GeoMet, Inc.
Form 10-K
March 28, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2012

or

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

For the transition period from to

Commission file number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
909 Fannin, Suite 1850, Houston, Texas 77010	**77010**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code

(713) 659-3855

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common stock, par value $0.001 per share	OTCQB
Preferred stock, par value $0.001 per share	NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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

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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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. (Check one):

Large accelerated filer o	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	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). Yes o No x

The aggregate market value of common stock, par value $0.001 per share, held by non-affiliates (based upon the closing sales price of $0.32 on the NASDAQ Capital Market on June 30, 2012) on the last business day of registrant s most recently completed second fiscal quarter was approximately $7.9 million.

As of March 1, 2013, 40,689,956 shares and 5,305,865 shares, respectively, of the registrant s common stock and preferred stock, par value $0.001 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant s definitive proxy statement for its 2013 annual meeting of stockholders, which will be filed on or before April 30, 2013.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Included in this annual report are certain forward-looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Exchange Act of 1934, as amended (the Exchange Act). All statements, other than statements of historical facts, included in this annual report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including statements regarding our reserve quantities and the present value thereof, planned capital expenditures, increases in natural gas production, the number of anticipated wells to be drilled, future cash flows and borrowings, our financial position, business strategy and other plans and objectives for future operations. We use the words may, will, expect, anticipate, estimate, believe, continue, intend, plan, budget and other similar words to identify forward-looking statements. You should statements that contain these words carefully and should not place undue reliance on these statements. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- the continued oversupply of natural gas in the US markets, which depresses the price we receive for our natural gas production;
- further declines in the prices we receive for our natural gas affecting our operating results, cash flows and credit capacity;
- general international and domestic economic conditions that may be less favorable than expected;
- changes in our business strategy;
- our financial position, including our cash flow and liquidity;
- the effects of our indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt, and could have other adverse consequences;
- volatility in the international and domestic capital and credit markets, including fluctuations in interest rates and availability of capital;
- uncertainties in estimating our natural gas reserves;

- our ability to replace our natural gas reserves;
- uncertainties in exploring for and producing natural gas;
- new natural gas development projects and exploration for natural gas in areas where we have little or no proven natural gas reserves;
- our ability to acquire water supplies needed for drilling, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental rules;
- other persons could have ownership rights in our advanced natural gas extraction techniques which could force us to cease using those techniques or pay royalties;
- availability of drilling and production equipment and field service providers;
- disruptions, capacity constraints in, or other limitations on the pipeline systems that deliver our natural gas;
- our need to use unproven technologies to extract coalbed methane in some properties;
- our ability to retain key members of our senior management and key technical employees;
- the outcomes of legal proceedings in which we may become involved;
- the possibility that the industry may be subject to future regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);
- the effects of government regulation and permitting and other legal requirements;

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors may negatively impact our businesses, operations or pricing; and

- our ability to operate effectively in a state or jurisdiction where land ownership and coalbed methane rights are complicated or unresolved.

Other factors which could affect the events discussed in our forward looking statements are described under Item 1A. Risk Factors in this annual report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this annual report. All forward-looking statements speak only as of the date of this annual report. Other than as required under securities laws, we do not assume a duty to update these

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forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

All references in this annual report to the Company, GeoMet, we, us or our are to GeoMet, Inc. and our wholly owned subsidiaries. Unless otherwise noted, all information in this annual report relating to natural gas reserves and the estimated future net cash flows attributable to those reserves is based on estimates prepared by independent engineers and is net to our ownership interest.

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GLOSSARY OF NATURAL GAS AND COALBED METHANE TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this document.

Bcf. Billion cubic feet of natural gas.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

CBM. Coalbed methane.

CBM acres. Acreage under a lease that excludes oil, natural gas, and all other minerals other than CBM.

Coal seam. A single layer or stratum of coal.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Estimated proved reserves. Defined in Rule 4-10 of Regulation S-X under the Securities Act as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Estimated proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gas desorption test. A process to estimate the volume of natural gas adsorbed in a volume of coal (usually expressed as cubic feet per ton) by placing a sample of coal into a sealed canister and taking periodic measurements of gas desorbed, temperature and pressure for up to 90 days. The estimate of total gas adsorbed in the coal sample is the sum of: (i) the measurements of natural gas during the test period, corrected to standard temperature and pressure (the measured natural gas), (ii) the lost natural gas, which is calculated using the elapsed time the sample desorbed before its placement into the canister and the rate of desorption determined from the test period, and (iii) the remaining natural gas, which is determined by measuring the natural gas released while grinding the coal sample into a powder or which is calculated mathematically using the measurements from the test period.

Gathering system. Pipelines and other equipment used to move natural gas from the wellhead to the trunk or the main transmission lines of a pipeline system.

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Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Henry hub. The Henry hub is a distribution hub on the natural gas pipeline system in Erath, Louisiana. Due to its importance, it lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Net revenue interest. An owner s interest in the revenues of a well.

NYMEX. The New York Mercantile Exchange.

Overriding royalty interest. A fractional, undivided interest that is carved out of a working interest with the right to participate or receive proceeds from the sale of oil or natural gas.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

*Reasonable certaint*y. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Shale. A well hardened, very fine to fine grained sedimentary rock. Shale has ultra-low permeability and is formed from the compaction of silt, clay, or mud. Many shales contain a mixture of organic compounds called kerogen, which liberates natural gas during the maturation process of the shale. Gas within the shale can be stored onto the molecular surface of insoluble organic matter, trapped within the rock s pore space or present within open fractures.

Shut-in. An oil or natural gas well which has been stopped from producing.

Standardized measure. An estimate of the present value of the future net revenues from estimated proved natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs, operating expenses, and any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10% in accordance with the practice of the SEC, to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether or not such acreage contains estimated proved reserves.

Working interest. The operating or cost-bearing interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

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PART I

Items 1 and 2. *Business and Properties*

Overview

GeoMet, Inc. is primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. 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 December 31, 2012, we own a total of approximately 144,000 net acres of coalbed methane and oil and gas development rights.

The natural gas industry is capital intensive. Natural gas markets traditionally have been highly volatile. We have historically made substantial capital expenditures in the exploration, 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.

Developments in 2012

Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The low natural gas prices had pervasive adverse consequences to our business. Low gas prices caused a borrowing base deficiency under our credit facility when the amounts outstanding under our credit facility exceeded the borrowing base under the facility. On August 8, 2012, we amended the facility to include a conforming tranche equal to the borrowing base, and a non-conforming tranche in the amount of the excess. The amendment requires that we use all of our excess cash flows to reduce outstanding borrowings under the non-conforming tranche, and significantly limits our capital expenditures. The amended credit amendment has higher interest rates and increased bank fees and professional fees. The maturity date was amended to April 1, 2014. While the amendment provided time to seek a strategic corporate transaction, we believe these efforts have been impeded because of the borrowing base deficiency. The borrowing base deficiency has also adversely impacted our ability to hedge additional volumes of gas, thereby exhausting our hedging credit capacity. Retaining and attracting competent personnel has been challenging and is likely to worsen. The need to cut cost due to lower natural gas prices and operating margins creates vulnerability in conducting our business.

In addition, the depressed natural gas prices resulted in significant property impairments and full valuation of our deferred tax assets during 2012. Low natural gas prices and our indebtedness contributed to our common stock being delisted by NASDAQ as we had no remaining equity and diminished the market price of our common stock.

Current Business Plan

Management s current business plan is primarily focused on eliminating our borrowing base deficiency, maintaining compliance with the amended credit facility, maintaining production levels and keeping costs under control. In addition, management recently packaged all of the Company s Alabama properties to be marketed for sale by an asset divestiture firm. If the sale is successful, management expects that substantially all the net proceeds from the sale will go toward reducing the outstanding borrowings under the credit facility. Management remains open to possible corporate strategic transactions. There can be no assurance that the Company will be able to engage in a strategic transaction, sell properties or realize enough proceeds from the sale of our properties to eliminate the borrowing base deficiency. In addition, our credit facility matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the credit facility when it matures.

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 OTCQB 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 which is the cost of medical insurance premiums for continued coverage under the Company s group medical plan for that period 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.

On May 1, 2012, the Board of Directors of the Company appointed Michael Y. McGovern as the Company s Chairman of the Board; William C. Rankin, as a director and President and Chief Executive Officer; and Tony Oviedo, as the Company s Senior Vice President, Chief Financial Officer, Chief Accounting Officer and Controller.

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On July 2, 2012, Phil Malone resigned from his position on the Board of Directors in connection with his retirement from the Company. Mr. Malone receives $1,221 per month for 18 months which is the cost of medical insurance premiums for continued coverage under the Company s group medical plan for that period and $10,175 per month as a consulting fee for up to nine months.

In response to the Company s continuing efforts to reduce its cost structure to deal with depressed natural gas prices, Robert E. Creager resigned from his position on the Board of Directors effective January 22, 2013. Additionally, Charles D. Haynes is not expected to be nominated for election to the Board of Directors at the Company s 2013 annual meeting of stockholders.

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, although as long as we have a borrowing base deficiency, we believe a merger transaction is not likely. The Company has not entered into substantive negotiations with any person in connection with its review of strategic alternatives, although it may do so in the future.

On February 26, 2013, the Company announced that it engaged Lantana Oil & Gas Partners, a Houston based divestiture firm, to market all of the Company s coal bed methane interests located in the state of Alabama. The Company has non-operating interests in 1,058 wells located in the Black Warrior Basin. All of these wells have royalty and/or overriding royalty interests and additionally 498 of these wells include a 15% working interest. The Company also has a 100% working interest and operates 252 wells in the Cahaba Basin. The interests in these properties represented 30% of the Company s net daily sales of natural gas and 38% of operating income during the twelve months ending December 31, 2012. At December 31, 2012, using Securities and Exchange Commission guidelines, the interests in these wells represented approximately 31% of the Company s proved reserves and 38% of the PV10. If we sell these properties, net proceeds from the sale of these properties will be used to reduce the Company s borrowings under its bank credit agreement. The engagement term is one year and we have paid Lantana a retainer of $35,000. If Lantana is successful in selling our Alabama properties, they will receive a fee equal to one percent of the sales proceeds upon closing of the transaction.

C*eiling 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 December 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.78 per Mcf, resulting in a natural gas price of $2.91 per Mcf when adjusted for regional price differentials. For the year ended December 31, 2012, we recorded $95.7 million in write-downs of the carrying value of our full cost pool.

Deferred Tax Asset

As of March 31, 2012, as part of our assessment of the realization of our net deferred tax asset, we considered all available negative and positive evidence. We had incurred a cumulative pre-tax loss of $117.6 million, including ceiling impairment charges of $141.3 million, over the three year period ended March 31, 2012. We evaluated all available evidence including historical operating results, historical pricing, natural gas reserves as estimated and appraised by an independent third party engineer, the forward natural gas price curve, and the length of the carryforward period available. Upon the completion of that assessment, we established a full valuation allowance for our net deferred tax assets at March 31, 2012 of $47.3 million. These tax benefits will be available, prior to the expiration of carryforwards, to reduce future income tax expense resulting from earnings or increases in deferred tax liabilities.

Reclassification of Long-Term Debt

Borrowings under our credit facility mature on April 1, 2014. As a result, all borrowings under our credit facility will be classified as current on April 2, 2013. No assurances can be made that we will be able to negotiate an extension of our credit facility beyond April 1, 2014. Please see Item 1A. Risk Factors.

Going Concern Footnote

Because of the factors described elsewhere in this Form 10-K, our financial statement for 2012 contain a footnote indicating substantial doubt about our ability to continue as a going concern. See Item 1A. Risk Factors.

Characteristics of Coalbed Methane and Non-Conventional Shallow Gas

The source rock in conventional natural gas is usually different from the reservoir rock, while in coalbed methane the coal seam serves as both the source rock and the reservoir rock. The storage mechanism is also different as gas is stored in the pore or void space of the rock in conventional natural gas, but in coalbed methane, most, and frequently all, of the gas is stored by adsorption. Adsorption allows large quantities of gas to be stored at relatively low pressures. A unique characteristic of coalbed methane is that the gas flow can be increased by reducing the reservoir pressure. Frequently the coalbed pore space, which is in the form of cleats or fractures, is filled with water. The reservoir pressure is reduced by pumping out the water and releasing the methane from the molecular structure, which allows the methane to flow through the cleat structure to the well bore. While a conventional natural gas well typically decreases in flow as the reservoir pressure is drawn down, a coalbed methane well, after desorption pressure has been achieved, will typically increase in production for up to five years from achievement of desorption pressure depending on well spacing. In some cases, achievement of desorption pressure may take an extended period of time.

Coalbed methane and conventional natural gas both have methane as their major component. While conventional natural gas often has more complex hydrocarbon gases, coalbed methane rarely has more than 2% of the more complex hydrocarbons. In the eastern coal fields of the U.S., coalbed methane is generally 98% to 99% pure methane and requires only dehydration of the gas to remove moisture to achieve pipeline quality. In the western coal fields of the U.S., it is also sometimes necessary to strip out either carbon dioxide or nitrogen. Once coalbed methane has been produced, it is gathered, transported, marketed, and priced in the same manner as conventional natural gas.

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The content of gas within a coal seam is measured through gas desorption testing. The ability to flow gas and water to the well bore in a coalbed methane well is determined by the fracture or cleat network in the coal. At shallow depths of less than 500 feet, these fractures often open enough to produce the fluids naturally. At greater depths the networks are progressively squeezed shut, reducing the ability to flow. It is necessary to provide other avenues of flow such as hydraulically fracturing the coal seam. By pumping fluids at high pressure, fractures are opened in the coal and a slurry of fluid and sand proppant is pumped into the fractures so that the fractures remain open after the release of pressure, thereby enhancing the flow of both water and gas to allow the economic production of gas.

Areas of Operation

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.

Central Appalachia

Pond Creek and Lasher Fields We are the operator of 298 producing vertical CBM wells in which we own a 99.0% average working interest in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia. At December 31, 2012, approximately 64% of our estimated proved developed reserves, or 87.6 Bcf, is in the Pond Creek field. Net daily sales of gas averaged 16.5 MMcf per day for 2012. Our natural gas production from the Pond Creek field is delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). We have two long-term transportation agreements with ETNG which went into effect in April 2007 with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. Our gas from the Lasher field is delivered into the Columbia Gas Transmission pipeline with firm transportation for 500 MMBtu s per day. We also own and operate a 12 mile, 8 inch high-pressure steel pipeline and gas treatment and compression facilities through which the Pond Creek field natural gas production is gathered, dehydrated, and compressed for delivery into the Jewell Ridge Lateral of the East Tennessee pipeline system. In addition, we own and operate a disposal well to dispose of produced water from both the Pond Creek and Lasher fields. Water produced from these fields averaged 625 barrels per day for 2012.

Pinnate Horizontal Wells We are the operator of 44 producing pinnate horizontal CBM wells in which we own a 71.6% average working interest in central and northern West Virginia. We also have a 33.7% average working interest in 67 non-operated pinnate horizontal wells in central West Virginia. At December 31, 2012, approximately 5% of our estimated proved developed reserves, or 6.5 Bcf, is associated with these pinnate horizontal wells. Net daily sales of natural gas averaged 10.1 MMcf per day for 2012. We are party to two firm transportation agreements with total maximum daily capacity of 18,500 MMBtu per day and primary terms expiring from April 2013 through November 2024 which can be automatically extended at GeoMet s option at the maximum tariff rate. We are also party to a 10,000 MMBtu per day gathering contract that is currently in a month-to-month evergreen term. In some cases, our natural gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our natural gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

Alabama

Gurnee Field We are the operator of 217 producing vertical CBM wells, of which we own a 100.0% working interest, in the Gurnee field located in the Cahaba Basin in central Alabama. At December 31, 2012, approximately 19% of our estimated proved developed reserves, or 26.7 Bcf, is located within the Gurnee field. Net daily sales of gas averaged 4.8 MMcf for 2012. Our natural gas sales volumes from the Cahaba Basin are delivered and sold into the Southern Natural Gas pipeline system and no firm transportation arrangements are necessary. We own and operate a water gathering system which includes an approximately 39 mile pipeline to the Black Warrior River for disposal of produced water under a permit issued by the Alabama Department of Environmental Management. We also own and operate an approximately 17 mile, 12 inch high-pressure steel pipeline and gas treatment and compression facilities through which we gather, dehydrate, and compress natural gas for delivery into the Southern Natural Gas pipeline system.

Black Warrior Basin We own working, overriding royalty or royalty interests in 1,056 non-operated producing vertical CBM wells in the Black Warrior Basin in central Alabama. All of these non-operated vertical wells have an average royalty and or overriding royalty interest of 12.0%. We also own an average working interest of 15.4% in 498 of these wells. At December 31, 2012, approximately 12% of our estimated proved developed reserves, or 16.3 Bcf, is located in these Warrior Basin properties. Net daily sales of gas averaged 6.4 MMcf for 2012. Our gas sales volumes from the Black Warrior Basin are delivered and sold into the Southern Natural Gas pipeline system under transportation arrangements controlled by the operators of the properties.

Canada

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

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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.

Estimated Proved Reserves

Estimated proved natural gas reserves as of December 31, 2012, as estimated by DeGolyer and MacNaughton (D&M) and Ryder Scott Company, L.P. (Ryder Scott), independent petroleum engineers, totaled approximately 137 Bcf. Our proved natural gas reserves as of December 31, 2011, as estimated by D&M and Ryder Scott, totaled approximately 198 Bcf. The decrease of 62 Bcf from the prior year was primarily attributed to a 31% decrease in the price of natural gas used in the estimation of our reserves. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $72.9 million at December 31, 2012. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $173 million at December 31, 2011. A price of $2.91 per Mcf was used at December 31, 2012 compared to $4.21 per Mcf at December 31, 2011. Our estimated proved reserves at December 31, 2012 are 100% coalbed methane and 100% proved developed. Approximately 69% of total proved reserves at December 31, 2012 are in our Central Appalachia producing region and 31% are in its Alabama producing region.

The following table presents information related to our estimated proved reserves as of December 31, 2012:

Field	Proved Developed Producing (MMcf)	Proved Developed Non-Producing (MMcf)	Proved Undeveloped (MMcf)	Total Proved (MMcf)
Central Appalachia:				
Pond Creek and Lasher fields	87,632			87,632
Pinnate wells	6,513			6,513
Alabama:				
Gurnee field	26,709			26,709
Black Warrior fields	16,327			16,327
Totals	137,181			137,181

We annually review all proved undeveloped reserves (PUDs) to ensure an appropriate plan for development exists. We expect to convert our PUDs to proved developed reserves within five years of the date they are first booked as PUDs. There are no PUD reserves at December 31, 2012 included in our proved reserves at year end.

On December 31, 2011, we had 10.1 Bcf of estimated net proved undeveloped reserves. Because of the depressed natural gas prices and the lack of capital resources to develop our gas properties, during 2012 we did not convert any of these PUD reserves into proved developed reserves. We have removed all of our PUD and proved developed non-producing reserves from the proved category as of December 31, 2012.

CBM-producing natural gas reservoirs generally are characterized by an initial period of incline followed by an extended period of declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities or acquisitions, our reserves and production will decline. Such decline rate, however, is lower than what is generally experienced with non-CBM wells. See Risk Factors for a discussion of the risks inherent in CBM gas estimates and for certain additional information concerning the estimated proved reserves.

Our policies and procedures regarding internal controls over the recording of our oil and natural gas reserves is structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with both accounting principles generally accepted in the United States and the SEC s regulations. The technical person primarily responsible for preparation of our internal reserve estimates and overseeing the reserve estimates prepared by D&M and Ryder Scott, independent petroleum engineers, is our Reservoir Engineering Manager. Our Reservoir Engineering Manager received a Bachelor of Science of Mineral Engineering (Petroleum) degree in December 1983 from the University of Alabama and is a Licensed Professional Engineer in the state of Alabama. He has worked as a petroleum engineer for approximately 27 years, including nine years with River Gas Corporation in Northport, Alabama from 1992 to 2001 and the last 11 years with GeoMet in Hoover, Alabama. He also worked briefly with Phillips Petroleum following its acquisition of River Gas Corporation. During the last 21 years, our Reservoir Engineering Manager s primary responsibility has been methane reservoir characterization and evaluation. As such, he has had the opportunity to participate in the development and evaluation of over 2,000 coalbed methane wells located in the Black Warrior basin, the Cahaba basin, the Central Appalachian basin in West Virginia and Virginia, and the Uinta basin in Utah. Our Reservoir Engineering Manager accumulates and reviews the inputs and assumptions used by D&M and Ryder Scott to estimate our year-end reserves and assesses them for reasonableness.

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Our controls over reserve estimates included retaining D&M and Ryder Scott as our independent petroleum engineers. We provided information about our oil and natural gas properties, including production profiles, prices and costs, to D&M and Ryder Scott and they prepared their own estimates of our oil and natural gas reserves attributable to our properties. All of the information regarding reserves in this annual report on Form 10 K is derived from the reports of D&M and Ryder Scott, which are included as exhibits to this annual report on Form 10 K. The technical persons at D&M and Ryder Scott that are responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our controls also include oversight of our reserves estimation process by our Board of Directors. Both our Chief Executive Officer and Chief Financial Officer are charged with the responsibility of reviewing and approving the natural gas reserve estimates prepared by D&M and Ryder Scott.

Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. Coalbed methane-producing natural gas reservoirs generally are characterized by an initial period of inclining production rates as pressure in the reservoir decreases, followed by declining production rates that vary depending upon reservoir characteristics and other factors. These decline rates, however, are commonly lower than what is generally experienced with non-coalbed methane wells and the life of coalbed methane wells are generally longer lived than conventional natural gas wells.

The reserves information in this filing on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by D&M and Ryder Scott and other information about our natural gas reserves, see Supplementary Financial and Operating Information on Gas Exploration, Development and Producing Activities (Unaudited) included elsewhere in this annual report on Form 10-K.

Production and Operating Statistics

The following table presents certain information with respect to production and operating data for the years ended December 31:

		2012		**2011**
Natural Gas:				
Net sales volume (Bcf) (1)		13.8		8.5
Average natural gas sales price ($ per Mcf)	$	2.83	$	4.15
Average natural gas sales price ($ per Mcf) realized(2)	$	4.02	$	5.28
Lease operations expenses	$	1.27	$	1.49
Compression and transportation expenses	$	0.60	$	0.54
Production taxes	$	0.14	$	0.18
Total production expenses ($ per Mcf) (3)	$	2.01	$	2.21

(1) Increased production is due to the properties acquired in November 2011.

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

(3) Decreased expenses per Mcf are the result of higher production.

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we owned a working interest as of December 31, 2012. Gross represents the total number of acres or wells in which we owned a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are producing or capable of producing natural gas.

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we owned a working interest as of December 31, 2012:

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	Productive Wells		Developed Acres		Undeveloped Acres	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Pond Creek and Lasher fields	298.0	295.1	19,650	19,649	26,735	16,530
Pinnate wells (Central Appalachia)	111.0	54.1	66,135	35,297	87,516	51,295
Gurnee field	217.0	217.0	17,547	17,507	21,685	21,685
Black Warrior fields	498.0	76.9	58,253	8,540	10,943	4,611
Other			880	880	18,059	16,797
Total	1,124.0	643.1	162,465	81,873	164,938	110,918

Our material undeveloped leases are in the Gurnee field in Alabama and the Pond Creek, Triangle, and Crab Orchard fields of the Central Appalachian Basin. Generally, the undeveloped acreage expires on various dates from 2013 through 2014; The following table sets forth, as of January 1, 2013, undeveloped acreage which expires through 2014 which management believes to be material to future operations:

	2013		2014	
Area	**Gross**	**Net**	**Gross**	**Net**
Gurnee			21,685	21,685
Crab Orchard	4,408	2,204		
Total	4,408	2,204	21,685	21,685

The terms of the undeveloped acreage may be extended by drilling and production operations or through negotiation with lessors. However, we have no current plans in place to develop any of our lease acreage or to negotiate extensions of these leases.

Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells that we participated in for each of the last two fiscal years. The number of wells drilled refers to the number of wells completed at any time during the respective year. Productive wells are producing wells and wells capable of production. All wells were drilled on our properties in the United States.

	Gross					
	Exploratory			Development		
Well Activity (Gross) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2012						
Year ended December 31, 2011				20		20

The following table sets forth, for each of the last two fiscal years, the number of completed net exploratory and net development wells drilled by us based on our proportionate working interest in such wells.

	Net					
	Exploratory			Development		
Well Activity (Net) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**

Year ended December 31, 2012		
Year ended December 31, 2011	19	19

No drilling is currently scheduled for 2013.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

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Insurance

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to certain of our natural gas assets, auto liability, worker s compensation and employer s liability, among other things. At the depths and in the areas in which we operate we typically do not encounter high pressures or extreme drilling conditions. Accordingly, we do not carry control of well insurance.

Currently, we have general liability insurance coverage up to $2 million per occurrence, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from our operations. Our insurance policies contain maximum policy limits and in most cases, deductibles, generally less than $25,000 per occurrence. Our insurance policies are subject to certain customary exclusions and limitations. In addition, we maintain $15 million in excess liability coverage, which increases coverage limits if the general liability, auto or employers liability policy limit is reached.

We attempt to have our third-party contractors, including those that perform hydraulic fracturing operations for us, sign master service agreements in which each party agrees to indemnify the other party against personal injury and property damage claims for which they had no responsibility.

We evaluate the need and availability of insurance, coverage limits and deductibles as circumstances warrant. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Bonding

Companies engaged in oil and gas operations are generally required by regulatory authorities and other parties to post bonds in connection with their operations. These bonds provide a guarantee to the holder of the bond that the company will perform as required under the terms of the agreement requiring such bond. As of February 18, 2013, the Company had approximately $900,000 bonds issued on its behalf. If we fail to perform under the terms any agreement requiring such bond, the bond holder may demand that the surety make payments or provide services under the bond. We must reimburse the sureties for any expenses or outlays they incur on our behalf. To date, we have not been required to make any reimbursements to our sureties for bond-related costs.

As is common in the surety industry, sureties issue bonds on an individual basis and can decline to issue bonds at any time. Our relationship with our surety has, to date, allowed us to provide surety bonds as required. However, current market conditions, as well as changes in our surety s assessment of our operating and financial risk, could cause our surety to decline to issue bonds for our work. The indemnity agreement we have executed with our surety also permits them, at any time, to require the Company provide collateral to secure the Company s obligations to the surety. The Company, to date, has not received any such requests for collateral.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil and natural gas companies in acquiring properties, contracting for drilling and other services and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit. We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program. Competition is also strong for attractive natural gas producing properties, undeveloped leases and drilling rights, and there can be no assurances that we will be able to compete satisfactorily when attempting to make further acquisitions.

Principal Customers and Marketing Arrangements

The market for our natural gas production depends on factors beyond our control, including the amount of domestic production of natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, the demand for natural gas, weather conditions, the marketing of competitive fuels and the effect of state and federal regulation. The natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Five purchasers of our natural gas production purchased 97.8% of the gas we delivered to market during the year ended December 31, 2012, of which 55.3% was purchased by one entity. We do not believe the loss of the aforementioned purchaser would

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materially affect our ability to sell the natural gas we produce as we believe other purchasers are available in our area of operations. As of December 31, 2012, three of our natural gas purchasers and two joint interest owners accounted for 95% of our accounts receivable related to gas sales, of which one natural gas purchaser accounted for 51% of our accounts receivable related to gas sales.

Seasonality of Business

Weather conditions can affect the demand for natural gas and can also delay drilling activities, disrupting our business operations. Historically, demand for natural gas has been higher in the fourth and first quarters, which has traditionally resulted in higher natural gas prices. However, we believe that the recent over-supply in the natural gas market has diminished this seasonal fluctuation. Still, due to these potential seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Governmental, State and Local Regulations

Our coalbed methane exploration and production operations are subject to significant federal, state, and local laws and regulations governing the gathering and transportation of our gas production across state and federal boundaries. The following is a summary of some of the existing regulations to which our operations are subject.

Regulation by the Federal Energy Regulatory Commission (FERC   ) of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or the FERC, does not directly regulate any of our operations. However, the FERC   s regulation influences certain aspects of our business and the market for our products. In general, the FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and

- various other matters.

In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Intrastate Regulation of Natural Gas Transportation Pipelines. We own a pipeline in Alabama that provides intrastate natural gas transportation as defined by the Alabama Public Service Commission (APSC). The APSC regulates gas pipelines that transport gas on an intrastate basis in situations where the gas has been cleaned and pressurized to the point that it is ready for sale. All pipeline systems in Alabama must be constructed, operated and maintained to be in compliance with the defined federal minimum safety standards. The APSC has not enacted its own regulations relating to pipeline safety. Instead, it enforces the U.S. Department of Transportation Office of Pipeline Safety Regulations, including as to reporting, design, construction, and operating requirements of the pipeline. We are inspected annually by the APSC to ensure we are in compliance with the regulations.

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own interstate and intrastate natural gas gathering lines that we believe would meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC s jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

In the states in which we operate, regulation of intrastate gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirement and complaint based rate regulation. For example, we are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. In certain circumstances, such laws will apply even to gatherers like us that do not provide third party, fee-based gathering service and may require us to provide such third party service at a regulated rate. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

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Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement, and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our natural gas sales are affected by the availability, terms, and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The stated purpose of many of these regulatory programs is to promote competition among the various sectors of the natural gas industry, and generally reflect light handed regulation. We cannot predict the ultimate impact of regulatory initiatives to our natural gas operations. We do not believe that we will be affected by any such FERC action materially differently than other sellers of natural gas with whom we compete.

Virginia Regulation. The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to coalbed methane absent an express grant of coalbed methane, natural gases, or minerals in general. The situation may be different if there is any expression in the severance deed indicating more than mere coal is conveyed. Virginia courts have also found that the owner of the coalbed methane did not have the right to fracture the coal in order to retrieve the coalbed methane and that the coal operator had the right to ventilate the coalbed methane in the course of mining. In Virginia, we believe that we own the relevant property rights in order to capture gas from the vast majority of our producing properties. In addition, Virginia has established the Virginia Gas and Oil Board and a procedure for the development of coalbed methane by an operator in those instances where the owner of the coalbed methane has not leased it to the operator or in situations where there are conflicting claims of ownership of the coalbed methane. The general practice is to force pool both the coal owner and the gas owner. In those instances, any royalties otherwise payable are paid into escrow and the burden then is upon the conflicting claimants to establish ownership by court action. The Virginia Gas and Oil Board does not make ownership decisions.

West Virginia Regulation. West Virginia s Supreme Court has held that, in a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding coalbed methane operations, the oil and gas lessee did not acquire the right to produce coalbed methane. As of December 31, 2012, the West Virginia courts have not clarified who owns coalbed methane in West Virginia. Therefore, the ownership of coalbed methane is an open question in West Virginia. West Virginia has enacted a law, the Coalbed Methane Wells and Units Article of the Environmental Resources Act (the West Virginia Act), regulating the commercial recovery and marketing of coalbed methane. Although the West Virginia Act does not specify who owns, or has the right to exploit, coalbed methane in West Virginia and instead refers ownership disputes to judicial resolution, it contains provisions similar to Virginia s pooling law. Under the pooling provisions of the West Virginia Act, an applicant who proposes to drill is permitted to prosecute an administrative proceeding with the West Virginia Coalbed Methane Review Board to obtain authority to produce coalbed methane from pooled acreage. Owners and claimants of coalbed methane interests who have not consented to the drilling are afforded certain elective forms of participation in the drilling (e.g., royalty or owner) but their consent is not required to obtain a pooling order authorizing the production of coalbed methane by the operator within the boundaries of the drilling unit. The West Virginia Act also provides that, where title to subsurface minerals has been severed in such a way that title to coal and title to natural gas are vested in different persons, the operator of a coalbed methane well permitted, drilled and completed under color of title to the coalbed methane from either the coal seam owner or the natural gas owner has an affirmative defense to an action for willful trespass relating to the drilling and commercial production of coalbed methane from that well.

Alabama Regulation. In 1983, the State Oil & Gas Board of Alabama, in cooperation with the coalbed methane operator s group, established the first rules for coalbed methane drilling, development and producing operations. The evolution of Alabama coalbed methane permits is a continuing process. The coalbed methane industry in Alabama has a long history of working closely with Alabama Department of Environmental Management and other government agencies on the continual improvement of coalbed methane permits.

Environmental Regulations

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

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injunctive relief, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future could have a material adverse impact on our operations.

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

The following is a summary of some of the existing environmental laws, rules and regulations to which our operations in the U.S. are subject.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes strict, joint and several liability without regard to fault or legality of conduct, on persons who are considered to have contributed to the release of a hazardous substance into the environment. Many states have similar laws regarding liability for contamination, some of which may have a broader coverage than CERCLA. Under CERCLA, persons potentially liable include the owner or operator of the site where the release occurred, past owners and operators of a contaminated site who owned when the release occurred, and persons that disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. Although CERCLA currently excludes petroleum and natural gas, natural gas liquids, liquefied natural gas or synthetic gas useable for fuel from the definition of hazardous substance, our operations may generate materials that are subject to regulation as hazardous substances under CERCLA. Further, not all state programs contain similar exclusions. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

CERCLA may require payment for cleanup of certain abandoned waste disposal sites, even if such waste disposal activities were undertaken in compliance with regulations applicable at the time of disposal. Under CERCLA, one party may, under certain circumstances, be required to bear more than its proportional share of cleanup costs if payment cannot be obtained from other responsible parties. CERCLA authorizes the U.S. Environmental Protection Agency and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. The scope of financial liability under CERCLA and similar laws involves inherent uncertainties.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, or RCRA, and comparable state programs regulate the management, treatment, storage, and disposal of hazardous and non-hazardous solid wastes. Our operations generate wastes, including hazardous wastes that are subject to RCRA and comparable state laws. We believe that these operations are currently complying in all material respects with applicable RCRA requirements. Although RCRA currently exempts certain natural gas and oil exploration and production wastes from the definition of hazardous waste, we cannot assure you that this exemption will be preserved in the future, which could have a significant impact on us as well as on the oil and natural gas industry, in general.

Water Discharges. Our operations are subject to the Clean Water Act, or CWA, as well as the Oil Pollution Act, or OPA, and analogous state laws and regulations. These laws and regulations impose detailed requirements, including permitting requirements, and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other substances and the placement of fill material (such as from our development operations), into waters of the U.S., including wetlands. Under the CWA and OPA, any unpermitted release of pollutants from operations could cause us to become subject to the costs of remediating a release; administrative, civil or criminal fines or penalties; or OPA specified damages, such as damages for loss of use, property damage and natural resource damages. Liability can be joint and several, regardless of fault. In addition, in the event that spills or releases of produced water from CBM production operations were to occur, we would be subject to spill notification and response requirements under the CWA or the equivalent state regulatory program. Depending on the nature and location of these operations, spill response plans may also have to be prepared.

Our CBM exploration and production operations produce substantial volumes of water that must be disposed of in compliance with requirements of the CWA, the Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to surface streams, or in evaporation ponds. Discharge of produced water to surface streams and other bodies of water must be authorized in advance pursuant to permits issued under the CWA, and disposal of produced water in underground injection wells must be authorized in advance pursuant to permits issued under the SDWA. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that

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the produced water has been disposed in substantial compliance with such permits and applicable laws. More stringent regulations on our water disposal practices could have a material impact upon our operations.

We own and operate an approximate 38.5-mile pipeline from the Cahaba Basin to the Black Warrior River for the disposal of produced water under a permit issued by the Alabama Department of Environmental Management (ADEM). This pipeline has a maximum design capacity of approximately 45,000 barrels of water per day, but would require additional pump stations and looping a portion of the line in order to reach the maximum design capacity, if needed. We are currently transporting less than 10,000 barrels of produced water per day through this line and we believe we have adequate takeaway capacity to meet our future needs. All National Pollutant Discharge Elimination System (NPDES) permits for the discharge of produced water from coalbed methane fields in Alabama are issued for five-year terms by the ADEM and are subject to renewal every five years. We were granted an NPDES permit for the discharge of produced water from the Gurnee field into the Black Warrior River in 2004. We have submitted a timely and complete renewal application to ADEM for a five-year renewal of our NPDES permit. No five-year renewal NPDES permits for the discharge of produced water from coalbed methane fields into streams or rivers have been granted by ADEM since our renewal application was submitted. ADEM is currently administratively extending all existing NPDES permits for disposal of produced water from coalbed methane fields into streams or rivers for which timely and complete renewal applications are received, including our NPDES permit.

In recent federal legislative sessions, bills have been introduced to eliminate certain exemptions for hydraulic fracturing from the SDWA and to require disclosure of chemicals used in hydraulic fracturing. Several states have already adopted disclosure requirements. In addition, the EPA has recently been taking steps to assert federal regulatory authority over hydraulic fracturing using diesel under the SDWA. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. EPA released a progress report in December 2012; final results of the study are expected in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Consequently, these studies and initiatives could spur further legislative or regulatory action regarding hydraulic fracturing or similar production operations.

Additionally, some states, regional authorities and localities have adopted or are considering adopting regulations that could restrict hydraulic fracturing. Further, the Bureau of Land Management is considering regulations for hydraulic fracturing on land it regulates. Further, the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

Air Emissions. The Clean Air Act, or CAA, and comparable state laws and regulations govern emissions of various air pollutants through the issuance of permits and the imposition of other requirements. Air emissions from some equipment used in our operations, such as gas compressors, are potentially subject to regulations under the CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulation or are regulated through general permits or similar generic authorizations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. These permits or authorizations may place restrictions upon our air emissions and may require us to install expensive pollution control equipment. The CAA imposes administrative, civil and even criminal penalties, as well as injunctive relief, for failure to comply. To date, we believe that no unusual difficulties have been encountered in obtaining air permits, and we believe that our operations are in substantial compliance with the CAA and analogous state and local laws and regulations. However, in the future, we may be required to incur capital expenditures or increased operating costs to comply with air emission-related requirements.

On April 17, 2011, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs under the CAA, and to impose new and amended requirements under both 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 new hydraulically 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.

Climate Change Legislation. Laws and regulations relating to climate change and greenhouse gases (GHGs), including methane and carbon dioxide, may be adopted and could cause us to incur material expenses in complying with them. The Environmental Protection Agency (EPA), as of January 2, 2011, requires the permitting of GHG emissions from stationary sources

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under the prevention of significant deterioration (PDS) and Title V operating permits program for all sources that have the potential to emit specific quantities of GHGs with the largest sources first subject to permitting. These permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. In November 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report, for 2011, being due in March 2012. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These or other potential federal and state initiatives may result in so-called cap-and-trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. These regulatory initiatives also could adversely affect the demand for and the marketability of the oil and natural gas we produce.

Other Laws and Regulations. Our operations are also subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from, and are often based on negligence, trespass, nuisance, strict liability or fraud.

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service designates the species protected habitat as part of the effort to protect the species. A protected habitat designation or the mere presence of threatened or endangered species could result in material restrictions to our use of the land use and may materially delay or prohibit land access for our development.

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon our projects on federal lands.

Hydraulic Fracturing

Regulation of hydraulic fracturing is further discussed above under Water Discharge. In connection with our hydraulic fracturing operations, we diligently review best practices and industry standards, and seek to comply with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources.

There have not been any incidents, citations or suits related to our hydraulic fracturing activities involving environmental concerns.

We did not drill and complete any well in 2012, we do not currently plan to drill and complete any wells in 2013, and we have no proved undeveloped reserves in any of our fields at December 31, 2012.

Industry Segment and Geographic Information

We operate in one industry, which is the exploration, development and production of natural gas. Our operational activities are conducted in the United States.

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Employees

At December 31, 2012, we had a total of 64 employees, all of which were full-time. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are generally satisfactory.

Corporate Offices

Our corporate headquarters are located at 909 Fannin, Suite 1850, Houston, Texas 77010. Our technical and operational headquarters are located at 5336 Stadium Trace Parkway, Suite 206, Birmingham, Alabama 35244.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to such reports available free of charge through our corporate website at *www.geometinc.com* as soon as reasonably practicable after we file any such report with the SEC. In addition, information related to the following items, among other information, can be found on our website: our press releases, our corporate governance guidelines, our corporate code of business ethics and conduct, our audit committee charter, and our compensation, nominating, corporate governance and ethics committee charter. You may also read and copy any document we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an internet site that contains our reports, proxy and information statements, and our other filings which are also available to the public over the internet at the SEC s website at *www.sec.gov*.

Item 1A. ***Risk Factors***

If any of the following risks develop into actual events, our business, financial condition, results of operations, cash flows, strategies and prospects could be materially adversely affected.

Our management concluded that due to our high level of indebtedness, the uncertainties surrounding our ability to service such indebtedness and other factors, substantial doubt exists as to our ability to continue as a going concern.

Our audited financial statements for the fiscal year ended December 31, 2012 were prepared on a going concern basis in accordance with United States generally accepted accounting principles. The going concern basis of presentation assumes that we will continue in operation for the next twelve months and will be able to realize our assets and discharge our liabilities and commitments in the normal course of business and do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from our inability to continue as a going concern. Our credit facility matures on April 1, 2014. Our operating and capital plans for the next twelve months call for dedication of substantially all of our excess cash flow to the repayment of indebtedness and the possible sale of assets to reduce indebtedness, with the goal of eliminating our borrowing base deficiency, and refinancing our credit facility. Our management concluded that due to the uncertainties surrounding our ability to sell assets at acceptable prices, to reduce our indebtedness to an amount less than the borrowing base and to refinance our credit facility before its maturity date, substantial doubt exists as to our ability to continue as a going concern. If we were unable to continue as a going concern, the values we receive for our assets on liquidation or dissolution could be significantly lower than the values reflected in our financial statements.

Natural gas prices have been depressed recently and have the potential to remain depressed for the next several years, which may have an adverse effect on our financial condition, results of operations and cash flows.

Natural gas prices have fallen substantially since early 2011 as a result of over-supply caused by, among other things, increased drilling in unconventional reservoirs, reduced economic activity associated with a recession and weather conditions. Natural gas prices may be depressed for the foreseeable future. All of our estimated net proved reserves and production are natural gas. Therefore, continued depressed natural gas prices may have a material adverse effect on our financial condition, results of operations and cash flows. See Management s Discussion and Analysis of Financial Condition and Results of Operations.

Natural gas prices are volatile, and sustained periods of lower natural gas prices have and will significantly affect our financial results and impede our growth.

Our revenue, profitability, and cash flow depend upon the prices for natural gas. Natural gas prices have been historically volatile, and such high levels of volatility are expected to continue. Recent prices for natural gas have been depressed and may remain depressed. Reduced natural gas prices have a significant impact on the value of our reserves, our cash flow, and our borrowing capacity. Lower natural gas prices may decrease our revenues, and may reduce the amount of natural gas that we can produce economically. This may result in substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition, results of operations, cash flow and borrowing capacity. If there are substantial downward adjustments to our estimated proved reserves, accounting rules may require us to impair, as a non-cash charge to earnings, the carrying value of our properties. During 2012, we recorded impairment charges of $95.7 million and we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Primarily because of low natural gas prices in 2012, the amounts borrowed under our credit facility exceeded the borrowing base attributable to our natural gas reserves as determined by the lenders under the credit facility. We have dedicated substantially all of our excess cash flow to repayment of amounts under our credit facility. If natural gas prices decline further or remain low for an extended period of time, we may, among other things, be unable to remain in compliance with our credit facility.

Basis differentials could decrease and adversely affect our results of operations and cash flows.

Basis or basis differential reflects the premium or discount to quoted Henry Hub prices related to the proximity of the gas delivery point to markets and the local supply demand balance. The delivery point is generally the contractual point where ownership of the natural gas transfers from the seller and is usually a point on a pipeline or a specific delivery or market location. Prices may vary significantly from one delivery point to another. For example, natural gas prices will generally be higher if the delivery point is closer to market centers than at Henry Hub which is near producing centers. The basis differential can be affected by several factors, including weather, transportation alternatives, supply and demand and market sentiment. Historically, we have enjoyed a premium to

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the Henry Hub natural gas spot price for our production. However, the factors that influence these basis differentials are dynamic and beyond our control. As a result, in the future, the premiums we have enjoyed could diminish or turn to discounts.

We are highly leveraged, which makes us more vulnerable to economic downturns and adverse developments in our business.

During most of 2012, the amounts outstanding under our credit facility exceeded the borrowing base under the facility. As a result of our indebtedness, we use substantially all of our excess cash flow to pay interest and principal, which substantially eliminates the amount we have available to finance our exploration, development and acquisition activities. The substantial level of indebtedness will limit our flexibility in planning for or reacting to changes in our business.

The indebtedness under our revolving credit facility is at a variable interest rate. As such, an increase in interest rates will generate greater interest expense. The amount of our debt makes us more vulnerable to economic downturns and adverse developments in our business.

Our obligations under the Credit Agreement contain covenants with which we must comply. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness and foreclose on their mortgages.

Our Credit Agreement imposes certain restrictions on us, including our ability to make capital expenditures, incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends. In addition, our credit facility is subject to periodic redeterminations of our borrowing base, and decreases in the gas prices used by our lenders to determine the borrowing base could result in a decreased borrowing base and cause us to be in default under the credit facility.

A breach of any of the terms of our Credit Agreement could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, it is unlikely that we will have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the revolving credit facility. Any acceleration in the repayment of our indebtedness or related foreclosure would adversely affect our business.

Inadequate liquidity could materially and adversely affect our business operations in the future.

Our efforts to improve our liquidity position will be challenging given the current economic climate. Current economic fundamentals portray an uncertain outlook for our natural gas business due to depressed natural gas prices and economic conditions. The depressed natural gas prices and economic conditions have resulted in a decline in our revenues and have caused us to suspend our drilling activities. Our ability to maintain adequate liquidity through 2013 may depend on consummation of a strategic transaction or sale of assets and, if so, the terms thereof, sustained commodity price improvement, reduction of operating expenses and capital spending.

Consummation of a strategic transaction or sale of assets may be necessary to fund our cash flow needs in the near term.

In 2012, we experienced reductions in our borrowing base and elimination of availability under our credit agreement, as well as a decline in revenues due to general economic conditions and commodity prices. Although we have significantly decreased our drilling activities in recent periods, any further reductions could materially and adversely affect our continuing operations. Thus, in response to these liquidity issues, in 2012, we announced that we were exploring strategic alternatives, including a sale of some or all of our assets or the sale of the entire company. Based on the current status of our balance sheet, the consummation of one or more of these types of transactions may be required to fund our operations in 2013 if adequate capital is not obtained from another source. Further, our borrowings under our credit facility are currently due on April 1, 2014. If we are unable to complete a strategic transaction or sale of assets, we may not be able to repay the amounts outstanding under the credit facility when due without obtaining other sources of capital from additional asset sales or other alternative financing.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from meeting our obligations under our indebtedness.

As of December 31, 2012, our total outstanding long term liabilities were $144 million, including $129 million of outstanding borrowings drawn under our credit facility. Additionally, we have $10 million due in the current period under our credit facility. Our degree of leverage could have important consequences, including the following:

- it may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, further exploration, debt service requirements, acquisitions and general corporate or other purposes;

- a substantial portion of our cash flows from operations will be dedicated to the payment of principal and interest on our indebtedness and will not be available for other purposes, including our operations, capital expenditures and future business opportunities;

- certain of our borrowings, including borrowings under our credit facility, are at variable rates of interest, exposing us to the risk of increased interest rates;

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- as we have pledged most of our natural gas properties and the related equipment, inventory, accounts receivable and proceeds as collateral for the borrowings under our credit facility, they may not be pledged as collateral for other borrowings and would be at risk in the event of a default thereunder;

- it may limit our ability to adjust to changing market conditions and place us at a competitive disadvantage compared to our competitors that have less debt;

- we are vulnerable in the present downturn in general economic conditions and in our business, and we will likely be unable to carry out capital spending and exploration activities that are important to our growth; and

- we may, from time to time, be out of compliance with covenants under our credit facility, which will require us to seek waivers from our banks, which may be more difficult to obtain in our current financial condition and, if obtained, may require the payment of substantial fees.

In addition, our bank borrowing base is subject to periodic redetermination, including a scheduled borrowing base redetermination in June 2013. A further reduction to our borrowing base could require us to repay indebtedness in excess of the borrowing base, or we might be required to provide the lenders with additional collateral. There is no assurance we would be capable of repaying such indebtedness or providing the lenders with additional collateral. Further, our existing credit facility matures on April 1, 2014 at which time all amounts outstanding thereunder will be due and payable. At current commodity prices, we do not project that we will be able to repay such borrowings without completing one or more capital raising or asset sale transactions, obtaining an extension of the credit facility from the lenders, or entering into a new credit facility.

Our substantial indebtedness could adversely impact our business, results of operations and financial condition.

In addition to making it more difficult for us to satisfy our debt and other obligations, our substantial indebtedness could limit our ability to respond to changes in the markets in which we operate and otherwise limit our activities. For example, our indebtedness, and the terms of agreements governing that indebtedness, could:

- increase our vulnerability to economic downturns and impair our ability to withstand sustained declines in commodity prices;

- subject us to covenants that limit our ability to fund future working capital, capital expenditures, exploration costs and other general corporate requirements;

- prevent us from borrowing additional funds for operational or strategic purposes (including to fund future acquisitions), disposing of assets or paying cash dividends;

- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage relative to our competitors that have less debt outstanding.

Our revolving credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

The terms of the credit agreement require us to comply with certain restrictions and covenants. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the credit agreement could result in a default under those agreements, which could cause all of our existing indebtedness to be immediately due and payable.

The credit agreement limits no longer allows us to borrow. The lenders can unilaterally adjust the borrowing base under the credit agreement. Outstanding borrowings in excess of the borrowing base must be repaid within 30 days. We may not have the financial resources in the future to make any mandatory principal prepayments required under the credit agreement. Our inability to borrow additional funds under our credit agreement could adversely affect our operations and our financial results.

We may not be able to fund the capital expenditures that will be required for us to increase reserves and production.

We must make capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have financed our capital expenditures primarily with cash flow from operations, borrowings under credit facilities, sales of producing properties, and sales of debt and equity securities and we expect to continue to do so in the future. We cannot assure you that we will have sufficient capital resources in the future to finance capital expenditures.

Volatility in natural gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

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The borrowing base under our credit facility is determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under our credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, an inability to drill or unfavorable drilling results, changes in gas reserve engineering, the lenders inability to agree to an adequate borrowing base or adverse changes in the lenders practices regarding estimation of reserves.

If cash flow from operations or our borrowing base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under our credit facility is reduced, we could be required to reduce borrowings under our credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

In recent years, the Obama administration s budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for our natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that require reporting by regulated facilities in 2012 and annually thereafter. The EPA has adopted rules requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an Endangerment Finding under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. The EPA issued its tailoring rules requiring GHG permits for certain sources of GHG emissions.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities, increases in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our operations by disrupting the transportation or process-related services provided by service companies or suppliers with whom we have a business relationship. We may not be able

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to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. Should climate change or other drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

We face uncertainties in estimating proved gas reserves, and inaccuracies in our estimates could result in lower than expected reserve quantities and a lower present value of our reserves.

Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. The estimated production profile of a field in the early stage of operations may vary significantly from the actual production profile as the field matures. As a result, quantities of estimated proved reserves, projections of future production rates, and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing, and production. Also, we make certain assumptions regarding future natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates.

The present value of future net cash flows, in accordance with the regulations promulgated by the SEC, from our estimated proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on current prices and costs. However, actual future net cash flows from our gas properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- future gas prices and operating costs; and
- capital costs of drilling new wells.

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The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from estimated proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas industry in general.

Our results of operations could be adversely affected as a result of non-cash impairments.

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 estimated future net revenues are estimated in accordance with SEC rules and regulations which include using a flat price throughout the life of our reserves calculated by taking the unweighted arithmetic average of the natural gas price for the first day of each month during the year. We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. During 2012, we took in impairment charges of $95.7 million. Future adverse changes to prices we receive for our production, costs, reserves or other factors could lead to an impairment of all or a portion of our full cost pool in future periods which could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to the full cost pool and stockholders equity.

Our net operating loss carryforwards may be limited or they may expire before utilization.

As of December 31, 2012, we had U.S. federal tax net operating loss carryforwards (NOL s) of approximately $138.2 million, which expire at various dates from fiscal year 2022 through fiscal year 2032. These net operating loss carryforwards may be used to offset future taxable income and thereby reduce our U.S. federal income taxes otherwise payable. Section 382 of the Internal Revenue Code of 1986, as amended (the Code), imposes an annual limit on the ability of a corporation that undergoes an ownership change to use its net operating loss carry forwards to reduce its tax liability. An ownership change would occur if stockholders, deemed under Section 382 to own 5% or more of our capital stock by value, increase their collective ownership of the aggregate amount of our capital stock to more than 50 percentage points over a defined period of time. In the event of certain changes in our stockholder base, we may at some point in the future experience an ownership change as defined in Section 382 of the Code. Accordingly, our use of the net operating loss carryforwards and credit carryforwards may be limited at some point in the future by the annual limitations described in Sections 382 and 383 of the Code.

Unless we replace our natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, results of operations, borrowing capacity and cash flows.

Producing natural gas reservoirs are typically characterized by declining production rates that vary depending upon reservoir characteristics and other factors. CBM production generally declines at a shallow rate after initial increases in production which result as a consequence of the de-pressuring process. The rate of decline from our existing wells may change in a manner different than we have estimated. Thus, our future natural gas reserves and production and, therefore, our borrowing capacity, cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs.

Our ability to sell the gas we produce depends in substantial part on the availability and capacity of pipeline systems owned and operated by third parties. Operational impediments on these pipeline systems may hinder our access to natural gas markets or delay our production.

The availability of a ready market for our natural gas production depends on a number of factors, including the proximity of our reserves to pipelines, capacity constraints on pipelines, and disruption of transportation of natural gas through pipelines. We transport the natural gas we produce principally through pipelines owned by third parties. If we cannot access these third-party pipelines, or if transportation of gas through any of these pipelines is disrupted, we may be required to shut-in or curtail production from some of our wells or seek alternate methods of transportation of our production. If any of these were to occur, our revenues would be reduced, which would in turn have a material adverse effect on our financial condition and results of operations.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

We own leasehold interests in areas not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

We may be unable to obtain adequate acreage to develop additional large-scale projects.

To achieve economies of scale and produce gas economically, we need to acquire large acreage positions to reduce our per unit costs. There are a limited number of coalbed formations in North America that we believe are favorable for CBM development. We face competition when acquiring additional acreage, and we may be unable to find or acquire additional acreage at prices that are acceptable to us.

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Coal mining may have an adverse effect on our business

Our gas wells are sometimes located in areas with existing surface or underground mining operations. In some cases, we may be required to temporarily or permanently abandon a producing well due to such mining operations resulting in loss of production, reserves and borrowing capacity.

Our exploration and development activities may not be commercially successful.

The exploration for and production of natural gas involves numerous high risks. The cost of drilling, completing, and operating wells for coalbed methane or other gas is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures;

- regulatory permitting problems;
- inability to dispose of produced water;
- legal issues; and
- unavailability or high cost of drilling rigs, other field services, and equipment.

Our future drilling activities may not be successful, and our drilling success rates could decline. Unsuccessful drilling activities could result in higher costs without any corresponding reserves and revenues.

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with the final report of the study anticipated to be available in 2014, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Although it was not passed, legislation was introduced before prior sessions of Congress to provide for increased federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states, regional authorities and localities have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized. Many states have adopted programs requiring companies to disclose chemicals used in hydraulic fracturing. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

We operate in a highly competitive environment and many of our competitors have greater resources than we do.

The gas industry is intensely competitive and we compete with companies from various regions of the U.S. and may compete with foreign suppliers for domestic sales, many of whom are larger and have greater financial, technological, human and other resources. If we are unable to compete, our operating results and financial position may be adversely affected.

In addition, larger companies may be able to pay more to acquire new properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new reserves also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

Our ability to produce natural gas may be hampered by the water present in the formation, which could affect our profitability.

Coalbeds frequently contain brine water that must be removed in order for the gas to desorb from the coal and flow to the well bore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce gas in commercial quantities. The cost of water disposal may affect our profitability.

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We may face unanticipated water disposal costs.

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

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

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

We may be unable to retain our existing senior management team and/or other key personnel that have expertise in coalbed methane extraction and our failure to continue to retain qualified new personnel could adversely affect our business.

Our business requires disciplined execution at all levels of our organization to ensure that we continually develop our reserves and produce gas at profitable levels. This execution requires an experienced and talented management and operations team. If we were to lose the benefit of the experience, efforts and abilities of any of our key executives or the members of our team that have developed substantial expertise in coalbed methane extraction, our business could be adversely affected. We do not maintain key person life insurance on any of our personnel. Our ability to manage our growth, if any, will require us to continue to train, motivate, and manage our employees and to motivate and retain additional qualified managerial and operations personnel. Competition for these types of personnel is intense, and we may not be successful in retaining the personnel required to grow and operate our business profitably.

Government laws, regulations, and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business increase our costs and may restrict our operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state, local, and foreign authorities, relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the injection of material into subsurface formations, the management and disposal of hazardous substances and wastes, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, control of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our respective costs of operations and competitive position. In addition, we could incur substantial costs, including clean-up costs, fines and civil or criminal sanctions, and third party damage claims for personal injury, property damage, wrongful death, or exposure to hazardous substances, as a result of violations of or liabilities under environmental and health and safety laws.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the cost of production. State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing, and well site restoration. If we fail to comply with statutes and regulations, we may be subject to substantial penalties, which would decrease our profitability.

We must obtain governmental and/or third party permits and approvals for drilling operations, which can be a costly and time consuming process and result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of gas may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. In some cases, consents from third parties may be required before a permit is issued. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

We depend on technology owned by others.

We rely on the technological expertise of the independent contractors that we retain for our operations. We have no long-term agreements with these contractors, and thus we cannot be sure that we will continue to have access to this expertise.

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We may incur additional costs to produce gas because our confirmation of title for gas rights for some of our properties may be inadequate or incomplete.

We generally obtain title opinions on significant properties that we drill or acquire. However, we cannot be sure that we will not suffer a monetary loss from title defects or failure. In addition, the steps needed to perfect our ownership varies from state to state and some states permit us to produce the gas without perfected ownership under forced pooling arrangements while other states do not permit this. As a result, we may have to incur title costs and pay royalties to produce gas on acreage that we own and these costs may be material and vary depending upon the state in which we operate.

We do not insure against all potential risks. We may incur substantial losses and be subject to substantial liability claims as a result of our natural gas operations.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations.

Pinnate well plugging may result in higher than expected costs.

Pinnate wells are multi-lateral horizontal wells with two well bores and there is limited history or experience related to plugging procedures or techniques. As a result, it is possible that the plugging cost may vary from lease to lease based on lateral length, hole stability, coal mining activity and regulatory changes.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

To our knowledge, we have not experienced cyber attacks in the past; however, there is no assurance that we will not suffer such attacks and attendant losses in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber attacks. If our systems for protecting against cyber security risks prove not to be sufficient, we could be adversely affected such as by having our business systems compromised, our proprietary information altered, lost or stolen, or our operations disrupted.

Risks Related to Our Capital Stock

The terms of our Preferred Stock prohibit us from issuing common stock at a price of less than the conversion price at the time of issuance without approval of a majority of the holders of the Preferred Stock, which could limit our ability to access the capital markets. We have granted certain rights to a holder of our Preferred Stock which may limit certain of the transactions we may enter into.

The terms of our Preferred Stock provide that we may not issue any additional shares of common stock (or securities convertible into common stock) for consideration per share (with regard to securities convertible into common stock, on an as-converted basis) less than the then-current conversion price of the Preferred Stock without the prior vote or consent of holders of a majority of the outstanding shares of Preferred Stock, for so long as at least 750,000 shares of Preferred Stock remain outstanding. The current price of our common stock is significantly lower than the conversion price of our preferred stock. This provision will prevent us from issuing common stock or securities convertible into our common stock for the foreseeable future, without the consent of the holders of our preferred stock, which could adversely affect our liquidity and results of operations.

In 2010, we entered into an agreement with Sherwood Energy LLC in connection with a rights offering of preferred stock to our stockholders in which Sherwood agreed to acquire any shares of preferred stock not acquired by our shareholders pursuant to the rights offering. Pursuant to this agreement, Sherwood is entitled to appoint up to two persons to our board of directors. In addition, without the consent of the Sherwood directors, we are prohibited from entering into certain corporate transactions. We also granted Sherwood the right to acquire additional securities that we may issue in the future, subject to the terms of the agreement. In addition, if we default under this agreement, Sherwood will have the right to appoint a majority of our directors, until the default is waived. If the default is not cured or waived within a year, Sherwood will have the right to require us to redeem the preferred stock it owns. See Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities Preferred Stock.

The terms of our Preferred Stock could prohibit us from obtaining long term financing or additional equity.

The terms of our preferred stock currently provide that we pay in-kind dividends (PIK) at 12.5 % or in cash at a rate of 8% until September 14, 2015, at which time the cash dividend rate will increase to 9.6%. At such date, we will no longer have the option to pay these dividends in-kind. The Company does not anticipate paying any cash dividends during the period it has the option to pay PIK dividends. The preferred stock is redeemable at the election of the preferred holders beginning 8 years after the effective date of the Preferred Stock issuance. The cumulative impact of paying PIK dividends negatively impacts our ability to obtain equity because of the significant dilutive effects on our common stock. In addition, the 9.6% cash dividend may impede our ability to raise debt financing.

Our common stock has experienced, and may continue to experience, price volatility and a low trading volume.

The trading price of our common stock has been and may continue to be subject to large fluctuations, which may result in losses to investors. Our stock price may increase or decrease in response to a number of events and factors, including:

- results of our drilling or the results of drilling by offset operators;
- global economic recession;
- trends in our industry and the markets in which we operate;
- changes in the market price of the natural gas we sell;
- changes in financial estimates and recommendations by securities analysts;
- acquisitions and financings;

- quarterly variations in operating results;
- operating and stock price performance of other companies that investors may deem comparable to us; and
- issuances, purchases or sales of blocks of our common stock.

This volatility may adversely affect the price of our common stock regardless of our operating performance.

Two existing stockholders each beneficially own a significant percentage of our common stock, which could limit your ability to influence the outcome of stockholder votes.

Sherwood Energy, LLC beneficially owns approximately 29% of our common stock outstanding as of December 31, 2012 (after giving effect to the conversion of the Series A Convertible Redeemable Preferred Stock held by Sherwood) and Yorktown Energy Partners IV, L.P. beneficially owns approximately 15% of our common stock. Additional shares of our Series A Convertible Redeemable Preferred Stock may be issued to Sherwood and our other Series A preferred stockholders as paid-in-kind dividends. In addition, two of the current members of our board of directors are appointed by Sherwood and another member of our board of directors is a member and a manager of the general partner of Yorktown. As a result, Sherwood and Yorktown have, and can be expected to have, a significant voice in our affairs, in the outcome of stockholder voting concerning the election of directors, the adoption or amendment of provisions in our charter and bylaws, the approval of mergers and other significant corporate transactions.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present common stockholders. We are currently authorized to issue 125,000,000 shares of common stock and 10,000,000 shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of December 31, 2012, 40,690,077 shares of common stock were outstanding, and 40,814,346 shares of common stock are issuable upon conversion of outstanding Series A Convertible Redeemable Preferred Stock. An additional 2,095,967 shares of our Series A preferred stock, convertible into 16,122,823 shares of common stock, are reserved for issuance and some or all of that amount may be issued to our preferred stockholders as paid-in-kind, or PIK, dividends. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes, or for other business purposes. Any such issuance would further dilute the interests of our existing common stockholders.

Future sales of our common stock by our existing stockholders may depress our stock price.

As of December 31, 2012, 40,690,077 shares of our common stock were outstanding, together with outstanding options representing the right to purchase up to 2,387,504 shares. As of December 31, 2012, our outstanding Series A Convertible Redeemable Preferred Stock is convertible into an aggregate of 40,814,346 shares of our common stock, which represents approximately 50% of our issued and outstanding common stock as of December 31, 2012, as converted. Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline.

We have not previously paid dividends on our common stock and we do not anticipate doing so in the foreseeable future.

We have not in the recent past paid, and do not anticipate paying in the foreseeable future, cash dividends on our common stock. Our outstanding revolving bank credit agreement contains covenants that prohibit our ability to pay dividends on our common stock. Additionally, any future decision to pay a dividend and the amount of any dividend paid, if permitted, will be made at the discretion of our board of directors.

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Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***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.

Environmental and Regulatory

As of December 31, 2012, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Common Stock

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 common stock now trades on the OTCQB under the symbol GMET . The table below shows the high and low closing prices of our common stock for the periods indicated.

		High		Low
Fiscal Year 2011:				
Quarter ended March 31, 2011	$	1.79	$	1.15
Quarter ended June 30, 2011	$	1.67	$	1.00
Quarter ended September 30, 2011	$	1.21	$	0.65
Quarter ended December 31, 2011	$	1.17	$	0.65
Fiscal Year 2012:				
Quarter ended March 31, 2012	$	0.98	$	0.64
Quarter ended June 30, 2012	$	0.64	$	0.23
Quarter ended September 30, 2012	$	0.35	$	0.13
Quarter ended December 31, 2012	$	0.19	$	0.14

Approximately 1,500 stockholders of record as of March 1, 2013 held our common stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares. Holders of our common stock are entitled to receive dividends if, as and when such dividends are declared by our board out of assets legally available therefore after payment of dividends required to be paid on shares of preferred stock, if any. We have not declared or paid any dividends on our shares of common stock and do not currently anticipate paying any dividends on our shares of common stock in the future. Currently our plan is to retain any future earnings for use in the operations and to reduce our outstanding borrowings. Our Credit Agreement prohibits us from paying any cash dividends.

Preferred Stock

On September 14, 2010, we issued and sold 4,000,000 shares of Series A Convertible Redeemable Preferred Stock (Preferred Stock), par value $0.001 per share, at a price of $10.00 per share, pursuant to a rights offering. The Preferred Stock is our most senior equity security. The Preferred Stock ranks senior to our common stock and junior to all of our existing indebtedness. Our Preferred Stock is listed on the NASDAQ Global Market under the symbol GMETP . The table below shows the high and low closing prices of our Preferred Stock for the periods indicated.

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	High		Low	
Fiscal Year 2011:				
Quarter ended March 31, 2011	$	13.26	$	8.84
Quarter ended June 30, 2011	$	12.76	$	10.36
Quarter ended September 30, 2011	$	11.28	$	8.80
Quarter ended December 31, 2011	$	10.57	$	7.90
Fiscal Year 2012:				
Quarter ended March 31, 2012	$	10.37	$	8.25
Quarter ended June 30, 2012	$	9.98	$	3.95
Quarter ended September 30, 2012	$	5.80	$	2.50
Quarter ended December 31, 2012	$	9.00	$	4.99

Approximately 300 stockholders of record as of March 1, 2013 held our Preferred Stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares. The applicable annual rate for dividends paid in cash is 8.0% for the first three years and 9.6% thereafter. The applicable annual rate for paid-in-kind dividends (PIK dividends), which can be paid until the fifth anniversary of the closing of the Preferred Stock offering, is 12.5%. All dividends are cumulative and all unpaid dividends compound on a quarterly basis at a 12.5% annual rate. Our revolving credit agreement contains a restrictive covenant which influences our ability to pay cash dividends. Cash dividends in excess of $2 million are permitted only if our ratio of debt-to-trailing twelve-month EBITDA, as defined in the revolving credit agreement and after giving effect to such cash dividend payment, is 3.5 to 1.0 or less.

In 2010, we entered into an agreement with Sherwood Energy LLC in connection with a rights offering of preferred stock made to our shareholders, in which Sherwood agreed to acquire any shares of preferred stock not acquired by our shareholders pursuant to the rights offering. Sherwood currently owns 59% of the preferred stock and beneficially owns 29% of our common stock on an as converted basis. Sherwood is entitled to appoint two members to our board of directors so long as it beneficially owns more than 40% of the shares of the preferred stock, or beneficially owns 20% or more of our common stock, on an as-converted basis. Sherwood may appoint one member to our board of directors so long as it beneficially owns 40% of the preferred stock it acquired or 10 % of our common stock, on an as-converted basis. Sherwood is entitled to appoint one of its designated directors to our Audit and Compensation Committees, provided that the director meets applicable independence requirements.

In addition, for so long as Sherwood beneficially owns more than 40% of the shares of preferred stock, or beneficially owns 10% or more of our common stock, on an as-converted basis, we may not incur additional material debt, issue additional equity securities senior to or pari passu with the preferred stock, engage in any material acquisitions or other significant corporate transactions, or engage in certain other activities without the consent of the director(s) designated by Sherwood.

If we default under this agreement, Sherwood has the right to appoint a majority of the members of our board of directors until such default is cured or waived by Sherwood. If the default continues for more than 12 months (absent a cure or waiver), Sherwood has the right to require us to redeem its shares of preferred stock at the redemption price.

This agreement also grants Sherwood a participation right to purchase its pro rata share, up to $30,000,000, of authorized but unissued debt securities and preferred stock, and all rights, options or warrants to purchase shares and securities of any type convertible into or exchangeable for debt securities or preferred stock.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

We did not purchase any of our equity securities during the fourth quarter of 2012.

Equity Compensation Plan Information

The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2012.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans excluding securities reflected in column(a)
Equity compensation plans approved by security holders	2,504,057	$ 1.61	1,495,943
Equity compensation plans not approved by security holders			
Total	2,504,057	$ 1.61	1,495,943

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Item 6. ***Selected Financial Data***

Not applicable.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

GeoMet, Inc. is primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. 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 December 31, 2012, we own a total of approximately 144,000 net acres of coalbed methane and oil and gas development rights.

The natural gas industry is capital intensive. Natural gas markets traditionally have been highly volatile. We have historically made substantial capital expenditures in the exploration, 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.

Developments in 2012

Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The low natural gas prices had pervasive adverse consequences to our business. Low gas prices caused a borrowing base deficiency under our credit facility when the amounts outstanding under our credit facility exceeded the borrowing base under the facility. On August 8, 2012, we amended the facility to include a conforming tranche equal to the borrowing base, and a non-conforming tranche in the amount of the excess. The amendment requires that we use all of our excess cash flows to reduce outstanding borrowings under the non-conforming tranche, and significantly limits our capital expenditures. The amended credit amendment has higher interest rates and increased bank fees and professional fees. The maturity date was amended to April 1, 2014. While the amendment provided time to seek a strategic corporate transaction, we believe these efforts have been impeded because of the borrowing base deficiency. The borrowing base deficiency has also adversely impacted our ability to hedge additional volumes of gas, thereby exhausting our hedging credit capacity. Retaining and attracting competent personnel has been challenging and is likely to worsen. The need to cut cost due to lower natural gas prices and operating margins creates vulnerability in conducting our business.

In addition, the depressed natural gas prices resulted in significant property impairments and full valuation of our deferred tax assets during 2012. Low natural gas prices and our indebtedness contributed to our common stock being delisted by NASDAQ as we had no remaining equity and diminished the market price of our common stock.

Current Business Plan

Management s current business plan is primarily focused on eliminating our borrowing base deficiency, maintaining compliance with the amended credit facility, maintaining production levels and keeping costs under control. In addition, management recently packaged all of the Company s Alabama properties to be marketed for sale by an asset divestiture firm. If the sale is successful, management expects that substantially all the net proceeds from the sale will go toward reducing the outstanding borrowings under the credit facility. Management remains open to possible corporate strategic transactions. There can be no assurance that the Company will be able to engage in a strategic transaction, sell properties or realize enough proceeds from the sale of our properties to eliminate the borrowing base deficiency. In addition, our credit facility matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the credit facility when it matures.

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 ten years. Presented below are the NYMEX Settle Prices for the period January 2012 through March 2013 and the NYMEX Forward Curve Prices (as of March 18, 2013) for natural gas for the period April 2013 through December 2013.

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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 OTCQB 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 which is the cost of medical insurance premiums for continued coverage under the Company s group medical plan for that period 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.

On May 1, 2012, the Board of Directors of the Company appointed Michael Y. McGovern as the Company s Chairman of the Board; William C. Rankin, as a director and 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. Mr. Malone receives $1,221 per month for 18 months which is the cost of medical insurance premiums for continued coverage under the Company s group medical plan for that period and $10,175 per month as a consulting fee for up to nine months.

In response to the Company s continuing efforts to reduce its cost structure to deal with depressed natural gas prices, Robert E. Creager resigned from his position on the Board of Directors effective January 22, 2013. Additionally, Charles D. Haynes is not expected to be nominated for election to the Board of Directors at the Company s 2013 annual meeting of stockholders.

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,

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although as long as we have a borrowing base deficiency, we believe a merger transaction is not likely. The Company has not entered into substantive negotiations with any person in connection with its review of strategic alternatives, although it may do so in the future.

On February 26, 2013, the Company announced that it engaged Lantana Oil & Gas Partners, a Houston based divestiture firm, to market all of the Company s coal bed methane interests located in the state of Alabama. The Company has non-operating interests in 1,058 wells located in the Black Warrior Basin. All of these wells have royalty and/or overriding royalty interests and additionally 498 of these wells include a 15% working interest. The Company also has a 100% working interest and operates 252 wells in the Cahaba Basin. The interests in these properties represented 30% of the Company s net daily sales of natural gas and 38% of operating income during the twelve months ending December 31, 2012. At December 31, 2012, using Securities and Exchange Commission guidelines, the interests in these wells represented approximately 31% of the Company s proved reserves and 38% of the PV10. If we sell these properties, net proceeds from the sale of these properties will be used to reduce the Company s borrowings under its bank credit agreement. The engagement term is one year and we have paid Lantana a retainer of $35,000. If Lantana is successful in selling our Alabama properties, they will receive a fee equal to one percent of the sales proceeds upon closing of the transaction.

C*eiling 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 December 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.78 per Mcf, resulting in a natural gas price of $2.91 per Mcf when adjusted for regional price differentials. For the year ended December 31, 2012, we recorded $95.7 million in write-downs of the carrying value of our full cost pool.

Deferred Tax Asset

As of March 31, 2012, as part of our assessment of the realization of our net deferred tax asset, we considered all available negative and positive evidence. We had incurred a cumulative pre-tax loss of $117.6 million, including ceiling impairment charges of $141.3 million, over the three year period ended March 31, 2012. We evaluated all available evidence including historical operating results, historical pricing, natural gas reserves as estimated and appraised by an independent third party engineer, the forward natural gas price curve, and the length of the carryforward period available. Upon the completion of that assessment, we established a full valuation allowance for our net deferred tax assets at March 31, 2012 of $47.3 million. These tax benefits will be available, prior to the expiration of carryforwards, to reduce future income tax expense resulting from earnings or increases in deferred tax liabilities.

Areas of Operation

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.

Central Appalachia

Pond Creek and Lasher Fields We are the operator of 298 producing vertical CBM wells in which we own a 99.0% average working interest in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia. At December 31, 2012, approximately 64% of our estimated proved developed reserves, or 87.6 Bcf, is in the Pond Creek field. Net daily sales of gas averaged 16.5 MMcf per day for 2012. Our natural gas production from the Pond Creek field is delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). We have two long-term transportation agreements with ETNG which went into effect in April 2007 with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. Our gas from the Lasher field is delivered into the Columbia Gas Transmission pipeline with firm transportation for 500 MMBtu s per day. We also own and operate a 12 mile, 8 inch high-pressure steel pipeline and gas treatment and compression facilities through which the Pond Creek field natural gas production is gathered, dehydrated, and compressed for delivery into the Jewell Ridge Lateral of the East Tennessee pipeline system. In addition, we own and operate a disposal well to dispose of produced water from both the Pond Creek and Lasher fields. Water produced from these fields averaged 625 barrels per day for 2012.

Pinnate Horizontal Wells We are the operator of 44 producing pinnate horizontal CBM wells in which we own a 71.6% average working interest in central and northern West Virginia. We also have a 33.7% average working interest in 67 non-operated pinnate horizontal wells in central West Virginia. At December 31, 2012, approximately 5% of our estimated proved developed reserves, or 6.5 Bcf, is associated with these pinnate horizontal wells. Net daily sales of natural gas averaged 10.1 MMcf per day for 2012. We are party to two firm transportation agreements with total maximum daily capacity of 18,500 MMBtu per day and primary terms expiring from April 2013 through November 2024 which can be automatically extended at GeoMet s option at the maximum tariff rate. We are also party to a 10,000 MMBtu per day gathering contract that is currently in a month-to-month evergreen term. In some cases, our natural gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our natural gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

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Alabama

Gurnee Field We are the operator of 217 producing vertical CBM wells, of which we own a 100.0% working interest, in the Gurnee field located in the Cahaba Basin in central Alabama. At December 31, 2012, approximately 19% of our estimated proved developed reserves, or 26.7 Bcf, is located within the Gurnee field. Net daily sales of gas averaged 4.8 MMcf for 2012. Our natural gas sales volumes from the Cahaba Basin are delivered and sold into the Southern Natural Gas pipeline system and no firm transportation arrangements are necessary. We own and operate a water gathering system which includes an approximately 39 mile pipeline to the Black Warrior River for disposal of produced water under a permit issued by the Alabama Department of Environmental Management. We also own and operate an approximately 17 mile, 12 inch high-pressure steel pipeline and gas treatment and compression facilities through which we gather, dehydrate, and compress natural gas for delivery into the Southern Natural Gas pipeline system.

Black Warrior Basin We own working, overriding royalty or royalty interests in 1,056 non-operated producing vertical CBM wells in the Black Warrior Basin in central Alabama. All of these non-operated vertical wells have an average royalty and or overriding royalty interest of 12.0%. We also own an average working interest of 15.4% in 498 of these wells. At December 31, 2012, approximately 12% of our estimated proved developed reserves, or 16.3 Bcf, is located in these Warrior Basin properties. Net daily sales of gas averaged 6.4 MMcf for 2012. Our gas sales volumes from the Black Warrior Basin are delivered and sold into the Southern Natural Gas pipeline system under transportation arrangements controlled by the operators of the properties.

Canada

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

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements that have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. Our significant accounting policies are described in Note 3 to our audited consolidated financial statements included elsewhere in this annual report. We believe the following critical accounting policies involve significant judgments, estimates, and a high degree of uncertainty in the preparation of our financial statements.

Reserves. Our most significant financial estimates are based on estimates of proved gas reserves. Proved gas reserves represent estimated quantities of gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production, and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering, and production data and, the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geologic interpretation, and judgment. In addition, as a result of changing market conditions, natural gas prices and future development costs will change from year to year, causing estimates of proved reserves to also change. Estimates of proved reserves are key components of our most significant financial estimates involving our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. Our reserves are fully engineered on an annual basis by D&M and Ryder Scott, independent petroleum engineers.

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

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

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Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling 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 impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The ceiling limitation test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for regional price differentials, held constant over the life of the reserves. In addition, subsequent to the adoption of Accounting Standards Codification (ASC) 410-20-25, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling limitation test calculation.

Asset Retirement Obligations We adopted ASC 410-20-25, effective January 1, 2003. It establishes accounting and reporting standards for retirement obligations associated with tangible long-lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement obligation, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Periodically, we update the cost assumptions resulting from changes in market and environmental regulation and revise the liability recorded accordingly.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. This assessment includes extensive analysis performed by the Company at the end of each reporting period. At December 31, 2012, a full valuation allowance has been recorded against our net deferred tax asset.

Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOL s).

ASC 740 also clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return. The adoption of this pronouncement did not have a significant impact on the Company s consolidated financial statements.

Revenue Recognition and Gas Balancing We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue whereby revenues, net of royalties, are recognized as the production is sold to a purchaser. The amount of gas sold may differ from the amount to which the Company is entitled based on its working interest or net revenue interest in the properties. In instances where we have wellhead imbalances, we use the entitlements method. A ready market for natural gas allows us to sell our natural gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title is transferred based on our nominations and net revenue interests. Pipeline imbalances occur when our production delivered into the pipeline varies from the gas we nominated for sale or depending on the agreement in place, imbalances may be made up in future production or are settled with cash approximately thirty days from date of production and are recorded as either a reduction or increase of revenue depending upon whether we are over-delivered or under-delivered.

Settlements of gas sales occur after the month in which the gas was produced. We estimate and accrue for the value of these sales using information available at the time financial statements are generated. Differences are reflected in the accounting period during which payments are received from the purchaser.

Derivative Instruments and Hedging Activities Our hedging activities consist of derivative instruments entered into in order to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we have entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2014. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through January 2011. Typically, these derivative instruments require payments to (receipts from) counterparties

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based on specific indices as required by the derivative agreements. These transactions are recorded in our audited consolidated financial statements in accordance with ASC 815. Although not risk free, we believe this policy will reduce our exposure to natural gas price fluctuations and changes in interest rates and thereby achieve a more predictable cash flow. As a result, our derivative instruments are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. We do not enter into derivative instruments for trading or other speculative purposes. At December 31, 2012, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

In accordance with ASC 815-20-25, as amended, all our derivative instruments are recorded on the balance sheet at fair value and changes in the fair value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income (loss) for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swaps qualify and have been designated as such in accordance with ASC 815-20-25.

At the inception of a derivative contract, we may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we document the relationship between the derivative instrument and the hedged items as well as the risk management objective for entering into the derivative instrument. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis.

Mezzanine Equity Our Series A Convertible Redeemable Preferred Stock has been classified within the mezzanine (temporary) equity section of the Consolidated Balance Sheets because the shares are redeemable at the option of the holder and therefore do not qualify for permanent equity.

Fair Value Measurement Effective January 1, 2008, we adopted ASC 820-10-55, which provides a framework for measuring fair value under GAAP. ASC 820-10-55 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC 820-10-55 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are derived from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure provided in the Notes to Consolidated Financial Statements.

Stock-Based Compensation We follow the fair value recognition provisions of ASC 718. The application of ASC 718 requires the use of an option pricing model, such as the Black Scholes model, to measure the estimated fair value of the options and as a result various assumptions must be made by management that require judgment and the assumptions could be highly uncertain. For share-based awards outstanding prior to the adoption of ASC 718, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we do not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

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Natural Gas Production Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the years ended December 31, 2012 and 2011. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31, 2012		2011	
Gas sales	$	39,147	$	35,335
Lease operating expenses	$	17,489	$	12,713
Compression and transportation expenses		8,356		4,591
Production taxes		1,962		1,536
Total production expenses	$	27,807	$	18,840
Net sales volumes (Consolidated) (MMcf)		13,808		8,511
Pond Creek and Lasher fields		6,025		5,796
Pinnate wells (Central Appalachian Basin)		3,692		591
Gurnee field (Cahaba Basin)		1,743		1,803
Black Warrior Basin fields		2,349		308
Per Mcf data ($/Mcf):				
Average natural gas sales price (Consolidated)	$	2.83	$	4.15
Pond Creek and Lasher fields	$	2.92	$	4.28
Pinnate wells (Central Appalachian Basin)	$	2.69	$	3.40
Gurnee field (Cahaba Basin)	$	2.83	$	4.10
Black Warrior Basin fields	$	2.86	$	3.43
Average natural gas sales price realized (Consolidated)(1)	$	4.02	$	5.28
Lease operating expenses (Consolidated)	$	1.27	$	1.49
Pond Creek and Lasher fields	$	1.07	$	1.17
Pinnate wells (Central Appalachian Basin)	$	1.35	$	1.21
Gurnee field (Cahaba Basin)	$	2.68	$	2.67
Black Warrior Basin fields	$	0.57	$	0.47
Compression and transportation expenses (Consolidated)	$	0.60	$	0.54
Pond Creek and Lasher fields	$	0.58	$	0.55
Pinnate wells (Central Appalachian Basin)	$	1.07	$	1.12
Gurnee field (Cahaba Basin)	$	0.26	$	0.34
Black Warrior Basin fields	$	0.19	$	0.16
Production taxes (Consolidated)	$	0.14	$	0.18
Pond Creek and Lasher fields	$	0.16	$	0.19
Pinnate wells (Central Appalachian Basin)	$	0.11	$	0.06
Gurnee field (Cahaba Basin)	$	0.12	$	0.20
Black Warrior Basin fields	$	0.17	$	0.21
Total production expenses (Consolidated)	$	2.01	$	2.21
Pond Creek and Lasher fields	$	1.81	$	1.91
Pinnate wells (Central Appalachian Basin)	$	2.53	$	2.39
Gurnee field (Cahaba Basin)	$	3.06	$	3.21
Black Warrior Basin fields	$	0.93	$	0.84
Depletion (Consolidated)	$	0.81	$	0.91

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

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Results of Operations

Year Ended December 31, 2012 compared with Year Ended December 31, 2011

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

	Year Ended December 31,				
		2012		2011	Change
				(in thousands)	
Gas sales volume (MMcf)		13,808		8,511	62%
Gas sales	$	39,147	$	35,335	11%
Lease operating expenses	$	17,483	$	12,600	39%
Compression expense	$	4,670	$	2,949	58%
Transportation expense	$	3,679	$	1,633	125%
Production taxes	$	1,962	$	1,536	28%
Depreciation, depletion and amortization	$	11,532	$	7,908	46%
Impairment of intangible asset	$	782	$		NM
Impairment of gas properties	$	95,729	$	7,940	NM
General and administrative	$	4,851	$	4,861	0%
Acquisition costs	$		$	956	NM
Restructuring costs	$	1,083	$		NM
Realized gains on derivative contracts	$	16,383	$	9,571	71%
Unrealized losses (gains) from the change in market value of open derivative contracts	$	11,967	$	(4,067)	NM
Interest expense	$	5,828	$	3,698	58%
Write off of debt issuance costs	$	1,378	$		NM
Discontinued operations	$	736	$	380	94%
Income tax expense	$	44,043	$	1,996	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $3.8 million, or 11%, to $39.1 million compared to the prior year period. The increase in gas sales was primarily the result of higher production volumes, of which 5.1 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 32% decrease in natural gas prices, excluding hedging transactions

Lease operating expenses. Lease operating expenses increased by $4.9 million, or 39%, to $17.5 million compared to the prior year period. The $4.9 million increase in lease operating expenses consisted of $5.5 million increase in expenses related to the properties acquired in November 2011, partially offset by a $0.5 million decrease in our previously existing properties.

Compression expense. Compression expense increased by $1.7 million, or 58%, to $4.7 million compared to the prior year period. The increase was primarily attributable to the $1.5 million increase in 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 $2.0 million, or 125%, to $3.7 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 $0.4 million, or 28%, to $1.9 million compared to the prior year period. The increase was primarily attributable to the $0.7 million increase in 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 $3.6 million, or 46%, to $11.5 million compared to the prior year period. This increase was primarily due to the $3.9 million increase in expenses related to the properties acquired in November 2011, partially offset by a decrease of $0.3 million related to our previously existing natural gas properties.

Impairment of intangible asset. During the current year period, the remaining value of $0.8 million related to a drilling license was written off due to no future drilling plans in place resulting from the depressed natural gas price environment.

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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, a $95.7 million aggregate impairment of gas properties was recorded.

General and administrative. General and administrative expenses remained flat compared to the prior year period.

Acquisition costs. During the prior year period, we incurred approximately $1.0 million of costs related to our recent acquisition of coalbed methane gas properties in Alabama and West Virginia. No such expenses were incurred in the current year.

Restructuring costs. Restructuring activities consist of senior management and board of directors realignment. The restructuring costs for the current year period of $1.1 million included cash payments to our former CEO of $0.8 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 $6.8 million, or 71%, to $16.4 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 gains from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $12.0 million in the current year period as compared to unrealized gains of $4.1 million in the prior year period. The current year period unrealized loss position was made up of $1.4 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 $10.5 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 $2.1 million, or 58%, to $5.8 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 year ended December 31, 2012 was different than the amount computed using the statutory rate primarily due to an $83.5 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	$	(36,004,892)	34.00%	$	(3,307)	25.00%	$	(36,008,199)	34.00%
State income taxes net of federal benefit		(3,319,194)	3.14%			0.00%		(3,319,194)	3.13%
Valuation Allowance		83,537,181	-78.89%		3,307	-25.00%		83,540,488	-78.88%
Nondeductible items and other		(169,895)	0.16%			0.00%		(169,895)	0.16%
Income tax provision	$	44,043,200	-41.59%	$		0.00%	$	44,043,200	-41.59%

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.

Liquidity and Capital Resources

Cash Flows and Liquidity

As of December 31, 2012, the Company had a working capital deficit of $4.7 million, a retained deficit of $302.0 million and stockholders deficit of $107.3 million. Natural gas prices in 2012 were depressed compared with prices generally prevailing over the last several years. The depressed natural gas prices resulted in significant property impairments and full valuation of our deferred tax assets during 2012. Low natural gas prices also caused the amounts outstanding under our credit facility to exceed the borrowing base under the facility. As discussed below, on August 8, 2012, we amended the credit facility to provide for a conforming tranche in the amount of our borrowing base, and a non-conforming tranche in the amount of the excess of the outstanding borrowings over the borrowing base. The borrowing base deficiency adversely impacted our working capital by reclassifying Long-Term Debt to short-term for the next twelve months required payments. Our credit facility matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the credit facility when it matures. As a result, on April 2, 2013, all amounts outstanding under our credit facility will be re-classified as current.

Management s current business plan is primarily focused on eliminating our borrowing base deficiency, maintaining compliance with the amended credit facility, maintaining production levels and keeping costs under control. In addition, management recently packaged all of the Company s Alabama properties to be marketed for sale by an asset divestiture firm. If successful, management expects that substantially all the net proceeds from a sale will go toward reducing the outstanding borrowings under the credit facility. Management remains open to possible corporate strategic transactions. There can be no assurance that the Company will be able to engage in a strategic transaction, sell properties or realize enough proceeds from the sale of our properties to eliminate the borrowing base deficiency. In addition, our credit facility matures on April 1, 2014, and there can be no assurances that we will be able to refinance or repay the credit facility when it matures.

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Credit Facility

We have a credit facility with a group of lenders. Under the credit facility, our outstanding borrowings may not exceed a borrowing base determined by the lenders under the credit facility. During 2012, the amounts borrowed under our credit facility exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the credit facility. Borrowings under the credit facility at August 8, 2012 totaled $148.6 million. The amended credit facility provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the excess. The borrowing base, determined as of December 15, 2012, is currently $115.0 million. The tranche B loan was $21.8 million as of March 1, 2013. The borrowing base will be re-determined as of each June and December with the next determination scheduled to be completed by June 15, 2013. Upon any re-determination of the borrowing base, the re-determined amount of the conforming borrowing base will constitute a new tranche A loan, 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 and any subsequent borrowing base determination, tranche B may not increase by more than 25% of the amount of the principal payments made on tranche B loans since the prior redetermination of the borrowing base. If a future determination of the borrowing base results in the outstanding amount of the tranche B loan exceeding the amount permitted under the credit facility, we have 30 days to repay such excess. The credit facility 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 facility are due and payable on April 1, 2014. In addition, the credit facility obligates us to reduce our borrowings monthly by substantially all of our available excess cash flow. The credit facility provides for interest to accrue at a rate calculated, at our 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 credit facility requires an additional payment to the lenders based on the amount of tranche B loans as follows:

Calculation Date	**Fee Amount (basis points)**	**Date Payable**
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**	
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 $0.8 million for the year ended December 31, 2012, respectively, which included an amendment fee of 50 basis points on the amount of tranche B loans 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 to the credit facility. Deferred financing costs of $1.4 million as of August 8, 2012 related to the credit facility prior to the amendment were written off upon execution of the amendment.

Capital Expenditures

The following table is a summary of our capital expenditures on an accrual basis by category for the years ended December 31, 2012 and 2011:

	2012	2011
Capital expenditures:		
Asset acquisition (the Acquisition)	$	$ 70,837
Leasehold acquisition	717	1,290
Exploration		3
Development	(27)	12,880
Asset retirement obligations	4,853	66
Capitalized overhead	134	881
Other items	99	397
Total capital expenditures	$ 5,776	$ 86,354

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In 2012, we revised our estimates primarily related to the costs to plug and abandonment our horizontal Pinnate wells, resulting in a $4.8 million non-cash charge to our full cost pool, offset by an increase to our asset retirement obligation. We are limited under the Credit Agreement to spend no more than $1.0 million in 2013.

Natural Gas Price Risk and Related Hedging Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices 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. At December 31, 2012, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

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

Commodity Price Risk and Related Hedging Activities

At December 31, 2012, we had the following natural gas collar positions:

Period	**Volume (MMBtu)**		**Sold Ceiling**		**Bought Floor**		**Fair Value**
January 2014 through December 2015	3,650,000	$	4.30	$	3.60	$	(556,636)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50		(796,266)
	7,300,000					$	(1,352,902)

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

Period	**Volume (MMBtu)**	**Fixed Price**	**Fair Value**

January through March 2013	360,000	$	6.42		1,100,395
January through March 2013	540,000	$	5.50		1,156,734
January 2013 through March 2014	3,640,000	$	3.81		613,675
January 2013 through March 2014	3,640,000	$	3.82		648,264
January 2013 through December 2013	2,190,000	$	3.60		127,253
April 2013 through December 2013	2,750,000	$	3.25		(919,572)
	13,120,000			$	2,726,749

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

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

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.

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Operating Lease Commitments

We have operating leases for office space, office equipment and field compressors expiring in various years through 2019. Future minimum lease commitments as of December 31, 2012 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,		Amount
2013	$	1,300,262
2014		994,314
2015		619,850
2016		616,275
2017 and thereafter		580,784
Total future minimum lease commitments	$	4,111,485

Total rental expenses under operating leases were approximately $2.8 million and $1.5 million for the years ended December 31, 2012 and 2011, respectively.

Transportation Contracts As of December 31, 2012, under the following firm transportation contracts, we can transport maximum daily volumes of (1) 500 MMBtu s continuing until October 31, 2015, (2) 15,000 MMBtu s continuing until April 1, 2022, (3) 10,000 MMBtu s continuing until April 1, 2017, (4) 15,000 MMBtu s continuing until October 31, 2024, (5) 10,000 MMBtu s continuing until June 30, 2017, and (6) 3,500 MMBtu s continuing until April 30, 2012. We have a right to extend each of these contracts at the maximum tariff rate. As of December 31, 2012, the maximum commitment remaining under the transportation contracts is approximately $21.2 million.

Recent Accounting Pronouncements

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

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company does not expect the adoption of ASU 2012-02 to impact its operating results, financial position or cash flows.

In July 2012, the FASB issued ASU 2012-02, which amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets, other than goodwill, for impairment. The FASB issued the ASU in response to feedback on ASU 2011-08, which amended the goodwill impairment testing requirements by allowing an entity to perform a qualitative impairment assessment before proceeding to the two- step impairment test. Similarly, under ASU 2012-02, an entity testing an indefinite-lived intangible asset for impairment has the option of performing a qualitative assessment before calculating the fair value of the asset. Although ASU 2012-02 revises the examples of events and circumstances that an entity should consider in interim periods, it does not revise the requirements to test indefinite-lived intangible assets (1) annually for impairment and (2) between annual tests if there is a change in events or circumstances. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. Early adoption is permitted. The Company does not expect the adoption of ASU 2012-02 to impact its operating results, financial position or cash flows.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in ASC 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the year ended December 31, 2012.

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In May 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 year ended December 31, 2012. See disclosure provided in the Notes to Audited Consolidated Financial Statements.

Item 7A. ***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 year ended December 31, 2012, a 10% decrease in the prices received for natural gas production would have had an approximate $3.9 million impact on our revenues, which would have been offset by approximately $2.2 million realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of December 31, 2012, we had $139,300,000 million of borrowings outstanding under our Credit Agreement. The rate at December 31, 2012 was 3.59%. For the year ended December 31, 2012, interest on the borrowings averaged 3.39% per annum. All of the debt outstanding under our Credit Agreement accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our Credit Agreement for the year ended December 31, 2012, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $1.5 million.

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Item 8. ***Financial Statements and Supplementary Data***

GEOMET, INC. AND SUBSIDIARIES

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

GeoMet, Inc.

We have audited the accompanying consolidated balance sheets of GeoMet, Inc. and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive (loss) income, stockholders equity, and cash flows for each of the two years in the period ended December 31, 2012. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoMet, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements, the Company has suffered recurring losses, has a working capital deficit of $4,659,296 at December 31, 2012, and expects to reclassify approximately $129,000,000 of long-term debt to current liabilities on April 2, 2013. These conditions, among others, raise substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Houston, Texas

March 28, 2013

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GEOMET, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,234,225	$ 457,865
Accounts receivable, net of allowance of $17,634 at December 31, 2012 and 2011	6,248,819	4,402,065
Inventory	262,885	597,197
Derivative asset natural gas contracts	3,929,767	20,685,187
Other current assets	1,437,819	1,141,310
Total current assets	19,113,515	27,283,624
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	539,077,119	561,451,504
Other property and equipment	3,749,621	3,671,123
Total property and equipment	542,826,740	565,122,627
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(467,702,053)	(388,730,093)
Property and equipment net	75,124,687	176,392,534
Other noncurrent assets:		
Derivative asset natural gas contracts		1,765,450
Deferred income taxes	1,125,804	48,171,298
Other	962,451	3,532,882
Total other noncurrent assets	2,088,255	53,469,630
TOTAL ASSETS	$ 96,326,457	$ 257,145,788
LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY		
Current Liabilities:		
Accounts payable	$ 5,728,879	$ 4,235,222
Royalties payable	3,830,904	3,265,546
Accrued liabilities	1,793,946	3,936,070
Deferred income taxes	1,125,804	4,153,099
Derivative liability natural gas contracts	919,572	
Asset retirement obligations	73,706	32,028
Current portion of long-term debt	10,300,000	91,757
Total current liabilities	23,772,811	15,713,722
Long-term debt	129,000,000	158,171,662
Asset retirement obligations	13,235,318	8,138,551
Derivative liability natural gas contracts	1,636,348	
Other long-term accrued liabilities	143,682	8,145
TOTAL LIABILITIES	167,788,159	182,032,080
Commitments and contingencies (Note 20)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $53,058,650; $.001 par value; 7,401,832 shares authorized, 5,305,865 and 4,549,537 shares were issued and outstanding at December 31, 2012 and 2011, respectively	35,851,887	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; 40,690,077 and 40,010,188 issued and outstanding at December 31, 2012 and 2011, respectively	40,690	40,010
Treasury stock 10,432 shares at December 31, 2012 and 2011	(94,424)	(94,424)
Paid-in capital	195,033,585	200,344,209
Accumulated other comprehensive loss	(53,020)	(1,309,926)
Retained deficit	(302,057,496)	(152,104,329)

Less notes receivable		(182,924)		(244,456)
Total stockholders (deficit) equity		(107,313,589)		46,631,084
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS (DEFICIT) EQUITY	$	96,326,457	$	257,145,788

See accompanying Notes to Audited Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31,

		2012		2011
Revenues:				
Gas sales	$	39,146,723	$	35,334,515
Other		236,364		280,646
Total revenues		39,383,087		35,615,161
Expenses:				
Lease operating expense		17,482,709		12,600,278
Compression and transportation expense		8,349,799		4,582,210
Production taxes		1,961,804		1,535,532
Depreciation, depletion and amortization		11,531,565		7,908,128
Impairment of intangible asset		782,462		
Impairment of gas properties		95,728,981		7,939,713
General and administrative		4,851,193		4,861,439
Restructuring costs		1,083,018		
Acquisition costs				956,100
Gains on natural gas derivatives		(4,415,617)		(13,637,867)
Total operating expenses		137,355,914		26,745,533
Operating (loss) income		(97,972,827)		8,869,628
Other income (expense):				
Interest income		5,527		16,869
Interest expense		(5,827,659)		(3,697,649)
Write off of debt issuance costs		(1,377,520)		
Other		(1,463)		2,299
Total other income (expense):		(7,201,115)		(3,678,481)
(Loss) income before income taxes from continuing operations		(105,173,942)		5,191,147
Income tax expense		44,043,200		1,996,417
(Loss) income from continuing operations		(149,217,142)		3,194,730
Discontinued operations		(736,025)		(380,323)
Net (loss) income	$	(149,953,167)	$	2,814,407
Accretion of discount on Series A Convertible Redeemable Preferred Stock		(1,913,134)		(1,766,653)
Paid-in-kind dividends on Series A Convertible Redeemable Preferred Stock		(3,934,094)		(6,293,065)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock		(2,757)		(2,794)
Net loss available to common stockholders	$	(155,803,152)	$	(5,248,105)
Net loss per common share basic:				
Net loss per common share from continuing operations	$	(3.86)	$	(0.12)
Net loss per common share from discontinued operations	$	(0.02)	$	(0.01)
Net loss per common share basic	$	(3.88)	$	(0.13)
Net loss per common share diluted:				
Net loss per common share from continuing operations	$	(3.86)	$	(0.12)
Net loss per common share from discontinued operations	$	(0.02)	$	(0.01)
Net loss per common share diluted	$	(3.88)	$	(0.13)
Weighted average number of common shares:				
Basic		40,123,608		39,610,761
Diluted		40,123,608		39,610,761

See accompanying Notes to Audited Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

FOR THE YEARS ENDED DECEMBER 31,

		2012		2011
Net (loss) income	$	(149,953,167)	$	2,814,407
Other comprehensive (loss) income, net of related taxes:				
Foreign currency translation adjustment		10,661		3,366
Reclassification adjustment for loss on foreign currency translation included in net loss		1,307,906		
Unrealized loss on available for sale securities		(61,661)		
Gain on interest rate swap				10,862
Comprehensive (loss) income	$	(148,696,261)	$	2,828,635

See accompanying Notes to Audited Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock Par Value $0.001 (shares outstanding)	Common Stock Par Value $0.001	Treasury Stock	Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Notes Receivable	Total Stockholders Equity
Balance at January 1, 2011	39,744,071	$ 39,744	$ (94,424)	$ 207,548,596	$ (1,324,154)	$ (154,918,736)	$ (242,909)	$ 51,008,117
Stock-based compensation	127,621	128		828,878				829,006
Purchase and cancellation of common stock	(1,563)	(2)		(2,143)				(2,145)
Exercise of stock options	41,643	42		29,941				29,983
Option exchange	98,416	98		(98)				
Dividends paid in-kind				(6,293,065)				(6,293,065)
Dividends paid in cash				(2,794)				(2,794)
Accretion of discount on Series A Convertible Redeemable Preferred Stock				(1,766,653)				(1,766,653)
Accrued interest on notes receivable				1,547			(1,547)	
Net income						2,814,407		2,814,407
Gain on interest rate swap, net of income taxes of $6,714					10,862			10,862
Foreign currency translation adjustment, net of income taxes of $0					3,366			3,366
Balance at December 31, 2011	40,010,188	$ 40,010	$ (94,424)	$ 200,344,209	$ (1,309,926)	$ (152,104,329)	$ (244,456)	$ 46,631,084
Stock-based compensation	682,288	682		602,930				603,612
Purchase and cancellation of common stock	(2,399)	(2)		(2,037)				(2,039)
Dividends paid in-kind				(3,934,094)				(3,934,094)
Dividends paid in cash				(2,757)				(2,757)
Accretion of discount on Series A Convertible Redeemable Preferred Stock				(1,913,134)				(1,913,134)
Write-off of notes receivable				(62,883)			62,883	
Accrued interest on notes receivable				1,351			(1,351)	
Net loss						(149,953,167)		(149,953,167)
Unrealized loss on available for sale securities, net of income taxes of $0					(61,661)			(61,661)
Reclassification adjustment for loss on foreign currency translation					1,307,906			1,307,906
Foreign currency translation adjustment, net of income taxes of $0					10,661			10,661
Balance at December 31, 2012	40,690,077	$ 40,690	$ (94,424)	$ 195,033,585	$ (53,020)	$ (302,057,496)	$ (182,924)	$ (107,313,589)

See accompanying Notes to Audited Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31,

	2012	2011
Cash flows provided by operating activities:		
Net (loss) income	$ (149,953,167)	$ 2,814,407
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization	11,529,846	8,145,316
Impairment of intangible asset	782,462	
Impairment of gas properties	95,728,981	7,939,713
Amortization of debt issuance costs	725,408	595,263
Write off of debt issuance costs	1,377,520	
Deferred income tax expense	44,018,200	1,971,417
Unrealized losses (gains) from the change in market value of open derivative contracts	11,967,386	(4,053,703)
Stock-based compensation	580,958	696,394
Loss on sale of Hudson s Hope Gas, Ltd.	683,154	
Loss on sale of other assets	4,400	9,993
Accretion expense asset retirement obligations	827,771	564,403
Changes in operating assets and liabilities:		
Accounts receivable	(1,850,161)	(1,801,821)
Other current assets	93,046	(497,673)
Accounts payable	2,518,597	176,660
Other accrued liabilities	(673,449)	(545,718)
Net cash provided by operating activities	18,360,952	16,014,651
Cash flows provided by (used in) investing activities:		
Capital expenditures	(1,077,249)	(14,409,393)
Acquisition		(78,738,611)
Return of original basis through the settlement of natural gas derivative contracts	9,109,404	1,575,349
Proceeds from sale of other property and equipment	4,300	3,050
Other assets		(286,323)
Net cash provided by (used in) investing activities	8,036,455	(91,855,928)
Cash flows (used in) provided by financing activities:		
Deferred financing costs	(832,401)	(1,530,201)
Proceeds from exercise of stock options		29,983
Proceeds from revolver borrowings	10,500,000	109,100,000
Payments on revolver	(29,100,000)	(31,700,000)
Cash dividends paid on Series A Convertible Redeemable Preferred Stock	(2,757)	(2,794)
Purchase and cancellation of treasury stock	(2,039)	(2,145)
Payments on other debt	(188,965)	(132,743)
Net cash (used in) provided by financing activities	(19,626,162)	75,762,100
Effect of exchange rate changes on cash and cash equivalents	5115	509
Increase (decrease) in cash and cash equivalents	6,776,360	(78,668)
Cash and cash equivalents at beginning of year	457,865	536,533

Cash and cash equivalents at end of year	$	7,234,225	$	457,865
Supplemental disclosure of cash flow information:				
Cash paid during the year for:				
Interest expense	$	5,022,738	$	3,564,115
Income taxes	$	25,000	$	25,000
Significant noncash investing and financing activities:				
Accrued capital expenditures	$	450,007	$	931,479
Fair value of common stock received in exchange for Hudson s Hope Gas, Ltd.	$	293,769		
Increase in estimated asset retirement obligations	$	4,846,818		

See accompanying Notes to Audited Consolidated Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM). All of our production is CBM, which is a dry natural gas containing no hydrocarbon liquids. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, developer and producer of coalbed methane properties since 1993. 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.

Note 2 Going Concern and Management s Plans

The accompanying consolidated financial statements have been prepared in conformity with generally accepted accounting principles which contemplate continuation of the Company as a going concern. In 2012, the amounts outstanding under the Company s credit facility exceeded the borrowing base as determined by the lenders under the facility. In August 2012, the Company amended the credit facility to provide for a conforming tranche limited to the borrowing base, and a non-conforming tranche in the amount outstanding in excess of the borrowing base. The Company is required to dedicate substantially all of its free cash flow to repayment of the non-conforming tranche. The credit facility matures on April 1, 2014, and no assurances can be made that the Company will be able to refinance, repay or further extend the maturity date of the facility. The borrowing base deficiency also adversely impacted the Company s working capital by reclassifying the next twelve months required payments from Long-term debt to Current Liabilities in the Consolidated Balance Sheet as of December 31, 2012. In addition, as of December 31, 2012, the Company had a working capital deficit of $4.7 million, a retained deficit of $302.0 million and stockholders deficit of $107.3 million. Depressed natural gas prices in 2012 resulted in significant property impairments and full valuation of our deferred tax assets during 2012. On April 2, 2013, all the indebtedness under the Company s credit facility will be reclassified to current liabilities. These and other factors raise substantial doubt about the Company s ability to continue as a going concern.

Management s current business plan is primarily focused on eliminating the borrowing base deficiency, maintaining compliance with the amended credit facility, maintaining production levels and keeping costs under control. In addition, management recently packaged all of the Company s Alabama properties to be marketed for sale by an asset divestiture firm. Management intends to use substantially all the net proceeds from a successful sale to reducing the outstanding borrowings under the credit facility. Management also remains open to possible corporate strategic transactions. There can be no assurance that the Company will be able to effect a strategic transaction, sell properties, or realize enough proceeds from the sale of properties to eliminate the deficiency under, or to refinance, the credit facility.

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

Note 3 Summary of Significant Accounting Policies

Principles of Consolidation The accompanying Audited Consolidated Financial Statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and include our accounts and the accounts of our wholly-owned subsidiaries, GeoMet Operating Company, Inc., GeoMet Gathering Company LLC, and Hudson s Hope Gas, Ltd. (disposed on June 20, 2012). All inter-company accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the audited consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Our most significant financial estimates are related to our proved gas reserves. Estimates of proved gas reserves are key components of our depletion rate for natural gas properties and our full cost ceiling test limitation. In addition, other significant estimates include estimates used in computing taxes, stock-based compensation, asset retirement obligations, fair value of derivative contracts and accrued receivables and payables. Actual results could differ from these estimates.

Gas Properties The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the SEC. For more information see Note 9 Gas Properties.

Asset Retirement Obligations Accounting Standards Codification (ASC) 410-20-25 establishes accounting and reporting standards for retirement obligations associated with tangible long-lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement obligation, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset, included in the depletable base of our natural gas properties, or impaired. Periodically, we update the cost assumptions resulting from changes in market and environmental regulation and revise the liability recorded accordingly.

Other Property and Equipment The cost of other property and equipment is depreciated over the estimated useful lives of the related assets. The cost of leasehold improvements is depreciated over the lesser of the length of the related leases or the estimated useful lives of the assets. Depreciation is computed on the straight-line basis over the following estimated useful lives which range from three to seven years.

Furniture and fixtures	7 years
Automobiles	3 years
Machinery and equipment	5 years
Software and computer equipment	3 years

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Cash and Cash Equivalents For purposes of these statements, short-term investments, which have an original maturity of three months or less, are considered cash equivalents.

Inventory Inventory consists primarily of materials and supplies used in the development and production of coal bed methane and is recorded at the lower of cost or market value using the specific identification costing method.

Notes Receivable Included in Stockholders Equity We have loaned money to employees to purchase our common stock. Such amounts, including accrued interest, are recorded as Notes Receivable, and are included as a component of Stockholders Equity. The balances at December 31, 2012 and 2011 were solely attributable to employees.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2012, a full valuation allowance has been recorded against our net deferred tax asset.

Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net operating losses under Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs).

ASC 740 also clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return.

Revenue Recognition and Gas Balancing We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue whereby revenues, net of royalties, are recognized as the production is sold to a purchaser. The amount of gas sold may differ from the amount to which the Company is entitled based on its working interest or net revenue interest in the properties. In instances where we have wellhead imbalances, we use the entitlements method. A ready market for natural gas allows us to sell our natural gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title is transferred based on our nominations and net revenue interests. Pipeline imbalances occur when our production delivered into the pipeline varies from the gas we nominated for sale or depending on the agreement in place, imbalances may be made up in future production or are settled with cash approximately thirty days from date of production and are recorded as either a reduction or increase of revenue depending upon whether we are over-delivered or under-delivered.

Settlements of gas sales occur after the month in which the gas was produced. We estimate and accrue for the value of these sales using information available at the time financial statements are generated. Differences are reflected in the accounting period during which payments are received from the purchaser.

Industry Segment and Geographic Information We operate in one industry, which is the exploration, development and production of natural gas.

Concentrations of Market Risk Our future results will be affected by the market price of natural gas. The availability of a ready market for natural gas will depend on numerous factors beyond our control, including weather, production of natural gas, imports, marketing, competitive fuels, proximity of natural gas pipelines and other transportation facilities, any oversupply or undersupply of natural gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

Concentration of Credit Risk Financial instruments, which subject us to concentrations of credit risk, consist primarily of cash and cash equivalents, accounts receivable and derivative assets. We place our cash investments with highly qualified financial institutions. Risks with respect to receivables as of December 31, 2012 and 2011 arise substantially from the sales of natural gas and joint interest billings from our working interest partners. We routinely assess the recoverability of all material trade and other receivables to determine their collectability. We accrue a reserve on a receivable when, based on management s judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. Risks with respect to derivative assets as of December 31, 2012 arise from cash settlements due to us from our derivative counterparties. Five purchasers of our natural gas production purchased 97.8% of the gas we delivered to market during the year ended December 31, 2012, of which 55.3% was purchased by one entity. We do not believe the loss of the aforementioned purchaser would materially affect our ability to sell the natural gas we produce as we believe other purchasers are available in our area of operations. As of December 31, 2012, three of our natural gas purchasers and two joint interest owners accounted for 95% of our accounts receivable related to gas sales, of which one natural gas purchaser accounted for 51% of our accounts receivable related to gas sales. At December 31, 2012 and 2011, we have

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recorded an allowance for doubtful accounts receivable of $17,634 related to other revenue and not a purchaser of our natural gas. We have not experienced any significant losses from uncollectible accounts.

The Company maintains deposits in financial institutions which are insured by the Federal Deposit Insurance Corporation (FDIC). At various times, the Company has deposits in these financial institutions in excess of the amount insured by the FDIC.

Capitalized General and Administrative Expenses Under the full cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our natural gas properties. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly associated with those activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the periods ended December 31, 2012 and 2011 of $134,350 and $880,917, respectively.

Derivative Instruments and Hedging Activities. Our hedging activities consist of derivative instruments entered into to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2014. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through January 2011. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. These transactions are recorded in our audited consolidated financial statements in accordance with ASC 815. Although not risk free, we believe this policy will reduce our exposure to natural gas price fluctuations and changes in interest rates and thereby achieve a more predictable cash flow. As a result, our derivative instruments are economic or cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. We do not enter into derivative instruments for trading or other speculative purposes. At December 31, 2012, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

In accordance with ASC 815-20-25, as amended, all our derivative instruments are recorded on the balance sheet at fair value and changes in the fair value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income (loss) for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swaps qualify and have been designated as such in accordance with ASC 815-20-25.

At the inception of a derivative contract, we may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we document the relationship between the derivative instrument and the hedged items as well as the risk management objective for entering into the derivative instrument. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis.

Mezzanine Equity Our Series A Convertible Redeemable Preferred Stock has been classified within the mezzanine (temporary) equity section of the Consolidated Balance Sheets because the shares are redeemable at the option of the holder and therefore do not qualify for permanent equity.

Fair Value Measurement Effective January 1, 2008, we adopted ASC 820-10-55, which provides a framework for measuring fair value under GAAP. ASC 820-10-55 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC 820-10-55 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Level 3 inputs are derived from unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. See disclosure related to the implementation of ASC 820-10-55 in Note 11 Derivative Instruments and Hedging Activities.

The fair value of cash and cash equivalents, current receivables and payables, approximate book value because of the short maturity of these accounts. The outstanding note receivable in Other Non-Current Assets and certain Other Debt carries a fixed interest rate.

Stock-Based Compensation We use the fair value recognition provisions of ASC 718. The application of ASC 718 requires the use of an option pricing model, such as the Black Scholes model, to measure the estimated fair value of the options and as a result various assumptions must be made by management that require judgment and the assumptions could be highly uncertain.

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Reclassifications Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total shareholders equity, net income or net cash provided by or used in operating, investing or financing activities.

Note 4 Recent Accounting Pronouncements

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

In January 2013, the FASB issued ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in this update clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company does not expect the adoption of ASU 2012-02 to impact its operating results, financial position or cash flows.

In July 2012, the FASB issued ASU 2012-02, which amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets, other than goodwill, for impairment. The FASB issued the ASU in response to feedback on ASU 2011-08, which amended the goodwill impairment testing requirements by allowing an entity to perform a qualitative impairment assessment before proceeding to the two- step impairment test. Similarly, under ASU 2012-02, an entity testing an indefinite-lived intangible asset for impairment has the option of performing a qualitative assessment before calculating the fair value of the asset. Although ASU 2012-02 revises the examples of events and circumstances that an entity should consider in interim periods, it does not revise the requirements to test indefinite-lived intangible assets (1) annually for impairment and (2) between annual tests if there is a change in events or circumstances. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. Early adoption is permitted. The Company does not expect the adoption of ASU 2012-02 to impact its operating results, financial position or cash flows.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, which revises the manner in which entities present comprehensive income in their financial statements. The new guidance removes the presentation options in ASC 220 and requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The ASU does not change the items that must be reported in other comprehensive income. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company has adopted and applied the provisions of this update for the year ended December 31, 2012.

In May 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 year ended December 31, 2012. See disclosure provided in the Notes to Audited Consolidated Financial Statements.

Note 5 Acquisition

On November 18, 2011, the Company completed the purchase of proved developed and undeveloped CBM reserves and undeveloped leasehold acreage in Alabama and West Virginia, as well as certain natural gas derivative contracts, and a license to use a certain drilling technology (the Acquisition). The Company closed the transaction with a preliminary adjusted purchase price of approximately $71 million related to the acquired gas properties, $11 million related to the acquired natural gas hedge contracts and $1 million for the license to use certain drilling technology. The transaction was primarily financed through $79 million drawn from the Company s revolving credit facility and $4 million in assumed liabilities allocated as follows:

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The estimated fair value of assets acquired in the purchase included the following:

Proved gas properties (net of asset retirement obligations)	$	70,837,474
Derivative asset natural gas contracts (current)		10,094,607
Derivative asset natural gas contracts (non-current)		590,146
Other assets		1,299,222
Other property and equipment		183,275
Total assets acquired	$	83,004,724

Total estimated fair value of consideration included the following:

Draw from revolving credit facility	$	78,738,611
Liabilities assumed royalties		1,598,415
Liabilities assumed ad valorem taxes		559,760
Liabilities assumed asset retirement obligations		2,048,876
Liabilities assumed other		59,062
Total consideration	$	83,004,724

Acquisition costs consist of payments made related to the Acquisition. For the year ended December 31, 2011, the Company recorded acquisition cost of $956,100, which primarily consisted of professional service fees. There were no acquisition costs for the year ended December 31, 2012.

For the properties acquired in the Acquisition for the period November 18, 2011 through December 31, 2011, total revenues were $3.0 million, production expenses were $1.7 million and realized and unrealized gains on derivative contracts combined for $1.4 million, all of which were included in the Consolidated Statement of Operations for the year ended December 31, 2011. Amortization of the drilling license for the period November 18, 2011 through December 31, 2011 was $23,507 which was included in Depreciation, depletion and amortization in the Consolidated Statement of Operations for the year ended December 31, 2011. The remaining asset balance of $983,959 related to the drilling license was amortized in the year ended December 31, 2012 as Depreciation, depletion and amortization in the Consolidated Statement of Operations.

Unaudited Pro Forma Financial Information

The unaudited pro forma financial information is based on the historical results of the Company, adjusted to reflect the Acquisition. The unaudited pro forma information is for informational purposes only and is not intended to represent or to be indicative of the combined results that the Company would have reported had the Acquisition been completed as of January 1, 2010 and should not be taken as indicative of the Company s future results. The actual results may differ significantly from that reflected in the unaudited pro forma information for a number of reasons, including, but not limited to, differences between the assumptions used to prepare the unaudited pro forma information and actual results.

The following table presents unaudited pro forma financial information for the year ended December 31, 2011 assuming the acquisition took place on January 1, 2011:

		2011
Revenue	$	65,505,416
Net income	$	10,226,851
Net income available to common stockholders	$	3,059,075
Basic earnings per common share	$	0.08
Diluted earnings per common share	$	0.08

Note 6 Discontinued Operations

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

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operations, net of tax, in the Consolidated Statements of Operations. 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 for the periods presented.

As a result of the disposition, we are classifying these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations for the years ended December 31, 2012 and 2011 were as follows:

	2012	2011
Revenues	$	$
Operating expenses	32,444	380,107
Operating loss	(32,444)	(380,107)
Loss on sale of Hudson s Hope Gas, Ltd.	(683,154)	
Other expense	(20,427)	(216)
Income tax expense		
Net income (loss)	$ (736,025)	$ (380,323)

Note 7 Net Loss Per Common Share

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

	2012	2011
Net loss available to common stockholders	$ (155,803,152)	$ (5,248,105)
Net loss per common share basic:		
Net loss per common share from continuing operations	$ (3.86)	$ (0.12)
Net loss per common share from discontinued operations	$ (0.02)	$ (0.01)
Net loss per common share basic	$ (3.88)	$ (0.13)
Net loss per common share diluted:		
Net loss per common share from continuing operations	$ (3.86)	$ (0.12)
Net loss per common share from discontinued operations	$ (0.02)	$ (0.01)
Net loss per common share diluted	$ (3.88)	$ (0.13)
Weighted average number of common shares:		
Basic	40,123,608	39,610,761

Diluted	40,123,608	39,610,761

Diluted net loss per share for the year ended December 31, 2012 excluded the effects of the Series A Convertible Redeemable Preferred Stock, the restricted shares, the restricted stock units and the stock options as the net impact would have been anti-dilutive. The impact of the Series A Convertible Redeemable Preferred Stock would have included an addition to the numerator of the Accretion of Series A Convertible Redeemable Preferred Stock of $1,913,134 and dividends on Series A Convertible Redeemable Preferred Stock of $3,936,851 and an addition to the denominator of 37,813,420 in dilutive Preferred Stock, as converted. Additionally, the denominator excluded 260,725 in dilutive restricted shares, 156,992 in dilutive restricted stock units, and 2,387,504 in dilutive stock options.

Diluted net loss per share for the year ended December 31, 2011 excluded the effects of the Series A Convertible Redeemable Preferred Stock, the restricted shares, the restricted stock units and the stock options as the net impact would have been anti-dilutive. The impact of the Series A Convertible Redeemable Preferred Stock would have included an addition to the numerator of the Accretion of Series A Convertible Redeemable Preferred Stock of $1,766,653 and dividends on Series A Convertible Redeemable Preferred Stock of $6,295,859 and an addition to the denominator of 33,473,357 in dilutive Preferred Stock, as converted. Additionally, the denominator excluded 16,521 in dilutive restricted shares, 89,645 in dilutive restricted stock units, and 101,388 in dilutive stock options.

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Note 8 Note Receivable

We had an unsecured note receivable of $174,455 as of December 31, 2011, which approximated the fair value of the note receivable on that date, from a third party included in other current assets and other non-current assets. The note was settled on August 23, 2012 for the remaining balance of $163,578, which approximated the fair value of the note receivable on that date.

Note 9 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 year ended December 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.78 per Mcf, resulting in a natural gas price of $2.91 per Mcf when adjusted for regional price differentials. For the year ended

December 31, 2012, we recorded $95.7 million in write-downs of the carrying value of our full cost pool.

For the year ended December 31, 2011, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.15 per Mcf, resulting in a natural gas price of $4.21 per Mcf when adjusted for regional price differentials. For the year ended December 31, 2011, we recorded $7.9 million in write-downs of the carrying value of our full cost pool.

The following table provides a summary of the capitalized cost of our gas properties as of December 31, 2012 and 2011, by the year in which the costs were incurred.

	2012	2011
Subject to depletion	$ 539,077,119	$ 561,451,504
Total not subject to depletion		
Gross gas properties	539,077,119	561,451,504
Less impairment of gas properties	(391,118,140)	(320,048,607)
Less accumulated depletion	(73,567,602)	(65,859,388)
Net gas properties	$ 74,391,377	$ 175,543,509

On February 26, 2013, the Company announced that it engaged Lantana Oil & Gas Partners, a Houston based divestiture firm, to market all of the Company s coal bed methane interests located in the state of Alabama. The interests in these properties represented 30% of the Company s net daily sales of natural gas and 38% of operating income during the twelve months ending December 31, 2012. If we sell these properties, net proceeds from the sale of these properties will be used to reduce the Company s borrowings under its bank credit agreement.

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Note 10 Asset Retirement Obligations

We record an asset retirement obligation (ARO) on the consolidated balance sheet and capitalize the asset retirement costs in gas properties in the period in which the retirement obligation is incurred. The amount of the ARO and the costs capitalized are equal to the estimated future costs to satisfy the obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date the abandonment obligation was incurred using an assumed cost of funds for GeoMet. Once the ARO is recorded, it is then accreted to its estimated future value using the same assumed cost of funds. Periodically, we update the cost assumptions resulting from market changes and revise the liability recorded accordingly.

The following table describes the changes to our asset retirement obligations for the years ending December 31, 2012 and 2011.

	2012	2011
Asset retirement obligation at beginning of year	$ 8,170,579	$ 5,498,691
Liabilities assumed in Vitruvian acquisition		2,048,876
Liabilities incurred	14,252	65,683
Liabilities settled	(554,991)	(239)
Accretion of discount	827,771	564,403
Revisions in estimates	4,846,818	
Currency translation adjustment	4,595	(6,835)
Asset retirement obligation at end of year	13,309,024	8,170,579
Less: current portion of obligation	73,706	32,028
Long-term asset retirement obligation	$ 13,235,318	$ 8,138,551

In 2012, we revised our estimates primarily related to the costs to plug and abandonment our horizontal Pinnate wells, resulting in a $4.8 million non-cash charge to our full cost pool, offset by an increase to our asset retirement obligation.

Note 11 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. At December 31, 2012, we do not have the ability to enter into additional natural gas hedges because we do not have the credit capacity with our existing natural gas hedge counterparties.

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

Commodity Price Risk and Related Hedging Activities

At December 31, 2012, we had the following natural gas collar positions:

Period	Volume (MMBtu)		Sold Ceiling		Bought Floor		Fair Value
January 2014 through December 2015	3,650,000	$	4.30	$	3.60	$	(556,636)
January 2014 through December 2015	3,650,000	$	4.20	$	3.50		(796,266)
	7,300,000					$	(1,352,902)

At December 31, 2011, we had no natural gas collar positions.

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

Period	Volume (MMBtu)		Fixed Price		Fair Value
January through March 2013	360,000	$	6.42		1,100,395
January through March 2013	540,000	$	5.50		1,156,734
January 2013 through March 2014	3,640,000	$	3.81		613,675
January 2013 through March 2014	3,640,000	$	3.82		648,264
January 2013 through December 2013	2,190,000	$	3.60		127,253
April 2013 through December 2013	2,750,000	$	3.25		(919,572)
	13,120,000			$	2,726,749

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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 December 31, 2012, we had no natural gas basis swap positions.

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

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

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

At December 31, 2011, we had the following fixed forward sale:

Period	Volume (MMBtu)		Fixed Market Price		Fixed Basis Differential
January through March 2012	273,000	$	5.20	$	0.130

The aforementioned forward physical sale contracts meet the definition of a derivative contract under ASC 815. However, they qualified for normal purchase and sale exemption and, as such, we have elected not to record it on the Consolidated Balance Sheets using mark-to-market accounting.

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

The application of ASC 820-10-55, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas derivative contracts and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of credit risk on the fair value of the assets and liabilities related to the items stated below. The consideration for discounting our

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counterparties liabilities (our assets) was based on the difference between the S&P credit rating of a comparable company to our counterparties and the 13-week Treasury bill rate, both at the reporting date. The consideration for discounting our liabilities was based on the difference between the market weighted average cost of debt capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt.

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

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the year ended December 31, 2012. Based on the use of observable market inputs, we have designated these types of instruments designated below as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our Level 2 derivative instruments were as follows:

	Asset Derivatives				**Liability Derivatives**			
	December 31, 2012		**December 31, 2011**		**December 31, 2012**		**December 31, 2011**	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives not designated as hedging instruments under ASC 815-20-25								
Natural gas hedge positions	Derivative asset (current)	$ 3,929,767	Derivative asset (current)	$ 20,685,187	Derivative liability (current)	$ 919,572	Derivative liability (current)	$
Natural gas hedge positions	Derivative asset (non-current)		Derivative asset (non-current)	1,765,450	Derivative liability (non-current)	1,636,348	Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 3,929,767		$ 22,450,637		$ 2,555,920		$

The following losses (gains) on our hedging instruments included in the consolidated statements of operations 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 2012**	**2011**
Natural gas collar/swap settled positions	Losses (gains) on natural gas derivatives	$ (16,383,003)	$ (9,571,180)
Natural gas collar/swap unsettled positions	Losses (gains) on natural gas derivatives	11,967,386	(4,066,687)
Total gain		$ (4,415,617)	$ (13,637,867)

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 and recognized as Interest expense in the Consolidated Statements of Operations.

Note 12 Investment in Canada Energy Partners

At December 31, 2012, we own two million shares of Canada Energy Partners (CEP), discussed in Note 6 Discontinued Operations, which we classify as available for sale and record at fair value in Other noncurrent assets on the Consolidated Balance Sheets based on the closing price of the shares on the TSX Venture Exchange on that date. Gains or losses related to both market price fluctuation and currency translation adjustment on the shares of CEP are held in Accumulated other comprehensive loss in the Consolidated Balance Sheets. At December 31, 2012, the value of the shares recorded in Other noncurrent assets was $240,749 using a Level 1 input. Accumulated other comprehensive loss of $53,020 in the Consolidated Balance Sheets as of December 31, 2012 consisted of a $61,661 decrease in market value offset by a $8,641 gain related to currency translation on the CEP shares. Accumulated other comprehensive loss of $1,309,926 in the Consolidated Balance Sheets as of December 31, 2011 consisted entirely of foreign currency translation adjustments.

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Note 13 Restructuring Costs

Restructuring activities consist of senior management and board of directors realignment. The restructuring costs for the year ended December 31, 2012 of $1.1 million included cash payments to our former CEO of $0.8 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 14 Long-Term Debt

We have a credit facility with a group of lenders. Under the credit facility, our outstanding borrowings may not exceed a borrowing base determined by the lenders under the credit facility. During 2012, the amounts borrowed under our credit facility exceeded the borrowing base. On August 8, 2012, in connection with the excess of borrowings over the borrowing base, we amended the credit facility. Borrowings under the credit facility at August 8, 2012 totaled $148.6 million. The amended credit facility provided for a tranche A loan in the amount of our borrowing base and a tranche B loan in the amount of the excess. The borrowing base, determined as of December 15, 2012, is currently $115.0 million. The tranche B loan was $21.8 as of March 1, 2013. The borrowing base will be re-determined as of each June and December with the next determination scheduled to be completed by June 15, 2013. Upon any re-determination of the borrowing base, the re-determined amount of the conforming borrowing base will constitute a new tranche A loan, 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 and any subsequent borrowing base determination, tranche B may not increase by more than 25% of the amount of the principal payments made on tranche B loans since the prior redetermination of the borrowing base. If a future determination of the borrowing base results in the outstanding amount of the tranche B loan exceeding the amount permitted under the credit facility, we have 30 days to repay such excess. The credit facility 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 facility are due and payable on April 1, 2014. In addition, the credit facility obligates us to reduce our borrowings monthly by substantially all of our available excess cash flow. The credit facility provides for interest to accrue at a rate calculated, at our 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 credit facility requires an additional payment to the lenders based on the amount of tranche B loans as follows:

Calculation Date	Fee Amount (basis points)	Date Payable
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
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 $0.8 million for the year ended December 31, 2012, respectively, which included an amendment fee of 50 basis points on the amount of tranche B loans 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 to the credit facility. Deferred financing costs of $1.4 million as of August 8, 2012 related to the credit facility prior to the amendment were written off upon execution of the amendment. Deferred financing costs were $1.5 million for the year ended December 31, 2011.

As of December 31, 2012, we had $139.3 million of borrowings outstanding under our Credit Agreement. As of December 31, 2012, the interest rates applied to borrowings under tranche A and tranche B were 3.21% and 5.21%, respectively. As of December 31, 2011, the weighted average interest rate applied to all borrowings was 2.84%. For the year ended December 31, 2012, we borrowed $10.5 million and made payments of $29.1 million under the Credit Agreement. For the year ended December 31, 2011, we

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borrowed $109.1 million and made payments of $31.7 million under the Credit Agreement. For the years ended December 31, 2012 and 2011, interest on the borrowings averaged 3.39% and 3.43% per annum, respectively.

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

		December 31, 2012		December 31, 2011
Borrowings under revolving credit facility:				
Tranche A	$	115,000,000	$	
Tranche B		24,300,000		
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		139,300,000		158,263,419
Less current maturities included in current liabilities		(10,300,000)		(91,757)
Total long-term debt	$	129,000,000	$	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 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 December 31, 2012 and 2011 was estimated to be approximately $121.6 million and $131.1 million, respectively.

The following were maturities of long-term debt for each of the next five years at December 31, 2012:

Year		Amount
2013	$	10,300,000
2014		129,000,000
2015		
2016		
2017		
	$	139,300,000

Note 15 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 $137.8 million and $127.0 million, respectively, at December 31, 2012 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $126.0 million and $132.3 million, respectively, at December 31, 2011 that were available to reduce future taxable income. Our first material NOL carryforward expires in 2022 and the last one expires in 2031.

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Additionally, for tax reporting purposes, we have a federal capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 6 Discontinued Operations, of approximately $34.9 million at December 31, 2012 that is available to reduce future taxable capital gains and expiring in 2017.

At December 31, 2012, we have a valuation allowance of $96.7 million recorded against our net deferred tax asset which includes $83.3 million related to our U.S. operations and $13.4 million related to the capital loss carryforward generated by the sale of Hudson s Hope Gas, Ltd., as described in Note 6 Discontinued Operations.

Deferred Tax Assets and Liabilities

An analysis of our deferred tax assets and liabilities as of December 31, 2012 and 2011:

		2012		2011
Current deferred tax asset:				
Compensation expense and other	$	24,089	$	268,848
Total current deferred tax asset		24,089		268,848
Current deferred tax liability:				
Book basis in excess of tax basis of derivative contracts		(1,149,893)		(4,421,947)
Net current deferred tax liability	$	(1,125,804)	$	(4,153,099)
Long-term deferred tax asset:				
Net operating loss carryforward	$	52,505,971	$	48,451,234
Compensation expense and other		1,066,856		647,910
Accrued asset retirement obligations		1,832,737		1,598,735
Tax basis in excess of book basis of derivative contracts		1,451,763		152,277
Tax basis of gas properties in excess of book basis		27,557,569		
Capital loss on sale of Canadian properties		13,352,031		
Valuation allowance		(96,641,123)		
Total long-term deferred tax assets		1,125,804		50,850,156
Long-term deferred tax liability:				
Book basis of gas properties in excess of tax basis				(2,678,858)
Total long-term deferred tax liabilities				(2,678,858)
Net long-term deferred tax asset	$	1,125,804	$	48,171,298

Effective Tax Rate

The income tax expense for the year ended December 31, 2012 was different than the amount computed using the statutory rate primarily due to an $83.5 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	$ (36,004,892)	34.00%	$ (3,307)	25.00%	$ (36,008,199)	34.00%
State income taxes net of federal benefit	(3,319,194)	3.14%		0.00%	(3,319,194)	3.13%
Valuation Allowance	83,537,181	78.89%	3,307	25.00%	83,540,488	78.88%
Nondeductible items and other	(169,895)	0.16%		0.00%	(169,895)	0.16%
Income tax provision	$ 44,043,200	41.59%	$	0.00%	$ 44,043,200	41.59%

Our effective tax rate differs from the federal statutory rate primarily due to the recording of valuation allowances primarily related to our Canadian operations and other nondeductible items as detailed below. Income tax expense for the year ended December 31, 2011 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	$ 1,764,990	34.00%	$ (95,081)	25.00%	$ 1,669,909	34.71%
State income taxes net of federal benefit	267,990	5.16%		0.00%	267,990	5.57%
Valuation Allowance		0.00%	95,081	25.00%	95,081	1.98%
Nondeductible items and other	(36,563)	0.70%		0.00%	(36,563)	0.76%
Income tax provision	$ 1,996,417	38.46%	$	0.00%	$ 1,996,417	41.50%

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The following components of the income tax expense (benefit) for the years ended December 31, 2012 and 2011 are as follows:

		2012		2011
Current:				
State	$	25,000	$	25,000
Federal				
Deferred:				
State		(3,344,193)		242,990
State valuation allowance		11,663,218		
Federal		(36,174,788)		1,728,427
Federal valuation allowance		71,873,963		
Income tax provision	$	44,043,200	$	1,996,417

Uncertain Tax Positions

ASC 740 also clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return. The amount of unrecognized tax benefits of $272,600 has not changed in the three year period ended December 31, 2012. It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or the financial position.

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

Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. We did not have any accrued interest or penalties associated with any unrecognized tax benefits at December 31, 2012 and 2011, nor was any interest expense recognized during the years ended December 31, 2012 and 2011. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2012.

Note 16 Common Stock

At December 31, 2012 and 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 December 31, 2012 and 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 years ended December 31, 2012 and 2011:

	Date	Shares
Common stock outstanding at January 1, 2011		39,744,071
Shares issued in option exchange	01/05/2011	98,416
Shares issued upon the exercise of options	02/11/2011	1,932
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	03/24/2011	(819)
Issued to members of our Board of Directors (50% of annual retainer)	04/05/2011	127,621
Shares issued upon the exercise of options	04/26/2011	3,333
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	06/15/2011	(744)
Shares issued upon the exercise of options	10/14/2011	36,378
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	01/05/2012	(1,981)
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	03/15/2012	(1,171)
Issued to members of our Board of Directors (12.5% of annual retainer)	03/28/2012	64,284
Shares Issued under the separation agreement of our former CEO	04/30/2012	99,108
Issued to members of our Board of Directors (12.5% of annual retainer)	05/11/2012	97,824
Restricted shares granted to executive officers	05/14/2012	150,000
Purchased by the Company and cancelled for the payment of withholding taxes due on vested shares of restricted stock	06/15/2012	(418)
Restricted shares forfeited upon employment termination	06/25/2012	(27,757)
Issued to members of our Board of Directors (12.5% of annual retainer)	08/10/2012	300,000
Common stock outstanding at December 31, 2012		40,690,077

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Note 17 Series A Convertible Redeemable Preferred Stock

At December 31, 2012 and 2011, 5,305,865 and 4,549,537 shares of preferred stock were issued and outstanding, respectively. At December 31, 2012, an additional 2,095,967 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 years ended December 31, 2012 and 2011:

	Dividend Period (Three Months Ended)	Date Issued	Number of Shares		Balance
Balance at January 1, 2011			4,148,538	$	22,074,320
Accretion of Preferred Stock					1,766,653
PIK Dividends Issued for Preferred Stock :	3/31/11	3/31/11	129,586		1,749,252
	6/30/11	6/30/11	133,625		1,684,382
	9/30/11	9/30/11	137,788		1,337,396
Issuance costs and other					(129,379)
Balance At December 31, 2011			4,549,537	$	28,482,624
Accretion of Preferred Stock					1,913,134
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
	9/30/12	10/1/12	155,847		864,951
	12/31/12	12/31/12	160,709		1,208,799
Balance At December 31, 2012			5,305,865	$	35,851,887

On December 7, 2011, we declared a quarterly dividend of 142,095 shares of Preferred Stock covering the period October 1, 2011 through December 31, 2011. As those shares were not issued until January 3, 2012, they were not been included in the Preferred Stock balance at December 31, 2011. As such, we recorded a dividend payable in Current liabilities in the Consolidated Balance Sheet at December 31, 2011 at an estimated fair value of $1,522,035. Additionally, on March 31, 2012, June 30, 2012, September 30, 2012, and December 31, 2012, cash dividends of $645, $651, $689 and $771, respectively, were paid for fractional share dividends not paid-in-kind.

Note 18 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 year ended December 31, 2012, we recorded compensation expense of $601,571 of which $35,319 was allocated to lease operating expenses, $414,513 was 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 December 31, 2012

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is $329,683 which will be amortized over the vesting period of such awards. The weighted average remaining useful life of the future compensation cost is 0.80 years.

During the year ended December 31, 2011, we recorded a compensation expense accrual of $829,006 of which $37,353 was allocated to lease operating expenses, $659,040 was allocated to general and administrative expenses, and $132,613 was capitalized to gas properties.

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 members of our Board of 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 members of our Board of 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.

Incentive Stock Options

The table below summarizes incentive stock option activity for the years ended December 31, 2012 and 2011:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at January 1, 2011	1,391,611	$	2.85	5.3	$	348,408
Granted	593,079	$	1.59			
Exercised	(41,643)	$	0.72			
Exchanged	(328,220)	$	8.41			
Forfeited	(39,941)	$	9.24			
Outstanding at December 31, 2011	1,574,886	$	1.11	3.2	$	113,071
Options exercisable at December 31, 2011	254,072	$	0.72	4.2	$	53,355
Forfeited	(162,147)	$	1.05			
Outstanding at December 31, 2012	1,412,739	$	1.11	4.1	$	
Options exercisable at December 31, 2012	958,090	$	0.99	4.3	$	

During the year ended December 31, 2011, incentive stock options were granted with a weighted average grant-date fair value of $1.06 per option. The total intrinsic value of incentive stock options exercised during the year ended December 31, 2011 was $0.25 per option.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the years ended December 31, 2012 and 2011:

	Number of Options		Weighted Average Exercise Price	Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at January 1, 2011	1,150,548	$	3.87			
Granted	80,472	$	1.59			
Exchanged	(238,748)	$	9.52			
Outstanding at December 31, 2011	992,272	$	2.32	2.4	$	21,798
Options exercisable at December 31, 2011	808,000	$	2.60	1.8	$	
Forfeited	(17,507)	$	2.12			
Outstanding at December 31, 2012	974,765	$	2.33	1.3	$	
Options exercisable at December 31, 2012	933,242	$	2.40	1.3	$	

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During the year ended December 31, 2011, non-qualified stock options were granted with a weighted average grant-date fair value of $1.08 per option.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the years ended December 31, 2012 and 2011:

	Number of Shares		Weighted Average Grant Date Fair Value
Non-vested restricted stock at December 31, 2010	292,512	$	3.95
Granted in option exchange	98,416	$	1.32
Vested	(97,762)	$	4.07
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 December 31, 2012	254,260	$	1.43

Option Exchange

The Company issued a Tender Offer on Schedule TO on December 7, 2010 offering eligible employees the opportunity to exchange certain outstanding stock options for a number of new restricted shares of GeoMet common stock (Restricted Stock), to be granted under the GeoMet, Inc. 2006 Long-Term Incentive Plan (the 2006 Plan). Options eligible for exchange, or eligible options, were 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, upon completion of the Tender Offer, 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 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

Restricted Stock Unit Awards

On April 5, 2011, we granted 232,089 restricted stock units to our five executive officers. These restricted stock units vest upon the Company s achievement of certain performance targets, but no earlier than ratably over the three year period following the grant date, at which time one common share will be issued and exchanged for each restricted stock unit held. If the requisite performance targets are not achieved in the seven year period ended April 5, 2018, the restricted stock units will expire. Restricted stock units are included in the calculation of diluted earnings per share utilizing the treasury stock method. On April 30, 2012, 99,108 restricted stock units vested with a vesting date fair value of $0.53 per share. On June 25, 2012, 16,428 restricted stock units were forfeited. There have been no grants of restricted stock units subsequent to the aforementioned grant. Unrecognized compensation cost related the restricted stock units was $116,553 at December 31, 2012.

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Note 19 Profit Sharing Plan

Substantially all of the employees are covered by our profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer some of their compensation. We are required to match 100 percent of the first three percent of their annual compensation contributed and 50 percent of the following two percent of their annual compensation contributed. Our matching contributions vest immediately. Our contributions to the Plan for the years ended December 31, 2012 and 2011 were $227,299 and $208,607, respectively. We elected a Safe Harbor 401(k) plan for the years ended December 31, 2012 and 2011. A Safe Harbor 401(k) plan generally satisfies the non-discrimination rules for elective deferrals and employer matching contributions. For a 401(k) plan to be considered a Safe Harbor plan, employers must satisfy certain contribution, vesting, and notice requirements. Under Safe Harbor, the matching contributions vest immediately.

Note 20 Commitments and Contingencies

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

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.

Environmental and Regulatory

As of December 31, 2012, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Operating Lease Commitments

We have operating leases for office space, office equipment and field compressors expiring in various years through 2019. Future minimum lease commitments as of December 31, 2012 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,		Amount
2013	$	1,300,262
2014		994,314
2015		619,850

2016		616,275
2017 and thereafter		580,784
Total future minimum lease commitments	$	4,111,485

Total rental expenses under operating leases were approximately $2.8 million and $1.5 million for the years ended December 31, 2012 and 2011, respectively.

Transportation Contracts As of December 31, 2012, under the following firm transportation contracts, we can transport maximum daily volumes of (1) 500 MMBtu s continuing until October 31, 2015, (2) 15,000 MMBtu s continuing until April 1, 2022, (3) 10,000 MMBtu s continuing until April 1, 2017, (4) 15,000 MMBtu s continuing until October 31, 2024, (5) 10,000 MMBtu s continuing until June 30, 2017, and (6) 3,500 MMBtu s continuing until April 30, 2012. We have a right to extend each of these contracts at the maximum tariff rate. As of December 31, 2012, the maximum commitment remaining under the transportation contracts is approximately $21.2 million.

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SUPPLEMENTARY FINANCIAL AND OPERATING INFORMATION ON GAS EXPLORATION, DEVELOPMENT AND PRODUCING ACTIVITIES (UNAUDITED)

This supplemental schedule provides unaudited information pursuant to ASC 932 and certain other information.

Capitalized Costs Capitalized costs and accumulated depletion and impairment of gas properties relating to our gas producing activities, all of which are conducted within the continental U.S. and Canada at December 31, 2012 and 2011 are summarized below.

	2012	2011
Unevaluated properties U.S.	$	$
Unevaluated properties Canada		
Properties subject to amortization U.S.	539,077,119	533,378,211
Properties subject to amortization Canada		28,073,293
Capitalized costs consolidated	539,077,119	561,451,504
Accumulated depletion and impairment of gas properties U.S.	(464,685,742)	(357,834,702)
Accumulated depletion and impairment of gas properties Canada		(28,073,293)
Net capitalized costs consolidated	74,391,377	175,543,509
Net capitalized costs Canada		
Net capitalized costs U.S.	74,391,377	175,543,509
Net capitalized costs consolidated	$ 74,391,377	$ 175,543,509

Capitalized Costs Incurred

We capitalize certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of our investment in natural gas properties over the periods benefited by these activities. During the years ended December 31, 2012 and 2011, these capitalized costs amounted to $134,350 and $880,917, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. For the years ended December 31, 2012 and 2011, no interest costs were capitalized. During the years ended December 31, 2012 and 2011, costs related to share based compensation included in development costs were $20,612 and $132,613, respectively. During the years ended December 31, 2012 and 2011, costs related to asset retirement obligations included in development costs were $4,852,941 and $65,683, respectively. During the years ended December 31, 2012 and 2011, currency translation adjustments included in Development costs incurred Canada were $317,666 and $(555,043), respectively. The following table discloses costs incurred in gas property acquisition, exploration and development activities for years ended December 31, 2012 and 2011.

	2012	2011
Acquisition costs-proved U.S (1)	$ 714,354	$ 72,063,138
Acquisition costs-unproved U.S.		
Exploration costs incurred U.S.		3,000
Development costs incurred U.S. (2)	4,984,554	13,779,815
Total costs incurred U.S.	5,698,908	85,845,953
Acquisition costs-proved Canada	2,542	63,428
Acquisition costs-unproved Canada		

Exploration costs incurred Canada				
Development costs incurred Canada		313,379		(375,604)
Total costs incurred Canada		315,921		(312,176)
Total costs incurred consolidated	$	6,014,829	$	85,533,777

(1) Includes $70,837,474 related to the Acquisition.

(2) In 2012, we revised our estimates primarily related to the costs to plug and abandonment our horizontal Pinnate wells, resulting in a $4.8 million non-cash charge to our full cost pool, offset by an increase to our asset retirement obligation.

Reserves The following table summarizes our net ownership interests in estimated quantities of proved gas reserves and changes in net proved reserves, all of which are located in the continental U.S. Reserve estimates for natural gas contained below were prepared by DeGolyer and MacNaughton (D&M) and Ryder Scott Company, L.P. (Ryder Scott), independent petroleum engineers.

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Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

	2012	2011
Natural Gas Reserves (Mcf) U.S.		
Proved reserves at beginning of year	198,114,000	215,939,000
Revisions of previous estimates	(47,125,000)	(57,217,000)
Extensions and discoveries		
Acquisition		47,903,000
Disposition		
Production	(13,808,000)	(8,511,000)
Proved reserves at end of year	137,181,000	198,114,000
Proved developed reserves at beginning of year	188,017,000	163,318,000
Proved developed reserves at end of year	137,181,000	188,017,000

There was no natural gas reserves related to our Canadian gas properties at December 31, 2012 and 2011, nor was there any activity in the years then ended.

During 2012, we had negative reserve revisions of 47.1 Bcf primarily due to the lower natural gas price used in the December 31, 2012 reserve report. During 2011 we had negative reserve revisions of 57.2 Bcf, which was primarily attributable to the removal of approximately 45.5 Bcf of proved undeveloped reserves because it is our belief that, in the current natural gas price environment, it is not certain that satisfactory rates of return could be generated from the development of our proved undeveloped locations in the Gurnee, Pond Creek and Lasher fields within the next five years. Other factors which contributed to the negative revision were the lower natural gas price used in the December 31, 2011 reserve report and a reduction in proved developed producing reserves in the Gurnee field due to production performance. Reserves for proved developed producing reserves related to the Acquisition were estimated using production performance. Certain new producing properties with little production history were forecast using a combination of production performance, volumetric analyses and analogy to offset production. Non-producing reserves were estimated using a combination of volumetric analyses and analogy to offset production.

The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with ASC 932. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental United States. As prescribed by this statement, the amounts shown for December 31, 2012 and 2011 are calculated using the unweighted arithmetic average of the 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. Future income taxes are based on year-end statutory rates, adjusted for tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. Extensive judgments are involved in estimating the timing of future production and the costs that will be incurred throughout the remaining lives of the fields. Accordingly, the estimates of future net revenues from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimated to be incurred in developing and producing the estimated proved gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other gas producers.

Standardized Measure U.S.	2012	2011
Future cash inflows	$ 399,431,000	$ 834,187,000
Future production costs	(250,563,000)	(411,082,000)
Future development costs	(8,976,000)	(29,957,000)
Future income taxes		(37,318,000)
Future net cash flows	139,892,000	355,830,000
10% annual discount to reflect timing of cash flows	(67,024,000)	(213,686,000)
Standardized measure of discounted future net cash flows	$ 72,868,000	$ 142,144,000

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Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2012 and 2011 are summarized below:

Changes in Standardized Measure		**2012**		**2011**
Standardized measure at beginning of year	$	142,144,000	$	119,924,000
Sales and transfers of oil and gas produced net of production cost		(11,352,000)		(16,399,000)
Net changes in prices and production cost		(103,004,000)		(30,956,000)
Acquisition/disposition (net)				59,711,000
Net change in development cost		14,088,000		50,061,000
Revision of previous quantity estimates		(22,242,000)		(32,456,000)
Accretion of discount before income taxes		20,478,000		14,172,000
Net change in income taxes		31,145,000		(24,895,000)
Changes in production rates (timing) and other		1,611,000		2,982,000
Subtotal net change		(69,276,000)		22,220,000
Standardized measure at end of year	$	72,868,000	$	142,144,000

For the above tables, the following natural gas pricing was utilized:

- For the year ended December 31, 2012, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $2.78 per Mcf, resulting in a natural gas price of $2.91 per Mcf when adjusted for regional price differentials.

- For the year ended December 31, 2011, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.15 per Mcf, resulting in a natural gas price of $4.21 per Mcf when adjusted for regional price differentials.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Management s Evaluation of Disclosure Controls and Procedures

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

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

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management s report in this annual report.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2012 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report On Internal Control Over Financial Reporting Vitruvian Exclusion

Management of GeoMet, Inc. (the Company), including the Company s Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company s internal control system was designed to provide reasonable assurance to the Company s Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2012.

/s/ WILLIAM C. RANKIN	/S/ TONY OVIEDO
William C. Rankin	**Tony Oviedo**
Chief Executive Officer	**Chief Financial Officer**

Houston, Texas

March 28, 2013

Item 9B. ***Other Information***

None.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

List of Documents Filed as Part of this Report

(1) Financial Statements

(2) Financial Statement Schedules

None.

(3) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated, previously filed exhibits are incorporated herein by reference.

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on July 25, 2006 (Registration No. 333-131716)).

3.2	Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Appendix B to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
3.3	Certificate of Amendment to the Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Form 8-K filed on December 28, 2010).
3.4	Amended and Restated Bylaws of GeoMet, Inc. (Adopted as of September 14, 2010) (incorporated herein by reference to Exhibit 3.1 of the Company s Form 8-K filed on September 20, 2010).
10.1	GeoMet, Inc. 2006 Long-Term Incentive Plan (Amended and Restated effective November 9, 2010) (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 15, 2010).
10.2	Second Amendment to Investment Agreement dated November 5, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.2 to the Company s Form 10-Q filed on November 10, 2009).
10.3	First Amendment to Investment Agreement dated September 3, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 10, 2010).
10.4	Investment Agreement dated June 2, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Appendix A to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
10.5	Form of Indemnification Agreement between GeoMet, Inc. and officers and directors of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.2 of the Company s Form 8-K filed on September 20, 2010).
10.6	Change of Control Severance Agreement dated January 26, 2011 between GeoMet, Inc. and Tony Oviedo

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Exhibit No.	Description
	(incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on January 31, 2011).
10.7	Coalbed methane assets purchase agreement, dated October 14, 2011, by and among GeoMet, Inc., Vitruvian Exploration, LLC, and CD Exploration, LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.8	Natural gas hedge contracts purchase agreement, dated October 14, 2011, by and between GeoMet, Inc. and Vitruvian Exploration, LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.9	Fifth Amended and Restated Credit Agreement, dated October 14, 2011, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.10	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.7 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.11	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.6 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.12	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.13 to the Company s 10-K filed on March 20, 2007).
10.13	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.14 to the Company s 10-K filed on March 20, 2007).
10.14	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.15 to the Company s 10-K filed on March 13, 2009).
10.15	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.16 to the Company s 10-K filed on March 13, 2009).
10.16	Separation Agreement dated April 30, 2012 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on April 27, 2012).
10.17	Consulting Agreement dated April 30, 2012 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on April 27, 2012).
10.18	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on May 14, 2012).
10.19	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and Tony Oviedo (incorporated herein by reference to Exhibit 10.2 to the Company s 8-K filed on May 14, 2012).
10.20	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and Brett S. Camp (incorporated herein by reference to Exhibit 10.3 to the Company s 8-K filed on May 14, 2012).
10.21	Second Amendment to Fifth Amended and Restated Credit Agreement, dated June 21, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on June 21, 2012).
10.22	

	Third Amendment to Fifth Amended and Restated Credit Agreement, dated July 25, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on July 27, 2012).
10.23	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated August 8, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on August 8, 2012).
21.1*	List of Subsidiaries of GeoMet, Inc.
23.1*	Consent of Independent Petroleum Engineers DeGolyer and MacNaughton.
23.2*	Consent of Independent Petroleum Engineers Ryder Scott Company, L.P.
23.3*	Consent of Hein & Associates LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton.
99.2*	Report of Ryder Scott Company, L.P.
101**	Interactive Data Files.

* Filed herewith.

** 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.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 28, 2013.

GEOMET, INC.

By:	/s/ WILLIAM C. RANKIN
Name:	**William C. Rankin**
Title:	**President and Chief Executive Officer**

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrants and in the capacities on March 28, 2013.

Signature	Capacity
/s/ MICHAEL Y. MCGOVERN **Michael Y. McGovern**	Chairman of the Board of Directors
/s/ WILLIAM C. RANKIN **William C. Rankin**	President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TONY OVIEDO **Tony Oviedo**	Senior Vice President, Chief Financial Officer, Chief Accounting Officer and Controller (Principal Financial Officer and Principal Accounting Officer)
/s/ JAMES C. CRAIN **James C. Crain**	Director
/s/ STANLEY L. GRAVES **Stanley L. Graves**	Director
/s/ CHARLES D. HAYNES **Charles D. Haynes**	Director
/s/ W. HOWARD KEENAN, JR. **W. Howard Keenan, Jr.**	Director
/s/ GARY S. WEBER **Gary S. Weber**	Director

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INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on July 25, 2006 (Registration No. 333-131716)).
3.2	Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Appendix B to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
3.3	Certificate of Amendment to the Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Form 8-K filed on December 28, 2010).
3.4	Amended and Restated Bylaws of GeoMet, Inc. (Adopted as of September 14, 2010) (incorporated herein by reference to Exhibit 3.1 of the Company s Form 8-K filed on September 20, 2010).
10.1	GeoMet, Inc. 2006 Long-Term Incentive Plan (Amended and Restated effective November 9, 2010) (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 15, 2010).
10.2	Second Amendment to Investment Agreement dated November 5, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.2 to the Company s Form 10-Q filed on November 10, 2009).
10.3	First Amendment to Investment Agreement dated September 3, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 10, 2010).
10.4	Investment Agreement dated June 2, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Appendix A to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
10.5	Form of Indemnification Agreement between GeoMet, Inc. and officers and directors of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.2 of the Company s Form 8-K filed on September 20, 2010).
10.6	Change of Control Severance Agreement dated January 26, 2011 between GeoMet, Inc. and Tony Oviedo (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on January 31, 2011).
10.7	Coalbed methane assets purchase agreement, dated October 14, 2011, by and among GeoMet, Inc., Vitruvian Exploration, LLC, and CD Exploration, LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.8	Natural gas hedge contracts purchase agreement, dated October 14, 2011, by and between GeoMet, Inc. and Vitruvian Exploration, LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.9	Fifth Amended and Restated Credit Agreement, dated October 14, 2011, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 22, 2011).
10.10	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.7 to the Company s Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-131716)).
10.11	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.6 to the Company s Registration Statement on Form S-1 filed on February 10, 2006

(Registration No. 333-131716)).

10.12 Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.13 to the Company s 10-K filed on March 20, 2007).

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Exhibit No.	Description
10.13	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.14 to the Company s 10-K filed on March 20, 2007).
10.14	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.15 to the Company s 10-K filed on March 13, 2009).
10.15	Second Amendment to Employment Agreement dated effective as of December 31, 2008 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.16 to the Company s 10-K filed on March 13, 2009).
10.16	Separation Agreement dated April 30, 2012 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on April 27, 2012).
10.17	Consulting Agreement dated April 30, 2012 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on April 27, 2012).
10.18	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.1 to the Company s 8-K filed on May 14, 2012).
10.19	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and Tony Oviedo (incorporated herein by reference to Exhibit 10.2 to the Company s 8-K filed on May 14, 2012).
10.20	Amended and Restated Employment Agreement dated May 14, 2012 between GeoMet, Inc. and Brett S. Camp (incorporated herein by reference to Exhibit 10.3 to the Company s 8-K filed on May 14, 2012).
10.21	Second Amendment to Fifth Amended and Restated Credit Agreement, dated June 21, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on June 21, 2012).
10.22	Third Amendment to Fifth Amended and Restated Credit Agreement, dated July 25, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on July 27, 2012).
10.23	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated August 8, 2012, by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. Bank National Association, Comerica Bank, and Capital One (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on August 8, 2012).
21.1*	List of Subsidiaries of GeoMet, Inc.
23.1*	Consent of Independent Petroleum Engineers DeGolyer and MacNaughton.
23.2*	Consent of Independent Petroleum Engineers Ryder Scott Company, L.P.
23.3*	Consent of Hein & Associates LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton.

99.2*	Report of Ryder Scott Company, L.P.
101**	Interactive Data Files.

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* Filed herewith.

** 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.