GeoMet, Inc.
Form 10-K
April 06, 2011
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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.

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.

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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	