GeoMet, Inc.
Form 10-K
March 30, 2012
Table of Contents

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, 2011

or

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

For the transition period from to

Commission file number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0662382**
(State or other jurisdiction of	**(I.R.S. Employer**

incorporation or organization)	Identification 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	NASDAQ Global Market
Preferred stock, par value $0.001 per share	NASDAQ Global 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 ¨ 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 ¨ 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 ¨

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 ¨

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	¨	Accelerated filer	¨
Non-accelerated filer	¨ (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 ¨ 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 $1.18 on the NASDAQ Global Market on June 30, 2011) on the last business day of registrant s most recently completed second fiscal quarter was approximately $27.4 million.

As of March 14, 2012, 40,008,207 shares and 4,691,632 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 2012 annual meeting of stockholders, which will be filed on or before April 30, 2012.

Table of Contents

GeoMet, Inc.

Form 10-K

TABLE OF CONTENTS

Table of Contents

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 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 read stateme 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 gas production;
- further declines in the prices we receive for our gas affecting our operating results, cash flows and credit capacity;
- general international and domestic economic conditions that may be less favorable than expected;
- 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 gas reserves;
- our ability to replace our gas reserves;
- uncertainties in exploring for and producing gas;
- new gas development projects and exploration for gas in areas where we have little or no proven 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 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 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 forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Table of Contents

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.

Table of Contents

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.

Additional drilling locations. Identified potential drilling locations on our existing acreage that are not included in our proved undeveloped reserves.

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.

Coal rank. Coal is a carbon rich rock derived from plant material accumulated in peat swamps. With increasing depth of burial, the plant material undergoes coalification, releasing volatile matter. The coal rank increases as the percentage of volatile mater (%VM) decreases. The generation of methane is a result of the thermal maturation or increasing rank of the coal. Coals targeted for CBM projects, from low rank to high rank, are lignite, sub-bituminous, high volatile bituminous, medium volatile bituminous and low volatile bituminous coals. The range of %VM associated with these coal ranks decrease from lignite at approximately 60%VM to low volatile bituminous coals at approximately 15%VM.

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.

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

Table of Contents

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.

NYMEX. The New York Mercantile Exchange.

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.

Table of Contents

PART I

Items 1 and 2. *Business and Properties*

Overview

GeoMet, Inc. is an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, 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, West Virginia, and British Columbia. As of December 31, 2011, we own a total of approximately 195,000 net acres of coalbed methane and oil and gas development rights.

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

Current Business Plan

During 2011 and the first quarter of 2012, natural gas prices in the United States declined significantly which we believe is due to over-supply, primarily from shale drilling, and reduced demand due to milder weather. In addition, the current 2012 NYMEX strip price for natural gas is depressed. We expect prices for natural gas to remain depressed in the foreseeable future. Consistent with actions we have taken in past low price environments, we currently intend to defer or limit additional drilling activity until gas prices rise from their current level. Our focus will be the reduction of costs and the optimization of production volumes to maintain maximum cash flow and liquidity. In response to low natural gas prices we plan to take the following steps during 2012:

- limit capital spending to maintenance levels,
- reduce operating and administrative costs with particular attention to the properties acquired in November of 2011,
- reduce bank debt,
- continue to monitor the markets for hedges and enter into hedging transactions opportunistically, and
- seek transactional opportunities to expand our natural gas reserves.

Budgeted capital expenditures for 2012 are less than $2 million; however, we may increase our capital budget later in the year if prices for natural gas improve. Cost reduction initiatives implemented or currently planned are expected to total between $2.5 million to $3 million on an annual basis. We have hedged approximately 75% of our estimated natural gas sales volumes for 2012 at an average hedged price of $4.94 per Mcf. We are seeking small acquisitions which enhance operational efficiencies in our existing properties without materially impairing our liquidity. We may also consider more strategic transactions that would provide more critical mass and spread fixed costs over a larger base. Please read Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations for additional information about the negative effects of low natural gas prices on our results of operations and liquidity.

Recent Developments

On November 18, 2011, we completed the purchase from Vitruvian Exploration LLC 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). We 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 our revolving credit facility and the assumption of $4 million in liabilities.

The properties acquired are located in our core operating areas of Alabama and West Virginia and complement our existing properties. The properties we acquired in West Virginia have significantly higher initial production rates but greater early decline rates which provide a balance with our pre-existing long lived, shallow decline reserves. The wells on the West Virginia properties acquired were drilled utilizing Z-Pinnate horizontal drilling technology (horizontal drilling) which results in a much larger drainage area per well as compared to our historical vertical wells. For example, individual horizontal wells to be drilled on our West Virginia properties may drain up to a thousand acres or more as compared to a vertical well on our existing properties which typically drains between 60 and 80 acres. As a result, reserves and initial production rates for a typical horizontal well are significantly higher than the rates historically achieved in our vertical wells. These horizontal wells typically have higher capital costs but generate higher rates of return.

Table of Contents

The Alabama properties acquired are composed of non-operated working interests, overriding royalty interests and royalty interests and include a field in which we previously held an interest and served as operator for over ten years. As a result of the overriding royalty interests and royalty interests, these properties generate higher operating margins, have long-life predictable reserves and limited future capital requirements. These properties represent approximately 69% of the portion of the purchase price allocated to gas properties.

Ceiling Write-Down

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. For the 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. Impairments recorded to gas properties for the year ended December 31, 2011, were $4.9 million (net of income tax of $3.0 million). In addition, based on the natural gas prices received thus far this year and the current natural gas futures price curve for the remainder of 2012, we expect to have significant non-cash impairments to our capitalized gas properties, potentially in excess of our total stockholders equity as reported herein in the Consolidated Balance Sheet at December 31, 2011.

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.

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. In addition to the areas listed below, we have non-producing properties in Canada which we are not currently operating or developing.

Table of Contents

Central Appalachia

In the Central Appalachian Basin, we are the operator of 300 vertical wells in which we own a 99.0% average working interest. Additionally, we are the operator of 89 horizontal wells in which we own a 66.0% average working interest. We also have a 33.0% average working interest in 67 non-operated horizontal wells. In Central Appalachia, we are party to six firm transportation agreements with total maximum daily quantities of approximately 54,000 MMBtu per day and primary terms expiring from April 2012 through November 2024 which can be automatically extended from time to time at the maximum tariff rate. In some cases, our gas sales volumes are delivered to market under transportation agreements controlled by our working interest partners. Generally, our gas sales volumes are sold at a delivery point into the respective interstate pipeline system utilized.

Black Warrior and Cahaba Basins

In the Black Warrior and Cahaba Basins in Alabama, we are the operator of 252 vertical wells for which we own a 100.0% working interest. Additionally, we own working, overriding royalty or royalty interests in 1,103 non-operated vertical wells. Of these non-operated vertical wells, we own an average working interest of 15.4% in 542 wells, and we own an average royalty or overriding royalty interest of 7.9% in the remaining 561 wells. 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. Our gas sales volumes from the Cahaba Basin are delivered and sold into the Southern Natural Gas pipeline system.

Estimated Proved Reserves

Estimated proved natural gas reserves as of December 31, 2011, as estimated by DeGolyer and MacNaughton (D&M) and Ryder Scott Company, L.P. (Ryder Scott), independent petroleum engineers, totaled approximately 198 Bcf, including approximately 49 Bcf attributable to the Acquisition. Our proved natural gas reserves as of December 31, 2010, as estimated by D&M, totaled approximately 216 Bcf. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $173 million at December 31, 2011, including approximately $64 million attributable to the Acquisition. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $126 million at December 31, 2010. A price of $4.21 per Mcf was used at December 31, 2011 compared to $4.49 per Mcf at year-end 2010. Our estimated proved reserves at December 31, 2011 are 100% coalbed methane and 95% proved developed. Approximately 63% of total year-end 2011 proved reserves are in our Central Appalachia producing region and 37% are in its Alabama producing region.

Estimated proved natural gas reserves as of December 31, 2011, as estimated by DeGolyer and MacNaughton (D&M) and Ryder Scott Company, L.P. (Ryder Scott), independent petroleum engineers, totaled approximately 198 Bcf, including approximately 49 Bcf acquired in a previously announced acquisition that closed on November 18, 2011. Our proved natural gas reserves as of December 31, 2010, as estimated by D&M, totaled approximately 216 Bcf. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $173 million at December 31, 2011, including approximately $64 million attributable to the acquired properties. The present value of future net cash flows attributable to proved reserves, discounted at 10%, was approximately $126 million at December 31, 2010. A price of $4.21 per Mcf was used at December 31, 2011 compared to $4.49 per Mcf at year-end 2010. Our estimated proved reserves at December 31, 2011 are 100% coalbed methane and 95% proved developed. Approximately 63% of total year-end 2011 proved reserves are in our Central Appalachia producing region and 37% are in its Alabama producing region.

The following table presents information related to our estimated proved reserves as of December 31, 2011.

Field	Proved Developed Producing (MMcf)	Proved Developed Non-Producing (MMcf)	Proved Undeveloped (MMcf)	Total Proved (MMcf)
Central Appalachia:				
Pond Creek field	99,475			99,475
Crab Orchard	8,125		8,664	16,789
Lasher field	3,553	214		3,767
Hillman/North Barbour	3,227			3,227
Itmann	1,836			1,836
Other	634			634

Alabama:				
Gurnee field	33,742	12,089		45,831
White Oak Creek	13,178			13,178
Warrior North	11,741		1,433	13,174
Other	203			203
Totals	175,714	12,303	10,097	198,114

Table of Contents

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. None of our PUD reserves at year end 2011 were included in our proved reserves at year end 2006. During 2011 we converted 10.1 Bcf of PUD reserves at year end 2010 into developed reserves for capital costs of $8.2 million. Additionally, we acquired 10.6 Bcf of PUDs in the acquisition.

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

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 and the notes to our consolidated financial statements included elsewhere in this annual report 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 26 years, including nine years with River Gas Corporation in Northport, Alabama from 1992 to 2001 and the last ten years with GeoMet in Hoover, Alabama. He also worked briefly with Phillips Petroleum following its acquisition of River Gas Corporation. During the last 20 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.

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. Estimates of our proved reserves at December 31, 2010, and 2009 were prepared by D&M. The technical persons at D&M and Ryder Scott 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. Additionally, the Board of Directors formed a sub-committee of the Board with the responsibility of overseeing the reserve reporting process. This committee is comprised of three independent directors, each of whom has experience in reserve evaluations.

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.

10

Table of Contents

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 our production and operating data for the periods presented.

	Year Ended December 31,		
	2011	**2010**	**2009**
Gas:			
Net sales volume (Bcf)	8.5	7.4	7.5
Average natural gas sales price ($ per Mcf)	$ 4.15	$ 4.49	$ 4.05
Average natural gas sales price ($ per Mcf) realized(1)	$ 5.28	$ 5.72	$ 5.47
Total production expenses ($ per Mcf)	$ 2.21	$ 2.27	$ 2.67
Expenses: ($ per Mcf)			
Lease operations expenses	$ 1.49	$ 1.57	$ 1.85
Compression and transportation expenses	$ 0.54	$ 0.56	$ 0.66
Production taxes	$ 0.18	$ 0.14	$ 0.16
Depletion of gas properties	$ 0.91	$ 0.79	$ 1.51
General and administrative	$ 0.57	$ 0.73	$ 1.11

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

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, 2011. 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, 2011:

	Productive Wells		Developed Acres		Undeveloped Acres	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Central Appalachian Basin	456.0	377.2	55,196	43,720	77,763	51,323
Cahaba Basin	252.0	252.0	17,547	17,507	21,685	21,685
Black Warrior Basin	542.0	83.7				
Other	11.0	8.0	1,600	1,240	86,946	59,469

Total	1,261.0	720.9	74,343	62,446	186,394	132,477

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 2012 through 2014; however, the term of the undeveloped acreage may be extended by drilling and production operations or through negotiations with lessors. As to the Gurnee field, we have fulfilled current drilling commitments on our largest lease through 2011. Otherwise, the remaining acreage either has expirations that occur from 2012 through 2014 or the leases can be extended by drilling and production operations or option payments. The following table sets forth, as of January 1, 2012, undeveloped acreage which expires through 2014 which management believes to be material to future operations:

Table of Contents

	2012		2013		2014	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gurnee					21,685	21,685
Pond Creek	12,042	10,201				
Crab Orchard	17,072	8,536	4,408	2,204		
Total	29,114	18,737	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. We have an option related to a farm-in agreement in our Pond Creek field to commence 26 wells by August 2012.

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 three 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.

	0000	0000	0000	0000	0000	0000
			Gross			
		Exploratory			Development	
Well Activity (Gross) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2011				20		20
Year ended December 31, 2010				20		20
Year ended December 31, 2009				4		4

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

	0000	0000	0000	0000	0000	0000
			Net			
		Exploratory			Development	
Well Activity (Net) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2011				19		19
Year ended December 31, 2010				20		20
Year ended December 31, 2009				4		4

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.

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 oil and 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.

Table of Contents

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.

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.

We have 5 purchasers of our natural gas production. Of the gas we delivered to market during the year ended December 31, 2011, 92% 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, 2011, two of our natural gas purchasers and one joint interest owner accounted for 76% of our accounts receivable related to gas sales.

Seasonality of Business

Weather conditions affect the demand for natural gas and can also delay drilling activities, disrupting our business operations. Demand for natural gas is typically higher in the fourth and first quarters and has traditionally resulted in higher natural gas prices. Due to these 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.

Table of Contents

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.

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.

Table of Contents

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, 2011, 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 can 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.

Canadian Governmental Regulation. Our operations in Canada are subject to regulation by provincial agencies in Canada. The natural gas industry in Canada remains subject to extensive controls and regulations imposable by various levels of government. We do not expect that any of these controls or regulations will affect our operations in a manner materially different than they would affect other natural gas industry participants of similar size.

Each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

NAFTA . The North American Free Trade Agreement (NAFTA) among the governments of Canada, the U.S. and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-U.S. Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the U.S. or Mexico will be allowed, so long as any export restrictions do not reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36-month period or another representative period agreed upon by the parties), impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports), or disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental Regulations

Our exploration and production operations are subject to significant federal, state, local, and Canadian 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 injunction, 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

Table of Contents

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. Our operations in Canada are subject to similar Canadian requirements.

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. 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. 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.

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 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.

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. Interim results of the study are expected in 2012, with final results expected in 2014.

Table of Contents

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 and public comment. 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.

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 July 28, 2011, the EPA proposed a rule to subject oil and gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs under the Clean Air Act, and to impose new and amended requirements under both programs. Under the proposal, the EPA would, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and gas operations, imposing requirements on those operations. The EPA is also proposing NSPS standards for completions of hydraulically fracturing gas wells. The proposed standards include the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology (MACT) standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. The EPA is under a court order to finalize the rules, with the current deadline of April 3, 2012. Should these rules become final and applicable to our operations, they could result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

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. In June 2010, the Environmental Protection Agency (EPA) published its GHG tailoring rule phasing in federal prevention of significant deterioration (PDS) permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. These permitting provisions, when 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 2010, being due in March 2011. 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 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 therefrom, 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.

Table of Contents

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.

Canadian Environmental Regulation. The natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with natural gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to remediate these sites to near natural conditions. Also, environmental laws may impose upon responsible persons remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures. A breach of environmental laws may result in the imposition of fines and penalties and suspension of production, in addition to the costs of abandonment and reclamation.

Hydraulic Fracturing

All of the vertical wells we have drilled in the Pond Creek field in Virginia and West Virginia and in the Gurnee field in Alabama require hydraulic fracturing in the completion operations in order to establish commercial production rates. In the Gurnee field we drilled and completed five wells in 2011 and the hydraulic fracturing process represented an average of approximately 45% of the total drilling and completion costs per well (approximately $317,000 per well). In the Pond Creek field we drilled 15 wells in 2011 and the hydraulic fracturing process represented an average of 26% of the total drilling and completion costs per well (approximately $119,000 per well). We do not currently plan to drill and complete any vertical wells in these fields in 2012 and have no proved undeveloped reserves in these fields at December 31, 2011.

Based on current techniques, a typical fracturing procedure for a well in the Gurnee field uses approximately 1,258,300 gallons of fluid (all of which is fresh water) and approximately 496,600 pounds of sand.

Based on current techniques, a typical fracturing procedure for a well in the Pond Creek field uses approximately 55,800 gallons of fluid (52,000 gallons of which is fresh water) and approximately 193,266 pounds of sand. By volume, fresh water makes up nearly 93% of the total fracturing fluid. Of the remaining 7% of fluid, approximately one third is comprised of material such as enzymes and Guar (a common food additive), and approximately two thirds is a combination of other chemicals.

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 these 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.

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.

Employees

At December 31, 2011, we had a total of 68 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.

Table of Contents

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, our compensation committee charter and our 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.

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 and results of operations.

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. In addition, the current 2012 NYMEX strip price for natural gas is depressed. We expect natural gas prices to be depressed during the foreseeable future. All of our estimated net proved reserves and production are natural gas. If natural gas prices do not increase above the current 2012 NYMEX strip price during the remainder of 2012, we would expect to report substantial full cost ceiling write downs of our gas properties during 2012, potentially exceeding the amount of our stockholders equity. In addition, sustained depressed prices for natural gas would likely have an adverse effect on our results of operation and financial condition.

Natural gas prices are volatile, and sustained periods of lower natural gas prices would 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 in general, and our regional prices in particular, have been historically highly volatile, and such high levels of volatility are expected to continue in the future. Recent prices for natural gas have been depressed and we expect prices to remain depressed in the foreseeable future. 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 not only decrease our revenues on a per Mcf basis, but also 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 or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to impair, as a non-cash charge to earnings, the carrying value of our properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carry amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

If natural gas prices decline further or remain low for an extended period of time, we may, among other things, be unable to maintain our borrowing capacity or extend the maturity of our revolving credit facility, repay current or future indebtedness or obtain additional capital on satisfactory terms, all of which could adversely affect the value of our common stock and preferred stock.

Basis differentials could decrease and adversely effect 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 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 have indebtedness, which makes us more vulnerable to economic downturns and adverse developments in our business.

We have incurred bank debt amounting to approximately $157.9 million as of December 31, 2011. As a result of our indebtedness, we use a portion of our cash flow to pay interest and principal, which reduces the amount we have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our revolving credit facility is at a variable interest rate. As such, an increase in interest rates will generate greater interest expense. The amount of our debt makes us more vulnerable to economic downturns and adverse developments in our business.

Our revolving credit facility contains a number of financial and other covenants, and our obligations under the revolving credit facility are secured by substantially all of our assets. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

Our revolving credit facility subjects us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, or pay dividends. We are also required by the terms of our revolving credit facility to comply with certain financial ratios. Our revolving credit facility also provides for periodic redeterminations of our borrowing base, which may affect our borrowing capacity. Our revolving credit facility is secured by a lien on substantially all of our assets, including equity interests in our subsidiaries. We expect that the current low prices for natural gas will result in a reduction in our borrowing base at the next borrowing base re-determination, scheduled for the second quarter of 2012. If the borrowing base is reduced below the amount outstanding, we are required to immediately repay the excess, and failure to do so is a default under our credit facility.

A breach of any of the covenants imposed on us by the terms of our revolving credit facility, including the financial covenants, could result in a default under such indebtedness. In the event of a default, the lenders could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the revolving credit facility. Any acceleration in the repayment of our indebtedness or related foreclosure would adversely affect our business.

In addition, the borrowing base under our revolving credit facility is redetermined semi-annually and may be redetermined at other times upon request by the lenders under certain circumstances. Redeterminations are based upon a number of factors, including natural gas prices and quantities of proved reserves.

In the event that the outstanding borrowings at any borrowing base determination date exceed the borrowing base (a borrowing base deficiency) the Company has three options in order to remain in compliance with the Credit Agreement, (i) to immediately reduce the outstanding borrowing by the amount of the borrowing base deficiency, (ii) provide additional collateral equal to the amount of the borrowing base deficiency, or (iii) make six equal monthly payments in an aggregate amount equal to the borrowing base deficiency.

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 counties 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 went into effect January 1, 2010, and require reporting by regulated facilities in 2012 and annually thereafter. In November 2010, the EPA issued a final rule 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.

Table of Contents

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodities Futures Trading Commission (the CFTC) is required to implement rules relating to these activities by July 16, 2012. On October 18, 2011, the CFTC approved regulations to set position limits for certain futures and option contracts in the major energy markets, which regulations are presently being challenged in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association. The Dodd-Frank Act may also require us to comply with margin requirements and with certain clearing and trade execution requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The schedule for promulgation of final rules has changed repeatedly, but the current schedule published by the CFTC contemplates finishing final regulations in 2012. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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 United States Securities and Exchange Commission, 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.

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.

Table of Contents

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. Future adverse changes to any of these 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. In addition, based on the natural gas prices received thus far this year and the current natural gas futures price curve for the remainder of 2012, we expect to have significant non-cash impairments to our capitalized gas properties, potentially in excess of our total stockholders equity as reported herein in the Consolidated Balance Sheet at December 31, 2011.

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

As of December 31, 2011, we had U.S. federal tax net operating loss carryforwards (NOL s) of approximately $126.0 million, which expire at various dates from fiscal year 2022 through fiscal year 2031. These net operating loss carryforwards may be used to offset future taxable income and thereby reduce our U.S. federal income taxes otherwise payable. If natural gas prices remain at current depressed levels prior to the expiration of our NOL s, we may not be able to meet the more likely than not standard in accordance with GAAP that we can utilize our NOL s in the future which, among other factors and circumstances, could require us to recognize a valuation allowance. The recognition of a valuation allowance would reduce earnings and would also result in a corresponding reduction of stockholders equity. Recognition of a valuation allowance is a non-cash charge to earnings and it does not preclude us from using the NOL s to reduce future taxable income 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.

As of December 31, 2011, we own leasehold interests in approximately 30,000 net acres in areas we believe are prospective for the Chattanooga Shale. A large portion of the acreage is 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.

Table of Contents

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.

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 draft results of the study anticipated to be available by late 2012 and the final report available in 2014, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states 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 Canada 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.

Table of Contents

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 and shales 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.

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.

Obtaining production from our additional drilling locations could take five years or longer, making them susceptible to uncertainties that could alter the occurrence of their drilling.

The additional drilling locations on our existing acreage represent a significant part of our growth strategy. Our ability to drill and produce these locations depends on a number of uncertainties, including, but not limited to, natural gas prices, permitting and the availability of capital.

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 attract 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 have not entered into employment nor severance agreements with any of our key employees, other than J. Darby Seré, our President and Chief Executive Officer, William C. Rankin, our Executive Vice President and Chief Financial Officer, and Tony Oviedo, our Vice President, Chief Accounting Officer and Controller. 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 attract, motivate, and retain additional qualified managerial and operations personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating, and 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 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.

Table of Contents

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.

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 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 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.

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.

The availability or high cost of drilling rigs, equipment, supplies, personnel, and field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment, and supplies are substantially greater. As a result of historically strong prices of gas, the demand for field services has risen, and the costs of these services are increasing. If the availability or high cost of drilling rigs, equipment, supplies, or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected.

26

Table of Contents

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.

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. This provision may prevent us from issuing common stock or securities convertible into our common stock at a time when the market price of our common stock is less than the conversion price, 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.

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 27% of our common stock outstanding as of December 31, 2011 (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 17% of our common stock. Additional shares of our Series A Convertible

Table of Contents

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, 2011, 40,010,188 shares of common stock were outstanding, and 34,996,439 shares of common stock are issuable upon conversion of outstanding Series A Convertible Redeemable Preferred Stock. An additional 2,852,295 shares of our Series A preferred stock, convertible into 21,940,731 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, 2011, 40,010,188 shares of our common stock were outstanding, together with outstanding options representing the right to purchase up to 2,567,158 shares. As of December 31, 2011, our outstanding Series A Convertible Redeemable Preferred Stock is convertible into an aggregate of 34,996,439 shares of our common stock, which represents approximately 47% of our issued and outstanding common stock as of December 31, 2011, 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 restrict 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.

We may not be able to maintain compliance with NASDAQ s continued listing requirements.

We must comply with NASDAQ s continued listing requirements in order to maintain our listing on NASDAQ s Global Market. These continued listing standards include requirements addressing the number of shares publicly held, market value of publicly held shares, stockholder s equity, number of round lot holders, and a $1.00 minimum closing bid price. If a company s closing bid price is below $1.00 for 30 consecutive trading days, it receives a notice from NASDAQ that it will be subject to delisting if it fails to regain compliance within 180 days following the date of the notice letter by maintaining a minimum bid closing price of at least $1.00 for ten consecutive business days. If the closing bid price for our common stock is below $1.00 per share for 30 consecutive days or if we in the future fail to meet the other requirements for continued listing on the NASDAQ Global Market, then our common stock could be delisted.

The delisting of our common stock would adversely affect the market liquidity for our common stock, the per share price of our common stock and impair our ability to raise capital that may be needed for future operations.

On February 3, 2012, we received a notification letter from NASDAQ advising the Company that for 30 consecutive trading days preceding the date of the Notice, the bid price of our common stock had closed below the $1.00 per share minimum required for continued listing on The NASDAQ Global Market pursuant to NASDAQ Marketplace Rule 5450(a)(1) (the Minimum Bid Price Rule).

The Notice has no effect on the listing of our common stock and preferred stock at this time and our common stock and preferred stock will continue to trade on the NASDAQ Global Market under the symbols GMET and GMETP, respectively.

Table of Contents

The Notice also stated that we will be provided 180 calendar days, or until August 1, 2012, to regain compliance with the Minimum Bid Price Rule. To do so, the bid price of our common stock must close at or above $1.00 per share for a minimum of ten consecutive trading days prior to that date.

If compliance with the Minimum Bid Price Rule cannot be demonstrated by August 1, 2012, NASDAQ will provide written notification to us that our common stock is subject to delisting. We may, however, be eligible for an additional grace period if it satisfies the initial listing standards (with the exception of the Minimum Bid Price Rule) for listing on the NASDAQ Capital Market, and submits a timely notification to NASDAQ to transfer the listing of its common stock to the NASDAQ Capital Market. We may also appeal NASDAQ s delisting determination to a NASDAQ Hearings Panel.

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. We have not received a formal letter claiming the exceptions and no reasonable estimate of potential liability related to this matter can be made at this time.

Environmental and Regulatory

As of December 31, 2011, 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.

Table of Contents

PART II

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

Common Stock

Our common stock is listed on the NASDAQ Global Market 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 2009:		
Quarter ended March 31, 2009	$ 1.81	$ 0.54
Quarter ended June 30, 2009	$ 1.62	$ 0.57
Quarter ended September 30, 2009	$ 1.75	$ 0.79
Quarter ended December 31, 2009	$ 2.29	$ 1.08
Fiscal Year 2010:		
Quarter ended March 31, 2010	$ 1.58	$ 0.89
Quarter ended June 30, 2010	$ 1.42	$ 1.06
Quarter ended September 30, 2010	$ 1.08	$ 0.83
Quarter ended December 31, 2010	$ 1.20	$ 0.65
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

Approximately 1,500 stockholders of record as of March 1, 2012 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 expansion of our natural gas exploration business. Our revolving credit facility 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.

	High	Low
Fiscal Year 2010:		
Quarter ended September 30, 2010	$ 10.12	$ 9.93
Quarter ended December 31, 2010	$ 10.35	$ 9.16
Fiscal Year 2011:		
Quarter ended March 31, 2011	$ 10.12	$ 9.93
Quarter ended June 30, 2011	$ 10.12	$ 9.93
Quarter ended September 30, 2011	$ 10.12	$ 9.93
Quarter ended December 31, 2011	$ 10.12	$ 9.93

Approximately 300 stockholders of record as of March 1, 2012 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 its 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.

Table of Contents

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 27% 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 will be 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 2011.

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, 2011.

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	2,567,158	$ 1.58	1,432,842
Equity compensation plans not approved by security holders			
Total	2,542,159	$ 3.31	1,432,392

Option Exchange

On December 7, 2010, we offered 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 the offer; and
- the options did not have a remaining term of less than 12 months immediately following January 5, 2010.

Table of Contents

On January 5, 2011, we issued 98,416 shares of restricted stock to employees tendering eligible options as follows:

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

Table of Contents

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

The following table shows our selected historical consolidated financial and operating data as of and for each of the last five years ended December 31, 2011. The selected historical financial data as of December 31, 2011 and 2010 and for each of the three years in the period ended December 31, 2011 are derived from our consolidated audited financial statements included herein. The selected historical financial data as of December 31, 2009, 2008 and 2007 and for each of the two years in the period ended December 31, 2008 was derived from our consolidated audited financial statements which are not included herein. You should read the following data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated audited financial statements and related notes included elsewhere in this annual report where there is additional disclosure regarding the information in the following table. Our historical results are not necessarily indicative of the results that may be expected in future periods.

	2011	2010	2009	2008	2007
STATEMENT OF OPERATIONS (in thousands):					
Total revenues	$ 35,615	$ 33,361	$ 30,964	$ 69,094	$ 50,984
Realized (gains) losses on derivative contracts	$ (9,571)	$ (9,006)	$ (10,694)	$ 500	$ (3,895)
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (4,067)	$ (5,950)	$ 3,995	$ (4,993)	$ 3,007
Impairment of gas properties	$ 7,940		$ 257,288	$ 50,734	
Terminated transaction costs		$ 1,403			
Acquisition costs	$ 956				
Total operating expenses	$ 27,126	$ 14,839	$ 291,093	$ 87,590	$ 37,852
Operating income (loss) from continuing operations	$ 8,489	$ 18,521	$ (260,129)	$ (18,496)	$ 13,132
Interest expense, net of amounts capitalized	$ (3,698)	$ (5,168)	$ (5,174)	$ (4,783)	$ (5,130)
Unrealized loss from the change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock		$ (2,164)			
Income (loss) before income taxes and discontinued operations	$ 4,811	$ 11,199	$ (265,275)	$ (23,199)	$ 7,983
Income tax expense (benefit)	$ 1,996	$ 5,407	$ (98,142)	$ (712)	$ 2,988
Income (loss) before discontinued operations, net of income tax	$ 2,814	$ 5,792	$ (167,134)	$ (22,487)	$ 4,995
Discontinued operations, net of income tax					$ 174
Net income (loss)	$ 2,814	$ 5,792	$ (167,134)	$ (22,487)	$ 5,169
Accretion of Series A Convertible Redeemable Preferred Stock	$ (1,767)	$ (498)			
Dividends on Series A Convertible Redeemable Preferred Stock	$ (6,296)	$ (1,487)			
Net (loss) income available to common stockholders	$ (5,248)	$ 3,808	$ (167,134)	$ (22,487)	$ 5,169
EARNINGS PER COMMON SHARE (in dollars):					
(Loss) Income from continuing operations					
Basic	$ (0.13)	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13
Diluted	$ (0.13)	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13
Discontinued operations					
Basic					
Diluted					
Net (loss) income per common share					
Basic	$ (0.13)	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13
Diluted	$ (0.13)	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13

Table of Contents

	2011	2010	2009	2008	2007
BALANCE SHEET DATA (in thousands, at period end):					
Working capital (deficit)(1)	$ 11,570	$ 1,545	$ (35)	$ (1,441)	$ (2,063)
Total assets	$ 257,146	$ 170,086	$ 160,928	$ 377,600	$ 378,677
Long-term debt	$ 158,172	$ 80,863	$ 119,996	$ 117,118	$ 96,730
Mezzanine equity	$ 28,483	$ 22,074			
Stockholders equity	$ 46,631	$ 51,008	$ 26,908	$ 192,432	$ 218,676
Cash flow data (in thousands):					
Net cash provided by operating activities	$ 16,015	$ 16,022	$ 8,518	$ 32,958	$ 17,487
Net cash used in investing activities (4)	$ (91,856)	$ (12,185)	$ (12,696)	$ (52,719)	$ (53,832)
Net cash provided (used in) by financing activities	$ 75,762	$ (4,292)	$ 2,888	$ 20,493	$ 36,191
Capital expenditures	$ 14,409	$ 12,293	$ 12,566	$ 52,797	$ 54,026
OTHER DATA:					
Net sales volume (Bcf)	8.5	7.4	7.5	7.5	7.1
Average natural gas sales price ($ per Mcf)	$ 4.15	$ 4.49	$ 4.05	$ 9.17	$ 6.97
Average natural gas sales price ($ per Mcf) realized(2)	$ 5.28	$ 5.72	$ 5.47	$ 9.10	$ 7.52
Total production expenses ($ per Mcf)	$ 2.21	$ 2.27	$ 2.67	$ 2.87	$ 2.86
Depletion of gas properties($ per Mcf)	$ 0.91	$ 0.79	$ 1.51	$ 1.35	$ 1.24
Estimated proved reserves (Bcf)(3)	198.1	215.9	209.3	319.5	350.2
Standardized measure of discounted future net cash flows ($ millions)	$ 142.1	$ 119.9	$ 149.2	$ 310.3	$ 495.9

(1) Working capital (deficit) is defined as current assets less current liabilities.

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

(3) Based on the reserve reports prepared by D&M and Ryder Scott, independent petroleum engineers, at each period end. Natural gas prices are volatile and may fluctuate widely affecting significantly the calculation of estimated net cash flows. Refer to Risk Factors for a more complete discussion.

(4) Includes $78.7 million related to the Vitruvian acquisition.

Table of Contents

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 an independent energy company primarily engaged in the exploration for and development and production of natural gas from coal seams (coalbed methane or CBM) and non-conventional shallow gas. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator, 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, West Virginia, and British Columbia. As of December 31, 2011, we own a total of approximately 195,000 net acres of coalbed methane and oil and gas development rights.

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

Current Business Plan

During 2011 and the first quarter of 2012, natural gas prices in the United States declined significantly which we believe is due to over-supply, primarily from shale drilling, and reduced demand due to milder weather. In addition, the current 2012 NYMEX strip price for natural gas is depressed. We expect prices for natural gas to remain depressed in the foreseeable future. Consistent with actions we have taken in past low price environments, we currently intend to defer or limit additional drilling activity until gas prices rise from their current level. Our focus will be the reduction of costs and the optimization of production volumes to maintain maximum cash flow and liquidity. In response to low natural gas prices we plan to take the following steps during 2012:

- limit capital spending to maintenance levels,
- reduce operating and administrative costs with particular attention to the properties acquired in November of 2011,
- reduce bank debt,
- continue to monitor the markets for hedges and enter into hedging transactions opportunistically, and
- seek transactional opportunities to expand our natural gas reserves.

Budgeted capital expenditures for 2012 are less than $2 million; however, we may increase our capital budget later in the year if prices for natural gas improve. Cost reduction initiatives implemented or currently planned are expected to total between $2.5 million to $3 million on an annual basis. We have hedged approximately 75% of our estimated natural gas sales volumes for 2012 at an average hedged price of $4.94 per Mcf. We are seeking small acquisitions which enhance operational efficiencies in our existing properties without materially impairing our liquidity. We may also consider more strategic transactions that would provide more critical mass and spread fixed costs over a larger base.

Recent Developments

On November 18, 2011, we completed the purchase from Vitruvian Exploration LLC 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). We 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 our revolving credit facility and the assumption of $4 million in liabilities.

The properties acquired are located in our core operating areas of Alabama and West Virginia and complement our existing properties. The properties we acquired in West Virginia have significantly higher initial production rates but greater early decline rates which provide a balance with our pre-existing long lived, shallow decline reserves. The wells on the West Virginia properties acquired were drilled utilizing Z-Pinnate horizontal drilling technology (horizontal drilling) which results in a much larger drainage area per well as compared to our historical vertical wells. For example, individual horizontal wells to be drilled on our West Virginia properties may drain up to a thousand acres or more as compared to a vertical well on our existing properties which typically drains between 60 and 80 acres. As a result, reserves and initial production rates for a typical horizontal well are significantly higher than the rates historically achieved in our vertical wells. These horizontal wells typically have higher capital costs but generate higher rates of return.

The Alabama properties acquired are composed of non-operated working interests, overriding royalty interests and royalty interests and include a field in which we previously held an interest and served as operator for over ten years. As a result of the overriding royalty interests and royalty interests, these properties generate higher operating margins, have long-life predictable reserves and limited future capital requirements. These properties represent approximately 69% of the portion of the purchase price allocated to gas properties.

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 2 to our consolidated audited 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 United States Securities and Exchange Commission (SEC). Under this method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our gas properties are capitalized and segregated into U.S. and Canadian cost centers.

Gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved gas reserves. Estimation of proved gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of gas properties unless the sale or disposition represents a significant quantity of gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

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

Ceiling Write-Down

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions, as allowed by the guidelines of the SEC. For the 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. Impairments recorded to gas properties for the year ended December 31, 2011, were $4.9 million (net of income tax of $3.0 million). In addition, based on the natural gas prices received thus far this year and the current natural gas futures price curve for the remainder of 2012, we expect to have significant non-cash impairments to our capitalized gas properties, potentially in excess of our total stockholders equity as reported herein in the Consolidated Balance Sheet at December 31, 2011.

Asset Retirement Liability 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 liability, 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.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740, formerly SFAS No. 109, Accounting for Income Taxes. 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.

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.

Deferred Tax Asset Recoverability

In determining the carrying value of a deferred tax asset, ASC 740 provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. In order to assess the realization of our net deferred tax asset as of December 31, 2011 and 2010, the Company considered all available negative and positive evidence. While the Company has incurred a cumulative loss over the three year period ended December 31, 2011, after evaluating all available evidence including historical operating results, historical pricing, current operating income including our return to profitability the last two fiscal years, consideration of the full cost ceiling test impairments in 2009 that resulted in the cumulative losses, our natural gas reserves level as estimated and appraised by an independent third party engineer, future pricing as indicated on the New York Mercantile Exchange, and the length of the carryforward period available, the Company concluded that it is more likely than not the deferred tax asset, net of the $3.1 million valuation allowance related to our Canadian operations and state NOLs, will be realized. The Company will continue to assess the need for additional valuation allowances in the future. If future results are less than projected using either our historical results or our forecast based on the reserve report and future market pricing, then additional valuation allowances may be required to reduce the deferred tax assets which could have a material impact on the Company s results of operations in the period in which it is recorded.

Our first material net operating loss (NOL) carryforward expires in 2022 and the last one expires in 2031. We also consider the lengthy carryforward period in the overall evaluation of our ability to realize our NOLs as it substantially increases the likelihood of utilization.

In addition, we performed a forecast based analysis based on inputs from third party sources. Our primary inputs for this analysis come from our reserve report that is estimated and appraised by an independent third party engineer as well as future market pricing as determined by the New York Mercantile Exchange. To test the sensitivity of the forecast, we adjusted several assumptions, including, but not limited to, the following: use of three-year historical average production, use of three-year average pricing, and use of three-year average margins. Under all scenarios, we generate sufficient taxable income to fully realize the net deferred tax asset prior to expiration.

Table of Contents

We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence in future reporting periods. If our assumptions regarding forecasted production, pricing, and margins are not achieved by amounts in excess of our sensitivity analysis, it may have a significant impact on the corresponding taxable income which may require a valuation allowance to be recorded against our then existing deferred tax assets.

If natural gas prices remain at current depressed levels prior to the expiration of our NOL s, we may not be able to meet the more likely than not standard in accordance with GAAP that we can utilize our NOL s in the future which, among other factors and circumstances, could require us to recognize a valuation allowance. The recognition of a valuation allowance would reduce earnings and would also result in a corresponding reduction of stockholders equity. Recognition of a valuation allowance is a non-cash charge to earnings and it does not preclude us from using the NOL s to reduce future taxable income otherwise payable.

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, we account for pipeline imbalances on the Sales method, imbalances may be made up in future production or are settled with cash approximately thirty days from date of production and are recorded as a reduction of revenue 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 based on specific indices as required by the derivative agreements. These transactions are recorded in our consolidated audited financial statements in accordance with ASC 815, formerly SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. 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.

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 hedge 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 /Embedded Derivative 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. In addition, we evaluated the conversion feature and determined that because of certain anti-dilution provisions, the conversion feature was not indexed to our stock and as such, the holder s conversion option was to be separated and recorded at fair value as a derivative liability. Subsequent changes in the fair value of the derivative liability were recorded as a component of other income and expense in the Consolidated Statements of Operations.

Table of Contents

The fair value of the derivative liability attributable to the conversion option was determined using an American binomial lattice model, which utilized assumptions including 80% volatility, a 17% discount factor and an expected term of 6.4 years determined using a Monte Carlo simulation model. For the year ended December 31, 2010, the Company recorded approximately $2.2 million to Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock in the Consolidated Statements of Operations as a result of the change in the fair value of the derivative liability. On December 21, 2010, the Company amended the terms of the Preferred Stock to adjust the anti-dilution provision and further limit the Company s ability to issue junior securities (including additional shares of common stock), at a price lower than the current conversion price, without the consent of holders of a majority of shares of Series A Preferred Stock. After the amendment, the conversion feature is indexed to our stock and as such, is no longer required to be accounted for as a derivative. On the effective date of the amendment, the bifurcated derivative liability on the Company s consolidated balance sheet related to the conversion feature was reclassified to paid-in capital on the Company s consolidated statements of stockholders equity and comprehensive income (loss).

Fair Value Measurement Effective January 1, 2008, we adopted ASC 820-10-55, formerly SFAS No. 157, Fair Value Measurements, 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 9 Derivative Instruments and Hedging Activities.

Stock-Based Compensation We follow the fair value recognition provisions of ASC 718, formerly SFAS No. 123(R), Share-Based Payment. 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.

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, 2011, 2010 and 2009. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31,		
	2011	**2010**	**2009**
Gas sales	$ 35,335	$ 33,074	$ 30,597
Lease operating expenses	$ 12,713	$ 11,544	$ 13,935
Compression and transportation expenses	4,591	4,164	5,012
Production taxes	1,536	1,021	1,178
Total production expenses	$ 18,840	$ 16,729	$ 20,125
Net sales volumes (Consolidated) (MMcf)	8,511	7,359	7,549
Pond Creek field (Central Appalachian Basin) (MMcf)	5,637	5,322	5,226
Other Central Appalachian Basin fields (MMcf)	750	150	98
Gurnee field (Cahaba Basin) (MMcf)	1,803	1,858	2,118
Black Warrior Basin fields (MMcf)	308	14	20
Per Mcf data ($/Mcf):			
Average natural gas sales price (Consolidated)	$ 4.15	$ 4.49	$ 4.05
Pond Creek field (Central Appalachian Basin)	$ 4.29	$ 4.50	$ 4.06

Other Central Appalachian Basin fields	$ 3.55	$ 4.43	$ 4.01
Gurnee field (Cahaba Basin)	$ 4.10	$ 4.47	$ 4.06
Black Warrior Basin fields	$ 3.43	$ 4.39	$ 3.87

Table of Contents

	Year Ended December 31,		
	2011	2010	2009
Average natural gas sales price realized (Consolidated)(1)	$ 5.28	$ 5.72	$ 5.47
Lease operating expenses (Consolidated)	$ 1.49	$ 1.57	$ 1.85
Pond Creek field (Central Appalachian Basin)	$ 1.16	$ 1.21	$ 1.38
Other Central Appalachian Basin fields	$ 1.32	$ 1.95	$ 4.07
Cahaba Basin field	$ 2.67	$ 2.36	$ 2.47
Black Warrior Basin fields (2)	$ 0.47	$ 0.13	$ 0.00
Compression and transportation expenses (Consolidated)	$ 0.54	$ 0.56	$ 0.66
Pond Creek field (Central Appalachian Basin)	$ 0.54	$ 0.62	$ 0.67
Other Central Appalachian Basin fields	$ 1.09	$ 0.99	$ 1.90
Cahaba Basin field	$ 0.34	$ 0.40	$ 0.49
Black Warrior Basin fields (2)	$ 0.16	$ 0.07	$ 0.03
Production taxes (Consolidated)	$ 0.18	$ 0.14	$ 0.16
Pond Creek field (Central Appalachian Basin)	$ 0.19	$ 0.16	$ 0.13
Other Central Appalachian Basin fields	$ 0.04	$ 0.00	$ 0.00
Cahaba Basin field	$ 0.20	$ 0.08	$ 0.23
Black Warrior Basin fields	$ 0.21	$ 0.45	$ 0.24
Total production expenses (Consolidated)	$ 2.21	$ 2.27	$ 2.67
Pond Creek field (Central Appalachian Basin)	$ 1.89	$ 1.99	$ 2.18
Other Central Appalachian Basin fields	$ 2.45	$ 2.94	$ 5.97
Cahaba Basin field	$ 3.21	$ 2.84	$ 3.19
Black Warrior Basin fields (2)	$ 0.84	$ 0.65	$ 0.27
Depletion (Consolidated)	$ 0.91	$ 0.79	$ 1.51

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

The following table presents certain information with respect to our production and operating data for each of the three month periods in the year ended December 31, 2011.

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Gas:				
Net sales volume (Bcf)	1.8	1.8	1.9	2.9
Average natural gas sales price ($ per Mcf)	$ 4.27	$ 4.53	$ 4.39	$ 3.68
Average natural gas sales price ($ per Mcf) realized(1)	$ 6.17	$ 5.36	$ 5.26	$ 4.67
Total production expenses ($ per Mcf)	$ 2.29	$ 2.29	$ 2.32	$ 2.05
Expenses: ($ per Mcf)				
Lease operations expenses	$ 1.62	$ 1.57	$ 1.56	$ 1.33
Compression and transportation expenses	$ 0.50	$ 0.52	$ 0.56	$ 0.56
Production taxes	$ 0.17	$ 0.20	$ 0.20	$ 0.16
Depletion of gas properties	$ 0.83	$ 0.83	$ 0.93	$ 1.01
General and administrative	$ 0.78	$ 0.82	$ 0.60	$ 0.27

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

Results of Operations

Year Ended December 31, 2011 compared with Year Ended December 31, 2010

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

Table of Contents

	Year Ended December 31, 2011	2010	Change
		(in thousands)	
Gas sales volume (MMcf)	8,511	7,359	16%
Gas sales	$ 35,335	$ 33,074	7%
Lease operating expenses	$ 12,713	$ 11,544	10%
Compression expense	$ 2,958	$ 2,890	2%
Transportation expense	$ 1,633	$ 1,275	28%
Production taxes	$ 1,536	$ 1,021	50%
Depreciation, depletion and amortization	$ 8,145	$ 6,296	29%
Impairment of gas properties	$ 7,940	$	NM
General and administrative	$ 4,883	$ 5,367	-9%
Acquisition costs	$ 956	$	NM
Terminated transaction costs	$	$ 1,403	NM
Realized gains on derivative contracts	$ (9,571)	$ (9,006)	6%
Unrealized gains from the change in market value of open derivative contracts	$ (4,067)	$ (5,950)	-32%
Interest expense, net of amounts capitalized	$ (3,698)	$ (5,168)	-28%
Unrealized loss from the change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	$	$ (2,164)	NM
Income tax expense	$ 1,996	$ 5,407	-63%

NM-Not Meaningful

Gas sales. Gas sales increased by $2.3 million, or 7%, to $35.3 million compared to the prior year. The increase in gas sales was primarily the result of higher production volumes, of which 0.9 Bcf was due to our recent acquisition of coalbed methane gas properties, while 0.3 Bcf was due to increased production in our previously existing properties, partially offset by an 8% decrease in natural gas prices, excluding hedging transactions.

Lease operating expenses. Lease operating expenses increased by $1.2 million, or 10%, to $12.7 million compared to the prior year. The $1.2 million increase in lease operating expenses consisted of $0.9 million increase due to our recent acquisition of coalbed methane gas properties and a $0.3 million increase in our previously existing properties. The $0.3 million increase related to our previously existing properties was due to increased production.

Compression expense. Compression expense remained relatively flat compared to the prior year. However, our recently purchased gas properties added $0.4 million in compression expense, offset by $0.3 million decrease in compression expense related to our previously existing properties.

Transportation expense. Transportation expense increased by $0.4 million, or 28%, to $1.6 million compared to the prior year. The increase was due to the recent acquisition of coalbed methane gas properties. Transportation expenses remained relatively flat in our previously existing gas properties.

Production taxes. Production taxes increased by $0.5 million, or 50%, to $1.5 million compared to the prior year. The increase in production taxes was primarily due to the phase-in of state taxes on production of coalbed methane gas in the West Virginia portion of our Pond Creek field and the absence of production tax refunds that were received in the prior year. Additionally, our recent acquisition of gas properties contributed an additional $0.1 million of production taxes in the current year.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.8 million, or 29%, to $8.1 million compared to the prior year. This increase was primarily due to the $1.2 million of expenses related to the natural gas properties recently acquired in combination with an increase of $0.6 million related to our previously existing natural gas properties. The increase in depreciation, depletion, and amortization at our pre-acquisition properties consisted of a $0.2 million increase related to production and a $0.4 million increase in the depletion rate.

Impairment of gas properties. During 2011, the gross carrying value of the Company s gas properties exceeded the full cost ceiling limitation and, as such, a $7.9 million ($4.9 million net of tax of $3.0 million) impairment of gas properties was recorded.

General and administrative. General and administrative expenses decreased by $0.5 million, or 9 %, to $4.9 million compared to the prior year. This decrease was primarily due a decrease in current year bonuses received by senior management.

Acquisition costs. During the current year, 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 prior year.

Table of Contents

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

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $0.6 million, or 6%, to $9.6 million compared to the prior year. The increase was primarily due to the $2.2 million of realized gains on derivative contracts acquired as part of our recent natural gas property acquisition. 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 gains on open derivative contracts decreased by $1.9 million, or 32%, to $4.1 million compared to the prior year. The decrease was primarily related to the current year decrease in unrealized gains of $3.32 million on our pre-acquisition derivative contracts. Additionally, the derivative contracts recently acquired as part of our coalbed methane gas property acquisition contributed $0.14 million of unrealized losses in the current year. 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 decreased by $1.5 million, or 28%, to $3.7 million compared to the prior year. The decrease was primarily due to a lower average outstanding revolver balance and a lower average borrowing rate in the current year.

Unrealized loss from the change in fair value of derivative liability Series A convertible Redeemable Preferred Stock. The loss in 2010 was primarily the result of the increase in the market price of our common stock from the issuance date of our Series A Preferred Stock of September 14, 2010 through the effective date of the amendment to Series A Preferred Stock anti-dilution feature. The Company amended the terms of the anti-dilution provisions of its Preferred Stock on December 21, 2010. The effect of the amendment was to extinguish the liability and reclassify it to paid-in capital. Since the amendment, changes in the price of our common stock do not result in the recognition of gains or losses attributable to the anti-dilution provisions of our preferred stock. No such loss was recorded in the current year.

Income tax expense. Income tax expense decreased by $3.4 million, or 63%, to $2.0 million compared to the prior year. The effective tax rate for the current year was 41.5%. 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%

Table of Contents

Year Ended December 31, 2010 compared with Year Ended December 31, 2009

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, 2010	Year Ended December 31, 2009 (in thousands)	Change
Gas sales volume (MMcf)	7,359	7,549	-3%
Gas sales	$ 33,074	$ 30,597	8%
Lease operating expenses	$ 11,544	$ 13,935	-17%
Compression expense	$ 2,890	$ 3,346	-14%
Transportation expense	$ 1,275	$ 1,666	-23%
Production taxes	$ 1,021	$ 1,178	-13%
Depreciation, depletion and amortization	$ 6,296	$ 12,030	-48%
Impairment of gas properties	$	$ 257,288	-100%
General and administrative	$ 5,367	$ 8,349	-36%
Terminated transaction costs	$ 1,403	$	100%
Realized gains on derivative contracts	$ (9,006)	$ (10,694)	-16%
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (5,950)	$ 3,995	NM
Interest expense, net of amounts capitalized	$ (5,168)	$ (5,174)	0%
Unrealized loss from the change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	$ (2,164)	$	NM
Income tax expense (benefit)	$ 5,407	$ (98,142)	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $2.5 million, or 8%, to $33.1 million compared to the prior year. The increase in gas sales was a result of higher natural gas prices, which increased approximately 11% excluding hedging transactions, partially offset by a 0.2 Bcf, or 3% decrease in production principally attributable to normal production declines with no drilling in 2009 to offset such normal production declines.

Lease operating expenses. Lease operating expenses decreased by $2.4 million, or 17%, to $11.5 million compared to the prior year. The $2.4 million decrease in lease operating expenses consisted of $2.0 million decrease in costs and a $0.4 million decrease related to production. The $2.0 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Compression expense. Compression expense decreased by $0.5 million, or 14%, to $2.9 million compared to the same period in the prior year. The $0.5 million decrease was comprised of $0.4 million decrease in costs and a $0.1 million decrease related to production. The $0.4 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Transportation expense. Transportation expense decreased by $0.4 million, or 23%, to $1.3 million compared to the prior year period. The decrease was primarily due to the permanent release of excess transportation capacity effective May 1, 2009.

Production taxes. Production taxes decreased by $0.2 million, or 13%, to $1.0 million compared to the prior year period. The decrease related to production taxes was primarily due to production tax refunds in the current year, partially offset by an increase in production taxes due to the phase-in of state taxes on production of natural gas in the West Virginia portion of our Pond Creek field.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $5.7 million, or 48%, to $6.3 million compared to the prior year period. The depreciation, depletion and amortization decrease consisted of a $0.3 million decrease related to production and a $5.4 million decrease in the depletion rate. The decrease in the depletion rate was due to the ceiling write-downs incurred throughout 2009.

Impairment of gas properties. During 2010, the carrying value of the Company s gas properties did not exceed the full cost ceiling limitation. As such, there was no such impairment recorded in 2010.

General and administrative. General and administrative expenses decreased by $3.0 million, or 36%, to $5.4 million compared to the prior year period. The decrease in general and administrative expenses was primarily due to a company-wide cost reduction strategy implemented in April 2009.

Table of Contents

Terminated transaction costs. During the current year, we incurred $1.3 million of costs related to a proposed financing transaction with certain parties and $0.1 million related to a potential sale of certain assets. Negotiations with those parties ceased and the related costs were expensed as terminated transaction costs. No such expenses were incurred in the prior year.

Realized gains on derivative contracts. Realized gains on derivative contracts decreased by $1.7 million, or 16%, to $9.0 million compared to the prior year. 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) losses from the change in market value of open derivative contracts. Unrealized gains on open derivative contracts were $6.0 million in the current year period as compared to unrealized losses of $4.0 million in the prior year period. Unrealized gains and losses are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Interest expense. Interest expense remained materially unchanged compared to the prior year.

Unrealized loss from the change in fair value of derivative liability Series A convertible Redeemable Preferred Stock. The loss in 2010 was primarily the result of the increase in the market price of our common stock from the issuance date of our Series A Preferred Stock of September 14, 2010 through the effective date of the amendment to Series A Preferred Stock anti-dilution feature. The Company amended the terms of the anti-dilution provisions of its Preferred Stock on December 21, 2010. The effect of the amendment was to extinguish the liability and reclassify it to paid-in capital. Future changes in the price of our common stock will not result in the recognition of gains or losses attributable to the anti-dilution provisions of our preferred stock.

Income tax expense (benefit). Income tax expense was $5.4 million in the current year as compared to an income tax benefit of $98.1 million in the prior year. The effective tax rate for the current year was 48.3%. Income tax expense for the year ended December 31, 2010 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	$ 4,144,123	34.00%	$ (247,465)	25.00%	$ 3,896,658	34.80%
State income taxes net of federal benefit	581,419	4.77%		0.00%	581,419	5.19%
Valuation Allowance		0.00%	247,465	-25.00%	247,465	2.21%
Nondeductible transaction costs	459,099	3.77%		0.00%	459,099	4.10%
Other nondeductible items and other	221,941	1.82%		0.00%	221,941	1.98%
Income tax provision	$ 5,406,582	44.36%	$	0.00%	$ 5,406,582	48.28%

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the years ended December 31, 2011, 2010 and 2009 were $16.0 million, $16.0 million and $8.5 million, respectively. As of December 31, 2011 and 2010, we had working capital of approximately $11.6 million and $1.5 million, respectively. We believe that our cash flow from operations and other financial resources such as borrowings under our revolving credit facility will provide us with sufficient capital resources to meet our limited projected capital expenditures for the next twelve months.

Revolving Credit Facility

On November 18, 2011, our Fifth Amended and Restated Credit Agreement (the Credit Agreement) with a group of six banks became effective. The Credit Agreement replaced our Fourth Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $250 million with an initial borrowing base of $180 million. The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by June 2012. All outstanding borrowings under the Credit Agreement become due and payable on November 18, 2015. In the event that the outstanding borrowings at any borrowing base determination date exceed the borrowing base (a borrowing base deficiency) the Company has three options in order to remain in compliance with the Credit Agreement, (i) to immediately reduce the outstanding borrowing by the amount of the borrowing base deficiency, (ii) provide additional collateral equal to the amount of the borrowing base deficiency, or (iii) make six equal monthly payments in an aggregate amount equal to the borrowing base deficiency. The Credit Agreement provides for interest to accrue at a rate calculated, at the Company s option, at the Adjusted Base Rate plus a margin of 1.25% to 1.75% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.25% to 2.75%. 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%). In all cases the applicable margin is dependent on the percentage of borrowing base usage. Under the Credit Agreement we are subject to certain financial covenants requiring maintenance of (i) a minimum Current Ratio, (ii) a maximum Debt Ratio and, (iii) depending on our Debt Ratio, either (a) a minimum Interest Coverage

Table of Contents

Ratio or (b) a minimum Fixed Charge Ratio. The Current Ratio of consolidated current assets (defined to include amounts available under our borrowing base) to consolidated current liabilities (defined to exclude up to $1.5 million in accrued and unpaid preferred dividends) is not permitted to be less than 1.0 to 1.0 as of the end of any fiscal quarter. The Debt Ratio (defined as funded debt at the end of each fiscal quarter to trailing four quarter consolidated EBITDA) at the end of each fiscal quarter cannot exceed 4.25 to 1.0 through the quarter ending December 31, 2012 and 4.0 to 1.0 thereafter. If our Debt Ratio at the end of each fiscal quarter is above 3.5 to 1.0, then the Fixed Charge Ratio (defined as consolidated EBITDA less capital expenditures to consolidated net cash interest expense for the four preceding quarters) is applicable and cannot be less than 1.25 to 1.0. If our Debt Ratio at the end of each fiscal quarter is 3.5 to 1.0 or less, the Interest Coverage Ratio (defined as consolidated EBITDA to consolidated net cash interest expense plus letter of credit fees accruing during the preceding four quarters) is applicable and cannot be less than 2.75. Consolidated EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization and also excludes non-recurring charges and other non-cash charges deducted in determining net income (loss), which would include unrealized gains and losses from a change in the market value of open derivative contracts and non-cash gains, losses or adjustments and charges on any oil and gas hedge transaction, including those resulting from the requirements of ASC Topic 815, as a result of changes in the fair market value of oil and gas hedge transactions. We are also subject to covenants restricting or prohibiting cash dividends and other restricted payments, transactions with affiliates, incurrence of debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities, and liens on properties. Cash dividends on our preferred stock above the $2 million discretionary amount allowable under the Credit Agreement are permitted if, following any such cash payment our availability is equal to or greater than 15% of the then current borrowing base and our Debt Ratio is less than 3.5 to 1.0. There are no restrictions associated with the payment of PIK dividends on our preferred stock.

We expect that the current low prices for natural gas will result in a reduction in our borrowing base at the next borrowing base re-determination, scheduled for the second quarter of 2012.

Series A Preferred Stock

On December 31, 2011, the Company had 4,549,537 shares of Series A Convertible Redeemable Preferred Stock (the Preferred Stock) issued and outstanding with a redemption amount of $45,495,370. Dividends continue to accrue quarterly on the Preferred Stock, including any Preferred Stock issued as paid-in-kind dividends (PIK dividends), which in our sole discretion, may be paid in any combination of cash, or, until the fifth anniversary of the closing of the rights offering, in PIK dividends. 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 PIK dividends is 12.5%. All dividends are cumulative and all unpaid dividends compound on a quarterly basis at a 12.5% annual rate. At December 31, 2011, an additional 2,852,295 shares of our Preferred Stock are reserved exclusively for the payment of PIK dividends.

During the year ended December 31, 2011, the Company declared PIK dividends of 543,094 shares to the holders of Preferred Stock and issued 400,999 shares. The remaining PIK dividend of 142,095 shares declared on December 7, 2011, for the three months ended December 31, 2011, was paid on January 3, 2012.

The following table details the activity related to the issuance and accretion of the Series A Convertible Redeemable Preferred Stock for the year ended December 31, 2011:

	Mezzanine Equity - Series A Convertible Redeemable Preferred Stock
Balance at December 31, 2010	$ 22,074,320
Accretion of Series A Convertible Redeemable Preferred Stock	1,766,653
PIK Dividends for Series A Convertible Redeemable Preferred Stock	4,771,030
Issuance costs and other	(129,379)
Balance at December 31, 2011	$ 28,482,624

Capital Expenditures

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

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Capital expenditures:			
Asset acquisition (the Acquisition)	$ 70,837	$	$
Leasehold acquisition	1,290	591	1,197
Exploration	3	3	29
Development	12,880	11,884	6,273
Other items (primarily capitalized overhead)	1,344	1,033	1,767
Total capital expenditures	$ 86,354	$ 13,511	$ 9,266

Table of Contents

Based on the prevailing low prices for natural gas, our Board of Directors has established a limited capital budget for 2012. We expect to spend $1.5 million in capital in 2012 primarily for maintenance operations associated with our existing properties.

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 from time to time primarily using derivative instruments in the form of three-way collars, traditional collars and swaps. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions, generally for forward periods up to two years or more, which increase the probability of achieving our targeted level of cash flows. We generally limit the amount of our natural gas derivative contracts during any period to no more than 50% to 70% of the then expected gas production for such future periods. During periods of perceived elevated price risk, we may hedge a higher percentage of our expected sales volumes but we are limited by our credit agreement to hedge no more than 85% of expected production.

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, 2011, we had no natural gas collar positions.

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
April through October 2012	856,000	$ 5.73	2,137,811
April 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

Table of Contents

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

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

Forward Physical Sale Contract

Our production is sold at an all-in price which includes the market price for natural gas plus a basis differential . In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the New York Mercantile Exchange (NYMEX) contract for the month of sale plus a basis differential of $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively.

As of December 31, 2011, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows:

Period	Volume (MMBtu)	Fixed Market Price	Fixed Basis Differential	All-In Price	Gross Sale
January through March 2012	273,000	$ 5.20	$ 0.130	$ 5.330	$ 1,419,600

The remaining volumes giving effect for the fixed amounts denoted above are as follows:

Period	Volume (MMBtu)	Fixed Basis Differential
January through March 2012	1,183,000	$ 0.130

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

Subsequent to December 31, 2011, we entered into the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price
April through October 2012	3,210,000	$ 2.89
November 2012 through March 2014	4,128,000	$ 3.81
November 2012 through March 2014	4,128,000	$ 3.82
	11,466,000	

Interest Rate Risks and Related Hedging Activities

When we enter into an interest rate swap, we may designate the derivative as a cash flow hedge, at which time we prepare the documentation required under ASC 815-20-25. Hedges of our interest rate are designated as cash flow hedges based on whether the interest on the underlying debt is converted to a fixed interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred as other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur. At December 31, 2011, we had no interest rate swaps.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2011, beginning January 1, 2012 (in thousands):

	2012	2013	2014	2015	2016 and thereafter
Long-term debt and other obligations(1)	$ 92	$ 100	$ 110	$ 157,961	$
Interest expense on revolving credit facility(2)	4,480	4,480	4,480	3,952	
Operating lease obligations	2,064	1,067	681	622	1,204

Table of Contents

Asset retirement obligations	32				8,139
Firm transportation contracts	2,515	2,441	2,441	2,435	13,907
Other	602				
Uncertain tax positions(3)					
Total commitments	$ 9,785	$ 8,088	$ 7,712	$ 164,970	$ 23,250

(1) Maturities based on the November 2011 amended bank credit agreement terms, as amended, which extended the maturity date to November 2015.

(2) The rate at December 31, 2011 was 2.84%.

(3) As of December 31, 2011, we had a liability for unrecognized tax benefits of approximately $273,000. We are unable to reliably estimate the timing and amount of any payments related to this liability because there are currently no outstanding unpaid assessments from any tax authority, and it is likely that assessments would be offset by existing deferred tax attributes as they arise.

The following were maturities of long-term debt for each of the next five years at December 31, 2011:

Year	Amount
2012	$ 91,757
2013	100,467
2014	110,035
2015	157,961,160
Total Debt	$ 158,263,419

In January 2011, we agreed to sell gross volumes of 16,000 MMBtu/day of natural gas from our Pond Creek field for the period February 2011 through March 2012 through a forward physical sale contract with our existing purchaser at a price equal to the last day settlement price for the NYMEX contract for the month of sale plus $0.15, $0.115, and $0.13 for the periods February 2011 through March 2011, April 2011 through October 2011, and November 2011 through March 2012, respectively. Additionally, we fixed the NYMEX settle on a portion of the aforementioned forward sale as follows: (1) 4,000 MMBtu /day for the period April 2011 through October 2011 was fixed at a total price for physical gas sales, including the aforementioned basis, of $4.915/ MMBtu and (2) 3,000 MMBtu /day for the period November 2011 through March 2012 was fixed at a total price for physical gas sales, including the aforementioned basis, of $5.33/ MMBtu. These contracted volumes represent approximately 89% of total expected gross production volumes for the contract period from the Pond Creek field. If we are unable to fulfill our commitment, or a portion thereof, we are obligated to reimburse our counterparty for any price paid to replace the quantity of natural gas we failed to deliver which is in excess of the contract price. This obligation is limited to the spot price for natural gas at the delivery point on the day we fail to deliver.

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, 2011 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	Amount
2012	$ 1,041,295
2013	1,067,145
2014	681,872
2015	621,883
2016	618,308
Thereafter	586,035
Total future minimum lease commitments	$ 4,616,538

Total rental expenses under operating leases were approximately $1,483,312, $1,528,739, and $1,857,026 for the years ended December 31, 2011, 2010 and 2009, respectively.

Transportation Contracts As of December 31, 2011, 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, 2011, the maximum commitment remaining under the transportation contracts is approximately $23.7 million.

Table of Contents

Recent Accounting Pronouncements

In December 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-29, Disclosure of Supplementary Pro Forma Information for Business Combinations (ASU 2010-29). ASU 2010-29 requires a public entity who discloses comparative pro forma information for business combinations that occurred in the current reporting period to disclose revenue and earnings of the combined entity as though the business combination(s) occurred as of the beginning of the comparable prior annual period only. This update also expands the supplemental pro forma disclosures required to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010 and early adoption is permitted. The Company adopted and applied the provisions of this update for any business combinations that occurred after January 1, 2011.

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

In June 2011, the FASB issued Accounting Standards Update No. 2011-05: Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. The update is intended to increase the prominence of other comprehensive income in the financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011. Early adoption is permitted. The Company has not elected to early adopt and is still evaluating the effect on its disclosures. The amendments do not require incremental disclosures in addition to those required by ASC 250 or any transition guidance

In December 2011, the FASB issued Accounting Standards Update No. 2011-12: Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). The Update defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income. As part of this update, the FASB did not defer the requirement to report comprehensive income either in a single continuous statement or in two separate but consecutive financial statements. ASU 2011-12 is effective for annual periods beginning after December 15, 2011. Early adoption is permitted. The Company has not elected to early adopt and is still evaluating the effect on its disclosures. The amendments do not require incremental disclosures in addition to those required by ASC 250 or any transition guidance

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the Company s financial position and results of operations.

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, 2011, a 10% decrease in the prices received for natural gas production would have had an approximate $3.5 million impact on our revenues, which would have been offset by approximately $1.8 million realized gas hedging gains.

Table of Contents

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of December 31, 2011, we had $157.9 million of borrowings outstanding under our revolving credit facility. The rate at December 31, 2011 was 2.84%. For the year ended December 31, 2011, interest on the borrowings averaged 3.43% per annum. All of the debt outstanding under our revolving credit facility accrues interest at floating or market rates. Fluctuations in market interest rates will cause our interest costs to fluctuate. Based upon the balance outstanding under our revolving credit facility for the year ended December 31, 2011, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.9 million.

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

Table of Contents

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

GEOMET, INC. AND SUBSIDIARIES

Index to Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of GeoMet, Inc.

Houston, Texas

We have audited the accompanying consolidated balance sheets of GeoMet, Inc and subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on the 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, such consolidated financial statements present fairly, in all material respects, the financial position of GeoMet, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

In 2009 the Company changed its method of accounting for natural gas reserves.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 29, 2012

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 457,865	$ 536,533
Accounts receivable, net of allowance of $17,634 and $60,848 at December 31, 2011 and 2010, respectively	4,402,065	2,600,319
Inventory	597,197	1,002,207
Derivative asset natural gas contracts	20,685,187	7,087,775
Other current assets	1,141,310	951,622
Total current assets	27,283,624	12,178,456
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	561,451,504	475,917,727
Other property and equipment	3,671,123	3,405,502
Total property and equipment	565,122,627	479,323,229
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(388,730,093)	(373,235,875)
Property and equipment net	176,392,534	106,087,354
Other noncurrent assets:		
Derivative asset natural gas contracts	1,765,450	2,186,767
Deferred income taxes	48,171,298	48,202,861
Other	3,532,882	1,430,584
Total other noncurrent assets	53,469,630	51,820,212
TOTAL ASSETS	$ 257,145,788	$ 170,086,022
LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 7,500,768	$ 5,950,861
Accrued liabilities	3,936,070	2,306,020
Deferred income taxes	4,153,099	2,206,531
Derivative liability interest rate swaps		4,592
Asset retirement liability	32,028	32,893
Current portion of long-term debt	91,757	132,743
Total current liabilities	15,713,722	10,633,640
Long-term debt	158,171,662	80,863,419
Asset retirement liability	8,138,551	5,465,798
Other long-term accrued liabilities	8,145	40,728
TOTAL LIABILITIES	182,032,080	97,003,585

Commitments and contingencies (Note 17)

Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,660,435; redemption amount $45,495,370; $.001 par value; 7,401,832 shares authorized, 4,549,537 and 4,148,538 shares were issued and outstanding at December 31, 2011 and 2010, respectively.	28,482,624	22,074,320
Stockholders Equity:		
Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 40,010,188 and 39,758,484 at December 31, 2011 and 2010, respectively	40,010	39,744
Treasury stock 10,432 shares at December 31, 2011 and 2010	(94,424)	(94,424)
Paid-in capital	200,344,209	207,548,596
Accumulated other comprehensive loss	(1,309,926)	(1,324,154)
Retained deficit	(152,104,329)	(154,918,736)
Less notes receivable	(244,456)	(242,909)
Total stockholders equity	46,631,084	51,008,117
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY	$ 257,145,788	$ 170,086,022

See accompanying Notes to Consolidated Audited Financial Statements.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31,

	2011	2010	2009
Revenues:			
Gas sales	$ 35,334,515	$ 33,073,567	$ 30,596,551
Operating fees and other	280,646	287,306	367,519
Total revenues	35,615,161	33,360,873	30,964,070
Expenses:			
Lease operating expense	12,713,015	11,543,674	13,934,840
Compression and transportation expense	4,591,242	4,164,186	5,011,511
Production taxes	1,535,532	1,020,950	1,178,435
Depreciation, depletion and amortization	8,145,316	6,296,288	12,029,982
Impairment of gas properties	7,939,713		257,288,257
General and administrative	4,882,589	5,367,204	8,349,268
Terminated transaction costs		1,402,534	
Acquisition costs	956,100		
Realized gains on derivative contracts	(9,571,180)	(9,005,621)	(10,694,496)
Unrealized (gains) losses from the change in market value of open derivative contracts	(4,066,687)	(5,949,840)	3,995,327
Total operating expenses	27,125,640	14,839,375	291,093,124
Operating income (loss)	8,489,521	18,521,498	(260,129,054)
Other income (expense):			
Interest income	16,869	44,287	27,739
Interest expense	(3,697,865)	(5,167,764)	(5,174,185)
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock		(2,164,080)	
Other	2,299	(35,206)	80
Total other income (expense):	(3,678,697)	(7,322,763)	(5,146,366)
Income (loss) before income taxes	4,810,824	11,198,735	(265,275,420)
Income tax expense (benefit)	1,996,417	5,406,582	(98,141,759)
Net income (loss)	$ 2,814,407	$ 5,792,153	$ (167,133,661)
Accretion of Series A Convertible Redeemable Preferred Stock	(1,766,653)	(497,782)	
Dividends on Series A Convertible Redeemable Preferred Stock	(6,295,859)	(1,486,843)	
Net (loss) income available to common stockholders	$ (5,248,105)	$ 3,807,528	$ (167,133,661)
(Loss) earnings per share:			
Net (loss) income per common share			
Basic	$ (0.13)	$ 0.10	$ (4.28)
Diluted	$ (0.13)	$ 0.10	$ (4.28)

Weighted average number of common shares:			
Basic	39,610,761	39,298,207	39,084,740
Diluted	39,610,761	39,299,082	39,084,740

See accompanying Notes to Consolidated Audited Financial Statements.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (LOSS)

	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, 2009	39,049,684	$ 39,050	$ (93,811)	$ 188,692,242	$ (2,399,992)	$ 6,422,772	$ (228,336)	$ 192,431,925
Stock-based compensation	244,705	245		978,373				978,618
Purchase and cancellation of treasury stock	(406)	(1)	(613)					(614)
Accrued interest on notes receivable				11,201			(11,201)	
Comprehensive loss:								
Net loss						(167,133,661)		(167,133,661)
Gain on interest rate swap, net of income taxes of $134,389					231,138			231,138
Foreign currency translation adjustment, net of income taxes of $0					400,333			400,333
Total comprehensive loss								(166,502,190)
Balance at December 31, 2009	39,293,983	$ 39,294	$ (94,424)	$ 189,681,816	$ (1,768,521)	$ (160,710,889)	$ (239,537)	$ 26,907,739
Stock-based compensation	375,584	376		513,498				513,874
Purchase and cancellation of treasury stock	(686)	(1)		(781)				(782)
Exercise of stock options	75,190	75		54,062				54,137
Dividends paid in-kind				(1,486,111)				(1,486,111)
Dividends paid in cash				(732)				(732)
Accretion of discount recorded for Series A Convertible Redeemable Preferred Stock				(497,782)				(497,782)
Extinguishment of derivative liability related to Series A Convertible Redeemable Preferred Stock				19,281,254				19,281,254
Accrued interest on notes receivable				3,372			(3,372)	
Comprehensive income:								
Net income						5,792,153		5,792,153
Gain on interest rate swap, net of income taxes of $269,803					436,487			436,487
Foreign currency translation adjustment, net of income taxes of $0					7,880			7,880
Total comprehensive income								6,236,520
Balance at December 31, 2010	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 treasury 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 recorded for Series A Convertible Redeemable Preferred Stock				(1,766,653)				(1,766,653)
Accrued interest on notes receivable				1,547			(1,547)	
Comprehensive income:								
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
Total comprehensive income								2,828,635
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

See accompanying Notes to Consolidated Audited Financial Statements.

Table of Contents

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2011	2010	2009
Cash flows provided by operating activities:			
Net income (loss)	$ 2,814,407	$ 5,792,153	$ (167,133,661)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation, depletion and amortization	8,145,316	6,296,288	12,029,982
Impairment of gas properties	7,939,713		257,288,257
Amortization of debt issuance costs	595,263	574,601	196,152
Terminated transaction costs		666,306	
Deferred income tax expense (benefit)	1,971,417	5,381,582	(98,050,852)
Unrealized (gains) losses from the change in market value of open derivative contracts (including premium amortization)	(4,053,703)	(5,962,824)	3,995,327
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock		2,164,080	
Stock-based compensation	696,394	409,873	792,560
Loss on sale of other assets	9,993	52,551	22,248
Accretion expense	564,403	484,114	431,733
Changes in operating assets and liabilities:			
Accounts receivable	(1,801,821)	311,591	2,553,045
Other current assets	(497,673)	364,667	(102,448)
Accounts payable	176,660	26,731	(3,394,439)
Other accrued liabilities	(545,718)	(539,171)	(109,645)
Net cash provided by operating activities	16,014,651	16,022,542	8,518,259
Cash flows used in investing activities:			
Capital expenditures	(14,409,393)	(12,293,100)	(12,566,498)
Acquisition	(78,738,611)		
Return of original basis through the settlement of natural gas derivative contracts	1,575,349		
Proceeds from sale of assets	3,050	58,937	36,315
Other assets	(286,323)	48,947	(166,260)
Net cash used in investing activities	(91,855,928)	(12,185,216)	(12,696,443)
Cash flows provided by financing activities:			
Proceeds from sale of preferred stock		40,000,000	
Deferred financing costs	(1,530,201)	(4,557,594)	
Deferred financing costs related to terminated transactions		(666,306)	
Proceeds from exercise of stock options	29,983	54,137	
Proceeds from revolver borrowings	109,100,000	28,750,000	39,350,000
Payments on revolver	(31,700,000)	(67,750,000)	(36,350,000)
Dividends paid	(2,794)	(732)	
Treasury stock	(2,145)		(613)
Payments on other debt	(132,743)	(121,792)	(111,767)
Net cash provided by (used in) financing activities	75,762,100	(4,292,287)	2,887,620
Effect of exchange rate changes on cash and cash equivalents	509	17,774	167,723
Decrease in cash and cash equivalents	(78,668)	(437,187)	(1,122,841)

Cash and cash equivalents at beginning of year		536,533		973,720		2,096,561
Cash and cash equivalents at end of year	$	457,865	$	536,533	$	973,720
Supplemental disclosure of cash flow information:						
Cash paid during the year for:						
Interest expense	$	3,564,115	$	5,422,325	$	5,197,538
Income taxes	$	25,000	$	25,000	$	25,000
Significant noncash investing and financing activities:						
Accrued capital expenditures	$	931,479	$	1,154,146	$	397,375