0.06
Gurnee field (Cahaba Basin)	$ 0.21	$ 0.09	$ 0.18	$ 0.10
Black Warrior Basin fields	$ 0.23	$ 0.14	$ 0.23	$ 0.15
Total production expenses (Consolidated)	$ 2.28	$ 2.06	$ 2.24	$ 2.02
Pond Creek field (Central Appalachian Basin)	$ 2.00	$ 1.82	$ 1.98	$ 1.77
Other Central Appalachian Basin fields	$ 2.92	$ 2.61	$ 2.89	$ 2.64

Gurnee field (Cahaba Basin)	$ 3.40	$ 3.07	$ 3.31	$ 2.96
Black Warrior Basin fields	$ 1.21	$ 0.94	$ 1.13	$ 0.86
Depletion (Consolidated)	$ 0.48	$ 0.92	$ 0.46	$ 0.95

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

(2) Average natural gas sales prices realized for the three and six months ended June 30, 2013 would have been $3.65/Mcf and $4.09/Mcf when excluding $1.2 million in realized losses on derivative contracts related to natural gas swap positions terminated in order to prevent the Company from being over-hedged after the closing of the sale of its coalbed methane properties in Alabama.

Table of Contents

Results of Operations

Three months ended June 30, 2013 compared with three months ended June 30, 2012

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

	Three Months Ended June 30,		
	2013	2012	Change
	(in thousands)		
Gas sales volume (MMcf)	2,908	3,448	-16%
Gas sales	$ 12,053	$ 7,712	56%
Lease operating expenses	$ 4,123	$ 4,492	-8%
Compression expense	$ 1,189	$ 1,256	-5%
Transportation expense	$ 679	$ 1,045	-35%
Production taxes	$ 647	$ 364	78%
Depreciation, depletion and amortization	$ 1,371	$ 3,290	-58%
Impairment of gas properties	$	$ 42,256	NM
General and administrative	$ 1,409	$ 1,366	3%
Realized losses (gains) on derivative contracts	$ 2,647	$ (5,311)	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (6,797)	$ 10,203	NM
Gain on the sale of Properties in Alabama	$ 37,136	$	NM
Interest expense	$ 1,559	$ 1,268	23%
Income tax expense	$ 6	$ 6	%

NM-Not Meaningful

Gas sales. Gas sales increased by $4.3 million, or 56%, to $12.1 million compared to the prior year period. The increase in gas sales was the result of a 85% increase in natural gas prices, excluding hedging transactions, partially offset by of 11% lower daily production volumes and 5% lower total volume resulting from the sale of our Alabama properties on June 14, 2013.

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

Compression expense. Compression expense remained flat compared to the prior year period.

Transportation expense. Transportation expense decreased by $0.4 million, or 35%, to $0.7 million compared to the prior year period. The decrease was primarily due to contract expirations or renegotiations.

Production taxes. Production taxes remained flat compared to the prior year period. However, we expect future production taxes to increase over time as our West Virginia exemptions diminish.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $1.9 million, or 58%, to $1.4 million compared to the prior year period. This decrease was primarily due to the $95.7 million in impairments recorded to our gas properties in 2012.

General and administrative. General and administrative expense remained flat compared to the prior year period. Included in general and administrative expense was a decrease in professional fees, offset by non-recurring executive compensation. In November 2012, the Compensation Committee approved the payment of a contingent bonus in the amount of $0.4 million to be paid to the named executive officers in connection with the elimination of the borrowing base deficiency that existed under the Company s Credit Agreement.

Realized losses (gains) on derivative contracts. Realized losses on derivative contracts were $2.6 million in the current year period of which $1.2 million was related to natural gas swap positions terminated in order to prevent the Company from being over-hedged after the closing of the sale of its coalbed methane properties in Alabama. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Table of Contents

Unrealized (gains) losses from the change in market value of open derivative contracts. Unrealized gains on open derivative contracts were $6.8 million in the current year period. Unrealized gains and losses are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked-to-market at the end of each reporting period.

Gain on the sale of Properties in Alabama. On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama, recording a gain on the sale of $37.1 million, as described in Note 2 Sale of Coalbed Methane Properties in Alabama in the Notes to Consolidated Financial Statements (Unaudited).

Interest expense. Interest expense increased by $0.3 million, or 23%, to $1.6 million compared to the prior year period. The increase was primarily due to average interest on the borrowings increasing to 3.83% per annum in the current year period from 2.99% per annum in the prior year period. The increased rates resulted from the August 2012 amendment to the Credit Agreement.

Income tax expense. The income tax expense in the current year period was different than the amount computed using the statutory rate primarily due to a $15.6 million reduction of the valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

		Total	
Amount computed using statutory rates	$	14,407,806	34.00%
State income taxes net of federal benefit		1,084,723	2.56%
Reduction of valuation allowance		(15,629,252)	-36.88%
Nondeductible items and other		142,973	0.33%
Income tax provision	$	6,250	0.01%

Six months ended June 30, 2013 compared with six months ended June 30, 2012

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

	Six Months Ended June 30,		
	2013	2012	Change
	(in thousands)		
Gas sales volume (MMcf)	6,016	7,078	-15%
Gas sales	$ 22,932	$ 17,855	28%
Lease operating expenses	$ 8,592	$ 8,933	-4%
Compression expense	$ 2,305	$ 2,453	-6%
Transportation expense	$ 1,402	$ 2,087	-33%
Production taxes	$ 1,198	$ 834	44%
Depreciation, depletion and amortization	$ 2,877	$ 6,921	-58%
Impairment of gas properties	$	$ 58,035	NM
General and administrative	$ 2,407	$ 2,668	-10%

Realized gains on derivative contracts	$	(453)	$ (10,104)	NM
Unrealized losses gains from the change in market value of open derivative contracts	$	1,838	$ 4,979	NM
Gain on the sale of Properties in Alabama	$	37,136	$	NM
Interest expense	$	3,236	$ 2,544	27%
Income tax expense	$	13	$ 44,031	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $5.1 million, or 28%, to $22.9 million compared to the prior year period. The increase in gas sales was the result of a 51% increase in natural gas prices, excluding hedging transactions, partially offset by of 13% lower daily production volumes and 2% lower total volume resulting from the sale of our Alabama properties on June 14, 2013.

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

Compression expense. Compression expense remained flat compared to the prior year period.

Transportation expense. Transportation expense decreased by $0.7 million, or 33%, to $1.4 million compared to the prior year period. The decrease was primarily due to contract expirations or renegotiations.

Table of Contents

Production taxes. Production taxes increased by $0.4 million, or 44%, to $1.2 million compared to the prior year period. The increase was primarily due to the increase over time as our West Virginia exemptions diminish.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $4.0 million, or 58%, to $2.9 million compared to the prior year period. This decrease was primarily due to the $95.7 million in impairments recorded to our gas properties in 2012.

General and administrative. General and administrative expense remained flat compared to the prior year period. Included in general and administrative expense was a decrease in professional fees, offset by non-recurring executive compensation. In November 2012, the Compensation Committee approved the payment of a contingent bonus in the amount of $0.4 million to be paid to the named executive officers in connection with the elimination of the borrowing base deficiency that existed under the Company s Credit Agreement.

Realized gains on derivative contracts. Realized gains on derivative contracts were $0.5 million in the current year period of which $1.2 million was related to natural gas swap positions terminated in order to prevent the Company from being over-hedged after the closing of the sale of its coalbed methane properties in Alabama. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $1.8 million in the current year period. Unrealized gains and losses are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked-to-market at the end of each reporting period.

Gain on the sale of Properties in Alabama. On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama, recording a gain on the sale of $37.1 million, as described in Note 2 Sale of Coalbed Methane Properties in Alabama in the Notes to Consolidated Financial Statements (Unaudited).

Interest expense. Interest expense increased by $0.7 million, or 27%, to $3.2 million compared to the prior year period. The increase was primarily due to average interest on the borrowings increasing to 4.06% per annum in the current year period from 2.94% per annum in the prior year period. The increased rates resulted from the August 2012 amendment to the Credit Agreement.

Income tax expense. The income tax expense in the current year period was different than the amount computed using the statutory rate primarily due to a $13.5 million reduction of the valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

		Total	
Amount computed using statutory rates	$	12,453,260	34.00%
State income taxes net of federal benefit		876,006	2.39%
Reduction of valuation allowance		(13,472,543)	-36.78%

Nondeductible items and other		155,777	0.42%
Income tax provision	$	12,500	0.03%

Liquidity and Capital Resources

Cash Flows and Liquidity

As of June 30, 2013, we had a working capital deficit of $71.3 million, a retained deficit of $265.4 million and stockholders deficit of $74.1 million. Natural gas prices in 2012 were depressed compared with prices generally prevailing during prior years. The depressed natural gas prices resulted in significant property impairments, a full valuation of our net deferred tax asset, and a borrowing base deficiency under our Credit Agreement during 2012. Our Credit Agreement matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the borrowings under our Credit Agreement before it matures. As a result, on April 2, 2013, all amounts outstanding under our Credit Agreement were re-classified as current. These and other factors raise substantial doubt about our ability to continue as a going concern for the next twelve months. Our ability to continue as a going concern is dependent upon our ability to generate sufficient cash flows and sales proceeds or other sources of capital sufficient to repay or refinance our indebtedness, continue our operations and fund our long-term capital needs.

Cash flows provided by operations for the six months ended June 30, 2013 were $6.3 million, down $4.1 million from the prior year period. The decrease was primarily due to a $2.9 million decrease in revenues resulting from a decrease in production volumes and $1.2 million in realized hedging losses related to natural gas swap positions terminated in order to prevent the Company from being over-hedged after the closing of the sale of its coalbed methane properties in Alabama. Cash flows from operations of $6.3 million for the six months ended June 30, 2013 and the net proceeds from

Table of Contents

the sale of our Properties in Alabama of $60.7 million were sufficient to fund net cash used in financing activities of $62.3 million, consisting almost entirely of repayments of borrowings under our Credit Agreement.

Credit Agreement

Under our Credit Agreement, outstanding borrowings may not exceed a borrowing base determined by the lenders. During 2012, the amounts borrowed under our Credit Agreement exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Credit Agreement, as amended, provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the excess.

On June 14, 2013, the Company closed the sale of all of its coal bed methane properties located in the state of Alabama. Simultaneously with the close of the property sale, approximately $57.0 million was used to repay outstanding borrowings under the Company s Credit Agreement, which eliminated the borrowing base deficiency. After this repayment, borrowings outstanding under the Credit Agreement totaled $77.0 million. The new borrowing base will be the lesser of the total amount of outstanding borrowings under the Credit Agreement and the current balance of $77.0 million. The next scheduled borrowing base determination is expected to occur on or around December 15, 2013 and will be based on the Company s reserves at June 30, 2013. The Credit Agreement continues to have a maturity date of April 1, 2014.

The Credit Agreement no longer provides for loans to be available on a revolving basis up to the amount of the borrowing base. As a result, the current outstanding loans, once repaid, may not be re-borrowed by the Company. All outstanding borrowings under the Credit Agreement are due and payable on April 1, 2014. The Credit Agreement provides for interest to accrue at a rate calculated, at our option, at the Adjusted Base Rate plus a margin of 2.00% or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00%. Adjusted Base Rate is defined to be the greater of (i) the agent s base rate or (ii) the federal funds rate plus one half of one percent or (iii) the LIBOR Rate plus a margin of 1.00%. All financial covenants were deleted by the Amendment and were replaced with a capital expenditure covenant (a maximum of $1.5 million in 2012 and $1.5 million in 2013). As of June 30, 2013, we had $77.0 million of borrowings outstanding under our Credit Agreement. As of June 30, 2013, the interest rates applied to borrowings were 3.24%.

Natural Gas Price Risk and Related Hedging Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. At June 30, 2013, we do not have the ability to enter into natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has historically hedged natural gas prices 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. We entered into hedging transactions, generally for forward periods up to two years or more, which increased the probability of achieving our targeted level of cash flows. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum ceiling (a sold ceiling) and a minimum floor (a bought floor) future price. We have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in our Consolidated Balance Sheets (Unaudited) and Consolidated Statements of Operations (Unaudited).

Commodity Price Risk and Related Hedging Activities

At June 30, 2013, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Fair Value
January 2014 through December 2015	3,650,000	$ 4.30	$ 3.60	$ (302,324)
January 2014 through December 2015	3,650,000	$ 4.20	$ 3.50	(529,497)
	7,300,000			$ (831,821)

Table of Contents

At June 30, 2013, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
July 2013 through December 2013	1,104,000	$ 3.60	(47,156)
July 2013 through March 2014	2,192,000	$ 3.81	184,627
July 2013 through March 2014	1,832,000	$ 3.82	230,109
	5,128,000		$ 367,580

We have hedged approximately 91% of our remaining forecasted production for 2013 at a fixed price of $3.76 per Mcf. As a result, we expect changes in natural gas prices to have a minimal impact on our cash flows through the end of 2013.

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,		Six months ended June 30,	
	2013	2012	2013	2012
Capital expenditures:				
Leasehold acquisition	$ 14,626	$ 361,540	$ 110,892	$ 510,159
Development (1)	399,785	(274,773)	377,797	(337,979)
Asset retirement obligations		241,317		247,440
Other items (primarily capitalized overhead)	3,969	83,294	10,006	208,196
Total capital expenditures	$ 418,380	$ 411,378	$ 498,695	$ 627,816

(1) 2012 includes losses on inventory sold less insurance refunds related to our gas properties.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. There has been no material changes in those commitments disclosed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Commitments of our 2012 Annual Report on Form 10-K that we filed with the SEC on March 28, 2013.

Recent Pronouncements

In July 2013, the FASB, issued ASU, No. 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. The amendments in ASU 2013-10 permit the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to UST and LIBOR. The amendments also remove the restriction on using different benchmark rates for similar hedges. The amendments are effective prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We are presently assessing the potential impact of ASU 2013-11.

In February 2013, the FASB issued ASU No. 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date. ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations addressed within existing guidance. The update is effective for interim and annual periods beginning after December 15, 2013 and is required to be applied retrospectively to all prior periods presented for those obligations that existed upon adoption of ASU 2013-04. We are presently assessing the potential impact of ASU 2013-04.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under accounting principles generally accepted in the United States (GAAP) to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. The amendments are effective

Table of Contents

prospectively for reporting periods beginning after December 15, 2012. The Company has adopted and applied the provisions of ASU 2012-02 which did not impact its operating results, financial position or cash flows.

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company has adopted and applied the provisions of ASU 2013-01. See disclosure provided in Note 9 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements (Unaudited).

Environmental Regulations

Our exploration and production operations are subject to significant federal, state, and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities, and concentrations of various substances that can be released into the environment as a result of natural gas drilling, production, and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas or that impact protected species; require permits or other governmental authorization before commencing certain activities and require the installation of pollution control measures as a condition of such permits or authorizations; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunctive relief, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future could have a material adverse impact on our operations.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws or regulations or the modification of existing laws or regulations could have a material adverse effect on our operations. As a general matter, the recent trend in environmental legislation and regulation is toward stricter standards, and this trend will likely continue. To date, we have not been required to expend extraordinary resources in order to satisfy existing applicable environmental laws and regulations. However, costs to comply with existing and any new environmental laws and regulations could become material. Moreover, a serious incident of pollution may result in the suspension or cessation of operations in the affected area or in substantial liabilities to third parties. Although we maintain insurance coverage against costs of clean-up operations, no assurance can be given that we are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

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, 2013, a 10% decrease in the prices received for natural gas production would have decreased our gas revenues by approximately $1.2 million, which would have been offset by approximately $1.2 million by increased realized gas hedging gains. For the six months ended June 30, 2013, a 10% decrease in the prices received for natural gas production would have

decreased our gas revenues by approximately $2.3 million, which would have been offset by approximately $2.2 million by increased realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of June 30, 2013, we had $77.0 million of borrowings outstanding under our Credit Agreement. As of June 30, 2013, the interest rates applied to borrowings were 3.24%. For the three months ended June 30, 2013 and 2012, interest on the borrowings averaged 3.83% and 2.99% per annum, respectively. For the six months ended June 30, 2013 and 2012, interest on the borrowings averaged 4.06% and 2.94% per annum, respectively. All of the debt outstanding under our Credit Agreement accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the weighted average balance outstanding under our Credit Agreement, a 1% increase in market interest rates would have increased interest expense and negatively impacted our cash flows for the three and six months ended June 30, 2013 by approximately $0.3 million and $0.7 million, respectively.

Table of Contents

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, 2013 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal 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.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Environmental and Regulatory

As of June 30, 2013, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 1A. Risk Factors

There has been no changes from the risk factors disclosed in the Risk Factors section of our Annual Report on Form 10-K for the year ended December 31, 2012.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

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: August 14, 2013 By /S/ TONY OVIEDO
Tony Oviedo, Senior Vice President, Chief Financial Officer,
Chief Accounting Officer and Controller
(Principal Financial Officer)

Table of Contents

INDEX TO EXHIBITS

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

* Attached hereto.

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