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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 001-32960

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code

(713) 659-3855

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $0.001 per share	**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 ¨ 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 ¨ Smaller reporting company x

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ 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 $1.14 on the NASDAQ Global Market on June 30, 2010) on the last business day of registrant s most recently completed second fiscal quarter was approximately $24.6 million.

As of April 1, 2011, 39,858,013 shares and 4,278,124 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 2011 annual meeting of stockholders, which will be filed on or before April 30, 2011.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Included in this annual report are certain forward-looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Exchange Act of 1934 (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 statements that contain these words carefully and should not place undue reliance on these statements. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- 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;
- general economic conditions may be less favorable than expected, including the possibility that the reduced level of economic growth in the United States will be prolonged or a new economic recession may develop, which could adversely affect the demand for gas and make it difficult, if not impossible, to access financial markets;
- 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;
- 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;

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- 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.

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 interest.

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GLOSSARY OF NATURAL GAS AND COALBED METHANE TERMS

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

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

Appalachian Basin. A hydrocarbon producing mountainous region in the eastern United States, running from northern Alabama to Pennsylvania, and including parts of Georgia, South Carolina, North Carolina, Tennessee, Kentucky, Virginia, and all of West Virginia.

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.

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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.

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.

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

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

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

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PART I

Items 1 and 2. *Business and Properties*

Overview

GeoMet, Inc. is 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 Basin in Alabama and the central Appalachian Basin in West Virginia and 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, 2010, we own a total of approximately 160,000 net acres of coalbed methane and oil and gas development rights.

We primarily explore for, develop, and produce coalbed methane and non-conventional shallow gas. Our objective is to create a premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the investment of capital to increase reserves, production, cash flow and earnings. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane and non-conventional shallow gas fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane and non-conventional shallow gas offer certain operational advantages compared to conventional gas production. Coalbed methane and non-conventional shallow gas can also offer certain operational challenges and disadvantages to conventional gas producers.

Current Business Plan

In the current natural gas pricing environment, the Company intends to limit capital spending to its internally generated cash flows from operations. Accordingly, it is unlikely to consider any significant exploration activities until conditions improve, as such investments would likely not be economical. We currently intend to drill our proved undeveloped locations in the Pond Creek field and to continue to conduct hydraulic fracturing in new infill wells or in behind pipe shallow zones in the Gurnee field on a limited basis. Our current focus is to complete the developmental drilling program in the Pond Creek field and, in the Gurnee field, improve production and determine the commerciality of future development through hydraulic fracturing techniques. At current gas prices, it is unlikely that we would seek, nor could we obtain on reasonable terms, significant additional financing necessary to acquire additional properties or otherwise expand beyond our current developmental drilling and hydraulic fracturing programs. At December 31, 2009 and 2010, we had $15.5 million and $9.5 million, respectively, in available borrowing capacity. This business plan is consistent with our past actions taken in unfavorable pricing environments. For example, when the price of natural gas declined precipitously at the end of 2008, we stopped substantially all of our development activities, and in 2009 did not drill any new wells.

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

Pond Creek

In the Pond Creek field in the central Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 30,000 net CBM acres. At December 31, 2010, approximately 61% of our estimated proved reserves, or 132 Bcf, were located within the Pond Creek field, of which approximately 73% were classified as proved developed. As of December 31, 2010, we are the operator and own an average 99% working interest in 264 gross productive wells in the Pond Creek field. Net daily sales of gas averaged 14,581 Mcf for 2010.

In 2010, we drilled 20 net new wells in the Virginia portion of the field, adding 19 to sales during the year. 16 of these were added to sales in the last half of the year, mostly in the fourth quarter. The average production rate per well from these wells is currently greater than the current field wide average production rate per well. We expect production from this group of wells to continue to incline. We plan to drill 20 proved undeveloped wells annually in the Virginia portion of the Pond Creek field through 2013; however, we may drill as few as 14 of these wells during 2011 if we decide to reallocate additional capital to the Gurnee field. See discussion below on the Gurnee field.

We extract gas from an average of 12 coal seams within the Pocahontas and New River coal formations at depths ranging from 430 feet to 2,400 feet. At these depths overall coal thickness in this area ranges from 10 to 30 feet of low-medium volatile bituminous rank Pennsylvanian Age coal. Prior mining activity revealed that these coal groups are gas rich. A total of 42 core holes have been drilled on and in the area of our acreage in the central Appalachian Basin and a geographically extensive gas desorption testing program has been conducted to determine the gas content of the coal and to define the coalbed methane resource under a substantial portion of our leasehold position.

Wells in the Pond Creek field produce comparatively lower levels of water. Produced water is used in our operations, injected into our disposal well or ground applied after being processed through our reverse osmosis system. We believe we have adequate capacity to meet our future water disposal requirements in the Pond Creek field.

Our gas from the Pond Creek field is gathered into our central dehydration and compression facilities and delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC (ETNG). In January 2007, we executed two long-term transportation agreements with ETNG which became effective when our pipeline was placed in service on April 1, 2007, with total maximum daily quantities of 15,000 MMBtu s and 10,000 MMBtu s and primary terms of 15 years and 10 years, respectively. We believe we have adequate takeaway capacity to meet our future needs.

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.

Gurnee

We hold the development rights to approximately 39,000 net CBM acres throughout the Gurnee field in the Cahaba Basin of central Alabama. At December 31, 2010, approximately 36% of our estimated proved reserves, or 78 Bcf, were located in the Gurnee field, of which approximately 82% were classified as proved developed. We are the operator and own a 100% working interest in the area. As of December 31, 2010, we had 246 productive wells in the Gurnee field of which 31 wells are shut-in. Two wells are shut in due to a lack of infrastructure in that area of the field and the remaining 29 shut-in wells are due to poor gas production which resulted in those wells not being economic to operate at current price levels. Net daily sales of gas averaged 5,089 Mcf for 2010.

We extract gas from six coal groups within the Pottsville coal formation at depths ranging from 700 feet to 3,400 feet. At these depths, overall seam thickness in this area averages approximately 50 feet of high volatile bituminous rank coal. A total of 33 core holes have been drilled and over 600 gas desorption tests have been conducted on our acreage to determine the gas content of the coal and to define the coalbed methane resource under a substantial portion of the acreage in our leasehold position.

Our acreage is roughly evenly divided between a northern block, largely on the east side of the Cahaba River, and a southern block, largely on the west side of the river. The geology is generally more complex on the east side of the river with beds dipping from northwest to southeast. The geological setting west of the river tends to be less complex with more gently dipping beds. Most of the development to date in the Gurnee field has been on the east side of the river which is near existing infrastructure.

We own and operate an approximate 38.5-mile pipeline from the Cahaba Basin to the Black Warrior River for the disposal of produced water under a permit issued by the Alabama Department of Environmental Management (ADEM). This pipeline has a maximum design capacity of approximately 45,000 barrels of water per day, but would require additional pump stations and looping a portion of the line in order to reach the maximum design capacity, if needed. We are currently transporting less than 10,000 barrels of produced water per day through this line and we believe we have adequate takeaway capacity to meet our future needs. All National Pollutant Discharge Elimination System (NPDES) permits for the discharge of produced water from coalbed methane fields in Alabama are issued for five-year terms by the ADEM and are subject to renewal every five years. We were granted an NPDES permit for the discharge of produced water from the Gurnee field into the

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Black Warrior River in 2004. We have submitted a timely and complete renewal application to ADEM for a five-year renewal of our NPDES permit. No five-year renewal NPDES permits for the discharge of produced water from coalbed methane fields into streams or rivers have been granted by ADEM since our renewal application was submitted. ADEM is currently administratively extending all existing NPDES permits for disposal of produced water from coalbed methane fields into streams or rivers for which timely and complete renewal applications are received, including our NPDES permit.

We own and operate a 17.3-mile, 12-inch high pressure steel pipeline and a gas treatment and compression facility through which we gather, dehydrate, and compress our gas for delivery into the Southern Natural Gas pipeline system. As we own the gathering and delivery pipeline system, we incur no third party costs to gather and deliver our gas to market. We believe we have adequate takeaway capacity to meet our future needs.

In the third quarter of 2009, we postulated that fracture conductivity loss after commencing production was a main contributor to underperforming production, and that our Gurnee wells were draining only a small area around each wellbore. Since the third quarter of 2009, we have temporarily plugged off production from seven wells and conducted a new shale-like frac technique in primarily upper coal seams that were behind pipe. This technique has generated encouraging results. This technique has also been applied in two existing, previously fraced full wellbores but we were unsuccessful in isolating the existing perforations and these efforts failed. We believe that when we have been successful in getting the frac into the strata surrounding the coalseams, we have had consistently good results. In the fourth quarter of 2010, we drilled a new well in the Gurnee field in order to test this technique on a full wellbore without the complication of existing perforations. This well was completed in the lowest of three coal groups and produced several hundred barrels of water per day and only small volumes of gas for approximately three months before we set a temporary plug above the completion and completed the middle and upper coal groups in the well. We have recently commenced production from this completion and, after a dewatering period, we will remove the plug and produce from all three coal groups in the well. We have recently drilled and completed the first two of four additional infill wells planned in 2011 to further test this technique. If encouraging results continue, we will consider reallocating more capital to the Gurnee Field to drill additional wells and complete additional shallow behind pipe coal groups in existing wells where we expect good economic returns and immediate increases in gas production.

Lasher

In the Lasher field in the central Appalachian Basin of southern West Virginia, we have the rights to develop approximately 8,000 net CBM acres. At December 31, 2010, approximately 3% of our estimated proved reserves, or 7 Bcf, were located within the Lasher field, of which approximately 57% were classified as proved developed. As of December 31, 2010, we are the operator and own a 100% working interest in 18 productive wells. Our gas from the Lasher field is delivered into a Columbia Gas Transmission pipeline. We believe adequate takeaway capacity exists to meet our future needs.

Garden City

The Garden City Chattanooga Shale prospect is located in north central Alabama. At December 31, 2010, we have approximately 50,000 net acres of leasehold. As of December 31, 2010, we have no proved reserves booked for our Garden City Chattanooga Shale prospect. The Alabama Oil & Gas Board approved our proposal to temporarily inject produced water into one of our existing vertical wells which will also allow us to resume gas production from two existing horizontal wells without having to truck the produced water at prohibitive costs. We have recently put two horizontal wells back on production in our Garden City shallow shale prospect. We are attempting to complete a longer term production test in order to establish the potential economics of water disposal options.

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Estimated Proved Reserves

Our proved natural gas reserves as of December 31, 2010, as estimated by DeGolyer & MacNaughton (D&M), totaled approximately 216 Bcf, an increase of approximately 3% from the approximate 209 Bcf of proved natural gas reserves at December 31, 2009, as estimated by D&M. Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month, adjusted for regional price differentials, for the years ended December 31, 2010 and 2009. For the year ended December 31, 2010, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.41 per Mcf, resulting in a natural gas price of $4.49 per Mcf when adjusted for regional price differentials. For the year ended December 31, 2009, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.87 per Mcf, resulting in a natural gas price of $4.06 per Mcf when adjusted for regional price differentials. Natural gas prices associated with operating wells were held constant and estimates of operating expenses and capital costs based on current costs were used for the lives of the properties with no increases in the future based on inflation (in certain cases, future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating condition) in accordance with the amended SEC guidelines which were effective for financial statements for periods ending on or after December 31, 2009. For the year ended December 31, 2008, proved reserve estimates were based on prices as of the last day of the year. As a result, estimates of proved reserves as of December 31, 2010 and 2009 may not be comparable to those as of December 31, 2008.

Our proved reserves were 100% from coalbed methane reservoirs and were 76% developed. Approximately 64% of total year-end 2010 proved reserves are in the Pond Creek and Lasher fields in West Virginia and Virginia and 36% are in the Gurnee field in Alabama.

The following table presents information related to our estimated proved reserves as of December 31, 2010.

Field	Proved Developed Producing (MMcf)	Proved Developed Non-Producing (MMcf)	Proved Undeveloped (MMcf)	Total Proved (MMcf)
Central Appalachia:				
Pond Creek field	94,890	570	36,077	131,537
Lasher field	3,654	230	2,885	6,769
Alabama:				
Gurnee field	51,168	12,712	13,658	77,538
Other	95			95
Totals	149,807	13,512	52,620	215,939

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. For the year ended December 31, 2010, we had the following activity related to our PUDs:

	Mcf	Locations	Capital Expenditures
Proved Undeveloped Reserves at December 31, 2009	53,032,832	138	$ 55,780,241
Converted to Proved Developed Reserves	(7,992,013)	(21)	$ (10,154,527)
Converted from Probable Reserves	2,826,309	9	$ 2,989,101
Net impact of CNX acreage swap(1)	3,138,175	(5)	$ 2,434,946
Revisions	158,254	6	$ 2,945,508
Other (Prices & Costs)	1,457,731		$ 4,376,449
Proved Undeveloped Reserves at December 31, 2010	52,621,288	127	$ 58,371,718

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(1) The Company executed an acreage swap during 2010 which provided net additional PUDs through increased mineral interest and lost 5 drilling locations.

(2) The net negative impact of revisions included the effects of higher prices, lease expirations and lower performance related to offset locations.

In summary, the Company converted 15% of its PUDs to proved developed reserves from the prior year, converted 2.8 Bcf from probable reserves, added 3.1 Bcf of reserves from an acreage swap, and added 1.6 Bcf from other and revisions related primarily to price and cost assumptions. We do not have material PUDs that were included in the estimated quantities of proved undeveloped reserves as of December 31, 2005 and in addition we do not have any PUDs that are projected to be drilled beyond the five year window included in the estimated quantities of proved undeveloped reserves as of December 31, 2010.

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, an independent petroleum engineering consulting firm, 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 24 years, including nine years with River Gas Corporation in Northport, Alabama from 1992 to 2001 and the last nine years with GeoMet in Hoover, Alabama. He also worked briefly with Phillips Petroleum following its acquisition of River Gas Corporation. During the last 18 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 to estimate our year-end reserves and assesses them for reasonableness.

Our controls over reserve estimates included retaining D&M 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 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 report of D&M, which is included as an exhibit to this annual report on Form 10 K. Estimates of our proved reserves at December 31, 2010, 2009, and 2008 were prepared by D&M. The technical persons at D&M 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 the Company s 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. 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.

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

The reserves information in this filing on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by D&M and 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,		
	2010	**2009**	**2008**
Gas:			
Net sales volume (Bcf)	7.4	7.5	7.5
Average natural gas sales price ($ per Mcf)	$ 4.49	$ 4.05	$ 9.17
Average natural gas sales price ($ per Mcf) realized(1)	$ 5.72	$ 5.47	$ 9.10
Total production expenses ($ per Mcf)	$ 2.27	$ 2.67	$ 2.87
Expenses: ($ per Mcf)			
Lease operations expenses	$ 1.57	$ 1.85	$ 1.98
Compression and transportation expenses	$ 0.56	$ 0.66	$ 0.60
Production taxes	$ 0.14	$ 0.16	$ 0.29
Depletion of gas properties	$ 0.79	$ 1.51	$ 1.35
General and administrative	$ 0.73	$ 1.11	$ 1.26

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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, 2010.

	Three Months Ended			
	March 31, 2010	**June 30, 2010**	**September 30, 2010**	**December 31, 2010**
Gas:				
Net sales volume (Bcf)	1.8	1.8	1.8	1.9
Average natural gas sales price ($ per Mcf)	$ 5.43	$ 4.20	$ 4.47	$ 3.90
Average natural gas sales price ($ per Mcf) realized(1)	$ 6.23	$ 5.41	$ 5.45	$ 5.78
Total production expenses ($ per Mcf)	$ 2.37	$ 2.29	$ 2.28	$ 2.16
Expenses: ($ per Mcf)				
Lease operations expenses	$ 1.71	$ 1.54	$ 1.56	$ 1.47
Compression and transportation expenses	$ 0.55	$ 0.59	$ 0.60	$ 0.53
Production taxes	$ 0.11	$ 0.16	$ 0.12	$ 0.16
Depletion of gas properties	$ 0.83	$ 0.72	$ 0.78	$ 0.82
General and administrative	$ 0.81	$ 0.72	$ 0.65	$ 0.73

(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 own a working interest as of December 31, 2010. Gross represents the total number of acres or wells in which we own 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.

	Productive Wells		Developed Acres		Undeveloped Acres	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gurnee	246.0	246.0	17,347	17,307	21,883	21,883
Garden City			640	640	53,407	49,118
Pond Creek	264.0	262.0	17,117	17,117	13,440	13,247
Lasher	18.0	18.0	1,012	1,012	15,665	7,232
Peace River			720	360	51,138	25,569
Other			840	840	5,365	5,365
Total	528.0	526.0	37,676	37,276	160,898	122,414

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Our material undeveloped leases are in Alabama, which includes the Gurnee and Garden City fields, the Central Appalachian Basin, which includes the Pond Creek and Lasher fields, and Canada which includes the Peace River field. Generally, the undeveloped acreage expires on various dates from 2011 through 2013; 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 2011 through 2013 or the leases can be extended by drilling and production operations or option payments. The following table sets forth expiring undeveloped acreage through 2013 as of December 31, 2010:

	2011		2012		2013	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gurnee			21,883	21,883		
Garden City	25,435	22,853	13,548	13,226	13,859	12,511
Pond Creek	3,901	3,901	767	767		
Lasher			15,665	7,233		
Peace River	17,948	8,974	5,536	2,768	300	150
Other						
Total	47,284	35,728	57,399	45,877	14,159	12,661

The terms of the undeveloped acreage may be extended by drilling and production operations or through negotiation with lessors. We have a commitment in our Pond Creek field to commence 26 wells by August 2011 (12 of these wells were commenced in 2010) and an additional 26 wells must be commenced at our Pond Creek field by August 2012.

Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the U.S. and Canada 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.

	Gross					
	Exploratory			Development		
Well Activity (Gross) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2010				20		20
Year ended December 31, 2009				4		4
Year ended December 31, 2008	2		2	54		54

	Exploratory			Development		
Well Activity (Gross) Canada	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2010						
Year ended December 31, 2009						
Year ended December 31, 2008				5		5

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.

	Net					
	Exploratory			Development		
Well Activity (Net) U.S.	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2010				20		20
Year ended December 31, 2009				4		4
Year ended December 31, 2008	2		2	54		54

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Well Activity (Net) Canada	Exploratory Productive	Exploratory Dry	Exploratory Total	Development Productive	Development Dry	Development Total
Year ended December 31, 2010						
Year ended December 31, 2009						
Year ended December 31, 2008				2.5		2.5

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.

Current Business Environment

Our ability to successfully leverage our competitive strengths and execute our strategy depends upon many factors and is subject to a variety of risks. For example, our ability to fund our capital budget depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels, maintain borrowing capacity at or near current levels under our revolving credit facility, and the availability of future debt and equity financing on satisfactory terms. Our ability to fund CBM property acquisitions and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Prolonged weakness in the global economy and in natural gas prices, which may affect both our cash flows and the value of our gas reserves, limitations on our ability to replace production through drilling activities, a material adverse change in our gas reserves due to factors other than gas pricing changes, our ability to transport our gas to markets, drilling costs, lower than expected production rates, material adverse outcomes from lawsuits and other factors, many of which are beyond our control, may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel, among other things.

Changes in natural gas prices may significantly affect our revenues, financial condition, cash flows, natural gas reserves and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices, unless sufficient hedges are in place to offset such declines, will materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and/or result in a lower determination of our borrowing base. Although we will attempt to cure any non-compliance with covenants in our revolving credit facility in the event they occur, no assurance can be given that we will be able to cure such non-compliance. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, unless sufficient hedges are in place to offset such declines, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our future capital expenditure budgets are increasingly dependent on future natural gas prices, as our hedges decline over time, and compliance with revolving credit facility covenants and borrowing base levels.

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We believe that we are taking necessary actions and have certain attributes that position us to continue operations in the current credit and commodity market environment. These include premium natural gas pricing due to the geographic location of our properties, lower costs of finding and developing our natural gas reserves than industry averages, aggressive hedging of natural gas prices, long-lived reserves with shallow Company-wide annual production decline rates, and rigorous cost control.

We expect to fund our capital expenditure budget for 2011 from our operating cash flows. If our cash flows are not sufficient to fund all of our planned capital projects, we expect to reduce our capital budget accordingly. The amount and timing of our expenditures are subject to change based upon market conditions, results of operations and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results, and borrowing base redeterminations and compliance with covenants under our revolving credit facility.

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 primarily one purchaser of our natural gas production. For the year ended December 31, 2010, the aforementioned purchaser purchased 98% of our net natural gas production. As of December 31, 2010, the aforementioned purchaser represented 98% of our accounts receivable related to gas sales. We do not believe the loss of our 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.

See Areas of Operation Pond Creek above for a description of an agreement we have entered into regarding sale of gas production from our Pond Creek field.

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.

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Governmental, State and Local Regulations

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

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

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

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

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

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

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

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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.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. 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 FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas operations, and we note that some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other sellers of natural gas with whom we compete.

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

West Virginia Regulation. West Virginia s Supreme Court has held that, in a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding coalbed methane operations, the oil and gas lessee did not acquire the right to produce coalbed methane. As of December 31, 2010, 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 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

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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 the National Energy Board (NEB) and provincial agencies in Canada. These agencies have jurisdiction similar to the FERC for regulation. Business in Western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints basis. However, 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.

In addition to federal regulation, 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; 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 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. These persons include the owner or operator of the site where the release occurred and companies 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.

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 these 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 and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other substances, 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 and natural resource damages. 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, 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.

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 regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. 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.

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 the Company 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 the Company 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 the Company 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 the Company produces.

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.

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.

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 U.S. and Canada with only the U.S. currently having material revenue generating operating results.

Employees

At December 31, 2010, we had a total of 61 employees, all of which were full-time. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are generally satisfactory.

Corporate Offices

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

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Exchange Act of 1934, as amended, or 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*.

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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 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 and demand 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. Even relatively modest drops in prices can affect our financial results and impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves, our cash flow, and our borrowing capacity. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas;
- overall domestic and global economic conditions;
- the consumption pattern of industrial consumers, electricity generators, and residential users;
- weather conditions;
- technological advances affecting energy consumption;
- technological advances affecting natural gas supply such as recent development of shale gas;
- governmental regulations;
- proximity and capacity of gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Many of these factors are beyond our control. Because all of our estimated proved reserves as of December 31, 2010 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Recent natural gas prices have been extremely volatile and we expect this volatility to continue. For example, during 2009 natural gas prices declined to less than $3.00 per Mcf, the lowest level since 2002, before recovering later that year. During 2010, the Henry Hub spot price for natural gas ranged from $3.18 per Mcf to $7.51 per Mcf.

The results of increased investment in the exploration for and production of natural gas and other factors, such as global economic and financial conditions discussed below, may cause the price of gas to fall. 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 and cash flow. 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.

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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 $80.5 million as of December 31, 2010. As a result of our indebtedness, we must use a portion of our cash flow to pay interest, which reduces the amount we have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our revolving credit facility is at a variable interest rate. As such, an increase in interest rates will generate greater interest expense. The amount of our debt makes us more vulnerable to economic downturns and adverse developments in our business.

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.

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.

Our revolving credit facility currently expires in September 2013.

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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.

Among the changes contained in President Obama s fiscal year 2012 budget proposal, released by the White House on February 14, 2011, is the elimination or deferral of certain key U.S. federal income tax deductions currently available to oil and gas exploration and production companies. Such proposed 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 certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies, which, if enacted, would negatively affect our financial condition and results of operations. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change 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 by March 2011 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. EPA has proposed such greenhouse gas regulations and may issue final rules this year.

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.

Recent federal legislation could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

We enter into a number of commodity derivative contracts in order to hedge a portion of our natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act. Title VII of the Dodd-Frank Act (titled Wall Street Transparency and Accountability) repeals prior regulatory exemptions for over-the-counter (OTC) derivatives and, for the first time, creates a comprehensive framework for the regulation of the derivatives market and, in connection therewith, expands the power of the SEC and, in particular, the Commodity Futures Trading Commission (or CFTC). Among the provisions of the Dodd-Frank Act that may affect derivatives transactions are certain clearing and trade-execution requirements; establishing capital and margin requirements for certain derivatives participants; establishing business conduct standards, recordkeeping and reporting requirements; and providing the CFTC with authority to impose position limits in the OTC derivatives markets. The Dodd-Frank Act may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including 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.

Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations to be adopted by applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or these new rules and regulations may have on our hedging activities. To the extent that we are subject to capital or margin requirements relating to, or restrictions on, our hedging activities or the costs associated with hedging activities increase, it could have an adverse effect on our ability to hedge the risks associated with our business, 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 legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If a consequence of the legislation and regulations is to lower commodity prices, our revenues could be adversely affected. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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

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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.

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. 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.

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

As of December 31, 2010, we had U.S. federal tax net operating loss carryforwards of approximately $113.2 million, which expire at various dates from fiscal year 2022 through fiscal year 2030. The years that contributed most to our federal net operating loss carryforwards were fiscal years 2003, 2004, 2005 and 2009 in the amount of $20.5, $17.2, $22.4 and $20.4 million respectively and that portion of the losses will expire in fiscal years 2023, 2024, 2025 and 2029 respectively. These net operating loss carryforwards may be used to offset future taxable income and thereby reduce our U.S. federal income taxes otherwise payable. Section 382 of the Internal Revenue Code of 1986, as amended (the Code), imposes an annual limit on the ability of a corporation that undergoes an ownership change to use its net operating loss carry forwards to reduce its tax liability. An ownership change would occur if stockholders, deemed under Section 382 to own 5% or more of our capital stock by value, increase their collective ownership of the aggregate amount of our capital stock to more than 50 percentage points over a defined period of time. In the event of certain changes in our stockholder base, we may at some point in the future experience an ownership change as defined in Section 382 of the Code. Accordingly, our use of the net operating loss carryforwards and credit carryforwards may be limited at some point in the future by the annual limitations described in Sections 382 and 383 of the Code.

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

Producing natural gas reservoirs are typically characterized by declining production rates that vary depending upon reservoir characteristics and other factors. CBM production generally declines at a shallow rate after initial increases in production which result as a consequence of the de-pressuring process. The rate of decline from our existing wells may change in a manner different than we have estimated. Thus, our future natural gas reserves and production and, therefore, our borrowing capacity, cash flow and income are highly

dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs.

Currently the vast majority of our producing properties are located in two counties in Alabama, one county in West Virginia, and one county in Virginia, making us vulnerable to risks associated with having our production concentrated in a few areas.

The vast majority of our producing properties are geographically concentrated in two counties in Alabama, one county in West Virginia, and one county in Virginia. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, interruption of transportation of natural gas produced from the wells in these basins, or other events which impact these areas.

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, 2010, we own leasehold interests in approximately 50,000 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.

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 results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting 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, a draft of which must be published by June 1, 2011, followed by a 30-day comment period. 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.

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.

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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. Additionally, the size of these projects dictates that development proceeds in an orderly manner to assure continuity of resources and producibility. Furthermore, the additional drilling locations on acreage in our two early-stage CBM development projects and our Chattanooga Shale exploration prospect face additional uncertainties regarding the economic returns achievable in these areas where only a few wells have been drilled to date.

Our operations in British Columbia present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

We conduct our operations in British Columbia through a wholly owned subsidiary, Hudson s Hope Gas, Ltd. Our operations in British Columbia may be adversely affected by currency fluctuations. The expenses of such operations are payable in Canadian dollars. As a result, our Canadian operations are subject to risk of fluctuations in the relative value of the Canadian and U.S. dollars. Other risks of operations in Canada include, among other things, increases in taxes and governmental royalties and changes in laws and policies governing operations of foreign-based companies. Laws and policies of the U.S. affecting foreign trade and taxation may also adversely affect our operations in British Columbia.

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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.

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

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

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

We depend on technology owned by others.

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

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.

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.

In connection with the amendment of the terms of our Preferred Stock to revise the anti-dilution provisions of the Preferred Stock to eliminate the treatment of the conversion feature of our Preferred Stock as a derivative liability, we agreed not to 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

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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.

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 26% of our common stock outstanding as of December 31, 2010 (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 20% of our common stock. Additional shares of our Series A Convertible Redeemable Preferred Stock may be issued to Sherwood and our other Series A preferred stockholders as paid-in-kind dividends. In addition, two of the current members of our board of directors are appointed by Sherwood and another member of our board of directors is a member and a manager of the general partner of Yorktown. As a result, Sherwood and Yorktown have, and can be expected to have, a significant voice in our affairs, in the outcome of stockholder voting concerning the election of directors, the adoption or amendment of provisions in our charter and bylaws, the approval of mergers and other significant corporate transactions.

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

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present common stockholders. We are currently authorized to issue 125,000,000 shares of common stock and 10,000,000 shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of December 31, 2010, 39,758,484 shares of common stock are outstanding, and 31,911,830 shares of common stock are issuable upon conversion of outstanding Series A Convertible Redeemable Preferred Stock. An additional 3,253,294 shares, net of accrued PIK dividends, of our Series A preferred stock, convertible into 25,025,339 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

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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, 2010, 39,758,484 shares of our common stock were outstanding, together with outstanding options representing the right to purchase up to 2,542,159 shares. On September 14, 2010, we issued and sold 2,351,801 shares of our Series A Convertible Redeemable Preferred Stock to Sherwood Energy, LLC and agreed to register the shares of underlying common stock, presently 18,090,776 shares, for resale. In addition, on September 14, 2010 we issued and sold 1,648,199 shares of our Series A Convertible Redeemable Preferred Stock to participants in a registered rights offering. As of December 31, 2010, our outstanding Series A Convertible Redeemable Preferred Stock is convertible into an aggregate of 31,911,830 shares of our common stock, which represents approximately 80% of our issued and outstanding common stock as of December 31, 2010. Upon the effectiveness the resale registration statement relating to the common stock underlying shares of Series A Convertible Redeemable Preferred Stock held by Sherwood, much of the common stock underlying the Series A preferred stock may be sold by the selling security holders in market transactions from time to time. 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.

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.

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EQT Production Company Claim

In March 2011, we received a letter from EQT Production Company (EQT) stating that our fracturing operations in 2010 had damaged a well owned by EQT, and demanding the payment of the value of the well and other amounts totaling approximately $430,000. In April 2011, EQT revised their demand for payment to approximately $464,000. We are reviewing the claim to determine if we are liable for the damages alleged to have been sustained by EQT. We believe that if we are responsible for the damages, substantially all of the loss will be covered by our insurance. A majority of our proved undeveloped locations in the Pond Creek field are owned by us through a farmout agreement with EQT that provides that if we default under the agreement, our future development rights under the farmout agreement terminate. The failure to pay the amount of any damages to EQT for which we are liable may be a default as defined in the farmout agreement. We do not believe that the payment of any damages to EQT for which we may be liable will have a material impact on our results of operations, financial position nor cash flows.

Environmental and Regulatory

As of December 31, 2010, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

Item 4. [*Removed and Reserved*]

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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 2008:		
Quarter ended March 31, 2008	$ 7.28	$ 4.21
Quarter ended June 30, 2008	$ 9.52	$ 6.38
Quarter ended September 30, 2008	$ 9.40	$ 5.04
Quarter ended December 31, 2008	$ 5.32	$ 1.36
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

Approximately 1,500 stockholders of record as of March 1, 2011 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, the Company 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 (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

Approximately 300 stockholders of record as of December 31, 2010 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. The Company s revolving credit agreement contains a restrictive covenant which influences its ability to pay cash dividends. Cash dividends are permitted only if the Company s 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.

Investor Board Representation

In connection with the Rights Offering, Sherwood Energy LLC (Sherwood) entered into a Backstop Commitment to purchase any Preferred Stock not acquired by our stockholders in the Rights Offering. Pursuant to the Backstop Commitment, Sherwood acquired 2,351,801 shares of our Preferred Stock, or 59% of the 4,000,000 shares purchased in the Right Offering. For as long as Sherwood beneficially owns more than 40% of the shares Sherwood acquires pursuant to its Backstop Commitment or otherwise, or beneficially owns 10% or more of our common stock on an as-converted basis, Sherwood will be entitled to nominate two persons to serve on our board.

Board Committees

For as long as Sherwood beneficially owns more than 40% of the shares acquired in the Rights Offering, or beneficially owns 5% or more of our common stock on an as-converted basis, Sherwood will be entitled to nominate one person to serve on our board. Additionally, for such time that Sherwood has the right to nominate at least one director to our board, one member of each of the Audit Committee and the Compensation Committee will be a director nominated by Sherwood, provided that such person(s) meets the applicable independence requirements. We will recommend to our stockholders to vote for the Sherwood nominee(s) and use commercially reasonable efforts to solicit proxies from our stockholders to vote in favor of the Sherwood nominee(s).

Special Voting Rights

In the event of a default under the investment agreement, which includes a default of our obligations under our credit facility or our failure to pay dividends on the preferred stock, the board will be expanded and Sherwood will be allowed to appoint additional directors or we will secure the resignations of directors not appointed by Sherwood, such that Sherwood nominees will constitute a majority of the members of our board. Upon the cure or waiver of the event of default, as applicable, our board will be reduced to the size immediately preceding the default, and the Sherwood directors appointed in connection with the expansion will resign. If we are unable to effectuate an expansion or reconfiguration of our board, or if an event of default continues for more than twelve months, Sherwood may cause us to redeem all of Sherwood s shares of preferred stock (including PIK dividends) at the redemption price of $10.00 per share plus any unpaid dividends.

Matters Requiring Investor Director Approval

As long as Sherwood continues to beneficially own 40% or more of the shares of Preferred Stock Sherwood acquired in the Rights Offering, or continues to beneficially own 5% or more of our common stock on an as-converted basis, we shall not take any of the following actions without the approval of all of the Sherwood-nominated director(s):

- incur any new indebtedness for borrowed money or capital leases (excluding borrowings pursuant to our credit facility) in a single transaction in excess of $500,000 within any twelve-month period;

- authorize or issue equity securities that are senior or pari passu to the preferred stock or convertible into equity securities that are senior or pari passu to the preferred stock;

- redeem or repurchase equity securities;

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enter into or be a party to a transaction with any of our directors, officers or employees, any associate of such persons, or any related party that requires disclosure under Item 404(a) of Regulation S-K;

liquidate, dissolve or wind-up its affairs, or effect any business combination;

enter into a merger, consolidation or restructuring, transfer of assets or other business combination, sale of capital stock, tender offer, exchange offer, recapitalization or other similar transaction that if consummated would result in a person acquiring beneficial ownership of 50% or more of the voting power of the Company or all or substantially all of the consolidated total assets of the Company;

appoint a new Chief Executive Officer and/or President;

make any alteration or change in the right, preferences or privileges of the preferred stock or increase or decrease the number of authorized shares of preferred stock;

amend or waive any provision of our Certificate of Incorporation, our Bylaws, or the Certificate of Designations that adversely affects the rights of the preferred stock; or

make any material change in our business from the exploration, exploitation, development and production of oil and natural gas and related activities.

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 2010. On September 14, 2010, the Company issued and sold 4,000,000 shares of Preferred Stock. After paying transaction fees and expenses in the amount of $2.8 million, the Company used the net proceeds of approximately $37.2 million to reduce outstanding bank debt. 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 . For more discussion related to the Preferred Stock, see Completion of Rights Offering and Backstop Transaction in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

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, 2010.

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	2,542,159	$ 3.31	1,432,392(1)
Equity compensation plans not approved by security holders			

Total	2,542,159	$	3.31	1,432,392

(1) A total of 4,000,000 shares of our common stock were reserved for awards to be granted under the GeoMet, Inc. 2006 Long-Term Incentive Plan, which was originally adopted and approved by our stockholders in 2006 and amended in 2009 and 2010. In conjunction with the original approval of the 2006 Plan, no additional awards will be granted under our 2005 Plan; however, we will continue to issue shares of our common stock upon exercise of awards that were previously granted. The 1,432,392 shares of common stock available for future issuance does not include 242,448 shares that were reserved but not granted under our 2005 Plan.

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Option Exchange

On December 7, 2010, the Company 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.

On January 5, 2011, the Company 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

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Performance Graph

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that we specifically incorporate the performance graph by reference into such filing.

The following graph compares the cumulative total stockholder return on our common stock from July 28, 2006, the date our common stock was listed on the Nasdaq Global Market, through December 31, 2010 and compares it with the cumulative total return on the Russell 2000 and the S&P Oil and Gas Exploration and Production Index. The comparison assumes $100 was invested on July 28, 2006 and assumes reinvestment of dividends, if any. The comparisons in this table are not intended to forecast or be indicative of possible future performance of our stock.

COMPARISON OF CUMULATIVE TOTAL RETURN

	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
GeoMet, Inc.	100.00	50.29	16.63	14.12	11.12
Russell 2000 Index	100.00	97.28	63.43	79.42	99.52
S&P Oil & Gas	100.00	142.24	81.29	113.96	146.41

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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, 2010. The selected historical financial data as of December 31, 2010 and 2009 and for each of the three years in the period ended December 31, 2010 are derived from our consolidated audited financial statements included herein. The selected historical financial data as of December 31, 2008, 2007 and 2006 and for each of the two years in the period ended December 31, 2007 was derived from our consolidated audited financial statements which are not included herein. The table reflects a four-for-one common stock split in 2006. 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.

	2010	2009	2008	2007	2006
STATEMENT OF OPERATIONS (in thousands):					
Total revenues	$ 33,361	$ 30,964	$ 69,094	$ 50,984	$ 44,947
Realized (gains) losses on derivative contracts	$ (9,006)	$ (10,694)	$ 500	$ (3,895)	$ (1,118)
Unrealized (gains) losses from the change in market value of open derivative contracts	$ (5,950)	$ 3,995	$ (4,993)	$ 3,007	$ (16,877)
Impairment of gas properties		$ 257,288	$ 50,734		
Terminated transaction costs	1,403				
Total operating expenses	$ 14,839	$ 291,093	$ 87,590	$ 37,852	$ 13,678
Operating income (loss) from continuing operations	$ 18,521	$ (260,129)	$ (18,496)	$ 13,132	$ 31,269
Interest expense, net of amounts capitalized	$ (5,168)	$ (5,174)	$ (4,783)	$ (5,130)	$ (3,130)
Unrealized loss from the change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	$ (2,164)				
Income (loss) before income taxes, minority interest, discontinued operations and cumulative effect of change in accounting principle	$ 11,199	$ (265,275)	$ (23,199)	$ 7,983	$ 28,162
Income tax expense (benefit)	$ 5,407	$ (98,142)	$ (712)	$ 2,988	$ 10,866
Income (loss) before minority interest, discontinued operations and cumulative effect of change in accounting principle, net of income tax	$ 5,792	$ (167,134)	$ (22,487)	$ 4,995	$ 17,296
Discontinued operations, net of income tax				$ 174	$ 23
Minority interest, net of income tax					$ (23)
Income from discontinued operations				$ 174	
Net income (loss)	$ 5,792	$ (167,134)	$ (22,487)	$ 5,169	$ 17,296
Accretion of Series A Convertible Redeemable Preferred Stock	$ (498)				
Paid-in-kind dividends	$ (1,487)				
Net income (loss) available to common stockholders	$ 3,808	$ (167,134)	$ (22,487)	$ 5,169	$ 17,296
EARNINGS PER COMMON SHARE (in dollars):					
Income (loss) from continuing operations					
Basic	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13	$ 0.49
Diluted	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13	$ 0.48
Discontinued operations					
Basic					
Diluted					
Net income (loss) per common share					
Basic	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13	$ 0.49
Diluted	$ 0.10	$ (4.28)	$ (0.58)	$ 0.13	$ 0.48

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	2010	2009	2008	2007	2006
BALANCE SHEET DATA (in thousands, at period end):					
Working capital (deficit)(1)	$ 1,545	$ (35)	$ (1,441)	$ (2,063)	$ (1,625)
Total assets (including impairment of gas properties)	$ 170,086	$ 160,928	$ 377,600	$ 378,677	$ 335,195
Long-term debt	$ 80,863	$ 119,996	$ 117,118	$ 96,730	$ 60,832
Mezzanine equity	$ 22,074				
Stockholders equity	$ 51,008	$ 26,908	$ 192,432	$ 218,676	$ 210,007
Cash flow data (in thousands):					
Net cash provided by operating activities	$ 16,022	$ 8,518	$ 32,958	$ 17,487	$ 21,472
Net cash used in investing activities	$ (12,135)	$ (12,696)	$ (52,719)	$ (53,832)	$ (78,669)
Net cash (used in) provided by financing activities	$ (4,342)	$ 2,888	$ 20,493	$ 36,191	$ 58,086
Capital expenditures	$ 12,293	$ 12,566	$ 52,797	$ 54,026	$ 79,061
OTHER DATA:					
Net sales volume (Bcf)	7.4	7.5	7.5	7.1	6.2
Average natural gas sales price ($ per Mcf)	$ 4.49	$ 4.05	$ 9.17	$ 6.97	$ 7.19
Average natural gas sales price ($ per Mcf) realized(2)	$ 5.72	$ 5.47	$ 9.10	$ 7.52	$ 7.37
Total production expenses ($ per Mcf)	$ 2.27	$ 2.67	$ 2.87	$ 2.86	$ 2.75
Depletion of gas properties($ per Mcf)	$ 0.79	$ 1.51	$ 1.35	$ 1.24	$ 1.26
Estimated proved reserves (Bcf)(3)	215.9	209.3	319.5	350.2	325.7
Standardized measure of discounted future net cash flows ($ millions)	$ 119.6	$ 95.4	$ 310.3	$ 495.9	$ 359.5

(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, 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.

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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 and developer of coalbed methane properties since 1993. Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the central Appalachian Basin in West Virginia and Virginia. We also own additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia. As of December 31, 2010, we own a total of approximately 160,000 net acres of coalbed methane and oil and gas development rights.

Our ability to successfully leverage our competitive strengths and execute our strategy depends upon many factors and is subject to a variety of risks. For example, our ability to drill on our properties and fund our capital budgets may depend, to a large extent, upon our ability to generate cash flow from operations at or above current levels, maintain borrowing capacity at or near current levels under our revolving credit facility, and the availability of future debt and equity financing on satisfactory terms. Our ability to fund new opportunities and compete for and retain the qualified personnel necessary to conduct our business is also dependent upon our financial resources. Prolonged weakness in the global economy and in natural gas prices, which may affect both our cash flows and the value of our gas reserves, limitations on our ability to replace production through drilling activities, a material adverse change in our gas reserves due to factors other than changes in gas prices changes, our ability to transport our gas to markets, drilling costs, lower than expected production rates and other factors, many of which are beyond our control, may adversely affect our ability to fund our anticipated capital expenditures, pursue property acquisitions, and compete for qualified personnel, among other things.

Changes in natural gas prices may significantly affect our revenues, financial condition, cash flows, natural gas reserves and borrowing capacity. Markets for natural gas have historically been volatile and we expect this trend to continue. Prices for natural gas may fluctuate in response to changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we will receive for our natural gas. Accordingly, any significant or sustained declines in natural gas prices may materially adversely affect our financial condition, operating results, liquidity and ability to obtain financing. Declining or prolonged low natural gas prices may also result in non-compliance with the covenants in our revolving credit facility agreement and could result in a lower determination of our borrowing base. Although we will attempt to cure any non-compliance with covenants in our revolving credit facility in the event they occur, no assurance can be given that we will be able to cure such non-compliance. Lower natural gas prices also may reduce the amount of natural gas that we can produce economically. Further declines in natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our proved natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Our capital expenditure budgets are highly dependent on future natural gas prices.

Current Business Plan

In the current natural gas pricing environment, the Company intends to limit capital spending to its internally generated cash flows from operations. Accordingly, it is unlikely to consider any significant exploration activities until conditions improve, as such investments would likely not be economical. We currently intend to drill our proved undeveloped locations in the Pond Creek field and to continue to conduct hydraulic fracturing in new infill wells or in behind pipe shallow zones in the Gurnee field on a limited basis. Our current focus is to complete the developmental drilling program in the Pond Creek field and, in the Gurnee

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field, improve production and determine the commerciality of future development through hydraulic fracturing techniques. At current gas prices, it is unlikely that we would seek, nor could we obtain on reasonable terms, significant additional financing necessary to acquire additional properties or otherwise expand beyond our current developmental drilling and hydraulic fracturing programs. At December 31, 2009 and 2010, we had $15.5 million and $9.5 million, respectively, in available borrowing capacity. This business plan is consistent with our past actions taken in unfavorable pricing environments. For example, when the price of natural gas declined precipitously at the end of 2008, we stopped substantially all of our development activities, and in 2009 did not drill any new wells.

Completion of Rights Offering and Backstop Transaction

On September 14, 2010, the Company issued and sold 4,000,000 shares of Series A Convertible Redeemable Preferred Stock at $10.00 per share. After paying transaction fees and expenses in the amount of $2.8 million, the Company used the net proceeds of approximately $37.2 million to reduce outstanding bank debt. The Preferred Stock is senior to our common stock as to payment of dividends and distributions upon liquidation. See Liquidity and Capital Resources Completion of Rights Offering and Backstop Transaction for additional information.

NASDAQ Deficiency Letter

On September 28, 2010, the Company received a deficiency letter from the staff of The NASDAQ Stock Market, advising the Company that, for the previous 30 consecutive business days, the bid price for the Company s common stock had closed below the minimum $1.00 per share required under NASDAQ Marketplace Rule 5450(a)(1) for continued listing on the NASDAQ Global Market. The notification letter stated that the Company was afforded 180 calendar days to regain compliance with the minimum bid price requirement. On January 5, 2011, the Company received notice from The NASDAQ Stock Market that it has regained compliance with the minimum $1.00 bid price per share required under NASDAQ Marketplace Rule 5450(a)(1) and, as such, is in compliance for continued listing on the NASDAQ Global Market.

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, 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.

Unevaluated Properties The costs directly associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination of proved reserves together with overhead and interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairment to unevaluated properties is transferred to the amortization base.

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

Our total net deferred tax asset at December 31, 2010 was $46.0 million, which includes a valuation allowance of $3.1 million. Our valuation allowance primarily relates to our Canadian operations where we do not believe it is more likely than not that we will recover our net deferred tax asset prior to expiration as well as certain immaterial state net operating losses where the Company has ceased operations. In evaluating the need for a valuation allowance, we considered the fact that we have recorded a cumulative, pretax loss of $277.3 over the past three years. This cumulative loss was the result of the Company incurring a total of $308 million in full cost ceiling test impairments during 2009 and the fourth quarter of 2008. Relevant accounting guidance suggests that cumulative losses in recent years constitute significant negative evidence, and that future expectations about income may be insufficient to overcome a history of such losses. In developing our forecasts as to whether our net deferred tax asset would more likely than not be recovered, we considered the fact that there were no ceiling test impairments in 2010, as well as the fact that the situation that contributed to the impairments was the unprecedented economic downtown which began in the fourth quarter of 2008 and resulted in the price of natural gas falling from a high of $13.32 in the third quarter of 2008 to a low of $5.38 in the fourth quarter of 2008 and to a further low of $1.85 in the third quarter of 2009. In addition, we considered the fact that the current remaining capitalized costs plus planned future costs are significantly less than the historical ceiling test impairments and it is expected that future production will produce sufficient taxable income to cover these costs.

Our first material net operating loss (NOL) carryforward expires in 2022 and the last one expires in 2030. 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 order to test our net deferred tax asset for recoverability, we performed a historical based analysis by using our cumulative three-year historical book loss and added back the historical book impairment and book depletion. We used this three-year historical average taxable income before tax depletion and intangible drilling cost amortization to project taxable income for the next 20 years, which corresponds to our NOL carry forward period. We then reduced the total by the remaining book basis of our gas properties and projected future book basis. In this analysis, our net deferred tax assets including all NOLs will be utilized prior to expiration. We believe this analysis provides significant positive evidence that is objectively verifiable, as it uses three-year historical operating results to predict future taxable income. We have considered all applicable tax deductions in this analysis which are substantially known and are not subject to significant estimates.

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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.

The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained 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.

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 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. We typically do not have any significant producer gas imbalance positions because we own 100% working interest in the majority of our properties. 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. Pipeline imbalances are settled with cash approximately thirty days after the month 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 to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2013. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through 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

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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.

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 $2.1 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 8 Derivative Instruments and Hedging Activities. The FASB has also issued Staff Position FAS 157-2 (FSP 157-2), which delays the effective date of ASC 820-10-55 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We have elected to defer the application of ASC 820-10-55 thereof to nonfinancial assets and liabilities in accordance with FSP 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of ASC 820-10-55 include those measured at fair value in goodwill impairment testing, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination. On October 10, 2008, the FASB issued Staff Position No. FAS 157-3 (FSP 157-3). FSP 157-3 clarifies the application of ASC 820-10-55 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not

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active. On January 1, 2009, we adopted ASC 820-10-55 as it relates to nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired property, plant and equipment; goodwill; and initial recognition of asset retirement obligations. There has been no significant impact to our consolidated audited financial statements related to the implementation of ASC 820-10-55 for our existing non-financial assets and liabilities.

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 Producing Fields Operations Summary

The table below presents information on gas revenues, sales volumes, production expenses and per Mcf data for the years ended December 31, 2010, 2009 and 2008. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31,		
	2010	2009	2008
Gas sales	$ 33,074	$ 30,597	$ 68,314
Lease operating expenses	$ 11,544	$ 13,935	$ 14,757
Compression and transportation expenses	4,164	5,012	4,498
Production taxes	1,021	1,178	2,137
Total production expenses	$ 16,729	$ 20,125	$ 21,392
Net sales volumes (Consolidated) (MMcf)	7,359	7,549	7,453
Pond Creek field (MMcf)	5,322	5,226	5,003
Gurnee field (MMcf)	1,858	2,118	2,241
Per Mcf data ($/Mcf):			
Average natural gas sales price (Consolidated)	$ 4.49	$ 4.05	$ 9.17
Pond Creek field	$ 4.50	$ 4.06	$ 9.17
Gurnee field	$ 4.47	$ 4.06	$ 9.15
Average natural gas sales price realized (Consolidated)(1)	$ 5.72	$ 5.47	$ 9.10
Lease operating expenses (Consolidated)	$ 1.57	$ 1.85	$ 1.98
Pond Creek field	$ 1.21	$ 1.38	$ 1.54
Gurnee field	$ 2.36	$ 2.47	$ 2.98
Compression and transportation expenses (Consolidated)	$ 0.56	$ 0.66	$ 0.60
Pond Creek field	$ 0.62	$ 0.67	$ 0.68
Gurnee field	$ 0.40	$ 0.49	$ 0.49
Production taxes (Consolidated)	$ 0.14	$ 0.16	$ 0.29
Pond Creek field	$ 0.16	$ 0.13	$ 0.15
Gurnee field	$ 0.08	$ 0.23	$ 0.55
Total production expenses (Consolidated)	$ 2.27	$ 2.67	$ 2.87
Pond Creek field	$ 1.99	$ 2.18	$ 2.37
Gurnee field	$ 2.84	$ 3.19	$ 4.02
Depletion (Consolidated)	$ 0.79	$ 1.51	$ 1.35

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

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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, 2010.

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Gas:				
Net sales volume (Bcf)	1.8	1.8	1.9	1.9
Average natural gas sales price ($ per Mcf)	$ 5.43	$ 4.20	$ 4.47	$ 3.90
Average natural gas sales price ($ per Mcf) realized(1)	$ 6.23	$ 5.41	$ 5.45	$ 5.78
Total production expenses ($ per Mcf)	$ 2.37	$ 2.29	$ 2.28	$ 2.16
Expenses: ($ per Mcf)				
Lease operations expenses	$ 1.71	$ 1.54	$ 1.56	$ 1.47
Compression and transportation expenses	$ 0.55	$ 0.59	$ 0.60	$ 0.53
Production taxes	$ 0.11	$ 0.16	$ 0.12	$ 0.16
Depletion of gas properties	$ 0.83	$ 0.72	$ 0.78	$ 0.82
General and administrative	$ 0.81	$ 0.72	$ 0.65	$ 0.73

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

Results of Operations

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	2009	Change
	(in thousands)		
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 2.5% decrease related to production. The decrease related to production was principally attributable to the normal production declines with no drilling in 2009 to offset such normal production declines.

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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.

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

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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%

Year Ended December 31, 2009 compared with Year Ended December 31, 2008

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, 2009	Year Ended December 31, 2008	Change
	(in thousands)		
Gas sales	$ 30,597	$ 68,314	-55%
Lease operating expenses	$ 13,935	$ 14,757	-6%
Compression expense	$ 3,346	$ 3,054	10%
Transportation expense	$ 1,666	$ 1,444	15%
Production taxes	$ 1,178	$ 2,137	-45%
Depreciation, depletion and amortization	$ 12,030	$ 10,589	14%
Impairment of gas properties	$ 257,288	$ 50,734	NM
General and administrative	$ 8,349	$ 9,368	-11%
Realized (gains) losses on derivative contracts	$ (10,694)	$ 500	NM
Unrealized losses (gains) from the change in market value of open derivative contracts	$ 3,995	$ (4,993)	NM
Interest expense, net of amounts capitalized	$ (5,174)	$ (4,783)	8%
Income tax benefit	$ (98,142)	$ (712)	NM

NM-Not Meaningful

Gas sales. Gas sales decreased by $37.7 million, or 55%, to $30.6 million compared to the prior year. The decrease in gas sales was a result of significantly lower natural gas prices, which decreased approximately 56% excluding hedging transactions, partially offset by increased production, which increased 1%. The increase in production was principally attributable to the prior year development activities at our Pond Creek field and the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River in December 2008, partially offset by the sale of an overriding royalty interest that was sold effective July 1, 2008 and decreased current year production in our Gurnee field.

Lease operating expenses. Lease operating expenses decreased by $0.8 million, or 6%, to $13.9 million compared to the prior year. The $0.8 million decrease in lease operating expenses consisted of $1.0 million decrease in costs, partially offset by a $0.2 million increase in production. The $1.0 million decrease in costs was primarily due to a company-wide cost reduction strategy implemented in April 2009, partially offset by increased expenses related to the commencement of gas sales in our Garden City field in July 2008, Lasher field in October 2008, and Peace River in December 2008.

Compression expense. Compression expense increased by $0.3 million, or 10%, to $3.3 million compared to the same period in the prior year. The increase in compression expense was primarily due to the addition of Peace River compression costs where gas sales commenced on December 31, 2008.

Transportation expense. Transportation expense increased by $0.2 million, or 15%, to $1.7 million compared to the prior year period. The increase was primarily due to the fact that a greater amount of excess capacity was released in the prior year period effectively reducing transportation expense for that period. The excess transportation capacity that caused the increase was permanently released in May 2009. As a result of this permanent release, we expect to incur less transportation costs in the future.

Production taxes. Production taxes decreased by $1.0 million, or 45%, to $1.2 million compared to the prior year period. The decrease related to production taxes was primarily due to decreased natural gas sales caused by lower natural gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.4 million, or 14%, to $12.0 million compared to the prior year period. The depreciation, depletion and amortization increase consisted of $3.9 million in accelerated depletion caused by estimated natural gas reserve revisions recorded as of September 30, 2009, offset by a $2.5 million decrease due to the decrease in the depletion rate resulting from our ceiling write-downs incurred to-date.

Impairment of gas properties. For the year ended December 31, 2009, impairments recorded to gas properties were $159.7 million, net of tax benefit of $97.6 million. These impairments were caused by lower natural gas prices, as well as downward reserve revisions due in large part to continued under-performance in the Gurnee field. We were able to limit the effect of lower natural gas prices through our ongoing cost reduction strategy, which we implemented in April 2009.

General and administrative. General and administrative expenses decreased by $1.0 million, or 11%, to $8.3 million compared to the prior year period. The primary driver of the decrease in general and administrative expenses was the cost reduction strategy implemented in April 2009, offset by $0.8 million less capitalized overhead as a result of decreased drilling activities.

Realized (gains) losses on derivative contracts. Realized gains on derivative contracts were $10.7 million in the current year period as compared to realized losses of $0.5 million in the prior year period. Realized losses represent net cash flow settlements paid to the contract counterparty, while realized gains represent net cash flow settlements paid to us from the contract counterparty. Realized losses occur when natural gas prices exceed the derivative ceiling prices. Conversely, realized gains occur when natural gas prices go below the derivative floor prices.

Unrealized losses (gains) from the change in market value of open derivative contracts. Unrealized losses on open derivative contracts were $4.0 million in the current year period as compared to unrealized gains of $5.0 million in the prior year period. Unrealized losses and gains are non-cash transactions that occur when the corresponding asset or liability derivative contracts are marked to market at the end of each reporting period.

Interest expense. Interest expense increased by $0.4 million, or 8%, to $5.2 million compared to the prior year period. The increase is due to the effect of a higher average outstanding debt balance in the current year period, partially offset by a lower average interest rate in the current year period. Additionally, the prior year included $0.3 million of capitalized interest for which there was no comparable capitalized interest in the current year period as a result of no drilling activity.

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Income tax benefit. Income tax benefit was $98.1 million in the current year as compared to $0.7 million in the prior year. The increased benefit was primarily the result of the impairments recorded to gas properties of $159.7 million, net of tax benefit of $97.6 million. These impairments were caused by lower natural gas prices, as well as downward revisions due in large part to continued under-performance in the Gurnee field. We were able to limit the effect of lower natural gas prices through our ongoing cost reduction strategy, which we implemented in April 2009. The effective tax rate for the period was 37.0%. Income tax benefit for the year ended December 31, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	$ (87,751,624)	34.00%	$ (1,867,426)	26.00%	$ (89,619,050)	33.78%
State income taxes net of federal benefit	(10,714,162)	4.15%		0.00%	(10,714,162)	4.04%
Valuation Allowance		0.00%	1,867,426	-26.00%	1,867,426	-0.70%
Nondeductible items and other	324,027	-0.12%		0.00%	324,027	-0.12%
Income tax benefit	$ (98,141,759)	38.03%	$	0.00%	$ (98,141,759)	37.00%

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flows provided by operations for the years ended December 31, 2010, 2009 and 2008 were $16.0 million, $8.5 million and $33.0 million, respectively. As of December 31, 2010, we had working capital of approximately $1.5 million. As of December 31, 2009, we had a working capital deficit of less than $0.1 million. 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 projected capital expenditures for the next twelve months.

Revolving Credit Facility

On September 14, 2010, our Fourth Amended and Restated Credit Agreement (the Credit Agreement) with a group of five banks became effective. The Credit Agreement replaced our Third Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by June 2011. All outstanding borrowings under the Credit Agreement become due and payable on September 14, 2013. 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 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.75% to 3.25%. 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 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. At December 31, 2010, the Current Ratio, as defined, was 1.32. 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 4.5 to 1.0 through the quarter ending June 30, 2011 and 4.0 to 1.0 thereafter. At December 31, 2010, the Debt Ratio, as defined, was 3.46. 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. At December 31, 2010, the Fixed Charge Ratio, as defined, was 2.06. 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. At December 31, 2010, the Fixed Charge Ratio, as defined, was 5.07. 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. The Company expects continued compliance with the aforementioned covenant in the near term.

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 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.

Completion of Rights Offering and Backstop Transaction

On September 14, 2010, the Company 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. After paying transaction fees and expenses in the amount of $2.8 million, the Company used the net proceeds of approximately $37.2 million to reduce outstanding bank debt. The Preferred Stock ranks senior to our common stock as to payment of dividends and distribution upon liquidation.

Dividends 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, 2010, an additional 3,253,294 shares of our Preferred Stock are reserved exclusively for the payment of PIK dividends.

The Preferred Stock is immediately convertible into common stock, at the sole option of the holder, at an initial conversion price of $1.30 per common share (as it may be adjusted from time to time, the Conversion Price). The Preferred Stock converts into a number of shares of common stock determined by dividing (i) the sum of (A) $10.00 plus (B) accrued but unpaid dividends by (ii) the Conversion Price. At the current Conversion Price, up to an additional 31,911,830 shares of our common stock would be outstanding immediately after conversion of our Preferred Stock. The Conversion Price and resulting number of shares of common stock issued upon conversion of Preferred Stock is adjusted to reflect stock splits and similar events and is entitled to anti-dilution adjustments for any dividends paid on common stock in cash or in common stock, the issuance of additional equity securities at a price less than the Conversion Price (excluding shares, rights and options subject to certain employee benefit arrangements), and the occurrence of certain material corporate transactions at a per share valuation less than the Conversion Price.

At any time beginning eight years from the date of issuance, the Preferred Stock is redeemable, in whole or in part, at the sole option of the holder. The purchase price per share, payable in cash, will be equal to the sum of the original purchase price and any accrued and unpaid dividends.

We have the option, beginning three years from the date of issuance, to convert the Preferred Stock into our common stock at the then current Conversion Price, subject to certain volume and other limitations. In order for us to exercise this option, the daily volume-weighted average trading price of our common stock must be greater than 225% of the then current Conversion Price for twenty (20) out of the previous thirty (30) trading days.

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The holders of the Preferred Stock are entitled to vote on all matters on which the holders of our common stock are entitled to vote. The holders of the Preferred Stock generally vote together with the holders of the common stock as a single class, with the Preferred Stock holders entitled to the number of votes such holders would have on an as-converted basis. Certain actions also require a separate vote of the Preferred Stock.

Upon the occurrence of a liquidation, dissolution or winding up of the Company resulting in a payment or distribution of assets to the holders of any of our capital stock (each such event, a Liquidation Event), the holders of the Preferred Stock (including PIK dividends) are entitled to receive, prior and in preference to any payment, or segregation for payment, of any consideration to any holder of any junior security of the Company, an amount in cash equal to the greater of (i) $10.00 per share, plus any accrued but unpaid dividends (in each case adjusted for any stock dividends, splits, combinations or similar events), or (ii) an amount equal to the amount such holders of the Preferred Stock would have received upon the Liquidation Event if they had converted their shares of Preferred Stock into shares of our common stock.

If not converted, the Preferred Stock (including any PIK dividends) is redeemable by us on or at any time after a Liquidation Event. In the absence of a Liquidation Event, if not converted, a holder of Preferred Stock (including any PIK dividends) may cause us to redeem the Preferred Stock held by such holder, in whole or in part, on or after September 14, 2018, upon 30 days prior written notice to us. Upon any redemption of Preferred Stock by us, as of the effective date of the redemption, we will pay to each holder of Preferred Stock, $10.00 per share of Preferred Stock (including any PIK dividends) held plus any accrued but unpaid dividends (in each case adjusted for any stock dividends, splits, combinations or similar events).

During the year ended December 31, 2010, the Company declared and issued PIK dividends of 148,538 shares to the holders of Preferred Stock.

The 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. The Preferred Stock balance in mezzanine equity will be accreted to its redemption value over the eight year redemption period. In addition, we evaluated the conversion feature at September 14, 2010 and determined that its terms required the holder s conversion option to be separated and recorded at fair value as a derivative liability on the Consolidated Balance Sheet. 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.

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, and resulted in a fair value of approximately $18.4 million on the date of issuance. The remaining net proceeds of $20.4 million were allocated to Series A Convertible Redeemable Preferred Stock in the Consolidated Balance Sheets. For the year ended December 31, 2010, the Company recorded approximately $2.1 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.

The Preferred Stock initially contained an anti-dilution provision that was triggered when the Company issued certain additional common stock or securities convertible into common stock for consideration per share less than the conversion price of the Preferred Stock. The anti-dilution provision was amended during 2010 so that, in the event of such issuance, the conversion price of the Preferred Stock will be reduced to a price determined by multiplying the then-current conversion price by a fraction (a) the numerator of which will be the

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sum of (i) the number of shares of common stock outstanding, on a fully diluted basis, before the additional issuance plus (ii) the number of shares of common stock which the aggregate consideration received by the Company for the additional issuance would purchase at the conversion price then in effect, and (b) the denominator of which will be the sum of (x) the number of shares of common stock outstanding before the additional issuance plus (y) the number of such additional shares of common stock that were actually issued.

In addition, the terms of the Preferred Stock was amended to prohibit the Company from issuing 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 Series A Preferred Stock without the prior vote or consent of holders of a majority of the outstanding shares of Series A Preferred Stock, for so long as at least 750,000 shares of Series A Preferred Stock remain outstanding.

We amended the terms of the Preferred Stock because we believed that the valuation, accounting and disclosure obligations associated with the embedded derivative were burdensome and that such accounting treatment did not clearly represent the overall financial condition and results of operations of the Company. Determining the periodic change in the fair value of the derivative liability required a costly valuation each quarter and produced significant volatility in the Company s consolidated balance sheet and consolidated statement of operations. In addition, the valuation required Level 3 inputs and assumptions, under ASC 820-10-55, for reporting purposes, and was considered a critical accounting area which includes a high degree of judgment and uncertainty.

On the effective date of the Amendment, December 21, 2010, 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). In addition, we will no longer experience the potential volatility on the consolidated balance sheets and consolidated statements of operations from unrealized gains or losses resulting from future fair value fluctuations of the extinguished derivative liability. As a result, we expect our consolidated financial statements to be more consistent with the underlying operations of the Company.

The following table details the activity related to the issuance and accretion of the Series A Convertible Redeemable Preferred Stock and the related derivative liability for the year ended December 31, 2010:

	Mezzanine Equity - Series A Convertible Redeemable Preferred Stock	Derivative Liability - Series A Convertible Redeemable Preferred Stock	Total Liability & Mezzanine Equity Amounts Related to Series A Convertible Redeemable Preferred Stock
Balance at January 1, 2010	$	$	$
Issuance of Series A Convertible Redeemable Preferred Stock	40,000,000		40,000,000
Allocated to derivative liability	(18,378,517)	18,378,517	
Issuance costs(1)	(1,531,056)		(1,531,056)
Net issuance of Series A Convertible Redeemable Preferred Stock	20,090,427	18,378,517	38,468,944
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock		2,164,080	2,164,080
Accretion of Series A Convertible Redeemable Preferred Stock	497,782		497,782
PIK Dividends for Series A Convertible Redeemable Preferred Stock	1,486,111		1,486,111
Reclassification of Derivative Liability Series A Convertible Redeemable Preferred Stock to Equity		(20,542,597)	(20,542,597)
Balance at December 31, 2010	$ 22,074,320	$	$ 22,074,320

(1) Issuance costs of $2,832,472 were incurred as part of the issuance of the Series A Convertible Redeemable Preferred Stock. As the Series A Convertible Redeemable Preferred Stock was bifurcated on the Consolidated Balance Sheet as disclosed in the table above, $1,531,056 of the issuance costs were allocated to Mezzanine Equity Series A Convertible Redeemable Preferred Stock. The remaining $1,301,416 of issuance costs were allocated to Other current assets and Other noncurrent assets to be amortized over the term of the Series A Convertible Redeemable Preferred Stock and, as a result of the amendment to the Preferred Stock agreement on December 21, 2010, $1,261,343($1,301,416 of original issuance costs, less $40,073 amortized in 2010) were reclassified to equity.

Capital Expenditures

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

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Capital expenditures:			
Leasehold acquisition	$ 591	$ 1,197	$ 3,669
Exploration	3	29	405
Development	11,884	6,273	48,404
Other items (primarily capitalized overhead)	1,033	1,767	5,294
Total capital expenditures	$ 13,511	$ 9,266	$ 57,772

We expect our capital expenditure budget for 2011 to be $13.9 million. The amount and timing of our expenditures are subject to change based upon market conditions, natural gas prices, results of operations and other factors. We routinely adjust our capital expenditure budget in response to changes in natural gas prices, drilling and acquisition costs, cash flow, drilling results and changes in borrowing capacity under our revolving credit facility.

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

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

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

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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 price movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

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

Commodity Price Risk and Related Hedging Activities

At December 31, 2010, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2011	360,000	$ 7.45	$ 6.50		775,853

At December 31, 2010, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
January through March 2011	360,000	$ 6.67	836,287
January through March 2011	540,000	$ 7.27	1,576,095
April through October 2011	856,000	$ 6.37	1,572,738
April through October 2011	856,000	$ 5.37	715,726
April through October 2011	856,000	$ 5.43	771,155
November 2011 through March 2012	608,000	$ 7.12	1,216,885
November 2011 through March 2012	608,000	$ 6.12	611,002
November 2011 through March 2012	912,000	$ 5.08	(19,449)
April through October 2012	856,000	$ 5.73	653,211
April through October 2012	1,712,000	$ 4.94	(34,286)
November 2012 through March 2013	604,000	$ 6.42	563,413
November 2012 through March 2013	906,000	$ 5.50	35,912
	9,674,000		$ 8,498,689

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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 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. Gross sales from the Pond Creek field averaged approximately 17,800 MMBtu/day for the year ended December 31, 2010. As such, the overall delivery agreement represents approximately 90% of the 2010 average gross daily sales. Additionally, 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
April through October 2011	856,000	$ 4.80	$ 0.115	$ 4.915	$ 4,207,240
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	1,312,000				$ 6,637,720

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

Period	Volume (MMBtu)	Fixed Basis Differential
February through March 2011	944,000	$ 0.150
April through October 2011	2,568,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	5,488,000	

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.

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At December 31, 2010, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	(4,592)

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

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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, 2010, beginning January 1, 2011 (in thousands):

	2011	2012	2013	2014	2015 and thereafter
Long-term debt and other obligations(1)	$ 133	$ 92	$ 80,600	$ 110	$ 61
Interest expense on revolving credit facility(2)	2,893	2,893	2,283		
Operating lease obligations	1,172	646	437	189	783
Interest rate swap contracts	5				
Asset retirement obligations	33				5,466
Firm transportation contracts	1,350	1,350	1,350	1,350	6,921
ASC 740 (formerly FIN 48)(3)					
Total commitments	$ 5,586	$ 4,981	$ 84,670	$ 1,649	$ 13,231

(1) Maturities based on the September 2010 amended bank credit agreement terms, as amended, which extended the maturity date to September 14, 2013.

(2) The outstanding balances on the revolving credit facility bear interest at the Company s option of either (a) the Adjusted Base Rate, which is the greatest of (i) the agent s base rate, (ii) the federal funds rate plus 0.5%, or (iii) the LIBOR rate plus a margin of 1%, plus a margin of 1.75% to 2.25%, or (b) the LIBOR rate, plus a margin of 2.75% to 3.25%, based on borrowing base usage. The rate at December 31, 2010, excluding the effect of our interest rate swaps, was 3.30%.

(3) As of December 31, 2010, 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, 2010:

Year	Amount
2011	132,743
2012	91,757
2013	80,600,467
2014	110,035
2015	61,160
Thereafter	
Total Debt	$ 80,996,162

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, 2010 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	**Amount**
2011	$ 880,442
2012	646,475
2013	436,835
2014	189,672
2015	188,448
Thereafter	594,632
Total future minimum lease commitments	$ 2,936,504

Total rental expenses under operating leases were approximately $1,528,739, $1,857,026, and $2,005,994 for the years ended December 31, 2010, 2009 and 2008, respectively.

Transportation Contracts As of December 31, 2010, 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, and (3) 10,000 MMBtu s continuing until April 1, 2017. We have a right to extend each of these contracts, in five-year increments, at the maximum tariff rate. As of December 31, 2010, the maximum commitment remaining under the transportation contracts is approximately $12.3 million.

Recent Accounting Pronouncements

In December 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting (ASC 2010-3), which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, and added a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which was eliminated. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Companies affected by Release No. 33-8995 are now required to price estimated proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning for financial statements for fiscal years ending on or after December 31, 2009. The Company adopted SEC Release No. 33-8995 effective December 31, 2009. The impact on the Company s operating results, financial position and cash flows has been recorded in the consolidated audited financial statements and additional disclosures were added to the accompanying notes to the consolidated audited financial statements for the Company s supplemental oil and gas disclosure. See Supplementary Financial and Operating Information on Gas Exploration, Development and Producing Activities (Unaudited) for the years ended December 31, 2010, 2009 and 2008 for more details.

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) No. 2010-03 Oil and Gas Estimation and Disclosures (ASU 2010-03). This update aligns the current oil and natural gas reserve estimation and disclosure requirements of the Extractive Industries Oil and Gas topic of the FASB Accounting Standards Codification (ASC Topic 932) with the changes required by the SEC final rule ASC 2010-3. As discussed above, ASU 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and natural gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or natural gas, amends the definition of proved oil and natural gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and natural gas quantities and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. The Company adopted ASU 2010-03 effective December 31, 2009. See Supplementary Financial and Operating Information on Gas Exploration, Development and Producing Activities (Unaudited) for the years ended December 31, 2010, 2009 and 2008 for more details.

In January 2010, the FASB issued ASU No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 8 Derivative Instruments and Hedging Activities in the Notes to Consolidated Audited Financial Statements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodity Price Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the year ended December 31, 2010, a 10% decrease in the prices received for natural gas production would have had an approximate $3.3 million impact on our revenues, which would have been offset by approximately $1.8 million realized gas hedging gains.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of December 31, 2010, we had $80.5 million of borrowings outstanding under our revolving credit facility. The rates at December 31, 2010 and 2009, excluding the effect of our interest rate swaps, were 3.30% and 3.03%, respectively. For the years ended December 31, 2010 and 2009, interest on the borrowings averaged 3.64% per annum and 3.12% per annum, respectively. 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, 2010, a 1% increase in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $0.8 million. $23.5 million of the outstanding balance was excluded from our market rate analysis due to lack of interest rate exposure based on the interest rate swaps we have in place.

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.

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

GEOMET, INC. AND SUBSIDIARIES

Index To Financial Statements

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, 2010 and 2009, 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, 2010. 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 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, in 2009 the Company changed its method of accounting for natural gas reserves.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

April 6, 2011

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 536,533	$ 973,720
Accounts receivable, net of allowance of $60,848 at December 31, 2010 and 2009	2,600,319	2,909,293
Inventory	1,002,207	2,131,901
Derivative asset natural gas hedges	7,087,775	2,563,898
Other current assets	951,622	475,025
Total current assets	12,178,456	9,053,837
Gas properties utilizing the full cost method of accounting:		
Proved gas properties	475,917,727	461,003,091
Other property and equipment	3,405,502	3,480,202
Total property and equipment	479,323,229	464,483,293
Less accumulated depreciation, depletion, amortization and impairment of gas properties	(373,235,875)	(365,784,964)
Property and equipment net	106,087,354	98,698,329
Other noncurrent assets:		
Derivative asset natural gas hedges and interest rate swaps	2,186,767	761,192
Deferred income taxes	48,202,861	51,804,971
Other	1,430,584	609,972
Total other noncurrent assets	51,820,212	53,176,135
TOTAL ASSETS	$ 170,086,022	$ 160,928,301
LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 5,950,861	$ 5,169,174
Accrued liabilities	2,306,020	2,808,227
Deferred income taxes	2,206,531	157,256
Derivative liability interest rate swaps	4,592	724,253
Asset retirement liability	32,893	108,111
Current portion of long-term debt	132,743	121,792
Total current liabilities	10,633,640	9,088,813
Long-term debt	80,863,419	119,996,163
Asset retirement liability	5,465,798	4,862,278
Other long-term accrued liabilities	40,728	73,308
TOTAL LIABILITIES	97,003,585	134,020,562
Commitments and contingencies (Note 16)		
Mezzanine equity:		
Series A Convertible Redeemable Preferred Stock net of offering costs of $1,531,056; redemption amount $41,485,380; $.001 par value; 7,401,832 shares authorized, 4,148,538 shares were issued and outstanding at December 31, 2010, and no shares were authorized, issued and outstanding at December 31, 2009.	22,074,320	
Stockholders Equity:		

Preferred stock, $0.001 par value 2,598,168 shares authorized, none issued at December 31, 2010 and 10,000,000 shares authorized, none issued at December 31, 2009		
Common stock, $0.001 par value authorized 125,000,000 shares; issued and outstanding 39,758,484 and 39,460,060 at December 31, 2010 and 2009, respectively	39,744	39,294
Treasury stock 10,432 shares at December 31, 2010 and 2009	(94,424)	(94,424)
Paid-in capital	207,548,596	189,681,816
Accumulated other comprehensive loss	(1,324,154)	(1,768,521)
Retained deficit	(154,918,736)	(160,710,889)
Less notes receivable	(242,909)	(239,537)
Total stockholders equity	51,008,117	26,907,739
TOTAL LIABILITIES, MEZZANINE AND STOCKHOLDERS EQUITY	$ 170,086,022	$ 160,928,301

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31,

	2010	2009	2008
Revenues:			
Gas sales	$ 33,073,567	$ 30,596,551	$ 68,313,948
Operating fees and other	287,306	367,519	780,267
Total revenues	33,360,873	30,964,070	69,094,215
Expenses:			
Lease operating expense	11,543,674	13,934,840	14,756,521
Compression and transportation expense	4,164,186	5,011,511	4,498,243
Production taxes	1,020,950	1,178,435	2,136,963
Depreciation, depletion and amortization	6,296,288	12,029,982	10,589,490
Impairment of gas properties		257,288,257	50,733,757
General and administrative	5,367,204	8,349,268	9,368,279
Terminated transaction costs	1,402,534		
Realized (gains) losses on derivative contracts	(9,005,621)	(10,694,496)	500,452
Unrealized (gains) losses from the change in market value of open derivative contracts	(5,949,840)	3,995,327	(4,993,238)
Total operating expenses	14,839,375	291,093,124	87,590,467
Operating income (loss)	18,521,498	(260,129,054)	(18,496,252)
Other income (expense):			
Interest income	44,287	27,739	43,876
Interest expense (net of amounts capitalized)	(5,167,764)	(5,174,185)	(4,783,076)
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	(2,164,080)		
Other	(35,206)	80	36,961
Total other income (expense):	(7,322,763)	(5,146,366)	(4,702,239)
Income (loss) before income taxes	11,198,735	(265,275,420)	(23,198,491)
Income tax expense (benefit)	5,406,582	(98,141,759)	(711,900)
Net income (loss)	$ 5,792,153	$ (167,133,661)	$ (22,486,591)
Accretion of Series A Convertible Redeemable Preferred Stock	(497,782)		
Dividends paid on Series A Convertible Redeemable Preferred Stock	(1,486,843)		
Net income (loss) available to common stockholders	$ 3,807,528	$ (167,133,661)	$ (22,486,591)
Earnings (loss) per share:			
Net income (loss) per common share			
Basic	$ 0.10	$ (4.28)	$ (0.58)
Diluted	$ 0.10	$ (4.28)	$ (0.58)

Weighted average number of common shares:			
Basic	39,298,207	39,084,740	38,856,841
Diluted	39,299,082	39,084,740	38,856,841

See accompanying Notes to Consolidated Audited Financial Statements.

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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 Income (Loss)	Retained Earnings (Deficit)	Notes Receivable	Total Stockholders Equity
Balance at January 1, 2008	38,962,359	$ 38,962	$ (70,452)	$ 187,620,936	$ 2,394,001	$ 28,909,363	$ (217,104)	$ 218,675,706
Exercise of stock options	68,605	69		118,377				118,446
Stock-based compensation	18,720	19		941,697				941,716
Purchase of treasury stock (2,604 shares)			(23,359)					(23,359)
Accrued interest on notes receivable				11,232			(11,232)	
Comprehensive loss:								
Net loss						(22,486,591)		(22,486,591)
Loss on interest rate swap, net of income taxes of $410,906					(689,370)			(689,370)
Foreign currency translation adjustment, net of income taxes of $0					(4,104,623)			(4,104,623)
Total comprehensive income								(27,280,584)
Balance at December 31, 2008	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 income								(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
				3,372			(3,372)	

Accrued interest on notes receivable								
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

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2010	2009	2008
Cash flows provided by operating activities:			
Net income (loss)	$ 5,792,153	$ (167,133,661)	$ (22,486,591)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation, depletion and amortization	6,296,288	12,029,982	10,589,490
Impairment of gas properties		257,288,257	50,733,757
Amortization of debt issuance costs	574,601	196,152	172,935
Terminated transaction costs	666,306		
Deferred income tax expense (benefit)	5,381,582	(98,050,852)	(736,900)
Unrealized (gains) losses from the change in market value of open derivative contracts (including premium amortization)	(5,962,824)	3,995,327	(4,993,238)
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	2,164,080		
Stock-based compensation	409,873	792,560	566,416
Loss on sale of other assets	52,551	22,248	41,521
Accretion expense	484,114	431,733	365,103
Allowance for doubtful accounts			60,848
Changes in operating assets and liabilities:			
Accounts receivable	311,591	2,553,045	(595,689)
Other current assets	364,667	(102,448)	(1,058,790)
Accounts payable	26,731	(3,394,439)	3,130,996
Other accrued liabilities	(539,171)	(109,645)	(2,831,465)
Net cash provided by operating activities	16,022,542	8,518,259	32,958,393
Cash flows used in investing activities:			
Capital expenditures (including lease acquisitions)	(12,293,100)	(12,566,498)	(52,797,122)
Proceeds from sale of assets	58,937	36,315	43,084
Other assets	48,947	(166,260)	35,161
Net cash used in investing activities	(12,185,216)	(12,696,443)	(52,718,877)
Cash flows provided by financing activities:			
Proceeds from sale of preferred stock	40,000,000		
Deferred financing costs	(4,557,594)		
Deferred financing costs related to terminated transactions	(666,306)		
Proceeds from exercise of stock options	54,137		118,446
Proceeds from revolver borrowings	28,750,000	39,350,000	115,000,000
Payments on revolver	(67,750,000)	(36,350,000)	(94,500,000)
Dividends paid	(732)		
Treasury stock		(613)	(23,359)
Payments on other debt	(121,792)	(111,767)	(102,586)
Net cash (used in) provided by financing activities	(4,292,287)	2,887,620	20,492,501
Effect of exchange rate changes on cash and cash equivalents	17,774	167,723	(175,972)
(Decrease) increase in cash and cash equivalents	(437,187)	(1,122,841)	556,045
Cash and cash equivalents at beginning of year	973,720	2,096,561	1,540,516

Cash and cash equivalents at end of year	$ 536,533	$ 973,720	$ 2,096,561
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest expense	$ 5,422,325	$ 5,197,538	$ 4,891,199
Income taxes	$ 25,000	$ 25,000	$ 36,192
Significant noncash investing and financing activities:			
Accrued capital expenditures	$ 1,154,146	$ 397,375	$ 5,556,897

See accompanying Notes to Consolidated Audited Financial Statements.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS

Note 1 Organization and Our Business

GeoMet, Inc. (GeoMet, Company, we, or our) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are an independent natural gas producer primarily involved in the exploration, development and production of natural gas from coal seams (coal bed methane) and non-conventional shallow gas. Our principal operations and producing properties are located in Alabama, West Virginia, Virginia and Canada.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation The accompanying Consolidated Audited Financial Statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and include our accounts and the accounts of our wholly-owned subsidiaries, GeoMet Operating Company, Inc., GeoMet Gathering Company LLC, GeoMet Gathering Virginia, Inc. (terminated June 28, 2010), and Hudson s Hope Gas, Ltd. All inter-company accounts and transactions have been eliminated in consolidation.

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

Gas Properties The method of accounting for gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for gas properties as prescribed by the United States Securities and Exchange Commission (SEC). For more information see Note 6 Gas Properties.

Unevaluated Properties The costs directly associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination of proved reserves together with overhead and interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairment to unevaluated properties is transferred to the amortization base.

Asset Retirement Liability ASC 410-20-25 establishes accounting and reporting standards for retirement obligations associated with tangible long-lived assets that result from the legal obligation to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed or developed. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement 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.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Notes Receivable Included in Stockholders Equity We have loaned money to employees to purchase our common stock. Such amounts, including accrued interest, are recorded as Notes Receivable, and are included as a component of Stockholders Equity. The balances at December 31, 2010 and 2009 are solely attributable to employees.

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of ASC 740, 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.

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 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. We typically do not have any significant producer gas imbalance positions because we own 100% working interest in the majority of our properties. 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

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when our production delivered into the pipeline varies from the gas we nominated for sale. Pipeline imbalances 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.

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 U.S. and Canada with only the U.S. currently having material revenue generating operating results.

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

Concentration of Credit Risk Financial instruments, which subject us to concentrations of credit risk, consist primarily of cash, accounts receivable and derivative assets. We place our cash investments with highly qualified financial institutions. Risks with respect to receivables as of December 31, 2010 and 2009 arise substantially from the sales of natural gas and joint interest billings. We routinely assess the recoverability of all material trade and other receivables to determine their collectability. We accrue a reserve on a receivable when, based on management s judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. Risks with respect to derivative assets as of December 31, 2010 arise from cash settlements due to us from our derivative counterparties. We have primarily one purchaser of our natural gas production. For the year ended December 31, 2010, 2009 and 2008, the aforementioned purchaser purchased 98%, 99% and 100%, respectively, of our net natural gas production. As of December 31, 2010 and 2009, the aforementioned purchaser represented 98% of our accounts receivable related to gas sales. At December 31, 2010 and 2009, we have recorded an allowance for doubtful accounts receivable of $60,848 related to other revenue and not a purchaser of our natural gas. We have not experienced any significant losses from uncollectible accounts. We do not believe the loss of our 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.

Operating Fees and Other Operating fees and other for the years ended December 31, 2010, 2009 and 2008 include produced water disposal fees.

Capitalized General and Administrative Expenses Under the full cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our natural gas properties. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly associated with those activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the periods ended December 31, 2010, 2009, and 2008 of $971,467, $1,485,510, and $2,329,748, respectively.

Capitalized Interest Costs We capitalize interest based on the cost of major development projects which are excluded from current depreciation, depletion and amortization calculations. For the years ended December 31, 2010 and 2009, we did not capitalize any interest. For the year ended December 31, 2008, we capitalized $304,342 of interest. See Unevaluated Properties above for additional information on the criteria for including costs in unevaluated properties.

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Derivative Instruments and Hedging Activities. Our hedging activities consist of derivative instruments entered into to hedge against changes in natural gas prices and changes in interest rates related to outstanding debt under our credit facility primarily through the use of fixed price swap agreements, basis swap agreements, three-way collars, and traditional collars. Consistent with our hedging policy, we entered into a series of derivative instruments to hedge a significant portion of our expected natural gas production through 2013. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through 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.

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 $2.1 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).

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

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 8 Derivative Instruments and Hedging Activities.

The fair value of cash and cash equivalents, current receivables and payables, approximate book value because of the short maturity of these accounts. The outstanding note receivable in Other Non-Current Assets and certain Other Debt carries a fixed interest rate. See Notes 5 and 10 for the fair values of the receivable and debt.

Foreign Currency Translation For our wholly-owned Canadian subsidiary, Hudson s Hope Gas, Ltd., whose functional currency is deemed to be other than the U.S. dollar, asset and liability accounts are translated at period end exchange rates and revenue and expenses are translated at average exchange rates prevailing during the period. Translation adjustments are included in the Accumulated Other Comprehensive Income (Loss). Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net (loss) income in the current period. Hudson s Hope Gas, Ltd. is our only foreign subsidiary.

Stock-Based Compensation We use 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 as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, we will not recognize any equity compensation cost on these prior awards in the future unless such awards are modified, repurchased or cancelled.

Note 3 Recent Accounting Pronouncements

In December 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting (ASC 2010-3), which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, and added a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which was eliminated. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Companies affected by Release No. 33-8995 are now required to price estimated proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning for financial statements for fiscal years ending on or after December 31, 2009. The Company adopted SEC Release No. 33-8995 effective December 31, 2009. The impact on the Company s operating results, financial position and cash flows has been recorded in the consolidated audited financial statements and additional disclosures were added to the accompanying notes to the

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

consolidated audited financial statements for the Company s supplemental oil and gas disclosure. See Supplementary Financial and Operating Information on Gas Exploration, Development and Producing Activities (Unaudited) for the years ended December 31, 2010, 2009 and 2008 for more details.

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) No. 2010-03 Oil and Gas Estimation and Disclosures (ASU 2010-03). This update aligns the current oil and natural gas reserve estimation and disclosure requirements of the Extractive Industries Oil and Gas topic of the FASB Accounting Standards Codification (ASC Topic 932) with the changes required by the SEC final rule ASC 2010-3. As discussed above, ASU 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and natural gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or natural gas, amends the definition of proved oil and natural gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and natural gas quantities and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. The Company adopted ASU 2010-03 effective December 31, 2009. See Supplementary Financial and Operating Information on Gas Exploration, Development and Producing Activities (Unaudited) for the years ended December 31, 2010, 2009 and 2008 for more details.

In January 2010, the FASB issued ASU No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 8 Derivative Instruments and Hedging Activities.

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Note 4 Net Income (Loss) Per Common Share

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

	2010	2009	2008
Net income (loss)	$ 5,792,153	$ (167,133,661)	$ (22,486,591)
Accretion of Series A Convertible Redeemable Preferred Stock	(497,782)		
Dividends paid on Series A Convertible Redeemable Preferred Stock	(1,486,843)		
Net income (loss) available to common stockholders	$ 3,807,528	$ (167,133,661)	$ (22,486,591)
Earnings (loss) per common share:			
Net income (loss) available to common stockholders			
Basic	$ 0.10	$ (4.28)	$ (0.58)
Diluted	$ 0.10	$ (4.28)	$ (0.58)
Weighted average number of common shares:			
Basic	39,298,207	39,084,740	38,856,841
Add potentially dilutive securities:			
Stock options and non-vested restricted stock	875		
Diluted	39,299,082	39,084,740	38,856,841

Diluted net income per share for the year ended December 31, 2010 excluded the effects of the Series A Convertible Redeemable Preferred Stock, as the net impact would have been anti-dilutive. The impact of the Series A Convertible Redeemable Preferred Stock would have included an addition to the numerator of the Accretion of Series A Convertible Redeemable Preferred Stock of $497,782 and dividends paid on Series A Convertible Redeemable Preferred Stock of $1,486,111 and an addition to the denominator of 9,188,620 in dilutive shares, as converted, which is the weighted average outstanding for the year based on 31,911,830 total shares outstanding, as converted.

Diluted net loss per share for the year ended December 31, 2009 excluded the effect of outstanding options to purchase 2,398,546 shares and 311,684 restricted shares because we reported a net loss which caused options to be anti-dilutive. Diluted net loss per share for the year ended December 31, 2008 excluded the effect of outstanding options to purchase 1,757,256 shares and 401,075 restricted shares because we reported a net loss which caused options to be anti-dilutive.

Note 5 Note Receivable

We have an unsecured note receivable of $209,728 and $242,074 as of December 31, 2010 and 2009, respectively, from a third party included in other non-current assets. The note requires payment on a

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semi-monthly basis, including interest at 8.25%, of $2,168. The fair value of the receivable was $209,728 and $242,074 at December 31, 2010 and 2009, respectively. Scheduled maturities of the note receivable are detailed in the table below.

2011	$ 35,273
2012	38,466
2013	41,947
2014	45,743
2015	48,299
Thereafter	
Total note receivable	209,728
Less current portion of note receivable	35,273
Non-current note receivable	$ 174,455

Note 6 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 United States of America (U.S.) and Canadian cost centers. The Canadian cost center was fully impaired in 2009 and remains impaired at December 31, 2010.

Gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved gas reserves. Depletion for the years ended December 31, 2010, 2009 and 2008 was $0.79, $1.51, and $1.35 per Mcf, respectively.

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

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

The ceiling test is calculated using the unweighted arithmetic average of the natural gas price on the first day of each month within the 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

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

guidelines of the SEC. In addition, subsequent to the adoption of Accounting Standards Codification (ASC) 410-20-25, formerly Financial Accounting Standard Board (FASB) Statement No. 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations were not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

For the year ended December 31, 2010, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.41 per Mcf, resulting in a natural gas price of $4.49 per Mcf when adjusted for regional price differentials. No impairments were recorded to gas properties for the year ended December 31, 2010.

For the year ended December 31, 2009, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.87 per Mcf, resulting in a natural gas price of $4.06 per Mcf when adjusted for regional price differentials. Impairments recorded to gas properties for the year ended December 31, 2009, were:

	United States	Canada	Total
Impairment of gas properties	$ 255,401,961	$ 1,886,296	$ 257,288,257
Deferred income tax benefit	(97,627,986)		(97,627,986)
Impairment of gas properties, net of tax	$ 157,773,975	$ 1,886,296	$ 159,660,271

The natural gas price used in the valuation of natural gas reserves as of December 31, 2008 was $5.84 per Mcf ($5.71 Henry Hub spot market price for December 31, 2008, adjusted for regional price differentials). Impairments recorded to gas properties for the year ended December 31, 2008, were:

	United States	Canada	Total
Impairment of gas properties	$ 32,047,484	$ 18,686,273	$ 50,733,757
Deferred income tax benefit	(12,087,937)		(12,087,937)
Impairment of gas properties, net of tax	$ 19,959,547	$ 18,686,273	$ 38,645,820

The following table provides a summary of the capitalized cost of our gas properties as of December 31, 2010 and 2009, by the year in which the costs were incurred.

	2010	2009
Subject to depletion	$ 475,917,727	$ 461,003,091
Not subject to depletion:		
Acquisition costs		
Exploration costs		
Total 2010		
Total 2009		
Total 2008 and prior		

Total not subject to depletion		
Gross gas properties	475,917,727	461,003,091
Less impairment of gas properties	(312,595,071)	(311,416,980)
Less accumulated depletion	(58,157,433)	(52,202,296)
Net gas properties	$ 105,165,223	$ 97,383,815

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Note 7 Asset Retirement Liability

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

The following table describes the changes to our asset retirement liability for the years ending December 31, 2010 and 2009.

	2010	2009
Asset retirement obligation at beginning of year	$ 4,970,389	$ 4,466,361
Liabilities incurred	80,797	11,937
Liabilities settled	(3,797)	(14,545)
Accretion expense	484,114	431,733
Revisions in estimates	(47,609)	36,466
Currency translation adjustment	14,797	38,437
Asset retirement obligation at end of year	5,498,691	4,970,389
Less: current portion of obligation	32,893	108,111
Long-term asset retirement obligation	$ 5,465,798	$ 4,862,278

Note 8 Derivative Instruments and Hedging Activities

The energy markets have historically been volatile, and there can be no assurance that future natural gas prices will not be subject to wide fluctuations. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices 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 price movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

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

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Commodity Price Risk and Related Hedging Activities

At December 31, 2010, we had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor	Fair Value
January through March 2011	360,000	$ 7.45	$ 6.50		$ 775,853

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

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

At December 31, 2010, we had the following natural gas swap positions:

Period	Volume (MMBtu)	Fixed Price	Fair Value
January through March 2011	360,000	$ 6.67	836,287
January through March 2011	540,000	$ 7.27	1,576,095
April through October 2011	856,000	$ 6.37	1,572,738
April through October 2011	856,000	$ 5.37	715,726
April through October 2011	856,000	$ 5.43	771,155
November 2011 through March 2012	608,000	$ 7.12	1,216,885
November 2011 through March 2012	608,000	$ 6.12	611,002
November 2011 through March 2012	912,000	$ 5.08	(19,449)
April through October 2012	856,000	$ 5.73	653,211
April through October 2012	1,712,000	$ 4.94	(34,286)
November 2012 through March 2013	604,000	$ 6.42	563,413
November 2012 through March 2013	906,000	$ 5.50	35,912
	9,674,000		$ 8,498,689

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

Period

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

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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 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. Gross sales from the Pond Creek field averaged approximately 17,800 MMBtu/day for the year ended December 31, 2010. As such, the overall delivery agreement represents approximately 90% of the 2010 average gross daily sales. Additionally, 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
April through October 2011	856,000	$ 4.80	$ 0.115	$ 4.915	$ 4,207,240
November 2011 through March 2012	456,000	$ 5.20	$ 0.130	$ 5.330	2,430,480
	1,312,000				$ 6,637,720

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

Period	Volume (MMBtu)	Fixed Basis Differential
February through March 2011	944,000	$ 0.150
April through October 2011	2,568,000	$ 0.115
November 2011 through March 2012	1,976,000	$ 0.130
	5,488,000	

The aforementioned forward physical sale contract is defined as a derivative contract under ASC 815. However, it qualifies for the normal purchase and sale exemption and will not be marked-to-market on the Consolidated Balance Sheets.

Interest Rate Risks and Related Hedging Activities

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

We use fixed rate swaps to limit our exposure to fluctuations in interest rates with the objective of realizing a fixed cash flow stream from these activities. At December 31, 2010, we had the following interest rate swaps:

Description	Effective date	Designated maturity date	Fixed rate(1)	Notional amount	Fair Value
Floating-to-fixed swap	1/6/2009	1/6/2011	1.38%	$ 5,000,000	$ (4,592)

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

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

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

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

On September 14, 2010, we de-designated the remaining two interest rate swaps which we had previously designated as cash flow hedges under ASC 815-20-25. The de-designation resulted from entering into the Fourth Amended and Restated Credit Agreement which replaced our Third Amended and Restated Credit Agreement. In the new agreement, the notional and interest rates no longer match, and therefore, these two interest rate swaps are no longer effective hedges under ASC 815-20-25. Subsequently, we accounted for the remaining interest rate swaps on a mark-to-market basis which gave rise to both realized and unrealized gains and losses recorded in Interest expense (net of amounts capitalized) in the Consolidated Statements of Operations. Amounts in accumulated other comprehensive income have been frozen and are reclassified into earnings as the forecasted transactions impact earnings.

For the years ended December 31, 2010, 2009 and 2008, we recognized no ineffective portion of our cash flow hedges. We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our revolving credit facility agreement and the collateral for the outstanding borrowings under our revolving credit facility agreement is used as collateral for our hedges. We do not have rights to collateral from our counterparties, nor do we have rights of offset against borrowings under our revolving credit facility agreement.

The application of ASC 820-10-55, formerly SFAS No. 157, Fair Value Measurements, currently applies to our derivative instruments. Under the provisions of ASC 820-10-55, we estimate the fair value of our natural gas hedges and interest rate swaps using the income approach. The income approach uses valuation techniques that convert future cash flows to a single discounted value. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our counterparties and our credit risk, we have considered the effect of our credit risk on the fair value of the liabilities stated below. This consideration involved discounting our counterparties and our liabilities based on the difference between the S&P credit rating of a comparable company to ours and the 13-week Treasury bill rate, both as of the reporting date. The following is a description of the valuation methodologies used for our derivative instruments measured at fair value:

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

Interest Rate Swaps In order to estimate the fair value of our interest rate swaps, we use an interest yield curve based on Money Market rates and Interest Rate swaps, extrapolate a forecast of future

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

Series A Convertible Redeemable Preferred Stock Upon issuance, the fair value of an embedded derivative liability attributable to the conversion option of the Series A Convertible Redeemable Preferred Stock was bifurcated on the Consolidated Balance Sheet. The fair value of the liability was determined using an American binomial lattice model, which utilized assumptions including 80% volatility and a 17% discount factor. Based on an amendment to the terms of the Preferred Stock made on December 21, 2010, the liability was extinguished and reclassified to Paid-in capital on the Consolidated Balance Sheet at December 31, 2010. Changes in the fair value of the derivative liability were recorded as Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock in the Consolidated Statements of Operations for the year ended December 31, 2010.

We did not have any transfers of assets and liabilities between Level 1 and Level 2 of the fair value measurement hierarchy during the year ended December 31, 2010. Based on the use of observable market inputs, we have designated these types of instruments designated below as Level 2 for ASC 820-10-55 reporting purposes. The fair value of our Level 2 derivative instruments were as follows:

	Asset Derivatives				Liability Derivatives			
	December 31, 2010		December 31, 2009		December 31, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under ASC 815-20-25								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$	Derivative liability (current)	$ 724,253
Interest rate swaps	Derivative asset (non-current)		Derivative asset (non-current)	388	Derivative liability (non-current)		Derivative liability (non-current)	
Total derivatives designated as hedging instruments under ASC 815-20-25		$		$ 388		$		$ 724,253
Derivatives not designated as hedging instruments under ASC 815-20-25								
Interest rate swaps	Derivative asset (current)	$	Derivative asset (current)	$	Derivative liability (current)	$ 4,592	Derivative liability (current)	$
Natural gas hedge positions	Derivative asset (current)	7,087,775	Derivative asset (current)	2,563,898	Derivative liability (current)		Derivative liability (current)	
Natural gas hedge positions	Derivative asset (non-current)	2,186,767	Derivative asset (non-current)	760,804	Derivative liability (non-current)		Derivative liability (non-current)	
Total derivatives not designated as hedging instruments under ASC 815-20-25		$ 9,274,542		$ 3,324,702		$ 4,592		$

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The following (gains) losses on our hedging instruments included in the consolidated statements of operations and other comprehensive (loss) income (OCI) are as follows:

The Effect of Derivative Instruments on the Consolidated Statements of Operations and

Other Comprehensive Income for the Years Ended December 31, 2010 and 2009

Derivatives	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative 2010	2009
Derivatives designated as hedging instruments under ASC 815-20-25			
Interest rate swaps	Interest expense (net of amounts capitalized)	$ 666,720	$ 1,111,829
Total loss		$ 666,720	$ 1,111,829
Derivatives not designated as hedging instruments under ASC 815-20-25			
Derivative liability Series A Convertible Redeemable Preferred Stock	Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock	$ 2,164,080	$
Natural gas collar positions	Realized (gains) losses on derivative contracts	(9,005,621)	(10,694,496)
Natural gas collar positions	Unrealized (gains) losses from the change in market value of open derivative contracts	(5,949,840)	3,995,327
Total gain		$ (12,791,381)	$ (6,699,169)

Derivatives in ASC 815-20-25 Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) 2010	2009	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) 2010	2009
Interest rate contracts	$ 39,570	$ (746,302)	Interest expense	$ (666,720)	$ (1,111,829)
Total	$ 39,570	$ (746,302)		$ (666,720)	$ (1,111,829)

Accumulated comprehensive loss of $1,324,154 as of December 31, 2010 consists of $1,313,292 in foreign currency translation adjustment and a $10,862 loss (net of income tax benefit of $6,714) on interest rate swaps, net of income tax benefit. Accumulated comprehensive loss of $10,862 as of December 31, 2010 is expected to be realized as interest expense in the Consolidated Statement of Operations in the year ended December 31, 2011. Accumulated comprehensive loss of $1,768,521 as of December 31, 2009 consists of $1,321,173 in foreign currency translation adjustments and a $447,348 loss (net of income tax benefit of $276,517) on interest rate swaps, net of income tax benefit.

Accumulated comprehensive loss of $2,399,992 as of December 31, 2008 consists of $1,721,505 in foreign currency translation adjustments and a $678,487 loss (net of income tax benefit of $410,906) on interest rate swaps, net of income tax benefit.

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Note 9 Terminated Transaction Costs

Terminated transaction costs consist of payments made related to a terminated financing transaction between the Company, NGP Capital Resources Company (NGPC) and North Shore Energy, LLC (North Shore), an affiliate of Yorktown Energy Partners IV, L.P. (Yorktown) (Yorktown is a related party to the Company) and expenses related to a terminated sale of certain gas properties. The following is a detail of terminated transaction costs and related party amounts for the year ended December 31, 2010:

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

Note 10 Long-Term Debt

On September 14, 2010, our Fourth Amended and Restated Credit Agreement (the Credit Agreement) with a group of five banks became effective. The Credit Agreement replaced our Third Amended and Restated Credit Agreement and provides for revolving credit borrowings of up to $180 million with an initial borrowing base of $90 million. The borrowing base will be determined as of each June and December with the next determination scheduled to be completed by June 2011. All outstanding borrowings under the Credit Agreement become due and payable on September 14, 2013. 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 1.75% to 2.25% or the London Interbank Offered Rate (the LIBOR Rate) rate plus a margin of 2.75% to 3.25%. 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 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 4.5 to 1.0 through the quarter ending June 30, 2011 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. 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

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preferred stock 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.

As of December 31, 2010, we had $80.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $9.5 million under our $90.0 million borrowing base, subject to compliance with covenants. For the year ended December 31, 2010 we borrowed $28.75 million and made payments of $67.75 million under the revolving credit facility. The rate at December 31, 2010, excluding the effect of our interest rate swaps, was 3.30% per annum. For the year ended December 31, 2010, interest on the borrowings averaged 3.64% per annum.

As of December 31, 2009, we had $119.5 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $15.5 million under our $135.0 million borrowing base. For the year ended December 31, 2009 we borrowed $39.4 million and made payments of $36.4 million under the revolving credit facility. The rate at December 31, 2009, excluding the effect of our interest rate swaps, was 3.03% per annum. For the year ended December 31, 2009, interest on the borrowings averaged 3.12%.

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

	December 31, 2010	December 31, 2009
Borrowings under revolving credit facility	$ 80,500,000	$ 119,500,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	48,961	94,190
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	93,321	106,825
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, non-interest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	353,880	416,940
Total debt	80,996,162	120,117,955
Less current maturities included in current liabilities	(132,743)	(121,792)
Total long-term debt	$ 80,863,419	$ 119,996,163

The fair value of long-term debt at December 31, 2010 and 2009 was estimated to be approximately $68.4 million and $115.8 million, respectively. ASC 820-10-55 clarifies that a fair value measurement for an asset or liability reflects its nonperformance risk, the risk that the obligation will not be fulfilled. Because nonperformance risk includes our credit risk, we have considered the effect of our credit risk on the fair value of the long-term debt. This consideration involved discounting our long-term debt based on the difference between the market weighted average cost of equity capital plus a premium over the capital asset pricing model and the stated interest rates of the debt instruments included our long-term debt.

In connection with the Fourth Amended and Restated Credit Agreement that became effective September 14, 2010, we incurred $1.4 million in deferred financing costs. The deferred financing costs will be amortized over the term of the credit agreement. In addition, we expensed $0.1 million related to the Third Amended and Restated Credit Agreement which was replaced at that time. In connection with the Third Amended and Restated Credit Agreement, we incurred $0.3 million in deferred financing costs.

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The following were maturities of long-term debt for each of the next five years at December 31, 2010:

Year	Amount
2011	$ 132,743
2012	91,757
2013	80,600,467
2014	110,035
2015	61,160
Thereafter	
Total Debt	$ 80,996,162

Note 11 Income Taxes

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

For tax reporting purposes, we have federal and state NOL s of approximately $113.6 million and $123.0 million, respectively, at December 31, 2010 that are available to reduce future taxable income. For tax reporting purposes, we had federal and state NOL s of approximately $97.7 million and $106.4 million, respectively, at December 31, 2009 that were available to reduce future taxable income.

ASC 740 requires the Company to recognize income tax benefits for loss carry forwards that have not previously been recorded. The tax benefits recognized must be reduced by a valuation allowance when it is more likely than not that the deferred tax asset will not be realized. The Company has a net deferred tax asset of $46.0 million and $51.6 million as of December 31, 2010 and 2009, respectively, which includes recorded valuation allowances of $3.1 million and $2.7 million, respectively. Our valuation allowances primarily relate to our Canadian operations where we do not believe it is more likely than not that we will recover our net deferred tax asset prior to expiration and have recorded a full valuation allowance as we currently have no proved reserves in Canada. In addition, we have recorded a valuation allowance for certain immaterial state net operating losses where the Company has ceased operations.

Our first material net operating loss (NOL) carryforward expires in 2022 and the last one expires in 2030. 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 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, 2010 and 2009, 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, 2010, after evaluating all available evidence including historical operating results, historical pricing, current operating income, consideration of the full cost ceiling test impairments in 2009 and 2008 that resulted in the cumulative losses, our 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 valuation allowance related to our Canadian operations and state NOLs, will be realized. The Company will

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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.

Deferred Tax Assets and Liabilities

An analysis of our deferred tax assets and liabilities as of December 31, 2010 and 2009:

	2010	2009
Current deferred tax asset:		
Compensation expense and other	$ 499,245	$ 545,487
Total current deferred tax asset	499,245	545,487
Current deferred tax liability:		
Book basis in excess of tax basis of derivative contracts	(2,705,776)	(702,743)
Net current deferred tax liability	$ (2,206,531)	$ (157,256)
Long-term deferred tax asset:		
Net operating loss carryforward	$ 43,834,634	$ 37,732,386
Compensation expense and other	272,227	277,231
Accrued asset retirement obligations	1,390,748	1,212,465
Alternative minimum tax credit carryforward		
Tax basis of gas properties in excess of book basis	2,713,918	12,873,665
Total long-term deferred tax assets	48,211,527	52,095,747
Long-term deferred tax liability:		
Book basis in excess of tax basis of derivative contracts	(8,666)	(290,776)
Total long-term deferred tax liabilities	(8,666)	(290,776)
Net long-term deferred tax asset (liability)	$ 48,202,861	$ 51,804,971

Effective Tax Rate

Our effective tax rate differs from the federal statutory rate primarily due to the recording of valuation allowances primarily related to our Canadian operations and other nondeductible items as detailed below. The nondeductible transaction costs below relate to a terminated transaction described in Note 9 Terminated Transaction Costs. 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%

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Income tax expense for the year ended December 31, 2009 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	(87,751,624)	34.00%	(1,867,426)	26.00%	(89,619,050)	33.78%
State income taxes net of federal benefit	(10,714,162)	4.15%		0.00%	(10,714,162)	4.04%
Valuation Allowance		0.00%	1,867,426	-26.00%	1,867,426	-0.70%
Nondeductible items and other	324,027	-0.12%		0.00%	324,027	-0.12%
Income tax benefit	(98,141,759)	38.03%		0.00%	(98,141,759)	37.00%

Income tax expense for the for the year ended December 31, 2008 was different than the amount computed using the statutory rate as follows:

	U.S.		Canada		Total	
Amount computed using statutory rates	(938,137)	34.00%	(6,949,350)	34.00%	(7,887,487)	34.00%
State income taxes net of federal benefit	(147,556)	5.35%		0.00%	(147,556)	0.64%
Valuation Allowance	121,865	-4.42%	6,949,350	-34.00%	7,071,215	-30.48%
Nondeductible items and other	251,928	-9.13%		0.00%	251,928	-1.09%
Income tax benefit	(711,900)	25.80%		0.00%	(711,900)	3.07%

The following components of the income tax expense for the years ended December 31, 2010, 2009 and 2008 are as follows:

	Years Ended December 31,		
	2010	2009	2008
Current:			
State	$ 25,000	$ 25,000	$ 25,000
Federal		(115,907)	
Deferred:			
State	556,419	(9,964,882)	(106,231)
Federal	4,825,163	(88,085,970)	(630,669)
Income tax provision	$ 5,406,582	$ (98,141,759)	$ (711,900)

Uncertain Tax Positions

ASC 740 also clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements and prescribes a consistent threshold and measurement attribute for financial statement recognition and disclosure of tax positions taken, or expected to be taken, on a tax return. The amount of unrecognized tax benefits of $272,600 has not changed in the three year period ended December 31, 2010. It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or the financial position.

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

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Our continuing practice is to recognize estimated interest related to potential underpayment on any unrecognized tax benefits as a component of interest expense in the consolidated statement of operations. Penalties, if incurred, would be recognized as a component of penalty expense. We did not have any accrued interest or penalties associated with any unrecognized tax benefits at December 31, 2010 and 2009, nor was any interest expense recognized during the years ended December 31, 2010, 2009 and 2008. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2011.

Note 12 Common Stock

At December 31, 2010 and 2009, there were 39,758,484 and 39,460,060 shares, respectively, of common stock outstanding, both including 10,432 shares of treasury stock held by the Company. Also included in common stock outstanding at December 31, 2010 and 2009 were 292,512 and 311,684 shares of restricted stock, respectively.

For the year ended December 31, 2010, 75,190 shares of common stock were issued upon the exercise of stock options granted under our 2006 Long-Term Incentive Plan. No common stock was issued upon the exercise of stock options granted under our 2005 Stock Option Plan. On September 20, 2010, we issued 157,622 shares of common stock to our independent directors, representing 50% of their 2010 annual retainer. Additionally, on September 20, 2010, we issued 132,492 performance-based shares of restricted stock to the executives of the Company. For the year ended December 31, 2010, 66,194 shares of restricted stock were forfeited. On March 24, 2010, 300 shares of common stock were purchased by us from a non-executive employee for the payment of $289 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. On June 15, 2010, 386 shares of common stock were purchased by us from a non-executive employee for the payment of $494 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

For the year ended December 31, 2009, no common stock was issued upon the exercise of stock options granted under our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. On March 23, 2009, we issued 166,668 shares of common stock to our independent directors representing 50% of their 2009 retainer. For the year ended December 31, 2009, 11,354 shares of restricted stock were forfeited. On June 15, 2009, 403 shares of common stock were purchased by us from a non-executive employee for the payment of $613 in withholding taxes due on vested shares of restricted stock issued under our 2006 Long-Term Incentive Plan. The shares were not retained as treasury stock as they were immediately cancelled.

For the year ended December 31, 2008, a total of 68,605 shares of common stock were issued upon the exercise of stock options granted under our 2005 Stock Option Plan and no stock options were granted. In March 2008, we issued 253,806 shares of restricted stock to key employees, including four executive officers and two other officers, of the Company and 18,720 shares of common stock to our independent directors, representing 50% of their annual retainer. In September 2008, we issued 46,694 shares of restricted stock to key employees of the Company. The shares of common stock for our independent directors and the restricted stock were issued pursuant to our 2006 Long-Term Incentive Plan. For the year ended December 31, 2008, 45,032 shares of restricted stock were forfeited.

Note 13 Series A Convertible Redeemable Preferred Stock

On September 14, 2010, the Company 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. After

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

paying transaction fees and expenses in the amount of $2.8 million, the Company used the net proceeds of approximately $37.2 million to reduce outstanding bank debt. The Preferred Stock ranks senior to our common stock as to payment of dividends and distribution upon liquidation.

Dividends 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, 2010, an additional 3,253,294 shares of our Preferred Stock are reserved exclusively for the payment of PIK dividends.

The Preferred Stock is immediately convertible into common stock, at the sole option of the holder, at an initial conversion price of $1.30 per common share (as it may be adjusted from time to time, the Conversion Price). The Preferred Stock converts into a number of shares of common stock determined by dividing (i) the sum of (A) $10.00 plus (B) accrued but unpaid dividends by (ii) the Conversion Price. At the current Conversion Price, up to an additional 31,911,830 shares of our common stock would be outstanding immediately after conversion of our Preferred Stock. The Conversion Price and resulting number of shares of common stock issued upon conversion of Preferred Stock is adjusted to reflect stock splits and similar events and is entitled to anti-dilution adjustments for any dividends paid on common stock in cash or in common stock, the issuance of additional equity securities at a price less than the Conversion Price (excluding shares, rights and options subject to certain employee benefit arrangements), and the occurrence of certain material corporate transactions at a per share valuation less than the Conversion Price.

At any time beginning eight years from the date of issuance, the Preferred Stock is redeemable, in whole or in part, at the sole option of the holder. The purchase price per share, payable in cash, will be equal to the sum of the original purchase price and any accrued and unpaid dividends.

We have the option, beginning three years from the date of issuance, to convert the Preferred Stock into our common stock at the then current Conversion Price, subject to certain volume and other limitations. In order for us to exercise this option, the daily volume-weighted average trading price of our common stock must be greater than 225% of the then current Conversion Price for twenty (20) out of the previous thirty (30) trading days.

The holders of the Preferred Stock are entitled to vote on all matters on which the holders of our common stock are entitled to vote. The holders of the Preferred Stock generally vote together with the holders of the common stock as a single class, with the Preferred Stock holders entitled to the number of votes such holders would have on an as-converted basis. Certain actions also require a separate vote of the Preferred Stock.

Upon the occurrence of a liquidation, dissolution or winding up of the Company resulting in a payment or distribution of assets to the holders of any of our capital stock (each such event, a Liquidation Event), the holders of the Preferred Stock (including PIK dividends) are entitled to receive, prior and in preference to any payment, or segregation for payment, of any consideration to any holder of any junior security of the Company, an amount in cash equal to the greater of (i) $10.00 per share, plus any accrued but unpaid dividends (in each case adjusted for any stock dividends, splits, combinations or similar events), or (ii) an amount equal to the amount such holders of the Preferred Stock would have received upon the Liquidation Event if they had converted their shares of Preferred Stock into shares of our common stock.

If not converted, the Preferred Stock (including any PIK dividends) is redeemable by us on or at any time after a Liquidation Event. In the absence of a Liquidation Event, if not converted, a holder of Preferred Stock

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

(including any PIK dividends) may cause us to redeem the Preferred Stock held by such holder, in whole or in part, on or after September 14, 2018, upon 30 days prior written notice to us. Upon any redemption of Preferred Stock by us, as of the effective date of the redemption, we will pay to each holder of Preferred Stock, $10.00 per share of Preferred Stock (including any PIK dividends) held plus any accrued but unpaid dividends (in each case adjusted for any stock dividends, splits, combinations or similar events).

During the year ended December 31, 2010, the Company declared and issued PIK dividends of 148,538 shares to the holders of Preferred Stock.

The 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. The Preferred Stock balance in mezzanine equity will be accreted to its redemption value over the eight year redemption period. In addition, we evaluated the conversion feature at September 14, 2010 and determined that its terms required the holder s conversion option to be separated and recorded at fair value as a derivative liability on the Consolidated Balance Sheet. 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.

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, and resulted in a fair value of approximately $18.4 million on the date of issuance. The remaining net proceeds of $20.4 million were allocated to Series A Convertible Redeemable Preferred Stock in the Consolidated Balance Sheets. For the year ended December 31, 2010, the Company recorded approximately $2.1 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.

The Preferred Stock initially contained an anti-dilution provision that was triggered when the Company issued certain additional common stock or securities convertible into common stock for consideration per share less than the conversion price of the Preferred Stock. The anti-dilution provision was amended during 2010 so that, in the event of such issuance, the conversion price of the Preferred Stock will be reduced to a price determined by multiplying the then-current conversion price by a fraction (a) the numerator of which will be the sum of (i) the number of shares of common stock outstanding, on a fully diluted basis, before the additional issuance plus (ii) the number of shares of common stock which the aggregate consideration received by the Company for the additional issuance would purchase at the conversion price then in effect, and (b) the denominator of which will be the sum of (x) the number of shares of common stock outstanding before the additional issuance plus (y) the number of such additional shares of common stock that were actually issued.

In addition, the terms of the Preferred Stock was amended to prohibit the Company from issuing 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 Series A Preferred Stock without the prior vote or consent of holders of a majority of the outstanding shares of Series A Preferred Stock, for so long as at least 750,000 shares of Series A Preferred Stock remain outstanding.

GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

We amended the terms of the Preferred Stock because we believed that the valuation, accounting and disclosure obligations associated with the embedded derivative were burdensome and that such accounting treatment did not clearly represent the overall financial condition and results of operations of the Company. Determining the periodic change in the fair value of the derivative liability required a costly valuation each quarter and produced significant volatility in the Company s consolidated balance sheet and consolidated statement of operations. In addition, the valuation required Level 3 inputs and assumptions, under ASC 820-10-55, for reporting purposes, and was considered a critical accounting area which includes a high degree of judgment and uncertainty.

On the effective date of the Amendment, December 21, 2010, 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). In addition, we will no longer experience the potential volatility on the consolidated balance sheets and consolidated statements of operations from unrealized gains or losses resulting from future fair value fluctuations of the extinguished derivative liability. As a result, we expect our consolidated financial statements to be more consistent with the underlying operations of the Company.

The following table details the activity related to the issuance and accretion of the Series A Convertible Redeemable Preferred Stock and the related derivative liability for the year ended December 31, 2010:

	Mezzanine Equity Series A Convertible Redeemable Preferred Stock	Derivative Liability Series A Convertible Redeemable Preferred Stock	Total Liability & Mezzanine Equity Amounts Related to Series A Convertible Redeemable Preferred Stock
Balance at January 1, 2010	$	$	$
Issuance of Series A Convertible Redeemable Preferred Stock	40,000,000		40,000,000
Allocated to derivative liability	(18,378,517)	18,378,517	
Issuance costs(1)	(1,531,056)		(1,531,056)
Net issuance of Series A Convertible Redeemable Preferred Stock	20,090,427	18,378,517	38,468,944
Unrealized loss from change in fair value of derivative liability Series A Convertible Redeemable Preferred Stock		2,164,080	2,164,080
Accretion of Series A Convertible Redeemable Preferred Stock	497,782		497,782
PIK Dividends for Series A Convertible Redeemable Preferred Stock	1,486,111		1,486,111
Reclassification of Derivative Liability Series A Convertible Redeemable Preferred Stock to Equity		(20,542,597)	(20,542,597)
Balance at December 31, 2010	$ 22,074,320	$	$ 22,074,320

(1) Issuance costs of $2,832,472 were incurred as part of the issuance of the Series A Convertible Redeemable Preferred Stock. As the Series A Convertible Redeemable Preferred Stock was bifurcated on the Consolidated Balance Sheet as disclosed in the table above, $1,531,056 of the issuance costs were allocated to Mezzanine Equity Series A Convertible Redeemable Preferred Stock. The remaining $1,301,416 of

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

issuance costs were allocated to Other current assets and Other noncurrent assets to be amortized over the term of the Series A Convertible Redeemable Preferred Stock and, as a result of the amendment to the Preferred Stock agreement on December 21, 2010, $1,261,343($1,301,416 of original issuance costs, less $40,073 amortized in 2010) were reclassified to equity.

Note 14 Share-Based Awards

As of December 31, 2010, we have two stock-based award plans authorized, which include our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, we will not grant any additional awards under our 2005 Stock Option Plan now that we have adopted our 2006 Long-Term Incentive Plan. The 2005 Stock Option Plan was terminated on March 11, 2011 as no options granted under the plan remained outstanding at that time.

Our 2006 Long-Term Incentive Plan authorized the granting of incentive stock options, non-qualified stock options, stock appreciation rights, stock awards, restricted stock, restricted stock units and performance awards. A maximum of 4,000,000 shares is available for grant under this plan. The 2006 Long-Term Incentive Plan is available to our employees and independent directors and is designed to attract and retain employees and independent directors, to further align the interests of our employees and independent directors with the interests of our stockholders, and to closely link compensation with our performance. The exercise price of stock options granted under this plan may not be less than the fair market value of the common stock on the date of grant. The options generally have a term of seven years and vest evenly over three years, except performance based awards, granted to our named executive officers, and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criteria have been met. Options granted to our directors vest immediately.

During the year ended December 31, 2010, we recorded a compensation expense accrual of $510,840 of which $43,292 was allocated to lease operating expenses, $364,295 was allocated to general and administrative expenses, and $103,253 was capitalized to gas properties.

During the year ended December 31, 2009, we recorded a compensation expense accrual of $978,634 of which $54,008 was allocated to lease operating expenses, $738,568 was allocated to general and administrative expenses, and $186,058 was capitalized to gas properties.

During the year ended December 31, 2008, we recorded a compensation expense accrual of $941,697 of which $53,737 was allocated to lease operating expenses, $512,680 was allocated to general and administrative expenses, and $375,280 was capitalized to gas properties.

At December 31, 2010, the future compensation cost of all the outstanding awards is $584,351 which will be amortized over the vesting period of such stock options and restricted stock. The weighted average remaining useful life of the future compensation cost is 1.08 years.

For the year ended December 31, 2010, the significant assumptions used in determining the compensation costs included an expected volatility from 79.3% to 83.7%, risk-free interest rate of 1.47%, an expected term from 4.39 to 4.83 years, forfeiture rates from 5% to 15%, and no expected dividends. For the year ended December 31, 2009, the significant assumptions used in determining the compensation costs included an expected volatility of 56.10%, risk-free interest rate of 1.25%, an expected term of 4.5 years, forfeiture rates from 5% to 15%, and no expected dividends. For the year ended December 31, 2008, no stock options were granted.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Incentive Stock Options

The table below summarizes incentive stock option activity for the three years ended December 31, 2010:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at January 1, 2008	682,277	$ 6.96		
Exercised	(68,605)	$ 1.72		
Forfeited	(136,503)	$ 5.63		
Outstanding at December 31, 2008	477,169	$ 8.09	4.43	$ 4,008
Options exercisable at December 31, 2008	279,126	$ 7.84	3.83	$ 4,008
Granted	606,507	$ 0.72		
Transferred	(12,048)	$ 8.30		
Forfeited	(73,842)	$ 3.47		
Outstanding at December 31, 2009	997,786	$ 3.95	5.09	$ 422,100
Options exercisable at December 31, 2009	334,302	$ 8.52	3.29	$
Granted	600,699	$ 0.88		
Exercised	(75,190)	$ 0.72		
Forfeited	(131,684)	$ 3.43		
Outstanding at December 31, 2010	1,391,611	$ 2.85	5.28	$ 348,408
Options exercisable at December 31, 2010	487,803	$ 6.34	3.51	$ 61,072

During the years ended December 31, 2010 and 2009, incentive stock options were granted with a weighted average grant-date fair value of $0.55 and $0.33 per option, respectively. The total intrinsic value of incentive stock options exercised during the years ended December 31, 2010 and 2008 was $29,414 and $553,567, respectively.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the three years ended December 31, 2010:

	Number of Options	Weighted Average Exercise Price	Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at January 1, 2008	1,311,055	$ 4.02		
Forfeited	(30,968)	$ 10.22		
Outstanding at December 31, 2008	1,280,087	$ 3.87	4.3	$
Options exercisable at December 31, 2008	1,156,313	$ 3.33	4.2	$
Granted	114,012	$ 0.72		
Transferred	12,048	$ 8.30		
Forfeited	(5,387)	$ 13.00		
Outstanding at December 31, 2009	1,400,760	$ 3.61	3.6	$ 84,369
Options exercisable at December 31, 2009	1,114,196	$ 3.05	3.2	$
Forfeited	(250,212)	$ 2.43		
Outstanding at December 31, 2010	1,150,548	$ 3.87	3.1	$ 44,634
Options exercisable at December 31, 2010	950,020	$ 3.59	2.8	$

During the year ended December 31, 2009, non-qualified stock options were granted with a weighted average grant-date fair value of $0.33 per option.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the three years ended December 31, 2010:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock at January 1, 2008	173,998	$ 7.21
Granted	300,500	$ 6.34

Forfeited	(45,032)	$	6.84
Vested	(28,391)	$	7.23
Non-vested restricted stock at December 31, 2008	401,075	$	6.60
Forfeited	(11,354)	$	6.35
Vested	(78,037)	$	6.75
Non-vested restricted stock at December 31, 2009	311,684	$	6.57
Granted	132,492	$	0.88
Forfeited	(66,194)	$	6.50
Vested	(85,470)	$	6.74
Non-vested restricted stock at December 31, 2010	292,512	$	3.95

GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Option Exchange

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

the options had a per share exercise price greater than $5.00;

the options were granted under one of our existing equity incentive plans;

the options were outstanding and unexercised as of January 5, 2010;

the options were not granted within the twelve-month period immediately preceding the commencement of this offer, December 7, 2010; and

the options did not have a remaining term of less than 12 months immediately following January 5, 2010.

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

Exercise Price Per Share	Number of Eligible Options	Number of New Restricted Shares 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

Note 15 Profit Sharing Plan

Substantially all of the employees are covered by our profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer some of their compensation. We are required to match 100 percent of the first three percent of their annual compensation contributed and 50 percent of the following two percent of their annual compensation contributed. Our matching contribution vests evenly over three years. Once a participant is fully vested all future matching contributions vest immediately. Our contributions to the Plan for the years ended December 31, 2010, 2009 and 2008 were $198,131, $216,842, and $264,305, respectively. Additionally, during the year ended December 31, 2010, we elected in to be Safe Harbor for the year ended December 31, 2011. A Safe Harbor

401(k) plan generally satisfies the non-discrimination rules for elective deferrals and employer matching contributions. For a 401(k) plan to be considered a Safe Harbor plan, employers must satisfy certain contribution, vesting, and notice requirements. Under Safe Harbor, the matching contributions will vest immediately.

Note 16 Commitments and Contingencies

From time to time we are a party to litigation in the normal course of business. While the outcome of lawsuits or other proceedings against us 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.

GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

EQT Production Company Claim

In March 2011, we received a letter from EQT Production Company (EQT) stating that our fracturing operations in 2010 had damaged a well owned by EQT, and demanding the payment of the value of the well and other amounts totaling approximately $430,000. In April 2011, EQT revised their demand for payment to approximately $464,000. We are reviewing the claim to determine if we are liable for the damages alleged to have been sustained by EQT. We believe that if we are responsible for the damages, substantially all of the loss will be covered by our insurance. A majority of our proved undeveloped locations in the Pond Creek field are owned by us through a farmout agreement with EQT that provides that if we default under the agreement, our future development rights under the farmout agreement terminate. The failure to pay the amount of any damages to EQT for which we are liable may be a default as defined in the farmout agreement. We do not believe that the payment of any damages to EQT for which we may be liable will have a material impact on our results of operations, financial position nor cash flows.

Environmental and Regulatory

As of December 31, 2010, there were no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us.

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, 2010 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	Amount
2011	$ 880,442
2012	646,475
2013	436,835
2014	189,672
2015	188,448
Thereafter	594,632
Total future minimum lease commitments	$ 2,936,504

Total rental expenses under operating leases were approximately $1,528,739, $1,857,026, and $2,005,994 for the years ended December 31, 2010, 2009 and 2008, respectively.

Transportation Contracts As of December 31, 2010, 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, and (3) 10,000 MMBtu s continuing until April 1, 2017. We have a right to extend each of these contracts, in five-year increments, at the maximum tariff rate. As of December 31, 2010, the maximum commitment remaining under the transportation contracts is approximately $12.3 million.

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NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

Note 17 Additional Financial Statement Information

Certain balance sheet amounts are comprised of the following:

	December 31, 2010	December 31, 2009
Accounts payable:		
Trade payables	$ 2,457,347	$ 2,075,002
Capital costs payable	1,154,145	397,375
Revenues and royalties payable	1,858,936	1,807,085
Lease operating expenses payable	466,479	878,551
Other	13,954	11,161
Total accounts payable	$ 5,950,861	$ 5,169,174
Accrued liabilities:		
Accrued interest expense	$ 123,041	$ 377,602
Accrued employee compensation	1,169,564	1,237,751
Accrued ad valorem taxes payable	953,644	1,113,574
Accrued franchise taxes	59,771	79,300
Total accrued liabilities	$ 2,306,020	$ 2,808,227

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SUPPLEMENTARY FINANCIAL AND OPERATING INFORMATION ON GAS

EXPLORATION, DEVELOPMENT AND PRODUCING ACTIVITIES (UNAUDITED)

This supplemental schedule provides unaudited information pursuant to ASC 932, formerly SFAS No. 69, Disclosures About Oil and Gas Producing Activities an amendment of FASB Statements No. 19, 25, 33, and 39) and certain other information.

Capitalized Costs Capitalized costs and accumulated depletion and impairment of gas properties relating to our gas producing activities, all of which are conducted within the continental U.S. and Canada at December 31, 2010, 2009, and 2008 are summarized below.

	December 31, 2010	2009	2008
Unevaluated properties U.S.	$	$	$ 5,017
Unevaluated properties Canada			
Properties subject to amortization U.S.	447,532,258	434,093,992	425,437,272
Properties subject to amortization Canada	28,385,469	26,909,099	22,531,264
Capitalized costs consolidated	475,917,727	461,003,091	447,973,553
Accumulated depletion and impairment of gas properties U.S.	(342,367,035)	(336,710,177)	(72,743,290)
Accumulated depletion and impairment of gas properties Canada	(28,385,469)	(26,909,099)	(18,686,273)
Net capitalized costs consolidated	105,165,223	97,383,815	356,543,990
Net capitalized costs Canada			3,844,991
Net capitalized costs U.S.	105,165,223	97,383,815	352,698,999
Net capitalized costs consolidated	$ 105,165,223	$ 97,383,815	$ 356,543,990

Capitalized Costs Incurred

We capitalize certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of our investment in natural gas properties over the periods benefited by these activities. During the years ended December 31, 2010, 2009 and 2008, these capitalized costs amounted to $971,467, $1,485,510, and $2,329,748, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. For the years ended December 31, 2010 and 2009, no interest costs were capitalized. For the years ended December 31, 2008, interest costs of $304,342 were capitalized. During the years ended December 31, 2010, 2009 and 2008, costs related to share based compensation included in development costs were $103,253, $186,058, and $375,711, respectively. During the years ended December 31, 2010, 2009 and 2008, costs related to asset retirement obligations included in development costs were $33,178, $50,444, and $1,304,766, respectively. During the years ended December 31, 2010, 2009 and 2008, currency translation adjustments included in Development costs incurred Canada were $1,301,291, $3,633,389, and $(5,037,521), respectively. The following table discloses costs incurred in gas property acquisition, exploration and development activities for years ended December 31, 2010, 2009 and 2008.

	For the Years Ended December 31, 2010	2009	2008
Acquisition costs-proved U.S.	$ 1,502,264	$ 2,623,672	$ 3,153,568
Acquisition costs-unproved U.S.			2,779,865
Exploration costs incurred U.S.	3,115	28,549	6,055,041
Development costs incurred U.S.	11,932,887	5,999,482	34,670,459
Total costs incurred U.S.	13,438,266	8,651,703	46,658,933
Acquisition costs-proved Canada	60,582	59,318	65,251
Acquisition costs-unproved Canada			

Exploration costs incurred Canada			51,542
Development costs incurred Canada(1)	1,415,788	4,318,517	5,618,726
Total costs incurred Canada	1,476,370	4,377,835	5,735,519
Total costs incurred consolidated	$ 14,914,636	$ 13,029,538	$ 52,394,452

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

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

	2010	2009	2008
Natural Gas Reserves (Mcf) U.S.			
Proved reserves at beginning of year	209,274,000	315,711,000	350,176,000
Revisions of previous estimates	6,475,000	(101,172,000)	(42,708,000)
Extensions and discoveries	7,534,000		17,613,000
Acquisition			
Disposition			(1,917,000)
Revisions new rules(1)		2,242,000	
Production	(7,344,000)	(7,507,000)	(7,453,000)
Proved reserves at end of year	215,939,000	209,274,000	315,711,000
Proved developed reserves at beginning of year	156,241,000	242,518,000	266,943,000
Proved developed reserves at end of year	163,318,000	156,241,000	242,518,000

	2010	2009	2008
Natural Gas Reserves (Mcf) Canada			
Proved reserves at beginning of year		3,818,000	
Revisions of previous estimates		(3,776,000)	
Extensions and discoveries			3,818,000
Acquisition			
Disposition			
Production		(42,000)	
Proved reserves at end of year			3,818,000
Proved developed reserves at beginning of year		3,818,000	
Proved developed reserves at end of year			3,818,000

(1) Aggregated revisions resulting from the new SEC guidelines which became effective December 31, 2009

The technical person primarily responsible for preparation of our internal reserve estimates and overseeing the reserve estimates prepared by D&M, an independent petroleum engineering consulting firm, 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 24 years, including nine years with River Gas Corporation in Northport, Alabama from 1992 to 2001 and the last

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nine years with GeoMet in Hoover, Alabama. He also worked briefly with Phillips Petroleum following its acquisition of River Gas Corporation. During the last 18 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 to estimate our year-end reserves and assesses them for reasonableness.

Estimates of our proved reserves at December 31, 2010, 2009, and 2008 were prepared by D&M. The technical persons at D&M 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. Both the Company s 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. 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.

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.

Our proved natural gas reserves as of December 31, 2010, as estimated by D&M, totaled approximately 216 Bcf, an increase of approximately 3% from the approximate 209 Bcf of proved natural gas reserves at December 31, 2009, as estimated by D&M. Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month, adjusted for regional price differentials, for the years ended December 31, 2010 and 2009, respectively. For the year ended December 31, 2010, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.41 per Mcf, resulting in a natural gas price of $4.49 per Mcf when adjusted for regional price differentials. For the year ended December 31, 2009, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.87 per Mcf, resulting in a natural gas price of $4.06 per Mcf when adjusted for regional price differentials. Natural gas prices associated with operating wells were held constant and estimates of operating expenses and capital costs based on current costs were used for the lives of the properties with no increases in the future based on inflation (in certain cases, future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating condition) in accordance with the amended SEC guidelines which were effective for financial statements for periods ending on or after December 31, 2009.

Our proved reserves were 100% from coalbed methane reservoirs and were 76% developed. Approximately 64% of total year-end 2010 proved reserves are in the Pond Creek and Lasher fields in West Virginia and Virginia and 36% are in the Gurnee field in Alabama.

The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with ASC 932. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental U.S. and Canada. As prescribed by this statement, the amounts shown for December 31, 2010 and 2009 are will be calculated using the unweighted arithmetic average

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of the price on the first day of each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. The amounts shown for December 31, 2008 are based on prices and costs at December 31, 2008 and assume continuation of existing economic conditions. Future income taxes are based on year-end statutory rates, adjusted for tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. Extensive judgments are involved in estimating the timing of future production and the costs that will be incurred throughout the remaining lives of the fields. Accordingly, the estimates of future net revenues from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimated to be incurred in developing and producing the estimated proved gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other gas producers.

	December 31,		
Standardized Measure U.S.	**2010**	**2009**	**2008**
Future cash inflows	$ 969,994,000	$ 849,379,000	$ 1,844,199,000
Future production costs	(470,832,000)	(426,105,000)	(727,785,000)
Future development costs	(70,874,000)	(68,321,000)	(105,707,000)
Future income taxes	(77,060,000)	(47,935,000)	(290,341,000)
Future net cash flows	351,228,000	307,018,000	720,366,000
10% annual discount to reflect timing of cash flows	(231,304,000)	(157,820,000)	(413,859,000)
Standardized measure of discounted future net cash flows	$ 119,924,000	$ 149,198,000	$ 306,507,000

	December 31,		
Standardized Measure Canada	**2010**	**2009**	**2008**
Future cash inflows	$	$	$ 20,932,000
Future production costs			(7,126,000)
Future development costs			(30,000)
Future income taxes			
Future net cash flows			13,776,000
10% annual discount to reflect timing of cash flows			(9,936,000)
Standardized measure of discounted future net cash flows	$	$	$ 3,840,000

Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2010, 2009 and 2008 are summarized below:

Changes in Standardized Measure	**2010**	**2009**	**2008**
Standardized measure at beginning of year	$ 149,198,000	$ 310,347,000	$ 495,868,000
Sales and transfers of oil and gas produced net of production cost	(16,975,000)	(10,472,000)	(46,908,000)
Net changes in prices and production cost	15,634,000	(168,683,000)	(238,413,000)
Extensions and discoveries	2,241,000		17,666,000
Acquisition/disposition (net)			(9,708,000)
Net change in development cost	9,685,000	14,862,000	19,685,000
Revision of previous quantity estimates	4,086,000	(71,363,000)	(55,087,000)
Accretion of discount before income taxes	9,767,000	35,195,000	66,281,000
Net change in income taxes	(57,781,000)	93,133,000	125,336,000
Changes in production rates (timing) and other	4,069,000	(53,821,000)	(64,373,000)
Subtotal net change	(29,274,000)	(161,149,000)	(185,521,000)

Standardized measure at end of year	$ 119,924,000	$ 149,198,000	$ 310,347,000

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

For the year ended December 31, 2010, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $4.41 per Mcf, resulting in a natural gas price of $4.49 per Mcf when adjusted for regional price differentials.

For the year ended December 31, 2009, the unweighted arithmetic average of the Henry Hub spot market price on the first day of each month was $3.87 per Mcf, resulting in a natural gas price of $4.06 per Mcf when adjusted for regional price differentials.

The natural gas price used in the valuation of natural gas reserves as of December 31, 2008 was $5.84 per Mcf ($5.71 Henry Hub spot market price for December 31, 2008, adjusted for regional price differentials).

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GEOMET, INC.

QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations. The following table sets forth the results of operations by quarter for the years ended December 31, 2010 and 2009 (in thousands):

	Quarter Ended			
	Mar. 31	**Jun. 30**	**Sept. 30**	**Dec. 31**
Fiscal Year 2010:				
Total revenues	$ 9,958	$ 7,732	$ 8,316	$ 7,354
Lease operating expense	$ (3,107)	$ (2,813)	$ (2,877)	$ (2,746)
Compression and transportation expense	$ (1,004)	$ (1,075)	$ (1,096)	$ (989)
Production taxes	$ (208)	$ (288)	$ (227)	$ (298)
Depreciation, depletion and amortization	$ (1,645)	$ (1,450)	$ (1,561)	$ (1,640)
General and administrative	$ (1,478)	$ (1,315)	$ (1,206)	$ (1,368)
Terminated transaction costs	$	$ (1,403)	$	$
Realized gains on derivative contracts	$ 1,460	$ 2,211	$ 1,825	$ 3,510
Unrealized gains (losses) from the change in market value of open derivative contracts	$ 7,642	$ (2,974)	$ 5,096	$ (3,815)
Operating income (loss) from continuing operations	$ 11,617	$ (1,375)	$ 8,270	$ 9
Net income (loss) available to common stockholders	$ 6,027	$ (1,762)	$ 4,218	$ (4,675)
Net income (loss) per common share:				
Basic	$ 0.15	$ (0.04)	$ 0.11	$ (0.12)
Diluted	$ 0.15	$ (0.04)	$ 0.10	$ (0.12)
Fiscal Year 2009:				
Total revenues	$ 9,551	$ 6,915	$ 6,490	$ 8,008
Lease operating expense	$ (4,569)	$ (3,348)	$ (3,195)	$ (2,823)
Compression and transportation expense	$ (1,450)	$ (1,365)	$ (1,235)	$ (962)
Production taxes	$ (367)	$ (241)	$ (248)	$ (323)
Depreciation, depletion and amortization	$ (3,037)	$ (1,982)	$ (5,169)	$ (1,843)
Impairment of gas properties	$ (139,712)	$ (27,582)	$ (69,147)	$ (20,847)
General and administrative	$ (2,973)	$ (2,181)	$ (1,853)	$ (1,342)
Realized gains on derivative contracts	$ 2,723	$ 2,734	$ 3,169	$ 2,068
Unrealized gains (losses) from the change in market value of open derivative contracts	$ 186	$ (2,144)	$ (3,567)	$ 1,530
Operating (loss) from continuing operations	$ (139,649)	$ (29,194)	$ (74,753)	$ (16,533)
Net loss available to common stockholders	$ (87,726)	$ (19,386)	$ (48,343)	$ (11,679)
Net loss per common share:				
Basic	$ (2.25)	$ (0.50)	$ (1.23)	$ (0.30)
Diluted	$ (2.25)	$ (0.50)	$ (1.23)	$ (0.30)

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

None.

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

Management s Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified by the SEC s rules and forms and

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include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act) as of December 31, 2010, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and are effective at the reasonable assurance level that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC s rules and forms.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2010 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report On Internal Control Over Financial Reporting

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

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2010.

/s/ J. DARBY SERÉ	/s/ WILLIAM C. RANKIN
J. Darby Seré,	**William C. Rankin**
Chief Executive Officer	**Chief Financial Officer**

Houston, Texas

April 6, 2011

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

None.

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PART III

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

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

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

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

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

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

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

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

List of Documents Filed as Part of this Report

(1) Financial Statements

(2) Financial Statement Schedules

None.

(3) Exhibits:

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

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on July 25, 2006 (Registration No. 333-131716)).
3.2	Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Appendix B to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
3.3	Certificate of Amendment to the Certificate of Designations of Series A Convertible Redeemable Preferred Stock, par value $0.001 per share, of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company s Form 8-K filed on December 28, 2010).
3.4	Amended and Restated Bylaws of GeoMet, Inc. (Adopted as of September 14, 2010) (incorporated herein by reference to Exhibit 3.1 of the Company s Form 8-K filed on September 20, 2010).
10.1	GeoMet, Inc. 2006 Long-Term Incentive Plan (Amended and Restated effective November 9, 2010) (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 15, 2010).
10.2	Second Amendment to Investment Agreement dated November 5, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.2 to the Company s Form 10-Q filed on November 10, 2009).

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Exhibit No.	Description
10.3	First Amendment to Investment Agreement dated September 3, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 10, 2010).
10.4	Investment Agreement dated June 2, 2010 by and between GeoMet, Inc. and Sherwood Energy, LLC (incorporated herein by reference to Appendix A to the Company s Definitive Proxy Statement on Schedule 14A filed on June 24, 2010).
10.5	Form of Indemnification Agreement between GeoMet, Inc. and officers and directors of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.2 of the Company s Form 8-K filed on September 20, 2010).
10.6	Fourth Amended and Restated Credit Agreement dated May 8, 2010 by and among GeoMet, Inc., Bank of America, N.A, as Administrative Agent, BNP Paribas, as Syndication Agent, and Bank of Scotland, U.S. National Bank Association, and Sterling Bank (incorporated herein by reference to Exhibit 10.1 to the Company s Form 10-Q filed on July 27, 2010).
10.7	Change of Control Severance Agreement dated January 26, 2011 between GeoMet, Inc. and Tony Oviedo (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on January 31, 2011).
21.1*	List of Subsidiaries of GeoMet, Inc.
23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of Independent Petroleum Engineers DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton.

* Filed herewith.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on April 6, 2011.

GEOMET, INC.

By:	/s/ J. Darby Seré
Name:	**J. Darby Seré**
Title:	**President and Chief Executive Officer**

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrants and in the capacities on April 6, 2011.

Signature	Capacity
/s/ J. Darby Seré **J. Darby Seré**	Chairman of the Board, President, Chief Executive Officer (Principal Executive Officer)
/s/ William C. Rankin **William C. Rankin**	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ Tony Oviedo **Tony Oviedo**	Vice President, Chief Accounting Officer and Controller
/s/ J. Hord Armstrong, III **J. Hord Armstrong, III**	Director
/s/ James C. Crain **James C. Crain**	Director
/s/ Stanley L. Graves **Stanley L. Graves**	Director
/s/ Charles D. Haynes **Charles D. Haynes**	Director
/s/ W. Howard Keenan, Jr. **W. Howard Keenan, Jr.**	Director
/s/ Philip G. Malone **Philip G. Malone**	Director

/s/ MICHAEL Y. MCGOVERN	Director
Michael McGovern	
/s/ GARY S. WEBER	Director
Gary S. Weber	

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