GeoMet, Inc.
Form 10-Q
November 09, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

OR

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

For the transition period from to

Commission File Number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of 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 November 1, 2012, 40,690,077 shares and 5,145,156 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

Table of Contents

Part I. FINANCIAL INFORMATION

Item 1. Financial Statements

GEOMET, INC. AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,006,333	$ 457,865
Accounts receivable, net of allowance of $17,634 at September 30, 2012 and December 31, 2011	4,411,710	4,402,065
Inventory	298,807	597,197
Derivative asset natural gas contracts	6,812,576	20,685,187
Other current assets	1,387,418	1,141,310
Total current assets	19,916,844	27,283,624
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	534,401,745	561,451,504
Other property and equipment	3,743,084	3,671,123
Total property and equipment	538,144,829	565,122,627
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(453,432,823)	(388,730,093)
Property and equipment net	84,712,006	176,392,534
Other noncurrent assets:		
Derivative asset natural gas contracts		1,765,450
Deferred income taxes	1,421,903	48,171,298
Other	2,037,729	3,532,882
Total other noncurrent assets	3,459,632	53,469,630
TOTAL ASSETS	$ 108,088,482	$ 257,145,788
LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY		
Current Liabilities:		
Accounts payable	$ 8,777,675	$ 7,500,768
Accrued liabilities	2,465,657	3,936,070
Deferred income taxes	1,421,903	4,153,099
Derivative liability natural gas contracts	1,065,545	
Asset retirement obligation		32,028
Current portion of long-term debt	14,100,000	91,757
Total current liabilities	27,830,780	15,713,722

Long-term debt	131,500,000	158,171,662
Asset retirement obligation	8,485,761	8,138,551
Derivative liability natural gas contracts	3,703,048	
Other long-term accrued liabilities	151,245	8,145
TOTAL LIABILITIES	171,670,834	182,032,080
Commitments and contingencies (Note 15)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $49,893,090; $.001 par value; 7,401,832 shares authorized, 4,989,309 and 4,549,537 shares were issued and outstanding at September 30, 2012 and December 31, 2011, respectively	33,283,310	28,482,624
Stockholders (Deficit) Equity:		
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 40,690,077 and 40,010,188 at September 30, 2012 and December 31, 2011, respectively	40,690	40,010
Treasury stock 10,432 shares at September 30, 2012 and December 31, 2011	(94,424)	(94,424)
Paid-in capital	196,669,112	200,344,209
Accumulated other comprehensive income (loss)	31,738	(1,309,926)
Retained deficit	(293,330,144)	(152,104,329)
Less notes receivable	(182,634)	(244,456)
Total stockholders (deficit) equity	(96,865,662)	46,631,084
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY	$ 108,088,482	$ 257,145,788

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Operations (Unaudited)

Revenues:				
Gas sales	$ 9,609,586	$ 8,519,980	$ 27,464,729	$ 24,701,708
Operating fees	55,439	64,984	190,650	210,670
Total revenues	9,665,025	8,584,964	27,655,379	24,912,378
Expenses:				
Lease operating expense	4,417,390	2,982,932	13,350,417	8,793,883
Compression and transportation expense	2,217,610	1,082,145	6,757,864	2,959,209
Production taxes	442,129	390,045	1,276,215	1,077,754
Depreciation, depletion and amortization	2,539,531	1,676,872	9,460,420	4,900,669
Impairment of gas properties	25,431,734		83,467,022	
General and administrative	1,097,308	1,159,422	3,765,475	4,083,981
Restructuring costs	187,597		952,830	
Acquisition costs		370,621		370,621
Losses (gains) on natural gas derivatives	4,783,942	(4,225,508)	(341,525)	(6,605,612)
Total operating expenses	41,117,241	3,436,529	118,688,718	15,580,505
Operating (loss) income	(31,452,216)	5,148,435	(91,033,339)	9,331,873
Other income (expense):				
Interest income	814	4,207	5,113	12,968
Interest expense	(1,513,684)	(868,388)	(4,057,927)	(2,532,160)
Write off of debt issuance costs	(1,377,520)		(1,377,520)	
Other	943	12,501	(3,156)	8,176
Total other income (expense):	(2,889,447)	(851,680)	(5,433,490)	(2,511,016)
(Loss) income before income taxes and discontinued operations	(34,341,663)	4,296,755	(96,466,829)	6,820,857
Income tax expense	(6,250)	(1,619,739)	(44,036,950)	(2,527,036)
(Loss) income before discontinued operations	(34,347,913)	2,677,016	(140,503,779)	4,293,821
Discontinued operations, net of tax	(25,655)	(247,141)	(722,036)	(341,129)
Net (loss) income	$ (34,373,568)	$ 2,429,875	$ (141,225,815)	$ 3,952,692
Accretion of Series A Convertible Redeemable Preferred Stock	(485,338)	(449,347)	(1,418,307)	(1,308,519)
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock	(903,912)	(1,377,880)	(2,764,257)	(4,009,990)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(689)	(792)	(1,985)	(2,014)
Net (loss) income available to common stockholders	$ (35,763,507)	$ 601,856	$ (145,410,364)	$ (1,367,831)
Net (loss) income per common share basic:				
Net (loss) income per common share from continuing operations	$ (0.89)	$ 0.02	$ (3.61)	$ (0.02)
Net loss per common share from discontinued operations			(0.02)	(0.01)
Net (loss) income per common share basic	$ (0.89)	$ 0.02	$ (3.63)	$ (0.03)

Net (loss) income per common share diluted:								
Net (loss) income per common share from continuing operations	$	(0.89)	$	0.02	$	(3.61)	$	(0.02)
Net loss per common share from discontinued operations						(0.02)		(0.01)
Net (loss) income per common share diluted	$	(0.89)	$	0.02	$	(3.63)	$	(0.03)
Weighted average number of common shares:								
Basic		40,286,573		39,640,275		40,018,778		39,576,684
Diluted		40,286,573		39,968,064		40,018,778		39,576,684

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Comprehensive (Loss) Income

(Unaudited)

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Net (loss) income	$ (34,373,568)	$ 2,429,875	$ (141,225,815)	$ 3,952,692
Gain on foreign currency translation adjustment	14,240	3,342	2,019	4,082
Reclassification adjustment for loss on foreign currency translation included in net loss			1,307,906	
Unrealized (loss) gain on available for sale securities	(19,454)		31,738	
Gain on interest rate swap				10,862
Other comprehensive (loss) income	$ (34,378,782)	$ 2,433,217	$ (139,884,152)	$ 3,967,636

See accompanying Notes to Consolidated Financial Statements (Unaudited)

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Nine months ended September 30, 2012	2011
Cash flows provided by operating activities:		
Net (loss) income	$ (141,225,815)	$ 3,952,692
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	9,458,700	5,142,308
Impairment of gas properties	83,467,022	
Amortization of debt issuance costs	530,799	435,702
Write off of debt issuance costs	1,377,520	
Deferred income tax expense	44,018,200	2,508,286
Unrealized losses from the change in market value of open derivative contracts	13,258,958	122,246
Stock-based compensation	512,377	576,345
Loss on sale of Hudson s Hope Gas, Ltd.	683,154	
Loss on sale of other assets	5,200	1,164
Accretion expense asset retirement obligation	584,813	407,708
Changes in operating assets and liabilities:		
Accounts receivable	(13,052)	127,815
Other assets	193,953	(715,323)
Accounts payable	1,577,480	(401,321)
Other accrued liabilities	(833,930)	(574,953)
Net cash provided by operating activities	13,595,379	11,582,669
Cash flows provided by (used in) investing activities:		
Capital expenditures	(856,655)	(12,118,713)
Return of original basis through the settlement of natural gas derivative contracts	7,147,696	
Proceeds from sale of other property and equipment	3,500	
Other assets		246,134
Net cash provided by (used in) investing activities	6,294,541	(11,872,579)
Cash flows (used in) provided by financing activities:		
Proceeds from revolving credit facility borrowings	10,500,000	24,300,000
Payments on revolving credit facility	(22,800,000)	(23,800,000)
Proceeds from exercise of stock options		3,791
Deferred financing costs	(853,578)	(172,507)
Payments on other debt	(188,965)	(111,083)
Purchase and cancellation of treasury stock	(2,039)	(2,145)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(1,985)	(2,014)
Net cash (used in) provided by financing activities	(13,346,567)	216,042
Effect of exchange rate changes on cash	5,115	57
Increase (decrease) in cash and cash equivalents	6,548,468	(73,811)
Cash and cash equivalents at beginning of period	457,865	536,533

Cash and cash equivalents at end of period	$	7,006,333	$	462,722
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	$	5,960,054	$	2,573,915
Cash paid during the period for income taxes	$	18,750	$	18,750
Significant noncash investing and financing activities:				
Accrued capital expenditures	$	609,017	$	1,484,715
Fair value of common stock received in exchange for Hudson s Hope Gas, Ltd.	$	293,769	$	

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 a natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in Alabama, Virginia and West Virginia.

The accompanying unaudited consolidated financial statements include our accounts and those of our wholly-owned subsidiaries. All intercompany transactions and balances have been eliminated in consolidation. The unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the interim periods presented. These unaudited consolidated financial statements have been prepared in accordance with the guidelines of interim reporting; therefore, they do not include all disclosures required for our year-end audited consolidated financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Interim period results are not necessarily indicative of results of operations or cash flows for the full year. These unaudited consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements for the fiscal year ended December 31, 2011 and the accompanying notes included in our Annual Report on Form 10-K, which we filed with the Securities and Exchange Commission (the SEC) on March 30, 2012.

Note 2 Liquidity Considerations

As of September 30, 2012, we had a working capital deficit of $7.9 million. The working capital deficit as of September 30, 2012 was primarily the result of the classification of $14.1 million of our borrowings under our Fifth Amended and Restated Credit Agreement (the Credit Agreement), as described in Note 11 Long-Term Debt, as a current liability for scheduled payments over the next twelve months. We believe that our cash flows from operating activities, as well as the return of original basis through the settlement of natural gas derivative contracts, will provide us with sufficient resources to fund our working capital deficit and to meet our obligations in connection with operating our properties for at least the next twelve months. However, there can be no assurance that future borrowing base determinations will not result in additional payment obligations under the Credit Agreement or that our cash flows will not be adversely impacted by events beyond our control.

Note 3 Recent Pronouncements

On June 16, 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in Accounting Standards Codification (ASC) 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the three and nine months ended September 30, 2012.

On May 12, 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework that is, converged guidance on how (not when) to measure fair value and on what disclosures to provide about fair value measurements. Thus, there are few differences between the ASU and its international counterpart, IFRS 13. While the ASU is largely consistent with existing fair value measurement principles in U.S. GAAP, it expands ASC 820 s existing disclosure requirements for fair value measurements and makes other amendments. Many of these amendments were made to eliminate unnecessary wording differences between U.S. GAAP and IFRS. However, some could change how the fair value measurement guidance in ASC 820 is applied. The ASU is effective for interim and annual periods beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the three and nine months ended September 30, 2012. See disclosure provided in these Notes to Consolidated Financial Statements (Unaudited).

Table of Contents

Note 4 Net (Loss) Income Per Common Share

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

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Net (loss) income	$ (34,373,568)	$ 2,429,875	$ (141,225,815)	$ 3,952,692
Accretion of Series A Convertible Redeemable Preferred Stock	(485,338)	(449,347)	(1,418,307)	(1,308,519)
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock	(903,912)	(1,377,880)	(2,764,257)	(4,009,990)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(689)	(792)	(1,985)	(2,014)
Net (loss) income available to common stockholders	$ (35,763,507)	$ 601,856	$ (145,410,364)	$ (1,367,831)
Net (loss) income per common share basic:				
Net (loss) income per common share from continuing operations	$ (0.89)	$ 0.02	$ (3.61)	$ (0.02)
Net loss per common share from discontinued operations			(0.02)	(0.01)
Net (loss) income per common share basic	$ (0.89)	$ 0.02	$ (3.63)	$ (0.03)
Net (loss) income per common share diluted:				
Net (loss) income per common share from continuing operations	$ (0.89)	$ 0.02	$ (3.61)	$ (0.02)
Net loss per common share from discontinued operations			(0.02)	(0.01)
Net (loss) income per common share diluted	$ (0.89)	$ 0.02	$ (3.63)	$ (0.03)
Weighted average number of common shares:				
Basic	40,286,573	39,640,275	40,018,778	39,576,684
Add potentially dilutive securities:				
Stock options, non-vested restricted stock and non-vested restricted stock units		327,789		
Diluted	40,286,573	39,968,064	40,018,778	39,576,684

Net loss per common share diluted for the three months ended September 30, 2012 excluded the effect of outstanding options exercisable to purchase 2,397,603 shares, 116,732 weighted average restricted stock units for which common shares are distributed upon achievement of certain performance targets, 273,301 weighted average restricted shares outstanding, and 4,838,181 shares of Series A Convertible Redeemable Preferred Stock (37,216,776 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 nine months ended September 30, 2012 excluded the effect of outstanding options exercisable to purchase 2,397,603 shares, 170,570 weighted average restricted stock units for which common shares are distributed upon achievement of certain performance targets, 262,896 weighted average restricted shares outstanding, and 4,549,537 shares of Series A Convertible Redeemable Preferred Stock (34,996,440 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive.

Table of Contents

Net income per common share diluted for the three months ended September 30, 2011 excluded the effect of 4,411,749 shares of Series A Convertible Redeemable Preferred Stock (33,936,532 in dilutive shares, as converted, which assumes conversion on the first day of the period) because their effect would have been anti-dilutive. In accordance with ASC 260, in computing the dilutive effect of convertible securities, Net income available to common stockholders is also adjusted to add back any preferred dividends and accretion unless the preferred shares are anti-dilutive. As such, there was no add back to Net income available to common stockholders for the three months ended September 30, 2011 for accretion of, and dividends paid for, Series A Convertible Redeemable Preferred Stock (cash and PIK) of $449,347 and $1,378,672, respectively, in computing Net income per common share diluted as the preferred shares were anti-dilutive.

Net loss per common share diluted for the nine months ended September 30, 2011 excluded the effect of outstanding options exercisable to purchase 2,603,536 shares, 232,089 restricted stock units for which common shares are distributed upon achievement of certain performance targets, 355,705 weighted average restricted shares outstanding, and 4,148,538 shares of Series A Convertible Redeemable Preferred Stock (31,911,830 in dilutive shares, as converted, which assumes conversion on the first day of the period) because we reported a net loss available to common stockholders which caused the options, restricted stock units, restricted shares and preferred shares to be anti-dilutive. For the preferred shares, there was no add back to Net loss available to common stockholders for the nine months ended September 30, 2011 for accretion of, and dividends paid for, Series A Convertible Redeemable Preferred Stock (cash and PIK) of $1,308,519 and $4,012,004, respectively, in computing Net loss per common share diluted as the preferred shares were anti-dilutive.

Note 5 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 all 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 were as follows:

Statements of Operations (Unaudited):

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Revenues	$	$	$	$
Total operating expenses		(247,141)	(13,123)	(341,129)
Operating loss		(247,141)	(13,123)	(341,129)
Loss on sale of Hudson s Hope Gas, Ltd.			(683,154)	
Other expense	(25,655)		(25,759)	
Income tax expense				

Net loss	$	(25,655)	$	(247,141)	$	(722,036)	$	(341,129)

Table of Contents

Balance Sheets (Unaudited):

	September 30, 2012		December 31, 2011
ASSETS			
Total current assets	$	$	33,474
Gas properties utilizing the full cost method of accounting:			
Proved gas properties			28,073,293
Less accumulated depreciation, depletion, amortization and impairment of gas properties			(28,073,293)
Property and equipment net			
Total other noncurrent assets			2,941
TOTAL ASSETS	$	$	36,415
LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY			
Total current liabilities	$	$	54,827
Asset retirement obligation			303,169
TOTAL LIABILITIES			357,996
Total stockholders deficit			(321,581)
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY	$	$	36,415

Note 6 Gas Properties

The method of accounting for oil and gas producing activities determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the SEC. Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized.

Natural 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 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 (deficit) equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

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

For the twelve months ended September 30, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.84 per Mcf, resulting in a natural gas price of $2.99 per Mcf when adjusted for regional price

Table of Contents

differentials. For the three and nine months ended September 30, 2012, we recorded a $25.4 million and $83.5 million write-down, respectively, of the carrying value of our U.S. full cost pool.

Note 7 Asset Retirement Obligation

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. Asset retirement obligations incurred in the current period were non-recurring Level 3 (unobservable inputs) fair value measurements under ASC 820-10-55. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

The following table details the changes to our asset retirement obligation for the nine months ended September 30, 2012:

Current portion of liability at January 1, 2012	$	32,028
Add: Long-term asset retirement obligation at January 1, 2012		8,138,551
Asset retirement obligation at January 1, 2012		8,170,579
Liabilities incurred		14,252
Liabilities conveyed to buyer of Hudson s Hope Gas, Ltd.		(345,226)
Settlements		(184,570)
Accretion		584,813
Revisions in estimates		241,317
Foreign currency translation		4,596
Asset retirement obligation at September 30, 2012		8,485,761
Less: Current portion of liability		
Long-term asset retirement obligation	$	8,485,761

Note 8 Derivative Instruments and Hedging Activities

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

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. Our Credit Agreement limits amounts of future natural gas production that we may hedge.

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).

Table of Contents

Commodity Price Risk and Related Hedging Activities

At September 30, 2012, we had the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor	Sold Floor		Fair Value
January 2014 through December 2015	3,650,000	$	4.30	$	3.60		$	(910,759)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50			(1,150,697)
	7,300,000						$	(2,061,456)

At September 30, 2012, we had the following natural gas swap positions:

Period	Volume (MMBtu)		Fixed Price		Fair Value
October through December 2012	138,000	$	5.11	$	247,007
October through December 2012	57,000	$	5.12		102,594
October through December 2012	259,995	$	6.85		917,949
October through December 2012	119,616	$	6.99		438,504
October through December 2012	196,358	$	7.05		735,451
October 2012	124,000	$	5.73		335,664
October 2012	248,000	$	4.94		474,170
October 2012	465,000	$	2.89		(61,831)
November 2012 through March 2013	604,000	$	6.42		1,669,840
November 2012 through March 2013	906,000	$	5.50		1,677,012
November 2012 through March 2014	4,128,000	$	3.81		(196,105)
November 2012 through March 2014	4,128,000	$	3.82		(157,375)
January 2013 through December 2013	2,190,000	$	3.60		(498,957)
April 2013 through December 2013	2,750,000	$	3.25		(1,582,967)
	16,313,969			$	4,100,956

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

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

November 2012 through March 2013	906,000	$	5.50		1,544,680
	8,590,979			$	22,432,414

At September 30, 2012, we had the following natural gas basis swap position:

Period	Volume (MMBtu)		Fixed Basis		Fair Value
October through December 2012	138,000	$	0.04	$	4,483

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

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

Table of Contents

As of September 30, 2012, we had the following forward sales at NYMEX plus a fixed basis:

Period	Volume (MMBtu)		Fixed Basis
October 2012 through March 2013	910,000	$	0.19
November 2012 through March 2013	1,540,200	$	0.22
	2,450,200		

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

The application of ASC 820-10-55, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas derivative contracts using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of credit risk on the fair value of the assets and liabilities related to the items stated below. The consideration for discounting our counterparties liabilities (our assets) was based on the difference between the S&P credit rating of a comparable company to our counterparties and the 13-week Treasury bill rate, both at the reporting date. The consideration for discounting our liabilities was based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included in our long-term debt.

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

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the three and nine months ended September 30, 2012. Based on the use of observable market inputs, we have designated these types of instruments as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our derivative instruments was as follows:

	Asset Derivatives						Liability Derivatives					
	September 30, 2012			December 31, 2011			September 30, 2012			December 31, 2011		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives not designated as hedging instruments under ASC 815-20-25												
Natural gas hedge positions	Derivative asset (current)	$	6,812,576	Derivative asset (current)	$	20,685,187	Derivative liability (current)	$	1,065,545	Derivative liability (current)	$	

Natural gas hedge positions	Derivative asset (non-current)		Derivative asset (non-current)	1,765,450	Derivative liability (non-current)	3,703,048	Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 6,812,576		$ 22,450,637		$ 4,768,593		$

Table of Contents

Losses (gains) on natural gas derivatives included in the Consolidated Statements of Operations (Unaudited) and Other Comprehensive (Loss) Income (Unaudited) (OCI) are as follows:

Derivatives (not designated as hedging instruments under ASC 815-20-25)	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative — Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Natural gas collar/swap settled positions	Losses (gains) on natural gas derivatives	$ (3,496,348)	$ (1,681,756)	$ (13,600,483)	$ (6,714,874)
Natural gas collar/swap unsettled positions	Losses (gains) on natural gas derivatives	8,280,290	(2,543,752)	13,258,958	109,262
Losses (gains) on natural gas derivatives		$ 4,783,942	$ (4,225,508)	$ (341,525)	$ (6,605,612)

We had an interest rate swap mature on January 6, 2011 that had previously been designated as cash flow hedges under ASC 815-20-25. On the maturity date, a loss of $17,782 was released from Accumulated Other Comprehensive Income (Loss) in the Consolidated Balance Sheet (Unaudited) and recognized as Interest expense in the Consolidated Statements of Operations (Unaudited).

Note 9 Investment in CEP Shares

At September 30, 2012, we own two million shares of Canada Energy Partners (CEP), discussed in Note 5 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 on the shares of CEP are held in Accumulated other comprehensive income (loss), net of tax. At September 30, 2012, the value of the shares recorded in Other noncurrent assets was $330,721 using a Level 1 input. Accumulated other comprehensive income of $31,738 as of September 30, 2012 consisted entirely of unrealized gains on the CEP shares. Accumulated other comprehensive loss of $1,309,926 as of December 31, 2011 consisted entirely of foreign currency translation adjustments.

Note 10 Restructuring Costs

Restructuring activities consist of senior management and board of directors realignment. The restructuring costs for the three months ended September 30, 2012 of $0.2 million included cash payments to our former Chief Executive Officer (CEO) of $0.1 million under a consulting agreement and other costs of $0.1 million. The restructuring costs for the nine months ended September 30, 2012 of $1.0 million included cash payments to our former CEO of $0.7 million under separation and consulting agreements, share-based awards conveyed to our former CEO of $0.1 million and other costs of $0.2 million.

Note 11 Long-Term Debt

On November 18, 2011, our Credit Agreement with a group of six banks became effective. Effective August 8, 2012, we entered into the Fourth Amendment (the Amendment) to our Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Amendment provides for an initial conforming borrowing base of $115.0 million (Tranche A) with the balance then remaining in the amount of $33.6 million constituting a non-conforming tranche (Tranche B). The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by December 31, 2012. Upon any determination of the borrowing base, the redetermined amount of the conforming borrowing base shall constitute a new Tranche A, with any decrease in Tranche A causing an automatic corresponding increase in Tranche B, subject to certain limitations described below, and any increase in Tranche A causing an automatic corresponding decrease in Tranche B. At the next borrowing base determination, Tranche B shall not increase by more than fifty percent (50%) of the amount of the principal payments made on Tranche B Loans since the prior redetermination of the borrowing base. Thereafter, at each subsequent redetermination of the borrowing base, Tranche B shall not increase by more than twenty-five percent (25%) of the amount of the principal payments made on Tranche B Loans since the prior redetermination of the borrowing base. Should a future determination of the borrowing base result in the amount of the Tranche B Loan exceeding $33.6 million, the Company has 30 days to repay such excess. The Credit Agreement, as amended, 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, as amended, are due and payable on April 1, 2014. In addition, the Amendment obligates us to reduce our borrowings under the Credit Agreement, as amended, monthly by an amount equal to our bank cash, excluding the segregated account, minus (i) all outstanding and unpaid checks or Automated Clearing House payments and (ii) an amount equal to $1,000,000 as calculated on the 24th day of each month. The Amendment provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 2.00% on Tranche A Loans and 4.00% on

Table of Contents

Tranche B Loans or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00% on Tranche A loans and 5.00% on Tranche B Loans. 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%. The banks will be paid an additional fee based on the amount of Tranche B Loans as follows:

Calculation Date	Fee Amount (basis points)	Date Payable
11/25/2012	75 bps	12/1/2012
2/25/2013	100 bps	3/1/2013
5/25/2013	125 bps	6/1/2013
8/25/2013	150 bps	9/1/2013
11/25/2013	175 bps	12/1/2013

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 $1.0 million in 2013) and a maximum debt covenant as follows:

Quarter Ending		Maximum Principal Outstanding
9/30/2012	$	146,200,000
12/31/2012	$	139,300,000
3/31/2013	$	136,000,000
6/30/2013	$	132,700,000
9/30/2013	$	131,500,000
12/31/2013	$	129,000,000

Deferred financing costs were $0.4 million and $0.9 million for the three and nine months ended September 30, 2012, respectively, which included an amendment fee of 50 basis points on the amount of Tranche B which was capitalized in Deferred financing costs in the amount of $0.2 million on August 8, 2012 in connection with the execution of the Amendment. Deferred financing costs of $1.4 million as of August 8, 2012 related to the Credit Agreement prior to the Amendment were written off upon execution of the Amendment.

As of September 30, 2012, we had $145.6 million of borrowings outstanding under our Credit Agreement. As of September 30, 2012, the interest rates applied to borrowings under Tranche A and Tranche B were 3.24% and 5.24%, respectively. As of December 31, 2011, the weighted average interest rate applied to all borrowings was 2.84%.

For the three months ended September 30, 2012, we borrowed no amounts and made payments of $3.0 million under the Credit Agreement. For the nine months ended September 30, 2012, we borrowed $10.5 million and made payments of $22.8 million under the Credit Agreement.

For the three months ended September 30, 2011, we borrowed $8.5 million and made payments of $6.9 million under the Credit Agreement. For the nine months ended September 30, 2011, we borrowed $24.3 million and made payments of $23.8 million under the Credit Agreement.

For the three months ended September 30, 2012 and 2011, interest on the borrowings averaged 3.50% and 3.45% per annum, respectively. For the nine months ended September 30, 2012 and 2011, interest on the borrowings averaged 3.12% and 3.41% per annum, respectively.

Table of Contents

The following is a summary of our long-term debt at September 30, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
Borrowings under Credit Agreement:		
Tranche A	$ 115,000,000	$
Tranche B	30,600,000	
Revolving facility		157,900,000
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured		78,012
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured		285,407
Total debt	145,600,000	158,263,419
Less current maturities included in current liabilities	(14,100,000)	(91,757)
Total long-term debt	$ 131,500,000	$ 158,171,662

We record our debt instruments based on contractual terms. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities. On January 1, 2012, we adopted ASU 2011-04 Fair Value Measurement which requires the categorization by level of the fair value hierarchy for items not measured at fair value on our Consolidated Balance Sheets (Unaudited) but for which fair value is required to be disclosed. We measure the fair value of our debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 or 2 within the fair value hierarchy. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the market weighted average cost of equity capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included in our long-term debt. The fair value of long-term debt at September 30, 2012 and December 31, 2011 was estimated to be approximately $136.9 million and $131.1 million, respectively.

Note 12 Common Stock

At September 30, 2012 and December 31, 2011, there were 40,690,077 and 40,010,188 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. Also included in common stock outstanding at September 30, 2012 and December 31, 2011 were 254,260 and 293,166 shares of restricted stock, respectively. The following table details the activity related to our common stock for the nine months ended September 30, 2012:

	Date	Shares
Common stock outstanding at December 31, 2011		40,010,188
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	1/5/2012	(1,981)
Issued to our independent directors (12.5% of annual retainer)	3/28/2012	64,284
Shares Issued under the separation agreement of our former CEO	4/30/2012	99,108
	3/15/2012	(1,171)

Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock		
Issued to our independent directors (12.5% of annual retainer)	5/11/2012	97,824
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	6/15/2012	(418)
Restricted shares granted to executive officers	5/14/2012	150,000
Issued to our independent directors (12.5% of annual retainer)	8/10/2012	300,000
Restricted shares forfeited upon employment termination	6/25/2012	(27,757)
Common stock outstanding at September 30, 2012		40,690,077

Table of Contents

Note 13 Series A Convertible Redeemable Preferred Stock

At September 30, 2012 and December 31, 2011, 4,989,309 and 4,549,537 shares of preferred stock were issued and outstanding, respectively. At September 30, 2012, an additional 2,412,523 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 a discounted cash flow analysis based on our current borrowing rates (categorized as level 3).

The following table details the activity related to the Preferred Stock for the nine months ended September 30, 2012:

	Dividend Period (Three Months Ended)	Date Issued	Number of Shares		Balance
Balance at December 31, 2011			4,549,537	$	28,482,624
Accretion of Preferred Stock					1,418,307
PIK Dividends Issued for Preferred Stock :	12/31/11	1/3/12	142,095		1,522,035
	3/31/12	4/2/12	146,549		1,240,719
	6/30/12	7/2/12	151,128		619,625
Balance At September 30, 2012			4,989,309	$	33,283,310

On September 6, 2012, we declared a quarterly dividend of 155,847 shares of Preferred Stock covering the period July 1, 2012 through September 30, 2012. As those shares were not issued until October 1, 2012, they have not been included in the Preferred Stock balance at September 30, 2012. As such, we recorded a dividend payable in Current liabilities in the Consolidated Balance Sheet (Unaudited) at September 30, 2012 at an estimated fair value of $864,951. Additionally, on March 31, 2012, June 30, 2012 and September 30, 2012, cash dividends of $645, $651 and $689, respectively, were paid for fractional share dividends not paid-in-kind.

Note 14 Share-Based Awards

As of September 30, 2012, our 2006 Long-Term Incentive Plan (the 2006 Plan) is our only authorized stock-based award plan. Our 2005 Stock Option Plan was terminated on March 11, 2011 as no options granted under the plan remained outstanding at that time. Our 2006 Plan authorizes the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares are available for grant under this plan. The 2006 Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards which are granted solely to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the three months ended September 30, 2012, we recorded compensation expense of $118,840 of which $7,475 was allocated to lease operating expenses and $111,365 was allocated to general and administrative expenses. During the nine months ended September 30, 2012, we recorded compensation expense of $532,989 of which $29,769 was allocated to lease operating expenses, $351,481was allocated to general and administrative expenses, $131,127 was allocated to restructuring costs, and $20,612 was capitalized to gas properties. The future compensation cost of all the outstanding awards at September 30, 2012 is $398,265 which will be amortized over the vesting period of such awards. The weighted average remaining useful life of the future compensation cost is 0.91 years.

During the three months ended September 30, 2011, we recorded compensation expense of $161,880 which was allocated as an addition of $6,593 to lease operating expense, an addition of $117,898 to general and administrative expense, and $37,389 was capitalized to gas properties. During the nine months ended September 30, 2011, we recorded compensation expense of $679,034 of which $26,756 was allocated to lease operating expense, $549,589 was allocated to general and administrative expenses, and $102,689 was capitalized to gas properties.

Table of Contents

On May 15, 2012, 150,000 shares of restricted stock were granted to our executive officers. The compensation cost was determined using NASDAQ s closing price of our common stock on the day of issuance and is expensed ratably over the three-year vesting period.

On March 28, 2012, May 11, 2012, and August 10, 2012, 64,284, 97,824 and 300,000 shares of common stock, respectively, were issued under the 2006 Plan to our independent directors, each representing 12.5% of their annual retainer. The compensation cost was determined using NASDAQ s closing price of our common stock on the day of issuance.

On April 5, 2011, we granted 673,551 stock options with time vesting criteria to certain key employees, including our five executive officers, 232,089 restricted stock units with performance vesting criteria to our five executive officers and 113,208 shares of common stock to our independent directors, representing 50% of their annual retainer. The significant assumptions used in determining the compensation costs included an expected volatility of 87.2%, risk-free interest rate of 2.28%, an expected term from 4.38 to 4.83 years, forfeiture rates from 5% to 15%, and no expected dividends.

Option Exchange

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

- the options had a per share exercise price greater than $5.00;
- the options were granted under one of our existing equity incentive plans;
- the options were outstanding and unexercised as of January 5, 2010;
- the options were not granted within the twelve-month period immediately preceding the commencement of this offer, December 7, 2010; and
- the options did not have a remaining term of less than 12 months immediately following January 5, 2010.

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

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

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

Incentive Stock Options

The table below summarizes incentive stock option activity for the nine months ended September 30, 2012:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2011	1,574,886	$	1.11			
Forfeited	(152,048)	$	1.05			
Outstanding at September 30, 2012	1,422,838	$	1.11	4.4	$	
Options exercisable at September 30, 2012	965,831	$	0.99	4.6	$	

Table of Contents

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the nine months ended September 30, 2012:

[redacted]						
Outstanding at December 31, 2011	992,272	$	2.32			
Forfeited	(17,507)	$	2.12			
Outstanding at September 30, 2012	974,765	$	2.33	1.6	$	
Options exercisable at September 30, 2012	933,242	$	2.40	1.5	$	

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the nine months ended September 30, 2012:

	Number of Shares		Weighted Average Value at Grant Date
Non-vested restricted stock at December 31, 2011	293,166	$	3.03
Granted	150,000	$	0.43
Vested	(159,978)	$	3.00
Forfeited	(28,928)	$	3.77
Non-vested restricted stock at September 30, 2012	254,260	$	1.43

During the three and nine months ended September 30, 2012, 21,363 shares and 159,978 shares of restricted stock, respectively, vested with a weighted average vesting date fair value of $0.16 and $0.55 per share, respectively.

Restricted Stock Unit Awards

On April 5, 2011, we granted 232,089 restricted stock units to our five executive officers. These restricted stock units vest upon the Company s achievement of certain performance targets, but no earlier than ratably over the three year period following the grant date, at which time one common share will be issued and exchanged for each restricted stock unit held. The restricted stock units are included in the calculation of diluted earnings per share utilizing the treasury stock method. 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.

Note 15 Commitments and Contingencies

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

Lease Revenue Audit The lessor from one of our leases recently completed a five year revenue audit where the examiner claims to have identified an exception related to compressor fuel deductions. In May 2012, the claim was settled for $356,146, which was the amount recorded in the Consolidated Balance Sheet (Unaudited) as of March 31, 2012 and the Consolidated Statement of Operations (Unaudited) for the three months ended March 31, 2012 related to this matter.

Environmental and Regulatory

As of September 30, 2012, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Note 16 Income Taxes

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

For tax reporting purposes, we have federal and state net operating losses (NOL s) of approximately $136.9 million and $141.3 million, respectively, at September 30, 2012 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $126.0 million and $132.3 million, respectively, at December 31, 2011 that were available to reduce future taxable income. Our first material NOL carryforward expires in 2022 and the last one expires in 2031.

Table of Contents

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 5 Discontinued Operations, of approximately $34.9 million at September 30, 2012 that is available to reduce future taxable capital gains and expiring in 2017.

At September 30, 2012, we have a valuation allowance of $93.9 million recorded against our net deferred tax asset which includes $80.8 million related to our U.S. operations and $13.3 million related to the capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 5 Discontinued Operations.

The income tax expense for the nine months ended September 30, 2012 was different than the amount computed using the statutory rate primarily due to an $80.8 million valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	$ (33,039,717)	34.00%	$ (3,307)	25.00%	$ (33,043,024)	34.00%
State income taxes net of federal benefit	(3,580,778)	3.68%		0.00%	(3,580,778)	3.68%
Valuation Allowance	80,822,163	-83.17%	3,307	-25.00%	80,825,470	-83.16%
Nondeductible items and other	(164,718)	0.17%		0.00%	(164,718)	0.17%
Income tax provision	$ 44,036,950	-45.32%	$	0.00%	$ 44,036,950	-45.31%

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 under Item 1A. Risk Factors in our 2011 Annual Report on Form 10-K that we filed with the SEC on March 30, 2012, which you should read carefully in connection with our forward-looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

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

Overview

GeoMet, Inc. is primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba and Black Warrior Basins in Alabama and the central Appalachian Basin in Virginia and West Virginia. We also own additional coalbed methane and oil and gas development rights, principally in Alabama, Virginia, and West Virginia. As of September 30, 2012, we own a total of approximately 157,000 net acres of coalbed methane and oil and gas development rights.

The natural gas industry is capital intensive. We have historically made substantial capital expenditures in the exploration for, development and acquisition of natural gas reserves. Our capital expenditures have been financed primarily with internally generated cash from operations and proceeds from bank borrowings. The continued availability of capital sources depends upon a number of variables, including proved reserves, production from existing wells, the sales prices for natural gas, the existence of hedging opportunities, our ability to acquire, locate and produce new reserves, and events occurring within the global capital markets.

Natural gas prices continue to adversely affect the natural gas industry and GeoMet in particular by reducing our cash flows, capital expenditures and debt capacity. 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 10 years. Presented below are the NYMEX Settle Prices for the period January 2012 through November 2012 and the NYMEX Forward Curve

Prices (as of November 2, 2012) for natural gas for the period December 2012 through December 2013.

Table of Contents

Current Business Plan

Our current business plan is primarily focused around complying with our Fifth Amended and Restated Credit Agreement (the Credit Agreement), as amended, and reducing the borrowing base deficiency. In addition, we continue to focus on the reduction of costs and the optimization of production volumes to maintain maximum cash flow and liquidity in order to reduce the borrowings under our Credit Agreement.

The NASDAQ Capital Market

On May 10, 2012, we received approval from NASDAQ to transfer the listing of our common stock and preferred stock from The NASDAQ Global Market to The NASDAQ Capital Market. Our common stock and preferred stock began trading on The NASDAQ Capital Market at the opening of the market on May 14, 2012. On August 3, 2012, we received a notice from NASDAQ advising us that our common stock had failed to regain compliance with the $1.00 minimum bid price requirement for continued listing on The NASDAQ Capital Market and, as a result, our common stock was delisted from The NASDAQ Capital Market at the opening of business on August 13, 2012. Our preferred stock continues to be traded on The NASDAQ Capital Market under the symbol GMETP . Our common stock now trades on the OTC Bulletin Board under the symbol GMET .

Other Developments

Management and Board of Director Changes

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

Table of Contents

Strategic Alternatives

In February 2012, the Company retained FBR Capital Markets & Co. (FBR) as its advisor to review strategic alternatives, primarily focused on identifying potential merger partners. The Company continues to believe a merger transaction would be beneficial during the current natural gas price environment, allowing it to spread fixed costs over a larger production and reserve base. The Company will continue to pursue its long range plans pending identification of a suitable transaction. The initial retainer paid to FBR was $50,000 and there currently are no additional future financial commitments unless we enter into a transaction. The delisting of our common stock from The NASDAQ Capital Market may adversely impact our ability to execute on our strategic alternatives. Although we have been active in our efforts to pursue a strategic alternative, these efforts have not yielded any results to date. We have engaged in discussions with multiple parties and continue these efforts. Although we have targeted business combination opportunities where reserves and production are primarily natural gas, we have looked at other types of potential alternatives and remain open to all alternatives beneficial to shareholders, but can provide no assurances that such a transaction will be consummated.

Ceiling Write-Down

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. For the twelve months ended September 30, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.84 per Mcf, resulting in a natural gas price of $2.99 per Mcf when adjusted for regional price differentials. For the three and nine months ended September 30, 2012, we recorded a $25.4 million and $83.5 million write-down, respectively, of the carrying value of our U.S. full cost pool. We recorded a $15.8 million and $42.3 million write-down of the carrying value of our U.S. full cost pool at March 31, 2012 and June 30, 2012, respectively. Based on current forward natural gas price curve, we expect an additional ceiling write-down in the fourth quarter of 2012.

Operational Update

Our core areas of operations are in the Central Appalachian Basin of Virginia and West Virginia and the Black Warrior and Cahaba Basins in Alabama. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. The Black Warrior and Cahaba Basins are hilly, gently rolling regions and coal mining is also present but less active. Current production in the Central Appalachian Basin is 26.4 MMcf per day. Current production in our Alabama properties is 10.9 MMcf per day.

On June 20, 2012, we sold Hudson s Hope Gas, Ltd., which held our Canadian gas properties, in exchange for two million shares of Canada Energy Partners, Inc. which we are restricted from selling before June 20, 2013. In connection with the sale we recognized a non-cash loss of $0.7 million; however, this disposition will reduce our cash flow losses and future obligations such as plugging and abandonment.

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 nine months ended September 30, 2012.

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 nine months ended September 30, 2012 and 2011. 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).

Table of Contents

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Gas sales (1)	$ 9,610	$ 8,520	$ 27,465	$ 24,702
Lease operating expenses	$ 4,417	$ 2,983	$ 13,350	$ 8,794
Compression and transportation expenses	2,218	1,082	6,758	2,959
Production taxes	442	390	1,276	1,078
Total production expenses	$ 7,077	$ 4,455	$ 21,384	$ 12,831
Net sales volumes (Consolidated) (MMcf)	3,391	1,940	10,468	5,619
Pond Creek field (Central Appalachian Basin) (MMcf)	1,462	1,439	4,402	4,148
Other Central Appalachian Basin fields (MMcf)	912	41	2,941	120
Gurnee field (Cahaba Basin) (MMcf)	430	453	1,325	1,330
Black Warrior Basin fields (MMcf)	587	3	1,800	9
Per Mcf data ($/Mcf):				
Average natural gas sales price realized (Consolidated)(2)	$ 3.87	$ 5.26	$ 3.92	$ 5.59
Average natural gas sales price (Consolidated)(3)	$ 2.83	$ 4.39	$ 2.62	$ 4.40
Pond Creek field (Central Appalachian Basin)	$ 2.88	$ 4.44	$ 2.70	$ 4.44
Other Central Appalachian Basin fields	$ 2.69	$ 4.23	$ 2.48	$ 4.28
Gurnee field (Cahaba Basin)	$ 2.87	$ 4.25	$ 2.63	$ 4.28
Black Warrior Basin fields	$ 2.92	$ 4.26	$ 2.68	$ 4.24
Lease operating expenses (Consolidated)	$ 1.30	$ 1.54	$ 1.28	$ 1.56
Pond Creek field (Central Appalachian Basin)	$ 1.13	$ 1.13	$ 1.07	$ 1.17
Other Central Appalachian Basin fields	$ 1.34	$ 1.41	$ 1.40	$ 1.51
Gurnee field (Cahaba Basin)	$ 2.79	$ 2.76	$ 2.67	$ 2.74
Black Warrior Basin fields	$ 0.56	$ 0.00	$ 0.53	$ 0.01
Compression and transportation expenses (Consolidated)	$ 0.66	$ 0.56	$ 0.64	$ 0.53
Pond Creek field (Central Appalachian Basin)	$ 0.61	$ 0.60	$ 0.59	$ 0.56
Other Central Appalachian Basin fields	$ 1.18	$ 0.81	$ 1.17	$ 0.98
Gurnee field (Cahaba Basin)	$ 0.29	$ 0.39	$ 0.27	$ 0.36
Black Warrior Basin fields	$ 0.22	$ 0.01	$ 0.20	$ 0.03
Production taxes (Consolidated)	$ 0.13	$ 0.20	$ 0.12	$ 0.19
Pond Creek field (Central Appalachian Basin)	$ 0.15	$ 0.21	$ 0.15	$ 0.19
Other Central Appalachian Basin fields	$ 0.07	$ 0.00	$ 0.07	$ 0.00
Gurnee field (Cahaba Basin)	$ 0.13	$ 0.20	$ 0.11	$ 0.21
Black Warrior Basin fields	$ 0.17	$ 0.31	$ 0.16	$ 0.28
Total production expenses (Consolidated)	$ 2.09	$ 2.30	$ 2.04	$ 2.28
Pond Creek field (Central Appalachian Basin)	$ 1.89	$ 1.94	$ 1.81	$ 1.92
Other Central Appalachian Basin fields	$ 2.59	$ 2.22	$ 2.64	$ 2.49
Gurnee field (Cahaba Basin)	$ 3.21	$ 3.35	$ 3.05	$ 3.31
Black Warrior Basin fields	$ 0.95	$ 0.32	$ 0.89	$ 0.32
Depletion (Consolidated)	$ 0.72	$ 0.82	$ 0.87	$ 0.82

(1) Gas sales do not include realized gains and losses on derivative contracts.

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

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

Results of Operations

Three months ended September 30, 2012 compared with three months ended September 30, 2011

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

Table of Contents

	Three months ended September 30, 2012		2011	Change
	(In thousands)			
Gas sales	$ 9,610	$	8,520	13%
Lease operating expenses	$ 4,417	$	2,983	48%
Compression expense	$ 1,167	$	757	54%
Transportation expense	$ 1,050	$	325	223%
Production taxes	$ 442	$	390	13%
Depreciation, depletion and amortization	$ 2,540	$	1,677	51%
Impairment of gas properties	$ 25,432	$		NM
General and administrative	$ 1,097	$	1,159	-5%
Restructuring costs	$ 188	$		NM
Realized gains on derivative contracts	$ (3,496)	$	(1,682)	108%
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 8,280	$	(2,544)	NM
Interest expense	$ 1,514	$	868	74%
Write off of debt issuance costs	$ 1,378	$		NM
Income tax expense	$ 6	$	1,620	NM
Discontinued operations, net of tax	$ 26	$	247	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $1.1 million, or 13%, to $9.6 million compared to the prior year quarter. The increase in gas sales was primarily the result of higher production volumes, of which 1.5 Bcf was due to the properties acquired in November 2011, partially offset by a 0.1 Bcf decrease in production in our previously existing properties and a 35% decrease in natural gas prices, excluding hedging transactions.

Lease operating expenses. Lease operating expenses increased by $1.4 million, or 48%, to $4.4 million compared to the prior year quarter. The $1.4 million increase in lease operating expenses consisted of $1.5 million increase due to the properties acquired in November 2011, partially offset by a $0.1 million decrease in our previously existing properties.

Compression expense. Compression expense increased by $0.4 million, or 54%, to $1.2 million compared to the prior year quarter. The increase was attributable to the $0.4 million of expenses related to the properties acquired in November 2011.

Transportation expense. Transportation expense increased by $0.7 million, or 223%, to $1.1 million compared to the prior year quarter. The increase was due to the properties acquired in November 2011. Transportation expenses remained relatively flat in our previously existing gas properties.

Production taxes. Production taxes remained relatively flat compared to the prior year quarter as increased production was offset by lower gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $0.9 million, or 51%, to $2.5 million compared to the prior year quarter. This increase was primarily due to the $1.0 million of expenses related to the properties acquired in November 2011, partially offset by a decrease of $0.1 million related to our previously existing natural gas properties.

Impairment of gas properties. During the current quarter, the gross carrying value of the Company s gas properties exceeded the full cost ceiling limitation and, as such, a $25.4 million impairment of gas properties was recorded.

General and administrative. General and administrative expenses decreased by $0.1 million, or 5%, to $1.4 million compared to the prior year quarter. This decrease was primarily due to decreased employee expenses.

Restructuring costs. Restructuring activities consist of senior management and board of directors realignment. The restructuring costs for the current year quarter of $0.2 million included cash payments to our former CEO of $0.1 million under a consulting agreement and other costs of $0.1 million. No such expenses were incurred in the prior year quarter.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $1.8 million, or 108%, to $3.5 million compared to the prior year quarter. 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 (gains) from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $8.3 million in the current quarter as compared to unrealized gains of $2.5 million in the prior year quarter. The current quarter unrealized loss position was made up of $0.9 million in unrealized net losses on derivative contracts acquired as part of our coalbed methane gas property acquisition in November 2011, in addition to unrealized net losses of $7.4 million on pre-acquisition or recently executed derivative contracts. Unrealized gains and losses are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked-to-market at the end of each reporting period.

Table of Contents

Interest expense. Interest expense increased by $0.6 million, or 74%, to $1.5 million compared to the prior year quarter. The increase was primarily due to a higher average outstanding balance under our Credit Agreement in the current year quarter resulting from the properties acquired in November 2011.

Write off of debt issuance costs. Deferred financing costs of $1.4 million as of August 8, 2012 related to the Credit Agreement prior to the Amendment were written off upon execution of the Amendment.

Income tax expense. The income tax expense for the three months ended September 30, 2012 was different than the amount computed using the statutory rate primarily due to a $13.1 million valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

Amount computed using statutory rates	$	(11,684,888)	34.00%
State income taxes net of federal benefit		(1,340,569)	3.90%
Valuation Allowance		13,093,971	-38.10%
Nondeductible items and other		(62,264)	0.18%
Income tax provision	$	6,250	-0.02%

Discontinued operations, net of tax. Discontinued operations decreased to $0.03 million from $0.25 million in the prior year quarter. This decrease resulted from the disposal of Hudson s Hope Gas, Ltd. on June 20, 2012.

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

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

	Nine months ended September 30,				
	2012		2011		Change
	(In thousands)				
Gas sales	$	27,465	$	24,702	11%
Lease operating expenses	$	13,350	$	8,794	52%
Compression expense	$	3,620	$	2,003	81%
Transportation expense	$	3,138	$	956	228%
Production taxes	$	1,276	$	1,078	18%
Depreciation, depletion and amortization	$	9,460	$	4,901	93%
Impairment of gas properties	$	83,467	$		NM
General and administrative	$	3,765	$	4,084	-8%
Restructuring costs	$	953	$		NM
Realized gains on derivative contracts	$	(13,600)	$	(6,715)	103%
Unrealized losses from the change in market value of open derivative contracts	$	13,259	$	109	NM
Interest expense	$	4,058	$	2,532	60%

Write off of debt issuance costs	$	1,378	$		NM
Income tax expense	$	44,037	$	2,527	NM
Discontinued operations, net of tax	$	722	$	341	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $2.8 million, or 11%, to $27.5 million compared to the prior year period. The increase in gas sales was primarily the result of higher production volumes, of which 4.6 Bcf was due to the properties acquired in November 2011, while 0.2 Bcf was due to increased production in our previously existing properties, partially offset by a 40% decrease in natural gas prices, excluding hedging transactions.

Lease operating expenses. Lease operating expenses increased by $4.6 million, or 52%, to $13.4 million compared to the prior year period. The $4.6 million increase in lease operating expenses consisted of $4.9 million increase due to the properties acquired in November 2011, partially offset by a $0.3 million decrease in our previously existing properties.

Compression expense. Compression expense increased by $1.6 million, or 81%, to $3.6 million compared to the prior year period. The increase was primarily attributable to the $1.4 million of expenses related to the properties acquired in November 2011 combined with an increase of $0.2 million related to our previously existing properties. The increase in compression expenses in our previously existing properties was due to increased production.

Transportation expense. Transportation expense increased by $2.2 million, or 228%, to $3.1 million compared to the prior year period. The increase was primarily due to the properties acquired in November 2011. Transportation expenses remained relatively flat in our previously existing gas properties.

Production taxes. Production taxes increased by $0.2 million, or 18%, to $1.3 million compared to the prior year period. The increase was primarily attributable to the $0.5 million of expenses related to the properties acquired in November 2011, partially offset by a decrease of $0.3 million related to our previously existing properties.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $4.6 million, or 93%, to $9.5 million compared to the prior year period. This increase was primarily due to the $4.2 million of expenses related to the properties acquired in November 2011 in combination with an increase of $0.4 million related to our previously existing natural gas properties.

Impairment of gas properties. During the current year period, the gross carrying value of the Company s gas properties exceeded the full cost ceiling limitations measured quarterly and, as such, an $83.5 million aggregate impairment of gas properties was recorded.

General and administrative. General and administrative expenses decreased by $0.3 million, or 8%, to $3.8 million compared to the prior year period. This decrease was primarily due to decreased employee expenses.

Restructuring costs. Restructuring activities consist of senior management and board of directors realignment. The restructuring costs for the current year period of $1.0 million included cash payments to our former CEO of $0.7 million under separation and consulting agreements, share-based awards conveyed to our former CEO of $0.1 million and other costs of $0.2 million. No such expenses were incurred in the prior year period.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $6.9 million, or 103%, to $13.6 million compared to the prior year period. 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 (gains) from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $13.3 million in the current year period as compared to $0.1 million in the prior year period. The current year period unrealized loss position was made up of $1.0 million in unrealized net losses on derivative contracts acquired as part of our coalbed methane gas property acquisition in November 2011, in addition to unrealized net losses of $12.3 million on pre-acquisition or recently executed derivative contracts. Unrealized gains and losses are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked-to-market at the end of each reporting period.

Interest expense. Interest expense increased by $1.5 million, or 60%, to $4.1 million compared to the prior year period. The increase was primarily due to a higher average outstanding balance under our Credit Agreement in the current year period resulting from the properties acquired in November 2011.

Write off of debt issuance costs. Deferred financing costs of $1.4 million as of August 8, 2012 related to the Credit Agreement prior to the Amendment were written off upon execution of the Amendment.

Income tax expense. The income tax expense for the nine months ended September 30, 2012 was different than the amount computed using the statutory rate primarily due to an $80.8 million valuation allowance on our deferred tax asset. A reconciliation of the effective tax rate to the statutory rate is as follows:

		U.S.			**Canada**			**Total**	
Amount computed using statutory rates	$	(33,039,717)	34.00%	$	(3,307)	25.00%	$	(33,043,024)	34.00%
State income taxes net of federal benefit		(3,580,778)	3.68%			0.00%		(3,580,778)	3.68%
Valuation Allowance		80,822,163	-83.17%		3,307	-25.00%		80,825,470	-83.16%
Nondeductible items and other		(164,718)	0.17%			0.00%		(164,718)	0.17%
Income tax provision	$	44,036,950	-45.32%	$		0.00%	$	44,036,950	-45.31%

Discontinued operations, net of tax. During the current year period, we incurred a loss of $0.7 million related to the disposal of our Canadian subsidiary, Hudson s Hope Gas, Ltd.

Table of Contents

Liquidity and Capital Resources

Cash Flows and Liquidity

As of September 30, 2012, we had a working capital deficit of $7.9 million. The working capital deficit as of September 30, 2012 was primarily the result of the classification of $14.1 million of our borrowings under our Fifth Amended and Restated Credit Agreement (the Credit Agreement), as described below, as a current liability for scheduled payments over the next twelve months. We believe that our cash flows from operating activities, as well as the return of original basis through the settlement of natural gas derivative contracts, will provide us with sufficient resources to fund our working capital deficit and to meet our obligations in connection with operating our properties for at least the next twelve months. However, there can be no assurance that future borrowing base determinations will not result in additional payment obligations under the Credit Agreement or that our cash flows will not be adversely impacted by events beyond our control.

On November 18, 2011, our Credit Agreement with a group of six banks became effective. Effective August 8, 2012, we entered into the Fourth Amendment (the Amendment) to our Credit Agreement. Borrowings under the Credit Agreement at August 8, 2012 totaled $148.6 million. The Amendment provides for an initial conforming borrowing base of $115.0 million (the Tranche A) with the balance then remaining in the amount of $33.6 million constituting a non-conforming tranche (Tranche B). The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by December 31, 2012. There can be no assurances that future borrowing base determinations will not result in additional payment obligations under the Credit Agreement. Upon any determination of the borrowing base, the redetermined amount of the conforming borrowing base shall constitute a new Tranche A, with any decrease in Tranche A causing an automatic corresponding increase in Tranche B, subject to certain limitations described below, and any increase in Tranche A causing an automatic corresponding decrease in a Tranche B. At the next borrowing base determination, Tranche B shall not increase by more than fifty percent (50%) of the amount of the principal payments made on Tranche B Loans since the prior redetermination of the borrowing base. Thereafter, at each subsequent redetermination of the borrowing base, Tranche B shall not increase by more than twenty-five percent (25%) of the amount of the principal payments made on Tranche B Loans since the prior redetermination of the borrowing base. Should a future determination of the borrowing base result in the amount of the Tranche B Loan exceeding $33.6 million, the Company has 30 days to repay such excess. The Credit Agreement, as amended, 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, as amended, are due and payable on April 1, 2014. In addition, the Amendment obligates us to reduce our borrowings under the Credit Agreement, as amended, monthly by an amount equal to our bank cash, excluding the segregated account, minus (i) all outstanding and unpaid checks or Automated Clearing House payments and (ii) an amount equal to $1,000,000 as calculated on the 24th day of each month. The Amendment provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 2.00% on Tranche A Loans and 4.00% on Tranche B Loans or the London Interbank Offered Rate (the LIBOR Rate) plus a margin of 3.00% on Tranche A loans and 5.00% on Tranche B Loans. 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%. The banks will be paid an additional fee based on the amount of Tranche B Loans as follows:

Calculation Date	Fee Amount	Date Payable
11/25/2012	75 bps	12/1/2012
2/25/2013	100 bps	3/1/2013
5/25/2013	125 bps	6/1/2013
8/25/2013	150 bps	9/1/2013
11/25/2013	175 bps	12/1/2013

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 $1.0 million in 2013) and a maximum debt covenant as follows:

Quarter Ending		Maximum Principal Outstanding
9/30/2012	$	146,200,000
12/31/2012	$	139,300,000
3/31/2013	$	136,000,000
6/30/2013	$	132,700,000
9/30/2013	$	131,500,000
12/31/2013	$	129,000,000

Table of Contents

An amendment fee of 50 basis points on the amount of Tranche B which was capitalized in Deferred financing costs in the amount of $0.2 million on August 8, 2012 in connection with the execution of the Amendment. Deferred financing costs of $1.4 million as of August 8, 2012 related to the Credit Agreement prior to the Amendment were written off upon execution of the Amendment.

Price Risk Management Activities

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

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. Our Credit Agreement limits amounts of future natural gas production that we may hedge.

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 unaudited Consolidated Balance Sheets and Consolidated Statements of Operations.

Commodity Price Risk and Related Hedging Activities

At September 30, 2012, we had the following natural gas collar positions:

Period	**Volume (MMBtu)**		**Sold Ceiling**		**Bought Floor**	**Sold Floor**		**Fair Value**
January 2014 through December 2015	3,650,000	$	4.30	$	3.60		$	(910,759)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50			(1,150,697)
	7,300,000						$	(2,061,456)

At September 30, 2012, we had the following natural gas swap positions:

Period	**Volume (MMBtu)**		**Fixed Price**		**Fair Value**
October through December 2012	138,000	$	5.11	$	247,007
October through December 2012	57,000	$	5.12		102,594

October through December 2012	259,995	$	6.85		917,949
October through December 2012	119,616	$	6.99		438,504
October through December 2012	196,358	$	7.05		735,451
October 2012	124,000	$	5.73		335,664
October 2012	248,000	$	4.94		474,170
October 2012	465,000	$	2.89		(61,831)
November 2012 through March 2013	604,000	$	6.42		1,669,840
November 2012 through March 2013	906,000	$	5.50		1,677,012
November 2012 through March 2014	4,128,000	$	3.81		(196,105)
November 2012 through March 2014	4,128,000	$	3.82		(157,375)
January 2013 through December 2013	2,190,000	$	3.60		(498,957)
April 2013 through December 2013	2,750,000	$	3.25		(1,582,967)
	16,313,969			$	4,100,956

At September 30, 2012, we had the following natural gas basis swap position:

Period	Volume (MMBtu)		Fixed Basis		Fair Value
October through December 2012	138,000	$	0.04	$	4,483

Table of Contents

As of September 30, 2012, we had the following forward sales at NYMEX plus a fixed basis:

Period	Volume (MMBtu)		Fixed Basis
October 2012 through March 2013	910,000	$	0.19
November 2012 through March 2013	1,540,200	$	0.22
	2,450,200		

We have hedged approximately 92% of our forecasted remaining production for 2012 at a fixed price of $4.88 per Mcf. Additionally, we have hedged approximately 90% of our forecasted production for 2013 at a fixed price of $3.80 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 September 30,				Nine months ended September 30,			
		2012		2011		2012		2011
Capital expenditures:								
Leasehold acquisition	$	83,209	$	154,072	$	593,368	$	689,790
Exploration								3,000
Development (1)		364,001		4,472,521		26,022		11,976,251
Asset retirement obligations				45,969		247,440		65,683
Other items (primarily capitalized overhead)		18,723		316,636		226,919		837,303
Total capital expenditures	$	465,933	$	4,989,198	$	1,093,749	$	13,572,027

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

We are limited under the Credit Agreement to spend no more than $1.5 million in capital in 2012 and are limited to $1.0 million in 2013.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. There has been no material changes in those commitments disclosed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Commitments of our 2011 Annual Report on Form 10-K that we filed with the SEC on March 30, 2012.

Recent Pronouncements

On June 16, 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in Accounting Standards Codification (ASC) 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the three and nine months ended September 30, 2012.

On May 12, 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework that is, converged guidance on how (not when) to measure fair value and on what disclosures to provide about fair value measurements. Thus, there are few differences between the ASU and its international counterpart, IFRS 13. While the ASU is largely consistent with existing fair value measurement principles in U.S. GAAP, it expands ASC 820 s existing disclosure requirements for fair value measurements and makes other amendments. Many of these amendments were made to eliminate unnecessary wording differences between U.S. GAAP and IFRS. However, some could change how the fair value measurement guidance in ASC 820 is applied. The ASU is effective for interim and annual periods beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the three and nine months ended September 30, 2012. See disclosure provided in the Notes to Consolidated Financial Statements (Unaudited).

Table of Contents

Environmental Regulations

On April 17, 2012, the Environmental Protection Agency (EPA) issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

We cannot predict how future environmental laws and regulations may impact our properties or operations. For the nine months ended September 30, 2012, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures during 2012 or that will otherwise have a material impact on our financial position, results of operations or cash flows.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the three and nine months ended September 30, 2012, a 10% decrease in the prices received for natural gas production would have decreased our gas revenues by approximately $0.96 million and $2.75 million, respectively, which would have been offset approximately $0.92 million and $2.23 million, respectively, by realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. At September 30, 2012, we had $148.6 million outstanding under our Credit Agreement. For the three months ended September 30, 2012 and 2011, interest on the borrowings averaged 3.50% and 3.45% per annum, respectively. For the nine months ended September 30, 2012 and 2011, interest on the borrowings averaged 3.12% and 3.41% 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 nine months ended September 30, 2012 by approximately $0.4 million and $1.1 million, respectively.

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 September 30, 2012 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.

Table of Contents

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Lease Revenue Audit The lessor from one of our leases recently completed a five year revenue audit where the examiner claims to have identified an exception related to compressor fuel deductions. In May 2012, the claim was settled for $356,146, which was the amount recorded in the Consolidated Balance Sheet (Unaudited) as of March 31, 2012 and the Consolidated Statement of Operations (Unaudited) for the three months ended March 31, 2012 related to this matter.

Environmental and Regulatory

As of September 30, 2012, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 1A. Risk Factors

There 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, 2011.

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: November 9, 2012	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.

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* 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.