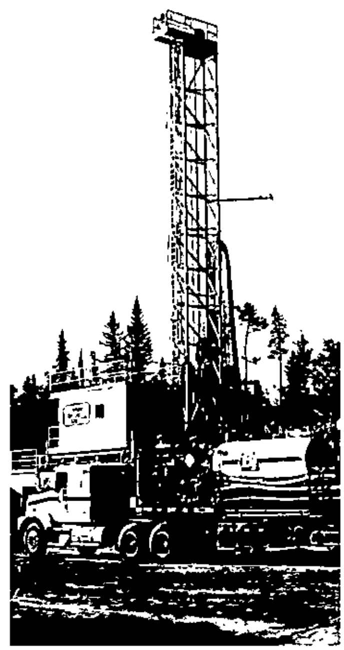
GeoMet

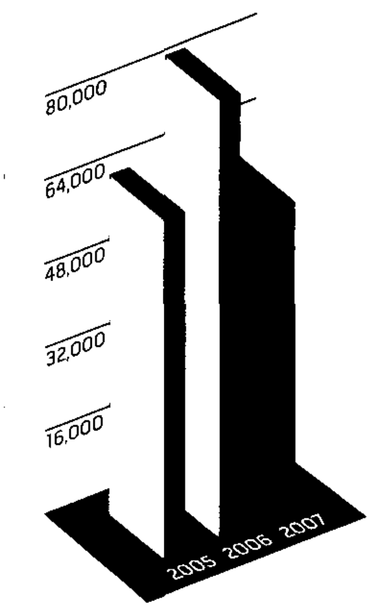
VALUE



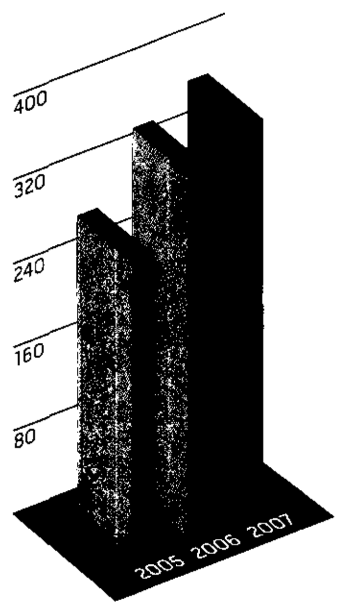
2007 Annual Report

=GROWTH

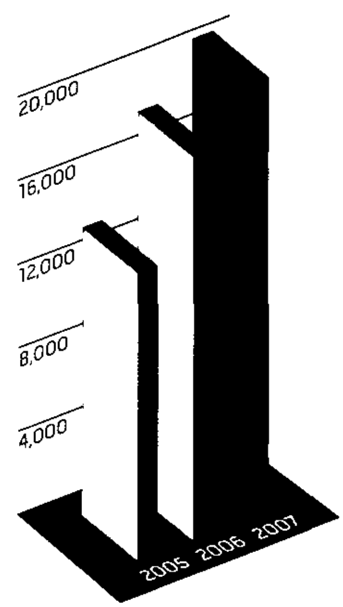
CAPITAL EXPENDITURES
(In Thousands)



PROVED RESERVES
(Bcf)



AVERAGE DAILY NET SALES
(Mcf per Day)



(In thousands, except per share amounts)	**2007**	2006	2005
Revenue	**$ 50,984**	$ 44,947	$ 41,980
Net Income			
As Reported	**$ 5,169**	$ 17,296	$ (1,573)
Excluding Aftertax Impact of Unrealized Hedging Gains & Losses	**$ 7,051**	$ 6,931	$ 6,505
Earnings Per Share - Diluted			
As Reported	**$ 0.13**	$ 0.48	$ (0.06)
Excluding Aftertax Impact of Unrealized Hedging Gains & Losses	**$ 0.18**	$ 0.19	$ 0.23
Weighted Average Number of Common Shares - Diluted	**39,700**	35,964	28,165
Total Assets	**$ 378,677**	$ 335,195	$ 247,909
Long Term Debt	**$ 96,730**	$ 60,832	$ 99,926
Stockholders' Equity	**$ 218,676**	$ 210,008	$ 95,422
Cash Flow from Operations, Excluding Changes in Working Capital	**$ 21,110**	$ 19,793	$ 14,344
Cash Capital Expenditures	**$ 54,026**	$ 79,061	$ 59,817

+ VISION +

TO OUR SHAREHOLDERS AND EMPLOYEES

In last year's annual report, we focused on the core strengths of our organization – experience, vision, growth and people. These are qualities that are important to the success of any business. They form the foundation for expansion of operations and the creation of shareholder value.

Although we faced several challenges in 2007 which tested our organizational strengths, we never lost our focus: *to deliver long-term value to shareholders*. Senior management and members of our board of directors own over 50% of the Company's outstanding shares. As such, management's interests are unequivocally aligned with all shareholders.

J. Darby Seré
Chairman of the Board,
President and Chief Executive Officer

POWER OF E

Our vision of being the premier coalbed methane (CBM) producer is unchanged. We are poised to deliver value over the next several years by growing reserves, production and cash flows. We have an attractive combination of low finding and development costs, long-lived reserves, efficient operations and a large acreage position, which provides us the ability to grow organically without having to raise significant external financing. In fact, only 34% of our operating cash flow, on a trailing 12-month basis, is required to maintain our proved reserves, leaving 66% available for growth. I would like to highlight the following areas of current value and future value creation.

HIGHLIGHTS OF 2007 INCLUDE:

- Increased proved reserves of natural gas to 350.2 billion cubic feet, up 8% from 2006
- Increased natural gas sales to an average of 19.5 million cubic feet per day, up 14.4% from 2006

PROVED RESERVES

As of December 31, 2007, the Company's proved reserves, as estimated by DeGolyer and MacNaughton, independent petroleum engineers, totaled 350.2 Bcf. Over 97% of our total proved reserves at year-end 2007 were located in the Company's more seasoned development projects in the Pond Creek and Gurnee fields. In excess of 76% of year-end 2007 reserves were classified as proved developed, which require little future capital investment, and are principally attributable to 448 net productive wells in those two fields. Approximately 2% of our proved reserves are attributable to a new project, the Lasher field, which commenced development in the fourth quarter. GeoMet owns a 100% working interest in each of these fields and is the operator.

XPERIENCE

The present value of total proved reserves at year-end 2007 (discounted at 10% per annum and using the SEC year-end price of $7.46 per Mcf) was $662.8 million. Over the last three years, our finding costs have averaged $1.25 per Mcf. During this period we replaced 882% of our production through additions, extensions and revisions.

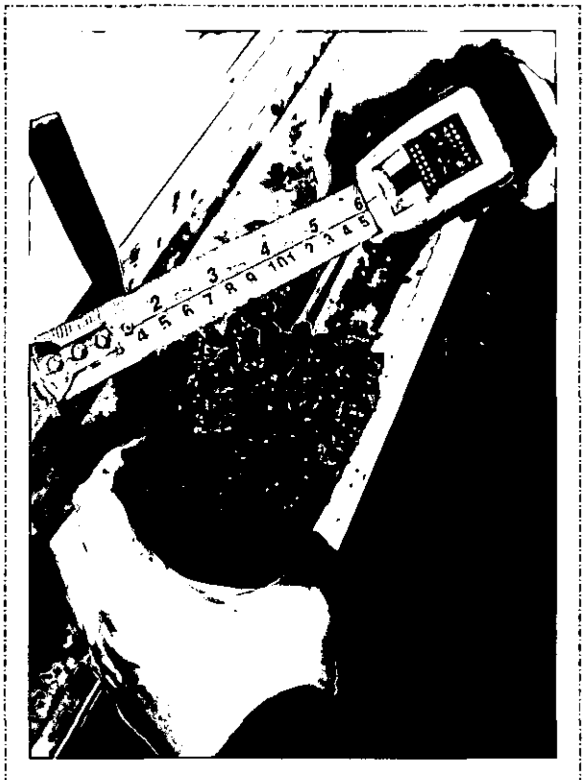
PROBABLE RESERVES

In addition to the proved reserves located in the three development projects, GeoMet had identified approximately 480 net additional unproved drilling locations in these fields at year-end 2007. As of December 31, 2007, DeGolyer and MacNaughton assigned net probable reserves of 189.1 Bcf to these additional unproved drilling locations.

We expect to drill most of these unproved locations over the next several years, providing for continued growth in proved reserves, production and cash flows. Because of extensive corehole drilling and gas desorption tests performed in these fields, we have a high level of confidence that these probable reserves represent additional value to our shareholders.

CAPITAL INVESTMENT PROGRAM

We plan capital expenditures of $48.8 million in 2008, with just over 70% of those expenditures allocated to drilling, completing and connecting 46 low-risk CBM development wells. Approximately 10% of those expenditures are allocated to exploratory drilling in our shale prospect discussed below and the remaining 20% are budgeted for leasehold and other capital costs. We have hedged over 50% of our projected gas sales for 2008 with an effective floor of approximately $7.89 per MMBtu to assure the funding of our capital expenditure program.



NEW DEVELOPMENT PROJECTS

We have two early stage development projects, the Lasher field in West Virginia and the Peace River field in British Columbia.

We own approximately 17,000 acres of leases in the Lasher field, which is located approximately 10 miles north of the Pond Creek field. At December 31, 2007, we had drilled four wells at Lasher, and we plan to drill 15 wells in 2008. The geological setting at Lasher is very similar to Pond Creek except that the coal seams are slightly thinner and more shallow. The Lasher field has two significant advantages over Pond Creek: a water disposal well and a major interstate pipeline are both located on our leasehold. We have adequate firm transportation capacity on the pipeline and have recently entered into a pipeline interconnect agreement. We believe that lower development costs resulting from reduced frac costs due to coal thickness, along with the operating efficiencies associated with the close proximity of the water disposal well, will allow us to achieve rates of return at Lasher that are comparable to returns being achieved in the Pond Creek field.

The Peace River field is located in northeast British Columbia near the community of Hudson's Hope. We operate this project, which covers approximately 50,000 acres of Crown tenure (rights to earn leases), and own a 50% working interest. As of year-end we had drilled six production wells and four coreholes, and tested several water disposal options. During 2007 we engaged Netherland, Sewell & Associates, independent

Philip G. Malone
Senior Vice President – Exploration and Director

Brett S. Camp
Senior Vice President – Operations

What is the status of the production performance issues in the Gurnee field?

GeoMet has the coalbed methane development rights to approximately 44,000 net acres in the Cahaba Basin of central Alabama. The acreage is 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 was near existing infrastructure.

Wells drilled to date can be grouped into three major categories:

1. **Wells that exhibit relatively flat production, including some with slight incline or slight decline. Over 70% of the wells in the field are in this category.**
2. **Wells with high initial water production and little or no gas production. Approximately 13% of the wells are in this category and are located primarily in the southern portion of the field.**
3. **Wells with low water and gas production. Approximately 16% of the wells are in this category.**

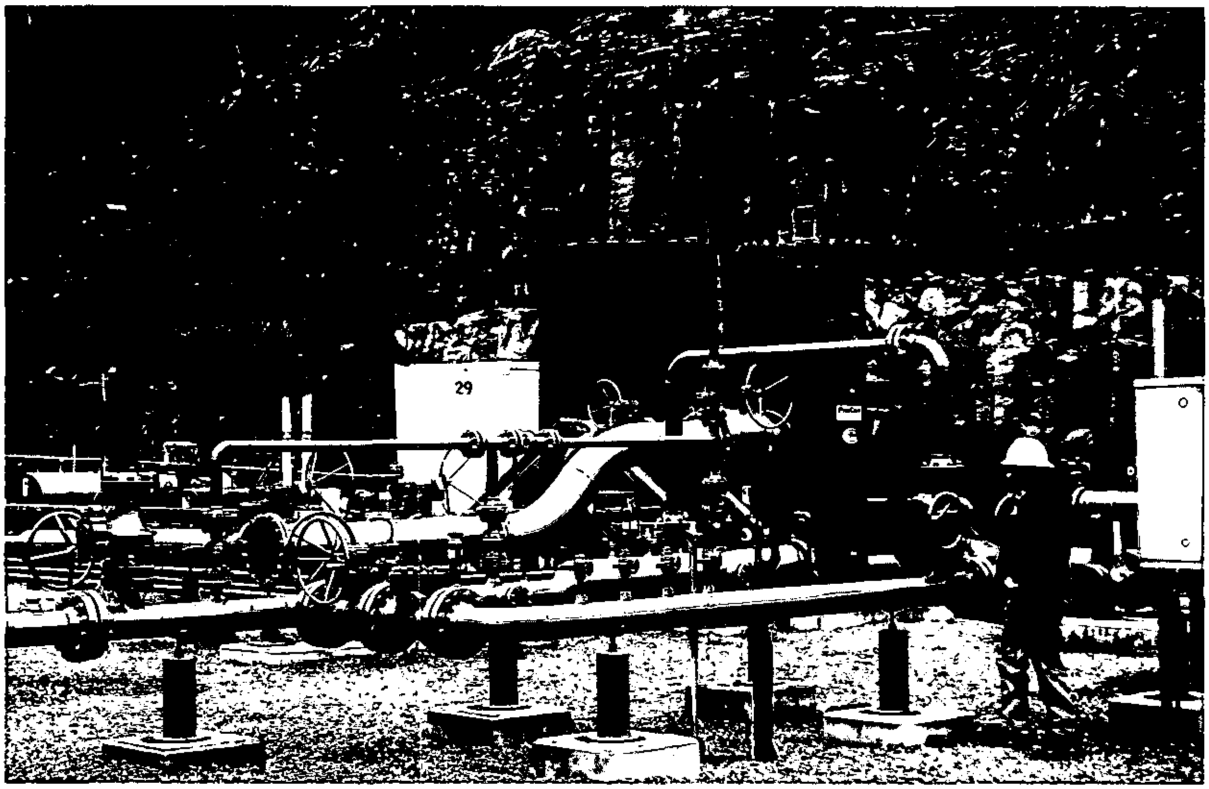
As to the first category of wells, we believe these wells will eventually incline and that the reserves assigned to them, and possibly more, will be recovered over time. The exact slope and timing of that incline is difficult to predict. The high water production from wells in the second category is an indication of good permeability. We also have high confidence of the gas-in-place. As the water production declines, we expect these wells will be among the best wells in the field. As to the last category of wells, we will need to employ new treatment or re-completion techniques to improve performance or face downward revisions to proved reserves over time. At December 31, 2007, the proved reserves assigned to wells in the third category are approximately 7% of our total proved reserves.

Average daily gas production per well has remained fairly flat in the Gurnee field. Normally we would expect this per well average to increase as gas production from wells in the field inclines. Therefore, until inclines become prevalent, new wells must be drilled for production to increase substantively. We reduced drilling activity in the Gurnee field in 2007 and plan to reduce it further in 2008.

We drilled our first two wells on the less geologically complex west side of the river in the southern acreage block in 2007 and have recently initiated production testing. Initial results are encouraging, but it is too early to reach any definitive conclusions.

As stated earlier, we are confident of the estimated gas-in-place in the Gurnee field because of an abundance of coreholes and gas desorption analyses. Reserves in the field are generally determined by applying a recovery factor to the gas-in-place. Although the recovery factor may be modified based on new data, the 55% generally used in the Gurnee field is considered conservative. The timing of recovery is more subjective and may change with time.

Drivers for increased production from the field could come from several sources: new drilling, especially from the west side of the river if initial positive results continue; the dewatering of the high water production wells; or commencement of expected gas production inclines from the wells with relatively flat production.



petroleum engineers, to prepare a reserve report for Peace River. This reserve report indicated that there was in excess of one trillion cubic feet of gas-in-place. We plan to drill five additional production wells and construct and install production, gas treatment and sales facilities in 2008. We hope to commence gas sales from the Peace River field in the fourth quarter.

EXPLORATION PROSPECT

We are evaluating our Garden City prospect, which targets the Chattanooga Shale in north central Alabama. During 2007, we drilled five coreholes and three production wells. The Chattanooga shale thickness ranges from 35 – 90 feet at a depth that ranges from 1,600 – 2,100 feet across the prospect area. Gas desorption tests and other analyses have confirmed significant gas-in-place and shale properties that are favorable when compared to other shales currently being developed. We plan to drill at least three more production wells in 2008, at least one of which will be a horizontal well. We are planning to connect the production wells to sales in the near term to facilitate extensive production testing. We have approximately 70,000 gross acres leased and are continuing to acquire additional leasehold

Explain the pipeline litigation with CNX Gas.

GeoMet is involved in several disputes with CNX Gas Corporation ("CNX") and its affiliates in the court system or before administrative bodies in Virginia. These disputes can generally be categorized as related to pipeline right-of-way issues, well permitting issues, or anti-trust and monopolistic behavior issues. These disputes were all instigated either by CNX or by us in response to aggressive behavior by CNX.

The most publicized disputes have been CNX's attempt to block the construction of, and later to prevent the flow of gas through, the gas gathering pipeline (the "Gathering Line") we constructed to deliver Pond Creek field gas sales to East Tennessee Natural Gas. CNX claims to have the exclusive right to transport gas across a certain property by virtue of the granting clause in the CBM lease it holds with the landowner ("PMC"). Absent extraordinary language, which is not present in the lease, it would be quite unusual for an oil and gas or coalbed methane lease to grant such a right; however, a circuit court in western Virginia ruled that CNX did have this exclusive right. Both PMC and GeoMet separately appealed the circuit court decision and the Virginia Supreme Court has agreed to hear both appeals as to all points of error. Briefings in these appeals are complete and oral arguments are expected to be heard by the Supreme Court in early June. Twice in 2007, the Virginia Supreme Court reversed adverse rulings by circuit courts in western Virginia which wrongly favored CNX.

We believe our position is strong, as do several parties to a supporting Amicus brief filed with the court, and we expect to win this appeal. In the unlikely event that we lose this appeal, GeoMet and PMC have other issues pending in the circuit court which could render this decision moot. Additionally, GeoMet is pursuing other options to deliver its gas to market in the unlikely event access to the Gathering Line is restricted. We do not expect gas sales to be materially interrupted.

Also, there is some confusion related to a punitive provision in one of the circuit court orders that would have required GeoMet to escrow the "net proceeds" from sales of any gas delivered through the Gathering Line. This portion of that order was vacated by the Virginia Supreme Court and never went into effect. Neither gas deliveries nor cash flows from the Pond Creek field have ever been interrupted.

William C. Rankin

Executive Vice President and Chief Financial Officer

Why is GeoMet pursuing a shale play?

The Chattanooga Shale represents a significant opportunity in close proximity to our existing operations and a natural step out for exploration and development. Based on our initial technical evaluation using the data from several coreholes, and gas desorption and other analyses of the cores, this shale prospect shares many attributes of our coalbed methane projects. It is expected to be a large resource play at shallow depths with low finding and development costs, low operating costs and long-lived reserves.

Although gas production characteristics from shale formations genrally differ from those of gas produced from coals, both types of plays lend themselves to low risk multi-well, multi-year drilling programs where drilling, completion and infrastructure costs can be driven down over time. Our exploration department generated this play using surface geology and logs from old wells in this area, which allowed us to evaluate the Chattanooga shale and acquire a significant land position at low entry costs.

acreage. Initial results have been encouraging, but more drilling and production testing is necessary before a decision to develop this prospect can be made.

CAPITAL RESOURCES

Our commercial banks have established a $180 million borrowing base under our credit facility which matures in 2011. As of December 31, 2007, the Company had $96 million borrowed under this commitment, leaving $84 million of available financing. Bank debt represented approximately 31% of our capital structure at year-end 2007 and only $0.27 per Mcf of proved reserves. We believe this commitment by our banks, together with internally generated funds, will be more than sufficient to enable the Company to execute its 2008 business plan.

In summary, GeoMet has the resources, the opportunities and the organizational strengths to create growth and shareholder value in 2008 and beyond.

We would like to thank our shareholders, bankers, vendors, directors and employees for their contributions to GeoMet in 2007. We truly value these relationships.

Sincerely,

J. Darby Seré
Chairman of the Board, President, and Chief Executive Officer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007

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 000-52155

GeoMet, Inc.
(Exact name of registrant as specified in its charter)

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

Securities registered pursuant to Section 12(g) of the Act
Title of Class
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 ☒

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 ☒

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 ☒ 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. ☐

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 ☐
(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 ☒

The aggregate market value of common stock, par value $0.001 per share, held by non-affiliates (based upon the closing sales price on the NASDAQ Global Market on June 30, 2007), the last business day of registrant's most recently completed second fiscal quarter was approximately $145 million.

As of March 1, 2008, 38,993,359 shares of the registrant's common 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 2008 annual meeting of stockholders, which will be filed on or before April 30, 2008.

GeoMet, Inc.

Form 10-K

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this annual report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future reserves, production, revenues, income, and capital spending. When we use the words "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," or their negatives, other similar expressions, or the statements that include those words are usually forward-looking statements.

The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the "Risk Factors" section 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 the securities laws, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy;
- our financial position;
- our cash flow and liquidity;
- declines in the prices we receive for our gas affecting our operating results and cash flows;
- uncertainties in estimating our gas reserves;
- replacing our gas reserves;
- uncertainties in exploring for and producing gas;
- ability to obtain additional financing necessary in order to fund our operations, capital expenditures, and to meet our other obligations;
- availability of drilling and production equipment and field service providers;
- disruptions, capacity constraints in, or other limitations on the pipeline systems which deliver our gas;
- competition in the gas industry;
- our ability to retain and attract key personnel;
- our joint venture arrangements;
- the effects of government regulation and permitting and other legal requirements;
- costs associated with perfecting title for gas rights in some of our properties;
- our need to use unproven technologies to extract coalbed methane in some properties; and
- other factors discussed under "Risk Factors."

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.

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 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 boundaries of an oil or natural gas reservoir with the intention of completing the 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.

Dth. Decatherm. One decatherm is 10 therms and 1 therm is equivalent to 100,000 Btu's at 59 degrees Fahrenheit.

Estimated proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

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

Finding and development costs. A non-GAAP performance measure, expressed in dollars per Mcf, commonly used throughout the oil and gas industry to measure the efficiency of a company in adding new reserves. The finding and development cost measure referred to in this annual report on Form 10-K is calculated for the three year time period by taking the sum of the cost incurred for exploration, development, and acquisition and dividing such amount by the total proved reserve additions. Management believes that this information is useful to an investor in evaluating GeoMet because it measures the efficiency of a company in adding proved reserves as compared to others in the industry. The cost and reserve information is derived directly from line items disclosed in the schedules of Capitalized Costs, Capitalized Costs Incurred, Natural Gas Reserves and Standardized Measure, which are all required to be disclosed by Statement of Financial Accounting Standards ("SFAS") No. 69, *Disclosures about Oil and Gas Producing Activities an amendment of FASB Statements 19, 25, 33, and 39* ("SFAS 69").

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.

Gas in-place. The total gas measured within any particular formation before any production. A portion of this total resource base is not economically recoverable. This portion varies due to the formation's reservoir characteristics such as pressure and permeability.

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.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from estimated proved natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes, a non-GAAP measure. The estimated future net revenues are discounted at an annual rate of 10% in accordance with the practice of the Securities and Exchange Commission ("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.

Reserve life index. This index is calculated by dividing total estimated proved reserves by the production from the previous year to estimate the number of years of remaining production.

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. Stopping an oil or natural gas well from producing.

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 interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

PART I

Item 1. *Business*

About GeoMet

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. 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 control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia.

At December 31, 2007, we controlled a total of approximately 266,000 net acres of coalbed methane and oil and natural gas development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. Our major holdings consist of approximately 44,000 net acres in the Gurnee field in the Cahaba Basin in Alabama, approximately 51,000 net acres in the Garden City prospect in Alabama, approximately 35,000 net acres in the Pond Creek field in the central Appalachian Basin, approximately 17,000 net acres in the Lasher field in the central Appalachian Basin, and approximately 25,000 net acres in the Peace River field in British Columbia.

Our proved reserves as of December 31, 2007, as estimated by DeGolyer and MacNaughton, an independent reservoir engineering firm, were approximately 350.2 Bcf, an increase of approximately 8% from year-end 2006 proved reserves of 325.7 Bcf. The 2007 proved reserves were 100% coalbed methane and 76% were developed. The PV-10 of proved year-end reserves was $662.8 million using SEC pricing of $7.46 per MMBtu at December 31, 2007 as compared to a PV-10 of $525.6 million at year-end 2006 using SEC pricing of $5.63 per MMBtu. Approximately 61% of year-end 2007 proved reserves are in the Gurnee field in Alabama and 38% in the Pond Creek and Lasher fields in West Virginia and Virginia.

Average daily net gas sales volumes for 2007 were 19.5 MMcf, an increase of 14.4% over 2006. December 2007 average daily net gas sales volumes were 20.5 MMcf. Average daily net sales volumes in the fourth quarter of 2007 increased approximately 3% as compared to the third quarter of 2007.

Our capital expenditure budget for 2008 totals approximately $48.8 million as compared to $59.8 million expended in 2007. The current year budget includes approximately $34.5 million for development, $4.7 million for exploration and evaluation, $1.5 million for leasehold and $8.1 million for other capitalized costs. In addition, the budget includes a $3 million payment related to the 2004 acquisition of a 50% interest in the Pond Creek field in West Virginia. The payment is based on actual gas prices received for the four-year period ended December 31, 2007 as compared to a stated price in the purchase and sales agreement.

Approximately $21.6 million of the 2008 capital budget is allocated to the Pond Creek and Lasher fields in Virginia and West Virginia; $9.7 million is allocated to the Gurnee field and the Garden City Chattanooga Shale prospect in Alabama; and $9.1 million is allocated to the Peace River field in British Columbia.

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. 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, 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 will typically increase in production for up to five years from initial production depending on well spacing.

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 United States, 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 United States, 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

Cahaba Basin

We have the development rights to approximately 44,000 net CBM acres throughout the Gurnee field in the Cahaba Basin of central Alabama. At December 31, 2007, approximately 61% of our estimated proved reserves, or 214.1 Bcf, were located in the Gurnee field, of which approximately 78% were classified as proved developed. At such time, we had developed approximately 38% of our Gurnee field CBM acreage. We are the operator and own a 100% working interest in the area. As of December 31, 2007, we had 234 productive wells in the Gurnee field. Net daily sales of gas averaged approximately 6,122 Mcf for 2007. At December 31, 2007, our undeveloped CBM acreage in the Gurnee field contained 82 proved undeveloped drilling locations and 232 additional drilling locations, based predominantly on 80-acre spacing. In 2008, we intend to spend approximately $4.1 million of our capital expenditure budget to drill five wells and expand our facilities in the Cahaba Basin.

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 have recently begun drilling on the less geologically complex west side of the river in the southern acreage block. Initial results are encouraging with early initial gas production inclines and average gas production rates higher than elsewhere in the field. However, it is too early to reach any definitive conclusions. Future production growth in the field could come from several sources, including; new drilling, especially from the west side of the river if initial positive results continue; the dewatering of the high water production wells; and from increased gas production from existing wells, either as a natural occurrence or from improved treatment or re-completion techniques.

We have constructed 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. 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. In October 2006, we executed a series of agreements with a third party operator located in the area, under which we agreed to designate up to 50% of the pipeline's capacity to dispose of produced water from the third party's operations in the Gurnee field. Our fees earned under the agreements are $0.35 per barrel of untreated produced water but may decline to $0.20 per barrel of produced water if the operator chooses to treat its own produced water prior to delivering it to our facilities. The disposal fees we generate are included in other revenues. We also operate a water treatment facility in the Gurnee field to condition the produced water prior to injection into the pipeline and a discharge pond at the river to aerate the water prior to disposal. We believe that our disposal pipeline and water treatment facility will meet all of our future water disposal requirements for the Gurnee field.

Additionally, we have secured firm capacity rights on a high pressure gas gathering pipeline which connects into Enbridge's Magnolia Pipeline System. The acquired rights entitle us to transport approximately 40 MMcf per day of coalbed methane gas at a fee of $0.05 per MMBtu actually gathered through the pipeline. We do not anticipate utilizing this capacity in the immediate future. This agreement provides us with a second outlet for our gas produced from the Gurnee field. Together with our existing capacity on the Southern Natural Gas Bessemer—Calera lateral, our total gas takeaway capacity is expected to meet all of our future requirements.

We control 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 control the gathering and delivery pipeline system, we incur no third party costs to gather and deliver our gas to market.

Garden City

Garden City is our Chattanooga Shale exploration prospect located in north central Alabama. The Chattanooga Shale is a dark gray-black, organic-rich, gas-bearing Devonian shale that is believed, like coal, to be both a source rock and reservoir rock. We have approximately 51,000 net acres of leasehold, we are the operator and own a 100% working interest in the area. The Chattanooga Shale is expected to be encountered at depths ranging from 1,600 to 2,100 feet across the prospect area. We drilled five core holes to determine the gas in-place and the reservoir properties of the shale. We drilled 3 production wells in 2007. We plan to drill three wells in 2008 and spend approximately $4.1 million. The proximity of the Garden City prospect to the Gurnee field presents several advantages which helps reduce cost and provides operational efficiencies. This includes using our Gurnee project personnel, contractors and vendors to conduct similar operations in the Garden City prospect.

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 35,000 net CBM acres. At December 31, 2007, approximately 36% of our estimated proved reserves, or 126.5 Bcf, were located within the Pond Creek field, of which approximately 77% were classified as proved developed. At such time, we had developed approximately 42% of our Pond Creek CBM acreage. As of December 31, 2007, we are the operator and own a 100% working interest in 212 productive wells and an average of 45% working interest in four productive wells in the Pond Creek field. Net daily sales of gas averaged approximately 12,311 Mcf for 2007. At December 31, 2007, our undeveloped CBM acreage in the Pond Creek field contained 68 net proved undeveloped drilling locations and 190 additional drilling locations, based predominantly on 60-acre spacing. In 2008, we intend to spend approximately $13 million of our capital expenditure budget to drill 21 wells in the Pond Creek field.

We extract gas from up to 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.

CBM wells in the Pond Creek field produce comparatively lower levels of water. Produced water is either used in our operations or injected into a disposal well that we own and operate. We believe this disposal well will 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 facility 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 went in service on April 1, 2007, with total maximum daily quantities of 15,000 dth and 10,000 dth and primary terms of 15 years and 10 years, respectively.

Lasher

In the Lasher field in the central Appalachian Basin of southern West Virginia, we have the rights to develop approximately 17,000 net CBM acres. At December 31, 2007, approximately 2% of our estimated proved reserves, or 7.4 Bcf, were located within the Lasher field, of which approximately 20% were classified as proved developed. We are the operator and own a 100% working interest in the area. As of December 31, 2007, we had drilled four core holes and completed four production wells. At December 31, 2007, our undeveloped CBM acreage in the Lasher field contained 20 proved undeveloped drilling locations and 109 additional drilling locations, based predominantly on 60-acre spacing. In 2008, we intend to spend approximately $8.1 million of our capital expenditure budget to drill 15 wells and to connect these wells along with three of the existing wells to a water and gas gathering system, which is to be installed along with a compressor station and a high pressure gas sales line that will connect into an interstate pipeline that is located on the Lasher leasehold. The proximity of the Lasher field to the Pond Creek field presents several advantages which helps reduce cost and provides operational efficiencies. This includes using our Pond Creek project personnel, contractors and vendors to conduct similar operations in the Lasher project.

British Columbia

Our Peace River Project is comprised of approximately 25,000 net acres along the Peace River near Hudson's Hope, British Columbia. We operate and own a 50% working interest. We have drilled four core holes targeting the medium volatile bituminous rank Lower Cretaceous Gething coals. Multiple, mostly thin, coal seams, with an aggregate average thickness of 52 feet, exist at depths from 1,000 to 3,000 feet. At December 31, 2007 we had drilled and completed a total of five production wells, re-completed an existing production well and drilled a water disposal well which has been used to dispose of the water produced from the test wells. In 2007 we completed one production test well and production tested four wells. We also drilled two water disposal wells in 2007, of which one well was deemed to have insufficient injection capabilities and the other well is still being evaluated. In early 2008 we plan to test zones in several existing wells for water disposal potential. At December 31, 2007, our undeveloped CBM acreage in the Peace River field contained 265 (132.5 net) additional drilling locations, based predominantly on 160-acre spacing. Pending the confirmation of adequate water disposal capacity, we plan to spend up to $9.1 million of capital in 2008 (net to our 50% working interest), to drill and complete five new wells, and connect these wells along with three of the existing wells to a water and gas gathering system to be installed with a gas plant/compressor station, and a high pressure gas sales line which will connect into the Spectra gas transmission line which crosses the property.

Strategy

Our objective is to create the premier non-conventional shallow gas company in North America (emphasizing coalbed methane) while maximizing stockholder value through the efficient investment of capital to increase reserves, production, cash flow and earnings. We intend to focus on the following strategies:

- Focus primarily on coalbed methane and non-conventional shallow gas to exploit our substantial expertise and experience.
- Maximize present value in existing development projects and expand into adjacent areas to leverage our information, knowledge and infrastructure.
- Develop new large scale projects, maintain operational control and reduce costs through economies of scale.
- Maintain financial discipline.

Competitive Strengths

We primarily explore for, develop, and produce CBM and non-conventional shallow gas. 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 significant operational advantages compared to conventional gas production, including:

- *Production Rates.* Unlike conventional natural gas production, which typically declines after initial production is established, production from CBM wells typically increases for the first few years of their productive lives although eventual peak rates are often lower than those of typical conventional gas wells. CBM wells also generally decline at a shallow rate relative to typical conventional gas wells.
- *Low Geologic Risks.* Most CBM areas are located in known coal basins where the coal resource has been evaluated for coal mining. These areas have extensive existing geologic information databases. The drilling of new coreholes and a limited number of production test wells reduces the geologic risk prior to committing large development expenditures.
- *Low Production Costs.* In the early stage of CBM project development per unit operating costs are high because production is initially low and many of our costs are fixed. As production from a project increases and economies of scale are realized, the per unit operating costs typically decrease. Over the life of a project, we believe our average per unit operating costs will be lower than those of many conventional gas industry projects.
- *Long-lived Reserves.* Because CBM wells typically have inclining production rates early in their lives and low decline rates thereafter, CBM projects typically result in a reserve life that is significantly longer than many types of conventional gas production.
- *Highly Experienced Team of CBM Professionals.* Our 18-person CBM management, professional, and project management team has an average of more than 18 years of CBM experience and has participated in the drilling and operation of more than 2,700 CBM wells worldwide since 1977.
- *Large Inventory of Organic Growth Opportunities.* Our extensive undeveloped acreage position provides us with an additional 615.5 net drilling locations.
- *Track Record of Success in Identifying and Exploiting Large Underdeveloped Resource Plays.* We pursue those projects that leverage our CBM expertise to exploit underdeveloped resource potential where we believe we can improve on the prior performance of other operators. We have a history of developing large scale projects in multiple basins with low finding and development costs and low project life operating costs.

Risks Affecting Our Business

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 depends, to a large extent, upon our ability to generate cash flow from operations at or above current levels and maintain borrowing capacity at or near current levels under our revolving credit facility, or the availability of future debt and equity financing at attractive prices. 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. Changes in natural gas prices, which may affect both our cash flows and the value of our gas reserves, 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 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. You are urged to read the section entitled "Risk Factors" for more information regarding these and other risks that may affect our business and our common stock.

Competition

Our operations primarily compete regionally in the United States and Canada. Competition throughout the United States and Canada is regionalized. We believe that the gas market is generally highly fragmented and not dominated by any single producer except in the immediate area of our Virginia development operations, where we believe there is one dominate producer that controls a substantial portion of the market. We believe that several of our competitors have devoted far greater resources than we have to gas exploration and development. We believe that competition within our market is based primarily on price and the proximity of gas fields to customers.

Seasonality of Business

Weather conditions affect the demand for and prices of natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Governmental 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 an intrastate natural gas pipeline that we believe would meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC's jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

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

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.

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 among the governments of Canada, the United States 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 United States 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 coalbed methane 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 United States 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 United States, 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.

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.

In addition, our operations may in the future be subject to the regulation of greenhouse gas emissions. Numerous countries, including Canada but not the United States, are participants in the Kyoto Protocol to the United Nations Framework Convention on Climate Change. Participating countries are required to implement national programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. Although the United States is not participating in the Protocol, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The oil and gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations in the United States currently are not adversely impacted by current state and local climate change initiatives. Our Canadian operations are subject to the Protocol, but implementation of the Protocol's greenhouse gas emission reduction requirements in British Columbia are not presently expected to have a material adverse effect on our operations. However, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions may impact our business.

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.

Employees

At December 31, 2007, we had 84 full-time employees and two full-time contractors. 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 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*.

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 a decline primarily in 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. The market for natural gas is very volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. 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;
- the price of foreign imports;
- overall domestic and global economic conditions;
- the consumption pattern of industrial consumers, electricity generators, and residential users;

- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign 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, 2007 were natural gas reserves, our financial results are sensitive to movements in natural gas prices. Earlier in this decade, natural gas prices were much lower than they are today. 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 our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. 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.

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

- geological conditions;
- changes in governmental regulations and taxation;
- assumptions governing future prices;
- 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.

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

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;
- 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.

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, and issuances of common stock.

If our revenues decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our revolving credit facility contains covenants restricting our ability to incur additional indebtedness without the consent of the lender. There can be no assurance that our lender will provide this consent or as to the availability or terms of any additional financing. If we incur additional debt, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- a leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our revolving credit facility will be at variable rates which makes us vulnerable to increases in interest rates.

Even if additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our projects, which in turn could lead to a possible loss of properties and a decline in our natural gas reserves.

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 more detailed description of our revolving credit facility is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and the footnotes to our consolidated financial statements included elsewhere in this annual report.

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 could 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 commodity prices and reserve levels.

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 United States 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. For example, one of our competitive strengths is as a low-cost producer of gas. If our competitors can produce gas at a lower cost than us, it would effectively eliminate our competitive advantage in that area.

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

Our ability to produce coalbed methane may be hampered by the water present in the formation which could affect our profitability.

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

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 the applicable volumetric permit limit, 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.

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. 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 our 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 United States 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 United States affecting foreign trade and taxation may also adversely affect our operations in British Columbia.

We may be unable to retain our existing senior management team and/or our 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 production 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 agreements or non-competition agreements with any of our key employees, other than J. Darby Seré, our President and Chief Executive Officer, and William C. Rankin, our Executive Vice President and Chief Financial Officer. 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 production 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 pricing 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 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 control 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 oilfield 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 oilfield 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.

Hedging transactions may limit our potential gains.

In order to manage our interest rate exposure and commodity price risks, we have entered into interest rate swaps and natural gas price hedging arrangements with respect to a portion of our expected production. We will most likely enter into additional hedging transactions in the future. While intended to reduce the effects of volatile interest rates and natural gas prices, such transactions may limit our potential gains or increase our potential losses.

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.

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

None.

Item 2. ***Properties***

Estimated Proved Reserves

The following table sets forth certain information with respect to our estimated proved reserves by field as of December 31, 2007. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and current costs held constant throughout the projected reserve life. The reserve information as of December 31, 2007 is based on estimates made in a reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers.

	Estimated Proved Reserves				
Field	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	PV-10
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(In thousands)
Central Appalachia:					
Pond Creek field	96,102	655	29,773	126,530	$279,316
Lasher field	—	1,450	5,915	7,365	7,475
Alabama:					
Gurnee field	139,711	26,815	47,545	214,071	365,667
White Oak Creek field	2,210	—	—	2,210	10,348
Total	238,023	28,920	83,233	350,176	$662,806

PV-10, a non-GAAP measure, is our estimated present value of future net revenues from estimated proved reserves before income taxes. We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that PV-10 is widely used by professional analysts and investors in evaluating gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. Management also uses PV-10 in evaluating acquisition candidates. PV-10 only differs from the standardized measure of discounted future net cash flows ("SMOG"), as calculated and presented in accordance with SFAS 69, in that SMOG takes into account the present value of income taxes related to our future net cash flows. See "Selected Financial Data—Reconciliation of Non-GAAP Financial Measures."

CBM-producing natural gas reservoirs generally are characterized by 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, after an initial period of incline, are expected to decline. This decline rate, however, is slower 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.

The weighted average price of gas at December 31, 2007 used to estimate proved reserves and future net revenue was $7.58 per MMBtu and was calculated using the Henry Hub cash price at December 31, 2007 of $7.46 per MMBtu of gas, adjusted for our price differentials at our sales point but excluding the effects of hedging.

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,		
	2007	2006	2005
Gas:			
Net sales volume (Bcf)	7.1	6.2	4.6
Average natural gas sales price ($ per Mcf)	$6.97	$7.19	$9.06
Average natural gas sales price ($ per Mcf) realized(1)	$7.52	$7.37	$7.43
Total production expenses ($ per Mcf)	$2.86	$2.75	$2.81
Expenses: ($ per Mcf)			
Lease operations expenses	$1.96	$1.86	$1.89
Compression and transportation expenses	$0.73	$0.72	$0.72
Production taxes	$0.17	$0.17	$0.20
Depreciation, depletion & amortization	$1.24	$1.26	$1.06
Research and development	$0.00	$0.02	$0.13
General and administrative	$1.30	$1.05	$0.70

(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, 2007. 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 and wells capable of producing natural gas.

	Productive Wells		Developed Acres		Undeveloped Acres	
Area	Gross	Net	Gross	Net	Gross	Net
Pond Creek	216	214	14,574	14,442	20,747	20,631
Lasher	—	—	—	—	16,572	16,572
Gurnee	234	234	16,540	16,540	27,316	27,066
Peace River	—	—	—	—	50,184	25,092
Garden City	—	—	—	—	58,998	50,598
Other	—	—	—	—	109,718	94,561
Total	450	448	31,114	30,982	283,535	234,520

Our material undeveloped leases are in Alabama, the Central Appalachian Basin and Canada, which includes our Gurnee, Lasher, Pond Creek, and Peace River fields, respectively. Generally, the undeveloped acreage expires on various dates from 2008 through 2013; however, the term of the undeveloped acreage can be extended by drilling and production operations. As to the Gurnee field, we have fulfilled drilling commitments on our largest lease that gives us the ability to postpone further drilling until 2009. Otherwise, the remaining acreage either has expirations that occur from 2008 through 2013 or the leases can be extended by drilling and production operations.

Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the United States 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 commenced at any time during the respective year. Productive wells are producing wells and wells capable of production.

	Gross					
	Exploratory			Development		
Well Activity (Gross)—United States	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	4	—	4	49	—	49
Year ended December 31, 2006	2	—	2	102	—	102
Year ended December 31, 2005	4	3	7	93	—	93

	Exploratory			Development		
Well Activity (Gross)—Canada	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	1	—	1	—	—	—
Year ended December 31, 2006	3	—	3	—	—	—
Year ended December 31, 2005	2	—	2	—	—	—

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)—United States	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	4.0	—	4.0	47.0	—	47.0
Year ended December 31, 2006	2.0	—	2.0	102.0	—	102.0
Year ended December 31, 2005	4.0	3.0	7.0	93.0	—	93.0

	Exploratory			Development		
Well Activity (Net)—Canada	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	0.5	—	0.5	—	—	—
Year ended December 31, 2006	1.5	—	1.5	—	—	—
Year ended December 31, 2005	1.0	—	1.0	—	—	—

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.

Item 3. *Legal Proceedings*

From time to time we are a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

CNX Surface Use Dispute

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company ("PMC"). The Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC ("CNX"), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. Assuming such an alternative is available, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

It is important to note that the Lasher field is in no way associated with the Pond Creek litigation described above.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company ("Island Creek"), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit seeks $561 million for compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX's alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleges CNX's intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX's position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we are preparing to file an amended petition which will re-state our claims against CNX and Island Creek with specificity.

As of December 31, 2007, 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. *Submission of Matters to a Vote of Security Holders*

None.

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 2006:		
Quarter ended September 30, 2006	$11.71	$9.40
Quarter ended December 31, 2006	$11.25	$8.66
Fiscal Year 2007:		
Quarter ended March 31, 2007	$10.34	$7.73
Quarter ended June 30, 2007	$ 9.67	$7.26
Quarter ended September 30, 2007	$ 7.75	$5.09
Quarter ended December 31, 2007	$ 5.49	$4.86

Approximately 1,500 stockholders of record as of December 31, 2007 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.

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 2007. In addition, we did not sell any of our equity securities which were not registered under the Securities Act of 1933, as amended, during the fourth quarter of 2007.

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, 2007.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column)
Equity compensation plans approved by security holders	1,993,332	$4.96	1,375,268(1)
Equity compensation plans not approved by security holders	—	—	—
Total	1,993,332	$4.96	1,375,268

(1) In 2006, our board of directors and stockholders approved the GeoMet, Inc. 2006 Long-Term Incentive Plan under which 2,000,000 shares of our common stock were reserved for awards to be granted. In conjunction

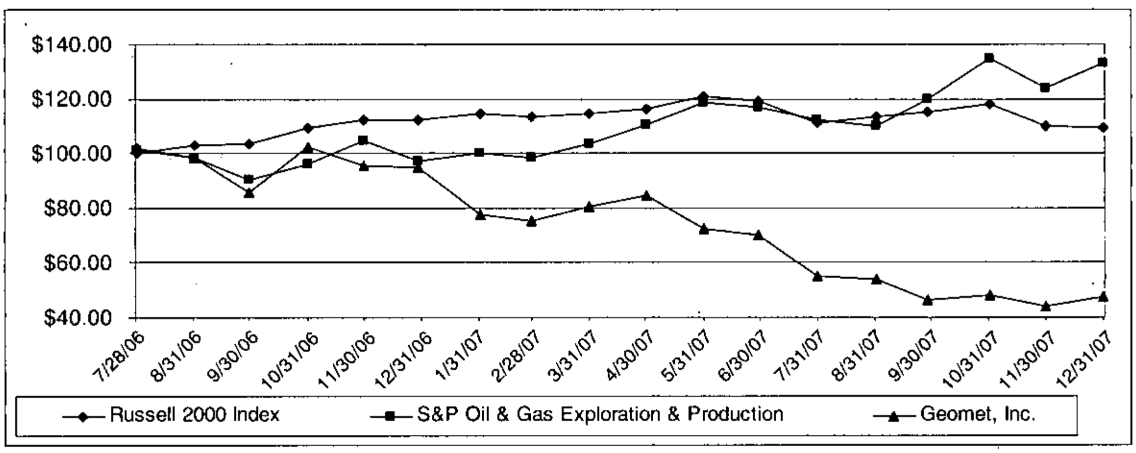
with the approval of the 2006 Plan, no additional awards were or will be granted under our 2005 Plan; however, we will continue to issue shares of our common stock upon exercise of awards that we have previously granted. The 1,375,268 of securities remaining available for future issuance includes 242,448 shares that were reserved but not issued under our 2005 Plan.

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, 2007 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 required by the SEC and are not intended to forecast or be indicative of possible future performance of our stock.

COMPARISON OF CUMULATIVE TOTAL RETURN



	7/28/2006	12/31/2006	12/31/2007
GeoMet, Inc.	$100.00	$ 94.80	$ 47.40
Russell 2000 Index	$100.00	$112.52	$109.43
S&P Oil & Gas	$100.00	$ 97.01	$132.82

Item 6. *Selected Financial Data*

The following table shows our selected historical consolidated financial and operating data as of and for each of the five years ended December 31, 2007. The selected historical consolidated financial and operating data for the three years ended December 31, 2007 are derived from our audited financial statements included herein. The selected historical consolidated financial and operating data for the two years ended December 31, 2004 was derived from our audited financial statements which are not included herein. The table reflects a four-for-one common stock split in 2006 and prior periods have been adjusted for the stock split. You should read the following data in conjunction with "Managements Discussion and Analysis of Results of Operations and Financial Condition" and our consolidated 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.

	2007	2006	2005	2004	2003
STATEMENT OF OPERATIONS (in thousands):					
Total revenues	$ 50,984	$ 44,947	$ 41,980	$ 20,924	$ 12,049
Realized (gain) losses on derivative contracts	(3,895)	(1,118)	7,473	815	44
Unrealized (gains) losses from the change in market value of open derivative contracts	3,007	(16,877)	12,059	(542)	102
Total operating expenses	37,852	13,678	41,149	13,272	7,123
Operating income from continuing operations	13,132	31,269	831	7,652	4,926
Interest expense, net of amounts capitalized	(5,130)	(3,130)	(3,895)	(986)	(232)
Income (loss) before income taxes, minority interest, discontinued operations and cumulative effect of change in accounting principle	7,983	28,162	(3,008)	6,732	4,782
Income tax expense (benefit)	2,988	10,866	(993)	2,312	1,651
Income (loss) before minority interest, discontinued operations and cumulative effect of change in accounting principle, net of tax	4,995	17,296	(2,015)	4,420	3,131
Discontinued operations, net of tax	174	23	—	—	—
Minority interest, net of tax	—	(23)	442	(584)	(571)
Income from discontinued operations	174	—	442	(584)	(571)
Net income (loss) from continuing operations before cumulative effect of change in accounting principle, net of income tax	5,169	17,296	(1,573)	3,836	2,560
Cumulative effect of change in accounting principle, net of income tax	—	—	—	—	(19)
Net income (loss)	$ 5,169	$ 17,296	$ (1,573)	$ 3,836	$ 2,541
EARNINGS PER COMMON SHARE (in dollars):					
Income (loss) from continuing operations					
Basic	$ 0.13	$ 0.49	$ (0.07)	$ 0.17	$ 0.20
Diluted	$ 0.13	$ 0.48	$ (0.07)	$ 0.17	$ 0.20
Discontinued operations					
Basic	$ —	$ —	$ 0.02	$ —	$ —
Diluted	$ —	$ —	$ 0.02	$ —	$ —
Net income (loss) per common share					
Basic	$ 0.13	$ 0.49	$ (0.06)	$ 0.17	$ 0.20
Diluted	$ 0.13	$ 0.48	$ (0.06)	$ 0.17	$ 0.20
BALANCE SHEET DATA (in thousands, at period end):					
Working (deficit) capital	$ (2,063)	$ (1,625)	$ (7,368)	$ (1,251)	$ 5,133
Total assets	$378,677	$335,195	$247,909	$142,090	$ 81,505
Long-term debt	$ 96,730	$ 60,832	$ 99,926	$ 51,513	$ 10,102
Stockholders' equity	$218,676	$210,007	$ 95,422	$ 65,692	$ 52,754
Cash flow data (in thousands):					
Net cash provided by operating activities	$ 17,487	$ 21,472	$ 12,433	$ 10,580	$ 10,801
Net cash used in investing activities	$ (53,832)	$ (78,669)	$ (59,661)	$ (66,193)	$(36,341)
Net cash provided by financing activities	$ 36,191	$ 58,086	$ 44,906	$ 50,192	$ 30,534
Capital expenditures	$ 54,026	$ 79,061	$ 59,817	$ 86,189	$ 36,069
OTHER DATA:					
Net sales volume (Bcf)	7.1	6.2	4.6	3.2	2.5
Average natural gas sales price ($ per Mcf)	$ 6.97	$ 7.19	$ 9.06	$ 6.12	$ 4.71
Average natural gas sales price ($ per Mcf) realized(1)	$ 7.52	$ 7.37	$ 7.43	$ 5.87	$ 4.69
Total production expenses ($ per Mcf)	$ 2.86	$ 2.75	$ 2.81	$ 2.36	$ 1.23
Depreciation, depletion and amortization ($ per Mcf)	$ 1.24	$ 1.26	$ 1.06	$ 0.84	$ 0.85
Estimated proved reserves (Bcf)(2)	350.2	325.7	262.5	209.9	103.9
Standardized measure of discounted future net cash flows ($ millions)	$ 495.9	$ 359.5	$ 632.7	$ 349.8	$ 172.5
Non-GAAP Measures:(3)					
PV-10 ($ millions)	$ 662.8	$ 525.6	$ 880.2	$ 481.8	$ 236.9

Reconciliation of Non-GAAP Financial Measures

The following table shows our reconciliation of our PV-10 to our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). PV-10 is our estimate of the present value of future net revenues from estimated proved natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our CBM gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	As of December 31,				
	2007	2006	2005	2004	2003
			(In thousands)		
Future cash inflows	$2,654,214	$1,858,104	$2,536,279	$1,302,830	$ 599,501
Less: Future production costs	725,272	501,956	463,416	290,425	125,765
Less: Future development costs	106,356	101,777	76,297	38,242	23,832
Future net cash flows	1,822,586	1,254,371	1,996,566	974,163	449,904
Less: 10% discount factor	1,159,780	728,739	1,116,413	(492,339)	(213,018)
PV-10	662,806	525,632	880,153	481,824	236,886
Less: Undiscounted income taxes	(724,399)	(410,391)	(579,689)	(274,975)	(125,858)
Plus: 10% discount factor	557,461	244,245	332,201	142,906	61,520
Discounted income taxes	(166,938)	(166,146)	(247,488)	(132,069)	(64,338)
Standardized measure of discounted future net cash flows	$ 495,868	$ 359,486	$ 632,665	$ 349,755	$ 172,548

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. 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 control additional coalbed methane and oil and gas development rights, principally in Alabama, British Columbia, Virginia, and West Virginia.

At December 31, 2007, we controlled a total of approximately 266,000 net acres of coalbed methane and oil and natural gas development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. Our major holdings consist of approximately 51,000 net acres in the Garden City prospect and approximately 44,000 net acres in the Gurnee field in the Cahaba Basin in Alabama, approximately 35,000 net acres in the Pond Creek field and approximately 17,000 net acres in the Lasher field in the central Appalachian Basin, approximately 25,000 net acres in the Peace River field in British Columbia.

The Company's proved reserves as of December 31, 2007, as estimated by DeGolyer and MacNaughton, an independent reservoir engineering firm, were approximately 350.2 Bcf, an increase of approximately 8% from year-end 2006 proved reserves of 325.7 Bcf. The 2007 proved reserves were 100% coalbed methane and 76% were developed. The PV-10 of proved year-end reserves was $662.8 million using SEC pricing of $7.46 per MMBtu at December 31, 2007 as compared to a PV-10 of $525.6 million at year-end 2006 using SEC pricing of $5.63 per MMBtu. Approximately 61% of year-end 2007 proved reserves are in the Gurnee field in Alabama and 38% in the Pond Creek and Lasher fields in West Virginia and Virginia.

Average daily net gas sales volumes for 2007 were 19.5 MMcf, an increase of 14.4% over 2006.

In 2006, we sold 2,317,023 shares of common stock in private placements to qualified institutional buyers pursuant to Rule 144A under the Securities Act and 5,750,000 shares of common stock in our initial public offering. We used the net proceeds of approximately $79.6 million and the receipt of approximately $17.5 million from the repayment of certain stockholder loans and from the exercise of stock options to reduce outstanding borrowings under our revolving credit facility and for general corporate purposes.

Cash flow from operations for the year ended December 31, 2007 and 2006 were $17.5 million and $21.7 million, respectively. Cash flow provided by operations for the year ended December 31, 2007 of $17.5 million combined together with $36 million borrowed from our revolving credit facility and $0.5 million from other sources were sufficient to fund our cash basis capital expenditures of $54 million.

As of December 31, 2007, we had a working capital deficit of approximately $2.1 million, a decrease of $0.5 million from the working capital deficit of $1.6 million at December 31, 2006. The decrease in the working capital was primarily a result of capital expenditures. At December 31, 2007, we had adequate cash flows from operating activities and credit availability to fund our working capital deficits.

The development of CBM 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, and the timing and volume of initial and subsequent natural gas production. . We estimate total capital expenditures in 2008 will be approximately $48.8 million as compared to $59.8 million expended in 2007. The current year budget includes approximately $34.3 million for development, $4.7 million for exploration and evaluation, $1.5 million for leasehold and $5.3 million for other capitalized costs. Approximately $21.6 million of the 2008 capital budget is allocated to the Pond Creek and Lasher fields in Virginia and West Virginia; $9.7 million is allocated to the Gurnee field and the Garden City Chattanooga Shale prospect in Alabama; and $9.1 million is allocated to the Peace River field in British Columbia. In addition, the budget includes a $3 million payment related to the 2004 acquisition of a 50% interest in the Pond Creek field in West Virginia. The payment is based on actual gas prices received for the four year period ended December 31, 2007 as compared to a stated price in the purchase and sales agreement. As of December 31, 2007, we had approximately $84 million of available borrowing capacity under our revolving credit facility.

Gurnee

At December 31, 2007, approximately 61% of our estimated proved reserves, or 214.1 Bcf, were located in the Gurnee field, of which approximately 78% were classified as proved developed and we had developed approximately 38% of our Gurnee field CBM acreage. We are the operator and own a 100% working interest in the area. As of December 31, 2007, we had 234 productive wells in the Gurnee field. Net daily sales of gas averaged approximately 6,122 Mcf for 2007. At December 31, 2007, our undeveloped CBM acreage in the Gurnee field contained 82 proved undeveloped locations and 232 additional drilling locations, based predominantly on 80-acre spacing. In 2008, we intend to spend approximately $4.1 million of our capital expenditure budget to drill five wells and expand our facilities in the Cahaba Basin.

We have the development rights to approximately 44,000 net CBM acres in the Cahaba Basin. The 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 was near existing infrastructure. Wells drilled to date fall into three major categories: 1) wells that exhibit relatively flat production, including some with slight incline or decline. Over 70% of the wells in the field are in this category, 2) wells with high initial water production and little or no gas production, Approximately 13% of the wells are in this category and are located primarily in the southern portion of the field, and 3) wells with low water and gas production. Approximately 16% of the wells are in this category. As to the first category of wells, we believe these wells will eventually incline and that the reserves assigned to them, and possibly more, will be recovered over time. The exact slope and timing of that incline is difficult to predict. The high water production from wells in the second category is an indication of good permeability. We also have high confidence of the gas in-place. As the water production declines we expect these wells to be among the better wells in the field. As to the third category of wells, we will need to employ new treatments or re-completion techniques to improve performance or face downward revisions to proved reserves. At December 31, 2007, the proved reserves assigned to wells in the third category represented approximately 7% of our total proved reserves.

Average daily production per well has remained fairly flat in the Gurnee field. Normally we would expect this per well average to increase as production from wells in the field incline. Therefore, until inclines become prevalent, new wells must be drilled for production to increase substantively. We reduced the annual drilling rate in the Gurnee field in 2007 and plan to reduce it further in 2008. This reduction in drilling is largely responsible for the reduced rate of production growth in the field. We drilled our first 2 wells on the less geologically complex west side of the river in the southern acreage block in 2007 and have recently initiated production testing. Initial results from our first well are encouraging. However, it is too early to reach any definitive conclusions with regard to the first well, and the second well is just now being put on production. Drivers for future increased production may include several sources: new drilling, especially from the west side of the river if initial positive results continue; the dewatering of the high water production wells; or from the commencement of expected incline from the wells with relatively flat production.

We have constructed 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. This pipeline had an initial design capacity of approximately 45,000 barrels of water per day, but will require additional pump stations and looping a portion of the line in order to meet the maximum design capacity if needed. In October 2006, we executed a series of agreements with a privately held company relating to our operations in the Cahaba Basin, under which we agreed to designate up to 50% of the pipeline's capacity to dispose of produced water from the company's operations in the Gurnee field. Our fees earned under the agreements are $0.35 per barrel of untreated produced water but may decline to $0.20 per barrel of produced water if the operator chooses to treat its own produced water prior to sending it to GeoMet. The disposal fees we generate are included in other revenues. We also operate a water treatment facility in the Gurnee field to condition the produced water prior to injection into the pipeline and a discharge pond at the river to aerate the water prior to disposal. We believe that our disposal pipeline and water treatment facility will meet all of our future water disposal requirements for the Gurnee field.

Additionally, under these agreements, we have secured firm capacity rights on a high pressure gas gathering pipeline which connects into Enbridge's Magnolia Pipeline System. The acquired rights entitle us to transport approximately 40 million cubic feet per day of coalbed methane gas at a fee of $0.05 per MMBtu actually gathered through the pipeline. We do not anticipate utilizing this capacity in the immediate future. This agreement provides us with a second outlet for our gas produced from the Gurnee field. Together with our existing capacity on the Southern Natural Gas Bessemer—Calera lateral, our total gas takeaway capacity is expected to meet all of our future requirements.

We control 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 control the gathering and delivery pipeline system, we incur no third party costs to gather and deliver our gas to market.

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 35,000 net CBM acres. At December 31, 2007, approximately 36% of our estimated proved reserves, or 126.5 Bcf, were located within the Pond Creek field, of which approximately 77% were classified as proved developed and we had developed approximately 42% of our Pond Creek CBM acreage. As of December 31, 2007, we were the operator and own a 100% working interest in 212 productive wells and an average of 45% working interest in 4 productive wells in the Pond Creek field. Net daily sales of gas averaged approximately 12,311 Mcf for 2007. At December 31, 2007, our undeveloped CBM acreage in the Pond Creek field contained 68 net proved undeveloped locations and 186 additional drilling locations, based predominantly on 60-acre spacing. In 2008, we intend to spend approximately $13 million of our capital expenditure budget to drill 21 wells in the Pond Creek field.

We extract gas from up to 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.

Our gas from the Pond Creek field is gathered into our central dehydration and compression facility and delivered into the Jewell Ridge pipeline system owned by East Tennessee Natural Gas, LLC ("ETNG"). In January 2007, we executed two long-term firm transportation agreements with ETNG, which became effective when our pipeline went in service on April 1, 2007, with total maximum daily quantities of 15,000 dth and 10,000 dth and primary terms of 15 years and 10 years, respectively.

Lasher

The Lasher field is located approximately 10 miles north of the Pond Creek field. At December 31, 2007, we had drilled four wells at Lasher, and we plan to drill 15 wells in 2008. The geological setting at Lasher is very similar to Pond Creek except that the coal seams are slightly thinner and shallower. The Lasher field has two significant advantages over Pond Creek in that a water disposal well and a major interstate pipeline are both located on our leasehold. We have adequate firm transportation capacity on the pipeline and have recently entered into an interconnect agreement. We believe that lower development costs, along with the operating efficiencies associated with the close proximity of the water disposal well will allow us to achieve rates of return at Lasher that are comparable to the Pond Creek field. In 2008, we intend to spend approximately $8.1 million of our capital expenditure budget to drill 15 wells and to connect these wells along with three of the existing wells to a water and gas gathering system, which is to be installed along with a compressor station and a high pressure gas sales line that will connect into an interstate pipeline that is located on the Lasher leasehold. The proximity of the Lasher field to the Pond Creek field presents several advantages which helps reduce cost and provides operational efficiencies. This includes using our Pond Creek project personnel, contractors and vendors to conduct similar operations in the Lasher project.

Garden City

The Chattanooga Shale, our target in north central Alabama, represents an opportunity in close proximity to our existing operations and a natural step out for exploration and development. Based on our initial technical evaluation using the data from several coreholes and gas desorption and other analyses of the cores, this shale prospect has many similarities to our coalbed methane projects, because it is a large resource play at shallow depths with expected low finding and development costs, low production costs and long-lived reserves. Although the production characteristics from shale may differ from coalbed methane, a shale play lends itself to multi-well, multi-year drilling programs where drilling and completion and infrastructure costs can be driven down. Being the first company to operate in this area has allowed us to amass a significant land position and to begin the evaluation process to determine the Chattanooga Shale's reservoir and production characteristics.

We have acquired approximately 59,000 gross acres of leasehold, we own a 100% working interest in the leases and are the operator. The Chattanooga Shale is expected to be encountered at an average depth of 1,600 to 2,100 feet across the prospect area. We have drilled five core holes to determine the gas in place and the reservoir properties of the shale. We have also drilled three production wells for the Garden City prospect. We plan to drill at least three more production wells in 2008, at least one of which is expected to be a horizontal well. We are continuing to lease additional acreage. Initial results have been encouraging but more drilling and production testing is necessary before a decision to develop this prospect can be made. We plan to drill three wells in 2008 and spend approximately $4.1 million. The proximity of the Garden City prospect to the Gurnee field presents several advantages which helps reduce cost and provides operational efficiencies. This includes using our Gurnee project personnel, contractors and vendors to conduct similar operations in the Garden City prospect.

Peace River

The Peace River field is located in northeast British Columbia near the community of Hudson's Hope. We operate this project, which covers approximately 50,000 acres of Crown tenure (rights to earn leases), and own a 50% working interest. As of year-end we had drilled 6 production wells, 4 coreholes and tested several water disposal options. Pending the confirmation of adequate water disposal capacity, we plan to spend up to $9.1 million of capital in 2008 (net to our 50% working interest), to drill and complete five new wells, and connect these wells along with three of the existing wells to a water and gas gathering system to be installed with a gas plant/compressor station, and a high pressure gas sales line which will connect into the Spectra gas transmission line which crosses the property. Consultations with the affected First Nations continue and we hope to commence gas sales from the Peace River field in the fourth quarter of 2008.

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 accounting principles generally accepted in the United States. 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 experiences 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 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, commodity 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 DeGolyer and MacNaughton, 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. 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 unit-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. Holding all other factors constant, if proved gas reserves were revised upward or downward, earnings would increase or decrease, respectively. 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 risk that we will be required to write down the carrying value of our gas properties increases when gas prices are depressed, even if low prices are temporary. In addition, a write-down may occur if estimates of proved gas reserves are substantially reduced or estimates of future development costs increase significantly.

The ceiling test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for "basis" or location differential, held constant over the life of the reserves; however, as allowed by the SEC guidelines, significant changes in gas prices subsequent to quarter end are used in the ceiling test. In addition, subsequent to the adoption of SFAS 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.

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 together with 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 impairments to unevaluated properties are transferred to the amortization base.

Future Abandonment Costs. We have legal obligations to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed, or developed. Liabilities for asset retirement obligations are recorded at fair value in the period 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. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. Additionally, increases in the discounted asset retirement liability resulting from the passage of time are recorded as lease operating expense or capitalized.

Estimating the future asset retirement liability requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments. These include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement liability, a corresponding adjustment will be made to the carrying cost of the related asset.

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 2008 and 2009. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through 2010. 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 financial statements in accordance with SFAS No. 133. "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"). Although not risk free, we believe this policy will reduce our exposure to commodity 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 SFAS No. 133, as amended, all our derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swap qualifies and has been designated as perfect hedge.

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.

Revenue Recognition. We derive revenue primarily from the sale of produced natural gas. We use the sales method of accounting for the recognition of gas revenue. Because there is a ready market for natural gas, we 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 net revenue interests. Gas sold in production operations is not significantly different from our share of production based on our interest in the properties.

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 that payments are received from the purchaser.

Income Taxes. We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS No. 109, Accounting for Income Taxes ("SFAS 109") as clarified by FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"). 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 SFAS 109, 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.

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 ("NOL") carryforwards. It is more likely than not that we will use these NOL's to offset current tax liabilities in future years (except our Canadian NOL's).

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" ("FIN 48") on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes", 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

Stock Compensation.

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123 (revised), *Share-Based Payment* ("SFAS 123(R)"), using the prospective transition method. The application of SFAS 123(R) requires the use of a model similar to 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. The significant assumptions include the expected term, volatility, interest rate and expected dividends. Due to the adoption of SFAS 123(R), we expect our compensation expense related to the granting of share-based awards subsequent to adoption to be higher than in prior periods. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. Therefore, no equity compensation cost will be recognized on these awards in the future unless such awards are modified, repurchased or cancelled.

Natural Gas Production—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, 2007, 2006 and 2005. This table should be read with the discussion of the results of operations for the periods presented below.

	Year Ended December 31,		
	2007	2006	2005
Gas sales	$49,694	$44,806	$41,604
Lease operating expenses	$13,981	$11,579	$ 8,687
Compression and transportation expenses	5,209	4,499	3,332
Production taxes	1,164	1,037	914
Total production expenses	$20,354	$17,115	$12,933
Net sales volumes (GeoMet) (MMcf)	7,125	6,228	4,594
Pond Creek field (MMcf)	4,494	3,844	2,923
Gurnee field (MMcf)	2,235	1,950	1,182
Per Mcf data ($/Mcf):			
Average natural gas sales price (GeoMet)	$ 6.97	$ 7.19	$ 9.06
Pond Creek field	$ 6.96	$ 7.26	$ 9.06
Gurnee field	$ 6.94	$ 7.05	$ 9.14
Average natural gas sales price realized (GeoMet)(1)	$ 7.52	$ 7.37	$ 7.43
Lease operating expenses (GeoMet)	$ 1.96	$ 1.86	$ 1.89
Pond Creek field	$ 1.60	$ 1.54	$ 1.52
Gurnee field	$ 3.05	$ 2.90	$ 3.55
Compression and transportation expenses (GeoMet)	$ 0.73	$ 0.72	$ 0.72
Pond Creek field	$ 0.92	$ 0.98	$ 0.95
Gurnee field	$ 0.47	$ 0.38	$ 0.43
Production taxes (GeoMet)	$ 0.17	$ 0.17	$ 0.20
Pond Creek field	$ 0.01	$ 0.02	$ 0.02
Gurnee field	$ 0.41	$ 0.41	$ 0.53
Total production expenses (GeoMet)	$ 2.86	$ 2.75	$ 2.81
Pond Creek field	$ 2.53	$ 2.54	$ 2.50
Gurnee field	$ 3.93	$ 3.68	$ 4.52
Depreciation, depletion and amortization (GeoMet)	$ 1.24	$ 1.26	$ 1.06

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

Results of Operations

Year Ended December 31, 2007 compared with Year Ended December 31, 2006

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,		
	2007	2006	Change
	(In thousands)		
Gas sales	$49,694	$ 44,806	11%
Lease operating expenses	$13,981	$ 11,579	21%
Compression and transportation expenses	$ 5,209	$ 4,499	16%
Production taxes	$ 1,164	$ 1,037	12%
Depreciation, depletion and amortization	$ 9,092	$ 7,876	15%
General and administrative	$ 9,294	$ 6,553	42%
Realized gains on derivative contracts	$ 3,895	$ 1,118	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$ 3,007	$(16,877)	NM
Interest expense (net of amounts capitalized)	$ 5,130	$ 3,130	64%
Income tax expense (benefit)	$ 2,987	$ 10,866	NM%
Discontinued operations	$ 174	$ —	NM%

NM-Not Meaningful

Gas sales. Gas sales increased by $4.9 million, or 11%, to $49.7 million compared to the prior year. The increase in gas sales was a result of increased production, partially offset by lower average gas prices. Production increased 14% while average gas prices, excluding hedging transactions, decreased 3%. The $4.9 million increase in gas sales consisted of a $6.5 million increase in production and a $1.6 million decrease in average prices. The increase in production was principally attributable to our Gurnee and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $2.4 million, or 21% to $14.0 million. The $2.4 million increase in lease operating expenses consisted of $1.7 million increase in production and $0.7 million increase in costs. The increase in costs is related to an increase in well service activities from the prior year period.

Compression and transportation expenses. Compression and transportation expenses increased by $0.7 million, or 16%, to $5.2 million ($2.6 million each for both compression and transportation). The $0.7 million increase was comprised of a $0.5 million increase in compression expenses due to increased production and a $0.2 million increase in transportation expenses due to increased production offset by a decrease in the actual per Mcf transportation expenses due to the certain gas transported on our own system in 2007.

Production taxes. Production taxes increased by $0.127 million, or 12%, to $1.164 million. The production taxes increase of $0.127 million was primarily due to increased production, partially offset by lower average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $1.2 million, or 15%, to $9.1 million. The depreciation, depletion and amortization increase of $1.2 million resulted from the increase in production. There were no significant changes in the depletion rate in 2007.

General and administrative. General and administrative expenses increased by $2.7 million, or 42%, to $9.3 million. The increase in general and administrative expenses was a result of increases in employee expenses (15%), professional services (94%), director and investor relations expenses (139%), insurance expense

(74%) and office expenses and business taxes (6%). The largest dollar increase was in employee expenses and professional services that resulted from the increased audit, Sarbanes Oxley, tax and legal services. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of being a public company.

Realized gains on derivative contracts. Realized gains on derivative contracts increased by $2.8 million to $3.9 million compared to a gain of $1.1 million in the prior period. Realized losses represent net cash flow settlements paid to the counterparty while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized (gains) losses from the change in market value of open derivative contracts. Unrealized (gains) losses from the change in market value of open derivative contracts generated a $3.0 million loss as compared to a $16.9 million gain in the prior 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. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair value of derivative liabilities increase. The $3.0 million loss was a result of increased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) increased by $2 million, or 64%, to $5.1 million. The increase was primarily due to higher outstanding debt and higher interest rates. Capitalized interest totaled $0.6 million and $1.0 for the years ended December 31, 2007 and 2006, respectively.

Income tax expense (benefit). Income tax expense decreased by $7.9 million to $3.0 million. The decrease in income tax expense for the current period was due to decreased pretax income compared to the prior period. In addition, the effective tax rate decreased for the current year to 37% from 39% in the comparable prior period. The principal driver for the difference in the effective tax rate was due to lower state income taxes resulting from state apportionment factor shifting.

Discontinued operations. In September of 2007, we discontinued the third party marketing business and second reportable segment which had been created in connection with the consolidation of Shamrock Energy LLC, a variable interest entity under FIN 46 (R) on August 1, 2006. The consolidation of the variable interest entity had no impact on our net income due to the 100% minority interest to Shamrock Energy LLC. On January 1, 2007, we acquired Shamrock Energy LLC as a wholly owned subsidiary and the consolidation of this wholly owned subsidiary had an insignificant impact on our net income. As a result of exiting our third party marketing business, we are treating these activities as a discontinued operation for all the periods presented.

Results of Operations

Year Ended December 31, 2006 compared with Year Ended December 31, 2005

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

	Year Ended December 31,		
	2006	2005	Change
	(In thousands)		
Gas sales	$ 44,806	$41,604	8%
Lease operating expenses	$ 11,579	$ 8,688	33%
Compression and transportation expenses	$ 4,499	$ 3,332	35%
Production taxes	$ 1,037	$ 914	13%
Depreciation, depletion and amortization	$ 7,876	$ 4,867	62%
General and administrative	$ 6,553	$ 3,208	104%
Realized (gains) losses on derivative contracts	$ (1,118)	$ 7,473	NM
Unrealized (gains) losses from the change in market value of open derivative contracts	$(16,877)	$12,059	NM
Interest expense (net of amounts capitalized)	$ 3,130	$ 3,895	(20)%
Income tax expense (benefit)	$ 10,866	$ (993)	NM
Discontinued operations	$ —	$ 442	NM

NM-Not Meaningful

Gas sales. Gas sales increased by $3.2 million, or 8%, to $44.8 million compared to the prior year. The increase in gas sales was a result of increased production, partially offset by lower average gas prices. Production increased 36% while average gas prices, excluding hedging transactions, decreased 20%. The $3.3 million increase in gas sales consisted of a $14.8 million increase in production and an $11.5 million decrease in average prices. The increase in production was principally attributable to our Gurnee and Pond Creek development activities.

Lease operating expenses. Lease operating expenses increased by $2.9 million, or 33% to $11.6 million. The $2.9 million increase in lease operating expenses consisted of $3.1 million increase in production and $0.2 million decrease in costs. The increase in costs is related to an increase in well service activities from the prior year period.

Compression and transportation expenses. Compression and transportation expenses increased by $1.2 million, or 35%, to $4.5 million. The $1.2 million increase in compression and transportation expenses was driven entirely by the increase in production.

Production taxes. Production taxes increased by $0.123 million, or 13%, to $1.0 million. The production taxes increase of $0.123 million was primarily due to increased production, partially offset by lower average gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $3.0 million, or 62%, to $7.9 million. The depreciation, depletion and amortization increase of $4.5 million consisted of a $3.3 million increase in depletion rate and a $1.2 million increase in production. The increase in the depletion rate was primarily due to $48.0 million added to the net book value of gas properties due to a purchase accounting adjustment related to the acquisition of the minority interest stock in a subsidiary on April 2005 and increased future development costs. Future development costs increased due to increased proved undeveloped wells and higher costs of drilling.

General and administrative. General and administrative expenses increased by $3.3 million, or 104%, to $6.6 million. The increase in general and administrative expenses was a result of increases in employee expenses (22%), professional services (466%), director and investor relations expenses (100%), insurance expense (176%) and office expenses and business taxes (56%). This increase was partially offset by increased capitalized general and administrative expenses recoveries (17%) related to field, operating recoveries and capitalized general and administrative expenses. The largest dollar increase was in employee expenses and professional services that resulted from the increased audit, Sarbanes Oxley, tax and legal services. The increase in general and administrative expenses was a result of expanding the overhead structure to support our growth and increased costs of being a public company.

Realized (gains) losses on derivative contracts. Realized (gains) losses on derivative contracts increased by $8.6 million to a gain of $1.1 million compared to a loss of $7.5 million in the prior period. Realized losses represent net cash flow settlements paid to the counterparty while realized gains represent net cash flow settlement paid to us from the counterparty. Realized losses occur when commodity gas prices or the derivative index price exceeds the derivative ceiling price. Conversely, realized gains occur when commodity gas prices go below the derivative floor price.

Unrealized (gains) losses from the change in market value of open derivative contracts. Unrealized (gains) losses from the change in market value of open derivative contracts generated a $16.9 million gain as compared to a $12.1 million loss in the prior 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. Unrealized gains are recognized when the fair values of derivative assets increase or the fair value of derivative liabilities decrease. Unrealized losses are recognized when the fair values of derivative assets decrease or the fair value of derivative liabilities increase. The $16.9 million gain was a result of decreased future commodity gas prices.

Interest expense (net of amounts capitalized). Interest expense (net of amounts capitalized) decreased by $0.765 million, or 20%, to $3.1 million. The decrease was primarily due to lower outstanding bank balances and was partially offset by higher interest rates. Capitalized interest totaled $1.0 million and $0.7 million for the years ended December 31, 2006 and 2005, respectively.

Income tax expense (benefit). Income tax expense (benefit) resulted in an expense of $10.9 million in the year ended December 31, 2006 compared to a benefit of $0.993 million in the prior period. The increase in income tax expense for the year was due to (1) pretax income versus a pretax loss in the prior period and (2) an increase in the effective tax rate for the year to 39% from 33% in the prior period as a result of certain state taxes not previously included in prior periods and the related cumulative non-cash adjustment of $0.406 million.

Liquidity and Capital Resources

Cash Flows and Liquidity

Cash flow from operations for the year ended December 31, 2007 and 2006 were $17.5 million and $21.7 million, respectively. Cash flow provided by operations for the year ended December 31, 2007 of $17.5 million combined together with $36 million borrowed from our revolving credit facility and $0.5 million from other sources were sufficient to fund our cash basis capital expenditures of $54 million.

As of December 31, 2007, we had a working capital deficit of approximately $2.1 million, a decrease of $0.5 million from the working capital deficit of $1.6 million at December 31, 2006. The decrease in the working capital was primarily a result of capital expenditures. At December 31, 2007, we had adequate cash flows from operating activities and credit availability to fund our working capital deficits.

The development of CBM 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, and the timing and volume of initial and subsequent natural gas production. We estimate total capital expenditures in 2008 will be approximately $48.8 million with approximately 79% allocated to development projects, representing a decrease of approximately $5.1 million under our actual 2007 capital expenditures. The 2008 estimated capital expenditures are primarily attributable to continued development expenditures at Peace River, Pond Creek, Lasher, Cahaba and Garden City. As of December 31, 2007 we have approximately $84 million of available borrowing capacity under our revolving credit facility. The following table is a summary of our capital expenditures on an accrual basis by category:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Capital expenditures:			
Leasehold acquisition	$ 7,333	$ 8,975	$ 2,012
Exploration	2,999	7,626	8.620
Development	44,831	62,211	46,397
Other items (primarily capitalized overhead and interest)	4,649	2,781	2,173
Total capital expenditures	$59,812	$81,593	$59,202

Capital expenditures for the year ended December 31, 2007 decreased by 27% from the prior year. We expect capital expenditures to decrease in 2008 by 18% from the 2007 levels. The decrease in 2007 and 2008 is primarily attributable to decreased development expenditures at our Gurnee field and Pond Creek field partially offset by increased expenditures in our other prospects. The decisions to reduce drilling activity in 2007 and 2008 were made for several reasons: 1) to keep our bank debt at acceptable levels, 2) to allow time to evaluate production results at the Gurnee field, 3) to provide additional capital for our other prospects and, 4) as a result of the Pond Creek field litigation. 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 volume of initial and subsequent natural gas production volumes.

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 volume of initial and subsequent natural gas production volumes.

Based upon current expectations, we believe that we will have adequate resources from cash flows provided by operations and from proceeds from our revolving credit facility borrowings to fund our 2008 capital expenditures and other working capital needs.

If natural gas commodity prices decrease from their current levels for an extended period, our ability to finance our planned capital expenditures could be affected negatively. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of estimated proved reserves and current natural gas prices. If either our estimated proved reserves or natural gas prices decrease, amounts available to us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated, amounts available for borrowing under our revolving credit facility are reduced or we are unable to sell equity at acceptable prices, we may be forced to defer planned capital expenditures.

Commodity Price Risk and Related Hedging Activities.

We engage in commodity price risk and related hedging activities from time to time. These activities are intended to manage our exposure to fluctuations in the price of natural gas. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. 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 and a minimum 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 to a predetermined amount, generally between $2.00 and $3.00 per MMBtu. In accordance with SFAS No. 133, as amended, all our derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings. The natural gas derivatives have not been designated as hedge transactions under SFAS No. 133, as amended.

Currently, we use collars and fixed-price swaps as our mechanism for hedging commodity prices. During the year ending December 31, 2007, the Company recognized gains on derivative contracts of $888,222, which included realized gains of $3,895,138. During the year ending December 31, 2006, the Company recognized gains on derivative contracts of $17,995,268, which included realized gains of $1,118,043. During the year ending December 31, 2005, the Company recognized losses on derivative contracts of $19,532,212, which included realized losses of $7,473,004.

At December 31, 2007 and at December 31, 2006, the fair values of open natural gas contracts were assets of approximately $2.3 million and $5.3 million, respectively.

At December 31, 2007, the Company had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Sold Floor	Bought Floor
Collars (3 way)				
January 2008—March 2008	728,000	$14.80	$6.00	$9.00
Summer 2008	1,712,000	$10.50	$5.00	$7.00
Winter 2008/2009	906,000	$11.00	$6.25	$8.50
Summer 2009	1,284,000	$10.00	$5.25	$7.50
Traditional Collar				
January 2008—March 2008	364,000	$11.25		$8.25

At December 31, 2007, we had the following natural gas swap position:

Period	Volume in MMBtu's	Price
Summer 2008	856,000	$8.00

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market of natural gas may have on the fair value of our natural gas derivative instruments. At December 31, 2007, the potential change in the fair value of our derivative contracts assuming a 10% increase in the underlying commodity price was a $2.7 million decrease in the unrealized gain on derivative contracts reported on our unaudited consolidated statements of operations and comprehensive income for the three months ended December 31, 2007.

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 SFAS No. 133. 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 in accumulated 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. A summary of the impacts of our cash flow hedges included in other comprehensive income, net of tax, as of December 31, 2007 follows:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount	Other comprehensive income, net of tax
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%(1)	$15,000,000	$10,884

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

For the years ended December 31, 2007, we recognized no ineffective portion of our cash flow hedges. On January 3, 2008, the Company entered an interest rate swap at an interest rate of 3.95% and a notional amount of $10,000,000 maturing January 4, 2010.

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Our hedge counterparties are participants in our credit agreement and the collateral for the outstanding borrowings under our credit agreement is used as collateral for our hedges.

Revolving Credit Facility

In June 2006, we entered into a $180 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under our credit agreement is subject to a borrowing base, which is currently set at $180 million. The borrowing base is subject to semi-annual redeterminations. The lenders also have the right to require one additional redetermination in any fiscal year. Our credit agreement provides for interest to accrue at a rate calculated, at our option, at either the adjusted base rate (which is the greater of the agent's base rate or the federal funds rate plus one half of one percent) or the London Interbank Offered Rate (LIBOR) plus a margin of 1.00% to 2.00%, based on borrowing base usage. Borrowings under our credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under our credit agreement become due and payable on January 6, 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. Our ratio of consolidated current assets (defined to include amounts available under our borrowing base) to our consolidated current liabilities is not permitted to be less than 1 to 1 as of the end of any fiscal quarter, and our ratio of consolidated EBITDA for the four preceding quarters at the end of each fiscal quarter to the sum of our consolidated net interest expense for the same period plus letter of credit fees accruing during such quarter is not permitted to be less than 2.75 to 1. Consolidated EBITDA as defined in the amended credit agreement excludes other non-cash charges deducted in determining net income (loss), which would include unrealized losses from the change in the market value of open derivative contracts. In addition, we are 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. 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 facility. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business. As of December 31, 2007, we were in compliance with all of the covenants in the credit agreement.

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 commodity prices and reserve levels. Using our December 31, 2007 reserve report, the borrowing base was reaffirmed at $180 million as of February 29, 2008. The next scheduled redetermination is to occur as of June 30, 2008. Upon a redetermination, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the revolving credit facility and an acceleration of our indebtedness.

At December 31, 2007, we had $96 million outstanding under our revolving credit facility. Interest on the borrowings averaged 6.29% per annum. Borrowing availability at December 31, 2007 was $84 million. 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 at December 31, 2007, a 1% change in market interest rates would have increased interest expense and negatively impacted our annual cash flows by approximately $810,000. Note that $15 million of outstanding balance was excluded from the analysis due to lack of interest rate exposure based on the interest rate swap discussed above.

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, 2007, beginning January 1, 2008 (in thousands):

	2008	2009	2010	2011	2012 and thereafter
Long-term debt and other obligations(1)	$ 103	$ 112	$ 122	$96,133	$ 363
Interest expense on revolving credit facility(2)	6,042	6,042	6,042	83	—
Operating lease obligations	1,629	1,421	1,294	1,294	1,082
Asset retirement obligations	74	—	—	—	2,481
Firm transportation contracts	2,526	2,526	2,442	1,908	10,512
Other operating commitments(3)	3,279	171	—	—	—
FIN 48(4)	—	—	—	—	—
Total commitments	$13,653	$10,272	$9,900	$99,418	$14,438

(1) Maturities based on the June 2006 amended bank credit agreement terms, which extended the maturity date to January 6, 2011.

(2) Assumes an annual rate on a 30-day LIBOR of 4.79% plus the current 1.50% margin for a total interest rate of 6.29%, net of swap recoveries.

(3) Includes a purchase price adjustment of $3,000,000 related to the 2004 acquisition of working interest in certain wells, primarily in the Pond Creek field.

(4) As of December 31, 2007, we had a liability for unrecognized tax benefits of approximately $273K. 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.

Recent Accounting Pronouncements

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified 269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48. The amount of unrecognized tax benefit did not materially change as of December 31, 2007.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. SFAS 157 applies only to fair value measurements that are already required or permitted by other accounting standards. SFAS 157 is effective for fiscal years beginning after November 15, 2007. We do not expect SFAS 157 to have a material impact on our consolidated financial position or results of operations upon adoption.

On February 15, 2007, the FASB issued FASB Statement No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB 115*," ("FASB 159"). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of FASB 159 are elective; however, the amendment to FASB 115, "Accounting for Certain Investments in Debt and Equity Securities," applies to all entities that own trading and available-for-sale securities. The fair value option created by FASB 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. FASB 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity (i) makes that choice in the first 120 days of that year, (ii) has not yet issued financial statements for any interim period of such year, and (iii) elects to apply the provisions of FASB 157, Fair Value Measurements. We do not believe there will be a material impact related to the implementation of FASB 159 on our financial statements.

Foreign Currency Exchange Rate Risk

We began exploratory operations in Canada in the fourth quarter of 2004 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. Because our Canadian project is not yet producing, the effect of changes in the exchange rate does not impact our revenues or expenses but primarily affects the costs of unevaluated properties. We 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.

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

Commodity 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, 2007, a 10% fluctuation in the prices received for natural gas production would have had an approximate $2.7 million impact on our revenues.

Interest Rate Risk. We have long-term debt subject to the risk of loss associated with movements in interest rates. As of December 31, 2007, we had $81 million of variable rate long-term debt outstanding due in January 2011. This variable rate obligation exposes us to the risk of increased interest expense in the event of increases in short-term interest rates. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be approximately $0.8 million.

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

GEOMET, INC. AND SUBSIDIARIES

Index To Financial Statements

MANAGEMENT'S 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, 2007.

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

Houston, Texas
March 14, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of GeoMet, Inc and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoMet, Inc and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 48, "Accounting for Uncertain in Income Taxes—an Interpretation of FASB Statement No. 109" on January 1, 2007. As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment" on January 1, 2006.

DELOITTE & TOUCHE LLP

Houston, TX
March 14, 2008

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,540,516	$ 1,414,476
Accounts receivable	4,881,397	10,881,479
Inventory	2,355,595	—
Derivative asset	2,247,248	4,290,599
Other current assets	484,341	729,234
Total current assets	11,509,097	17,315,788
Gas properties—utilizing the full cost method of accounting:		
Proved gas properties	370,404,336	310,011,154
Unevaluated gas properties, not subject to amortization	25,174,764	26,397,982
Other property and equipment	2,536,619	2,314,190
Total property and equipment	398,115,719	338,723,326
Less accumulated depreciation, depletion, and amortization	(31,886,633)	(22,849,903)
Property and equipment—net	366,229,086	315,873,423
Other noncurrent assets:		
Derivative asset	90,427	1,043,108
Other	848,816	962,447
Total other noncurrent assets	939,243	2,005,555
TOTAL ASSETS	$378,677,426	$335,194,766
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 7,536,274	$ 14,284,921
Accrued liabilities	5,087,871	2,917,575
Deferred income taxes	770,675	1,570,684
Asset retirement liability	74,387	73,047
Current portion of long-term debt	102,586	94,177
Total current liabilities	13,571,793	18,940,404
Long-term debt	96,729,722	60,832,110
Asset retirement liability	2,915,855	2,480,754
Other long-term accrued liabilities	138,471	154,455
Deferred income taxes	46,645,879	42,779,537
TOTAL LIABILITIES	160,001,720	125,187,260
Commitments and contingencies (Note 15)		
Stockholders' Equity:		
Preferred stock, $0.001 par value—authorized 10,000,000, none issued	—	—
Common stock, $0.001 par value—authorized 125,000,000 shares; issued and outstanding 38,962,359 and 38,678,713 at December 31, 2007 and December 31, 2006, respectively	38,962	38,679
Paid-in capital	187,550,484	186,852,852
Accumulated other comprehensive income (loss)	2,394,001	(193,888)
Retained earnings	28,909,363	23,740,144
Less notes receivable	(217,104)	(430,281)
TOTAL STOCKHOLDERS' EQUITY	218,675,706	210,007,506
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$378,677,426	$335,194,766

See accompanying Notes to Consolidated Financial Statements.

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31,

	2007	2006	2005
Revenues:			
Gas sales	$49,694,489	$ 44,805,876	$41,604,342
Operating fees and other	1,289,575	140,922	375,509
Total revenues	50,984,064	44,946,798	41,979,851
Expenses:			
Lease operating expense	13,981,093	11,579,112	8,687,550
Compression and transportation expense	5,209,206	4,498,850	3,332,045
Production taxes	1,164,159	1,037,401	913,885
Depreciation, depletion and amortization	9,091,610	7,876,212	4,867,134
Research and development	—	129,085	608,477
General and administrative	9,294,279	6,552,947	3,207,992
Realized (gains) losses on derivative contracts	(3,895,138)	(1,118,043)	7,473,004
Unrealized (gains) losses from the change in market value of open derivative contracts	3,006,916	(16,877,225)	12,059,208
Total operating expenses	37,852,125	13,678,339	41,149,295
Operating income from continuing operations	13,131,939	31,268,459	830,556
Other income (expense):			
Interest income	39,341	33,149	76,569
Interest expense (net of amounts capitalized)	(5,129,847)	(3,130,005)	(3,894,550)
Other	(58,589)	(9,773)	(21,366)
Total other income (expense):	(5,149,095)	(3,106,629)	(3,839,347)
Income (loss) before income taxes, minority interest & discontinued operations	7,982,844	28,161,830	(3,008,791)
Income tax expense (benefit)	2,987,407	10,865,614	(993,174)
Income (loss) before minority interest & discontinued operations	4,995,437	17,296,216	(2,015,617)
Discontinued operations:			
Discontinued operations, net of tax	173,782	22,535	—
Minority interest, net of tax	—	(22,535)	442,336
Income from discontinued operations	173,782	—	442,336
Net income (loss)	$ 5,169,219	$ 17,296,216	$ (1,573,281)
Earnings per Share:			
Income from continuing operations			
Basic	$ 0.13	$ 0.49	$ (0.07)
Diluted	$ 0.13	$ 0.48	$ (0.07)
Discontinued operations			
Basic	$ —	$ —	$ —
Diluted	$ —	$ —	$ —
Net income per common share			
Basic	$ 0.13	$ 0.49	$ (0.07)
Diluted	$ 0.13	$ 0.48	$ (0.07)
Weighted average number of common shares:			
Basic	38,822,671	35,018,122	28,164,946
Diluted	39,699,694	35,964,301	28,164,946

See accompanying Notes to Consolidated Financial Statements.

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	Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Notes Receivable	Total Stockholders' Equity
Balance at January 1, 2005	24,000,000	$24,000	$ 59,848,451	$ 2,119	$11,017,209	$ (5,200,000)	$ 65,691,779
Exercise of options	1,456,668	1,457	11,131,068				
Exercise of stock options	79,228	79	98,840				
Common stock issued	4,438,768	4,439	33,918,848			(10,905,144)	
Accrued interest on notes receivable			1,411,708			(1,411,708)	
Common stock dividends ($0.125 per share)					(3,000,000)		
Comprehensive income:							
Net income					(1,573,281)		$ (1,573,281)
Foreign currency translation adjustment, net of income tax of $0							54,191
Total comprehensive income				54,191			$ (1,519,090)
Balance at December 31, 2005	29,974,664	$29,975	$106,408,915	$ 56,310	$ 6,443,928	$(17,516,852)	$ 95,422,276
Sale of common stock, 144A and IPO	8,067,023	8,067	81,479,741				
Exercise of stock options	637,026	637	1,122,255				
Offering costs			(2,996,890)				
Stock-based compensation			1,328,784				
Payments on notes receivable						17,184,357	
Accrued interest on notes receivable			(489,953)			(97,786)	
Comprehensive income:							
Net income					17,296,216		$ 17,296,216
Foreign currency translation adjustment, net of income tax of $0				(250,198)			(250,198)
Total comprehensive income							17,046,018
Balance at December 31, 2006	38,678,713	$38,679	$186,852,852	$ (193,888)	$23,740,144	$ (430,281)	$210,007,506
Restricted stock awards	178,081	178	(178)				
Exercise of stock options	105,565	105	224,660				
Stock-based compensation			526,575				
Purchase of treasury stock (7,828 shares)			(70,452)			66,070	
Payments on notes receivable						164,134	
Accrued interest on notes receivable			17,027			(17,027)	
Comprehensive income:							
Net income					5,169,219		5,169,219
Gain on interest rate swap				10,884			$ 10,884
Foreign currency translation adjustment, net of income tax of $0				2,577,005			2,577,005
Total comprehensive income							$ 7,757,108
Balance at December 31, 2007	38,962,359	$38,962	$187,550,484	$2,394,001	$28,909,363	$ (217,104)	$218,675,706

See accompanying Notes to Consolidated Financial Statements.

GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2007	2006	2005
Cash flows provided by operating activities:			
Net income (loss)	$ 5,169,219	$ 17,296,216	$ (1,573,281)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation, depletion and amortization	9,265,167	8,033,265	5,015,767
Amortization of debt issuance costs	146,280	136,394	185,672
Minority interest	—	—	(442,336)
Deferred income taxes	3,066,333	10,737,531	(1,001,946)
Unrealized (gains) losses from the change in market value of open derivative contracts (including premium amortization)	3,006,916	(16,877,225)	12,059,208
Stock-based compensation	311,482	317,298	—
(Gain) loss on sale of other assets	(64,834)	(7,861)	21,366
Accretion expense	209,850	157,342	98,328
Changes in operating assets and liabilities:			
Accounts receivable	6,111,907	(5,323,795)	(2,078,553)
Other current assets	(2,348,588)	(233,821)	(45,555)
Accounts payable	244,892	5,836,535	(184,511)
Accrued income tax payable	(6,709,656)	—	(40,000)
Other accrued liabilities	(922,101)	1,400,201	418,679
Net cash provided by operating activities	17,486,867	21,472,080	12,432,838
Cash flows used in investing activities:			
Capital expenditures (including lease acquisitions)	(54,026,382)	(79,060,608)	(59,817,472)
Proceeds from sale of assets	126,285	204,917	6,739
Restricted cash		—	130,243
Collection of notes receivable			—
Other assets	67,927	186,553	19,204
Net cash used in investing activities	(53,832,170)	(78,669,138)	(59,661,286)
Cash flows provided by financing activities:			
Debt issuance costs	(100,000)	(341,730)	(114,882)
Proceeds from exercise of stock options	224,765	1,122,892	326,298
Equity offering costs	—	(2,280,447)	(716,443)
Proceeds from sales of common stock	—	81,487,808	—
Net proceeds from (payments on) revolver	36,000,000	(39,000,000)	48,500,000
Treasury stock	(4,382)	—	—
Common stock dividend	—	—	(3,000,000)
Proceeds from notes receivable and accrued interest	164,134	17,184,357	—
Payments on credit facility and other debt	(93,979)	(86,563)	(89,392)
Net cash provided by financing activities	36,190,538	58,086,317	44,905,581
Effect of exchange rate changes on cash and cash equivalents	280,805	(90,589)	(75,050)
Increase (decrease) in cash and cash equivalents	126,040	798,670	(2,397,917)
Cash and cash equivalents at beginning of year	1,414,476	615,806	3,013,723
Cash and cash equivalents at end of year	$ 1,540,516	$ 1,414,476	$ 615,806
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest expense	$ 5,672,771	$ 3,858,895	$ 4,214,028
Income taxes	$ 25,000	$ 55,000	$ 175,000
Issuance of common stock in exchange for note receivable	$ —	$ —	$ 10,905,144
Issuance of common stock in exchange for majority-owned subsidiary's minority interest	$ —	$ —	$ 33,923,287

See accompanying Notes to Consolidated Financial Statements.

GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Our Business

GeoMet, Inc. ("GeoMet," "Company," "we," or "our") (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. We are 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.

On April 13, 2005, we acquired, through an exchange of stock, the minority interest in our 81% owned subsidiary and merged the subsidiary into us. Following the merger, we changed our name from GeoMet Resources, Inc. to GeoMet, Inc. In connection with this transaction, we exchanged 4,438,768 shares of our common stock valued at $7.64 per share for all of the common stock of the subsidiary that we did not already own, approximately 19.05%. The acquisition was accounted for as a purchase in accordance with Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations* ("SFAS 141"), whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. No goodwill was recorded because the purchase price approximated the fair value of net assets acquired. The exchange value was determined through negotiations between a special committee of the 81% owned subsidiary's board of directors and management.

On January 1, 2007, we exercised our purchase option and acquired 100% of Shamrock Energy LLC, our discontinued gas marketing subsidiary (see Note 10—Discontinued Operations). In return, we provided Jon M. Gipson, the former owner of Shamrock, an at-will employment position with us. Also, pursuant to the terms of our purchase option, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this purchase option. Over 99% of the net assets acquired were current, approximated their fair value and were equal to zero. Shamrock Energy LLC is a low margin business and as a result it does not have a significant impact on our results of operations. The acquisition was accounted for as a purchase in accordance with SFAS No. 141, "Business Combinations," whereby the purchase price of the net assets acquired was allocated to those net assets based on their fair value. Goodwill was not recorded because the purchase price approximated the fair value of the net assets acquired.

Note 2—Summary of Significant Accounting Policies

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

Use of Estimates in the Preparation of Financial Statements—The preparation of 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Our most significant financial estimates are based on remaining 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"). 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.

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 test is calculated using natural gas prices in effect as of the balance sheet date and adjusted for "basis" or location differential, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC, significant changes in gas prices subsequent to quarter end are used in the ceiling test. In addition, subsequent to the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"), 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.

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 SFAS 143, 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.

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

Reclassifications—Certain amounts in prior periods have been reclassified to conform with the report classifications of the year ended December 31, 2007 with no effect on previously reported net income or stockholders' equity. The reclassification consisted of adding both the current and non-current portions of notes receivable to the balances of other current assets and other assets, respectively.

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 officers and 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, 2007 and 2006 are solely attributable to employees as all notes due from executive officers were paid in January 2006 in accordance with the rules and regulations of the SEC. See Note 12 for additional information regarding repayment.

Income Taxes—We record our income taxes using an asset and liability approach in accordance with the provisions of the SFAS No. 109, *Accounting for Income Taxes* ("SFAS 109") as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). 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 SFAS 109, 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.

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").

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes- an interpretation of FASB Statement No. 109" ("FIN 48") on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes", 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—We derive revenue primarily from the sale of produced natural gas. For sales of produced natural gas, we use the sales method of accounting for the recognition of gas revenue. Because there is a ready market for natural gas, we 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 and risk of loss is transferred based on our net revenue interests. Gas sold in production operations is not significantly different from our share of production based on its interest in the properties.

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, 2007 and 2006 arise substantially from the sales of natural gas and joint interest billings. Management does not expect there to be any significant risk of collectability of these receivables and therefore has not provided for an allowance for doubtful accounts. Risks with respect to derivative assets as of December 31, 2007 arise from cash settlements due to us from our derivative counterparties.

Fair Value of Financial Instruments—The fair value of cash and cash equivalents, current receivables and payables, approximate book value because of the short maturity of these accounts. Debt outstanding under the revolving credit facility is variable rate debt and as such, approximates fair value, as interest rates are variable based on market rates. The outstanding note receivable in Other Non-Current Assets and certain Other Debt carries a fixed interest rate. See Notes 5 and 9 for the fair values of the receivable and other debt.

Operating Fees and Other—We have received fees from operating coal bed methane gas fields from other owners. Where we have conducted contract operations in fields where we do not own a working interest the fees are recognized in Revenues. Where we have conducted contract operations in fields where we own a working interest the fees reduce general and administrative expenses. These fees were recognized in the period in which the services were performed.

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, 2007, 2006 and 2005 of $1,991,760, $1,174,149 and $1,777,566, 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, 2007, 2006 and 2005, we capitalized $587,884, $1,037,576 and $714,070 of interest, respectively. See Unevaluated Properties above for additional information on the criteria for including costs in unevaluated properties.

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 2008 and 2009. We also entered into an interest rate swap agreement to hedge interest rates associated with a portion of our variable rate debt through 2010. 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 financial statements in accordance with SFAS No. 133. "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"). Although not risk free, we believe this policy will reduce our exposure to commodity 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 SFAS No. 133, as amended, all our derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings for the natural gas derivatives or other comprehensive income for our interest rate swaps. The natural gas derivatives have not been designated as hedge transactions while the interest rate swap qualifies and has been designated as perfect hedge.

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.

Foreign Currency Translation—For subsidiaries whose functional currency is deemed to be other than the United States 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 income in the current period. Our only foreign subsidiary is our Canadian subsidiary, Hudson's Hope Gas, Ltd.

Stock-Based Compensation—Prior to January 1, 2006, stock-based employee compensation was accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25, *Accounting for Stock Issued to Employees* ("APB 25"). The exercise price of the options granted was equal to the estimated market value of our common stock at grant date, and therefore, no compensation costs have been recognized. We used the income method on a semi-annual basis to estimate the market value of our common stock at grant date.

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment* ("SFAS 123(R)"), using the prospective transition method. The application of SFAS 123(R) 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.

Discontinued Operations—We use the criteria in SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144") and EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations* (EITF 03-13), to determine whether our components that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS No. 144, the component being disposed of must have clearly distinguishable operations and cash flows. Additionally, pursuant to EITF 03-13, we must not have significant continuing involvement in the operations after the disposal (i.e. we must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the operations being disposed of must have been eliminated from GeoMet's ongoing operations (i.e. we do not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments, are reflected as (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statements of Operations.

Note 3—Recent Accounting Pronouncements

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified 269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48. The amount of unrecognized tax benefit did not materially change as of December 31, 2007.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. SFAS 157 applies only to fair value measurements that are already required or permitted by other accounting standards. SFAS 157 is effective for fiscal years beginning after November 15, 2007. We do not expect SFAS 157 to have a material impact on our consolidated financial position or results of operations upon adoption.

On February 15, 2007, the FASB issued FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB 115, ("FASB 159"). This standard permits an entity to measure financial instruments and certain other items at estimated fair value. Most of the provisions of FASB 159 are elective; however, the amendment to FASB 115, "Accounting for Certain Investments in Debt and Equity Securities," applies to all entities that own trading and available-for-sale securities. The fair value option created by FASB 159 permits an entity to measure eligible items at fair value as of specified election dates. The fair value option (a) may generally be applied instrument by instrument, (b) is irrevocable unless a new election date occurs, and (c) must be applied to the entire instrument and not to only a portion of the instrument. FASB 159 is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity (i) makes that choice in the first 120 days of that year, (ii) has not yet issued financial statements for any interim period of such year, and (iii) elects to apply the provisions of FASB 157, Fair Value Measurements. We do not believe there will be a material impact related to the implementation of FASB 159 on our consolidated financial statements.

Note 4—Net Income (Loss) Per Share

Net Income (Loss) Per Share of Common Stock—Basic income per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted net income per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities. Dilutive income per share 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:

	December 31,		
	2007	2006	2005
Income (loss) from continuing operations			
Basic	$ 0.13	$ 0.49	$ (0.07)
Diluted	$ 0.13	$ 0.48	$ (0.07)
Discontinued operations			
Basic	$ —	$ —	$ —
Diluted	$ —	$ —	$ —
Net income (loss) per common share			
Basic	$ 0.13	$ 0.49	$ (0.06)
Diluted	$ 0.13	$ 0.48	$ (0.06)
Numerator			
Net income (loss) available to common stockholders	$ 5,169,219	$17,296,216	$(1,573,281)
Denominator:			
Weighted average shares outstanding-basic	38,822,671	35,018,122	28,164,946
Add potentially dilutive securities:			
Stock options	877,023	946,179	—
Dilutive securities	39,699,694	35,964,301	28,164,946

Diluted net income per share for the year ended December 31, 2007 excluded the effect of outstanding options to purchase 640,477 shares because the average market price at December 31, 2007 was less than the exercise price. Diluted net income per share for the year ended December 31, 2006 excluded the effect of outstanding options to purchase 245,405 shares because the average market price at December 31, 2006 was less than the exercise price. Diluted net income per share for the year ended December 31, 2005 excluded the effect of outstanding options to purchase 2,093,324 shares because we reported a net loss.

Note 5—Note Receivable

We have an unsecured note receivable of $271,736 and $298,936 as of December 31, 2007 and 2006, respectively, from a third party included in other non-current assets. The note requires payment on a semi-monthly basis, including interest at 8.25%, of $2,168. The fair value of the receivable at December 31, 2007 was approximately $327,000 Scheduled maturities of the note receivable are detailed in the table below.

	Amount
2008	27,200
2009	29,662
2010	32,346
2011	35,273
2012	38,466
Thereafter	135,989
Total note receivable	298,936
Less current portion of note receivable	27,200
Non-current note receivable	$271,736

Note 6—Gas Properties

We use the full cost method of accounting for its investment in gas properties. Under this method of accounting, all costs of acquisition, exploration and development of gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs related to unsuccessful projects, tangible and intangible development costs) are included in the full cost pool. In addition, we capitalize interest expense, direct general and administrative expenses, direct stock-based compensation expense, and additions resulting from asset retirement liabilities. Also under full cost accounting rules, total net 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 using natural gas prices in effect as of the balance sheet date and adjusted for "basis" or location differential, held constant over the life of the reserves; however, as allowed by the guidelines of the SEC, significant changes in gas prices subsequent to quarter are be used in the ceiling test. To the extent that capitalized costs of gas properties, net of accumulated depreciation, depletion and amortization and income taxes, exceed the ceiling limitation, such excess capitalized costs would be charged to results of operations.

Acquisition and Dispositions

We have constructed 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. This pipeline had an initial design capacity of approximately 45,000 barrels of water per day, but will require additional pump stations and looping a portion of the line in order to meet the maximum design capacity if needed. In October 2006, we executed a series of agreements with a privately held company relating to our operations in the Cahaba Basin, under which we agreed to designate up to 50% of the pipeline's capacity to dispose of produced water from the company's operations in the Gurnee field. Our fees earned under the agreements are $0.35 per barrel of untreated produced water but may decline to $0.20 per barrel of produced water if the operator chooses to treat its own produced water prior to delivering it to our facilities. The disposal fees we generate are included in other revenues. We also operate a water treatment facility in the Gurnee field to condition the produced water prior to injection into the pipeline and a discharge pond at the river to aerate the water prior to disposal. We believe that our disposal pipeline and water treatment facility will meet all of our future water disposal requirements for the Gurnee field.

Additionally, under these agreements, we have secured firm capacity rights on a high pressure gas gathering pipeline which connects into Enbridge's Magnolia Pipeline System. The acquired rights entitle us to transport approximately 40 million cubic feet per day of coalbed methane gas at a fee of $0.05 per MMBtu actually gathered through the pipeline. We do not anticipate utilizing this capacity in the immediate future. This agreement provides us with a second outlet for our gas produced from the Gurnee field. Together with our existing capacity on the Southern Natural Gas Bessemer—Calera lateral, our total gas takeaway capacity is expected to meet all of our future requirements.

Finally, as part of the agreements, we received an assignment of 1,360 acres of undeveloped leasehold contiguous with our existing leasehold positions in the Gurnee field. The estimated fair value of the undeveloped acreage was charged to unevaluated properties and a corresponding credit of $5 million to the full cost pool. The estimated fair value of $5 million was determined by our in-house engineers using the discounted cash flow method. In addition, we obtained independent valuations from a third party for the salt water disposal right we granted and the gas gathering agreement that was granted to us using discounted cash flow method and residual value method to support the in-house valuation for the undeveloped acreage granted to us.

The following table provides a summary of unevaluated costs not being depleted as of December 31, 2007 and 2006, by the year in which the costs were incurred.

	2007	2006
Subject to depletion	$370,404,336	$310,011,154
Not subject to depletion:		
Acquisition costs	6,182,214	4,967,220
Exploration costs	6,695,569	13,542,413
Total 2007	12,877,783	18,509,633
Total 2006 and prior	12,296,981	7,888,349
Total not subject to depletion	25,174,764	26,397,982
Gross gas properties	395,579,100	336,409,136
Less accumulated depletion	(30,661,249)	(21,836,904)
Net gas properties	$364,917,851	$314,572,232

At December 31, 2007 the costs of our projects in Garden City and British Columbia accounted for approximately 26% and 74% of the total not subject to depletion, respectively, of the total balance of unevaluated properties. At December 31, 2006 the costs of our projects in British Columbia and North Central Louisiana accounted for approximately 48% and 21% of the total not subject to depletion, respectively, of the total balance of unevaluated properties. During 2006, we recorded an impairment of $10.6 million related to certain prospects located in North Central Louisiana.

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, 2007 and 2006.

	2007	2006
Asset retirement obligation at beginning of year	$2,553,801	$1,890,173
Liabilities incurred	247,379	496,738
Liabilities settled	(83,385)	(40,735)
Accretion expense	241,083	178,994
Revisions in estimates	—	28,873
Currency translation adjustment	31,364	(242)
Asset retirement obligation at end of year	2,990,242	2,553,801
Less: current portion of obligation	74,387	73,047
Long-term asset retirement obligation	$2,915,855	$2,480,754

Note 8—Derivative Instruments and Hedging Activities

Commodity Price Risk and Related Hedging Activities.

We engage in commodity price risk and related hedging activities from time to time. These activities are intended to manage our exposure to fluctuations in the price of natural gas. We have historically used swaps, costless collars and three-way costless collars in our hedging activities. 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 and a minimum 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 to a predetermined amount, generally between $2.00 and $3.00 per MMBtu. In accordance with SFAS No. 133, as amended, all our derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings. The natural gas derivatives have not been designated as hedge transactions under SFAS No. 133, as amended.

During the year ended December 31, 2007, we had gains on derivative contracts of $888,222, which consisted of $3,895,138 in realized gains on derivative contracts offset by $3,006,916 in unrealized losses on derivative contracts. During the year ended December 31, 2006, we had gains on derivative contracts of $17,995,268, which consisted of $1,118,043 in realized gains on derivative contracts and $16,877,225 in unrealized gains on derivative contracts. During the year ended December 31, 2005, we had losses on derivative contracts of $19,532,212, which consisted of $7,473,004 in realized losses on derivative contracts and $12,059,208 in unrealized losses on derivative contracts.

At December 31, 2007 and at December 31, 2006, the fair values of open natural gas contracts were assets of approximately $2.3 million and $5.3 million, respectively.

At December 31, 2007, the Company had the following natural gas collar positions:

Period	Volume (MMBtu)	Sold Ceiling	Bought Floor	Sold Floor
Collars (3 way)				
January 2008—March 2008	728,000	$14.80	$9.00	$6.00
Summer 2008	1,712,000	$10.50	$7.00	$5.00
Winter 2008/2009	906,000	$11.00	$8.50	$6.25
Summer 2009	1,284,000	$10.00	$7.50	$5.25
Traditional Collars				
January 2008—March 2008	364,000	$11.25	$8.25	

At December 31, 2007, we had the following natural gas swap position:

Period	Volume in MMBtu's	Price
Summer 2008	856,000	$8.00

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 SFAS No. 133. 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 in accumulated 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. A summary of the impacts of our cash flow hedges included in other comprehensive income, net of tax, as of December 31, 2007 follows:

Description	Effective date	Designated maturity date	Fixed rate	Notional amount	Other comprehensive income, net of tax
Floating-to-fixed swap	12/14/2007	12/14/2010	3.86%(1)	$15,000,000	10,884

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

For the years ended December 31, 2007, we recognized no ineffective portion of our cash flow hedges. On January 3, 2008, the Company entered an interest rate swap at an interest rate of 3.95% and a notional amount of $10,000,000 maturing January 4, 2010.

Note 9—Long-Term Debt

We initially entered into a revolving credit facility in December 2001. In January 2006, we amended and restated the revolving credit facility and, among other things, extended the maturity date to January 6, 2011. In June 2006, the revolving credit facility was amended and restated and increased to $180 million and the borrowing base was increased to $150 million. Pursuant to the amended credit agreement, we have a $180 million revolving credit facility that permits us to borrow amounts from time to time based on the available borrowing base as determined in the credit agreement. The revolving credit facility is secured by substantially all of our gas properties and the capital stock of our subsidiaries. The borrowing base under the revolving credit facility is based upon the valuation of our gas properties as of June 30 and December 31 of each year and other factors deemed relevant by the lenders, including Bank of America as agent. The lenders may also request one additional borrowing base re-determination in any fiscal year.

As of December 31, 2007, we had $96 million of borrowings outstanding under our revolving credit facility, resulting in a borrowing availability of $84 million under our $180 million borrowing base. For the year ended December 31, 2007 we borrowed $83 million and made payments of $47 million under the revolving credit facility. As of December 31, 2007 the outstanding balances on the revolving credit facility bear interest at either the bank's adjusted base rate, which is the bank's base rate of at least the Federal Funds Rate plus 0.5%, or the adjusted LIBOR rate, plus a margin of 1.00% to 2.00%, based on borrowing base usage. The rate at December 31, 2007 was 6.29%.

The following is a summary of our long-term debt at December 31, 2007 and 2006:

	December 31, 2007	December 31, 2006
Borrowings under revolving credit facility	$96,000,000	$60,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	174,570	210,227
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	129,240	138,308
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	528,498	577,752
Total debt	96,832,308	60,926,287
Less current maturities included in current liabilities	(102,586)	(94,177)
Total long-term debt	$96,729,722	$60,832,110

We are subject to certain restrictive financial and non-financial covenants under the credit agreement, including a minimum current ratio of 1.0 to 1.0, and a maximum rate of EBITDA to interest expense of 2.75 to 1.0, both as defined in the credit agreement. As of December 31, 2007, we were in compliance with all of the covenants in the credit agreement.

On October 26, 2007, the lenders, including Bank of America as agent, completed our mid-year borrowing base determination and established a borrowing base of $180 million.

The following were maturities of long-term debt for each of the next five years at December 31, 2007:

Year	Amount
2008	102,586
2009	111,768
2010	121,792
2011	96,132,743
2012	363,419
Thereafter	—
Total Debt	$96,832,308

The total fair value of the two notes payable and the salary continuation payable as of December 31, 2007 was approximately $710,043 million. The borrowing under the revolving credit facility approximates fair value because the interest rates are floating or market rates.

Note 10—Discontinued Operations

We marketed substantially all of our gas through Shamrock Energy LLC, which became a wholly owned subsidiary on January 1, 2007, under a natural gas purchase agreement. We discontinued operations of Shamrock Energy, LLC in September 2007. The purchase agreement called for Shamrock to purchase and us to sell gas produced from all of our major properties. In addition, Shamrock provided several related services including nominations, gas control, gas balancing, transportation and exchange, market and transportation intelligence and other advisory and agency services. We received the weighted average resale price for the gas sold, less a fee for Shamrock's services ranging from $0.03 to $0.045 per MMBtu purchased.

On June 14, 2006, we entered into an option agreement with Jon M. Gipson, the president of Shamrock, pursuant to which we had the right to acquire all of the outstanding equity interests and assets of Shamrock. In exchange for this option, we agreed (i) to extend our gas marketing agreement with Shamrock for a term ending no earlier than January 31, 2007, the termination date of the Shamrock purchase option (ii) to advance, on or before August 1, 2006, $90,000 to Shamrock for working capital purposes during the option period, (iii) to provide any guaranties on behalf of Shamrock for transactions that Shamrock entered into during the option period that require such guaranties, up to an aggregate of $1,500,000, and (iv) to advance Shamrock up to an additional $50,000 to Shamrock as may be required to cover certain expenses of Shamrock prior to January 31, 2007.

We exercised the Shamrock purchase option on January 1, 2007, at which time we provided Mr. Gipson an at-will employment position with us. Also, on March 9, 2007, we caused Shamrock to distribute to Mr. Gipson approximately $22,500, which equals 50% of the net profits generated by Shamrock from August 1, 2006 through January 1, 2007. This amount was accrued at December 31, 2006 as a dividend payable to Mr. Gipson. No additional consideration was paid as a result of our exercise of this option.

As a result of exiting the third-party marketing business, we are treating these activities as a discontinued operation for all the periods presented. Results for activities reported as discontinued operations were as follows:

Statement of Operations Data (for the year ended December 31):

	2007	2006
Gas marketing revenues	$ 21,873,248	$ 13,043,598
Purchased gas expense	(21,595,540)	(12,898,973)
General and administrative expense	—	(254,086)
Elimination of intercompany profit	—	146,151
Income from discontinued operations before tax	277,708	36,690
Income tax expense	(103,926)	(14,155)
Minority interest	—	(22,535)
Income from discontinued operations	$ 173,782	$ —

Balance Sheet Data:

	December 31, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$175,398	$ 190,765
Accounts receivable	15,530	9,060,488
Other	14,945	15,172
Total assets	205,873	9,266,425
Current Liabilities:		
Accounts payable	86,510	9,266,425
Stockholder's equity	119,363	—
Total liabilities and stockholder's equity	$205,873	$9,266,425

Note 11—Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB Statement No. 109, *Accounting for Income Taxes,* as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). This results in the recognition of deferred tax assets and liabilities using estimated effective tax rates for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities using enacted tax rates at the end of the period. Under FASB No. 109, 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. 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 Section 382 of the Internal Revenue Code. We have a significant deferred tax asset associated with net operating loss carryforwards (NOL's). It is more likely than not that we will use the NOL's in the United States to offset current tax liabilities in future years.

Our effective tax rate differs from the federal statutory rate primarily due to losses in Canada that we are unable to benefit from and state income taxes. The Canadian losses are fully reserved because it is more likely than not that we will not use those NOL's to offset current tax liabilities in future years.

Uncertain Tax Positions

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we identified $269,900 of unrecognized tax benefits, largely related to depletion methods used in years prior to 2006 from net deferred tax assets. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48 principally due to the size of our NOL's. The amount of unrecognized tax benefits did not materially change as of December 31, 2007. A reconciliation of beginning and ending amounts of unrecognized tax benefits is as follows:

Balance at January 1, 2007	$269,900
Additions based on tax positions related to the current year	—
Additions for tax positions of prior years	2,700
Reductions for tax positions of prior years	—
Settlements	—
Balance at December 31, 2007	$272,600

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 United States 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.

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. As of the date of adoption of FIN 48, we did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the year ended December 31, 2007.

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, 2008.

An analysis of our deferred taxes follows:

	2007	2006
Current deferred tax asset:		
Compensation expense and other	$ 83,616	$ 68,325
Tax basis in excess of book basis of derivative contracts	—	—
Total current deferred tax asset	83,616	68,325
Current deferred tax liability:		
Book basis in excess of tax basis of derivative contracts	(854,291)	(1,639,009)
Net current deferred tax liability	$ (770,675)	$ (1,570,684)
Long-term deferred tax asset:		
Net operating loss carryforward	28,972,421	25,262,553
Compensation expense and other	240,158	276,364
Accrued asset retirement obligations	966,442	915,470
Alternative minimum tax credit carryforward	115,907	115,907
Total long-term deferred tax assets	30,294,928	26,570,294
Long-term deferred tax liabilities:		
Book basis in excess of tax basis of derivative contracts	(34,543)	(398,467)
Book basis of gas properties in excess of tax basis	(76,906,264)	(68,951,364)
Total long-term deferred tax liabilities	(76,940,807)	(69,349,831)
Net long-term deferred tax liability	$(46,645,879)	$(42,779,537)

For tax reporting purposes, we have a federal and state net operating loss carryforward of approximately $74.2 million and $5.3 million, respectively, at December 31, 2007 that are available to reduce future taxable income. If not utilized, the federal carryforwards would begin to expire in 2022. Certain immaterial portions of the state NOL carryforward will expire prior to 2022. During 2007 and 2006, we generated a net operating loss in Canada in the amount of $296,722 and $204,550, respectively, and it is more likely than not that this net operating loss will not be available to reduce future taxable income. Accordingly, a full valuation allowance has been provided in the current year to reflect no tax asset realization.

Federal income tax expense (benefit) from continuing operations for each of the years ended December 31, 2007, 2006, and 2005 was different than the amount computed using the Federal statutory rate for the following reasons:

	2007	%	2006	%	2005	%
Amount computed using statutory rates	$2,714,167	34.00%	$ 9,575,022	34.0%	$(1,022,988)	(34.0)%
State income taxes—net of federal benefit	(84,618)	(1.06)%	980,032	3.48%	16,500	0.6%
Valuation Allowance	296,722	3.72%	204,550	0.73%	—	—
Nondeductible items and other	61,136	0.77%	106,010	0.38%	13,314	0.4%
Income tax provision (benefit)	$2,987,407	37.42%	$10,865,614	38.58%	$ (993,174)	(33.0)%

The following components of the federal income tax expense (benefit) for the years ended December 31, 2007, 2006 and 2005 are as follows:

	Years Ended December 31,		
	2007	2006	2005
Current:			
State	$ 25,000	$ 142,238	$ 25,000
Federal	—	—	(33,772)
Deferred:			
State	(109,618)	837,794	—
Federal	3,072,025	9,885,582	(984,402)
Income tax provision (benefit)	$2,987,407	$10,865,614	$(993,174)

Note 12—Common Stock

At December 31, 2007 and 2006, there were 38,962,359 shares and 38,678,713 shares, respectively, of common stock outstanding. Effective January 24, 2006, our board of directors approved a four-for-one common stock split and increased our authorized capital stock from 40,000,000 shares of common stock at December 31, 2005 to 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock and 10,000,000 shares of preferred stock. Prior periods have been adjusted for the stock split.

For the years ended December 31, 2007 and 2006, a total of 105,565 shares and 637,026 shares, respectively, of common stock were issued upon the exercise of stock options.

On January 30, 2006 and February 7, 2006, we completed private equity offerings of an aggregate 10,250,000 shares of our common stock, consisting of 2,317,023 shares issued by us and 7,932,977 shares sold by certain of our existing stockholders, to qualified institutional buyers exempt from registration under the Securities Act. We received aggregate consideration of approximately $28.0 million, or $12.09 per share. We did not receive any proceeds from the shares sold by certain of our existing stockholders. In addition, we received approximately $17.5 million from certain of the selling stockholders for repayment of loans from us, including accrued and unpaid interest thereon. We used the net proceeds from this private equity offering, together with the proceeds from the repayment of certain of the selling stockholders' loans, to repay a portion of the borrowings under our revolving credit facility and for general corporate purposes.

On July 27, 2006, we registered for re-sale with the SEC the 10,250,000 shares of common stock issued in the private equity offering discussed above. Also on July 27, 2006, we sold 5,750,000 shares of our common stock under an underwritten initial public offering. Our initial public offering closed on August 2, 2006, and the price per share was $10.00. We received net proceeds of approximately $52.6 million from our initial public offering, after deducting estimated offering expenses and underwriting discounts and commissions. We used the net proceeds from the initial public offering to reduce outstanding borrowings under our revolving credit facility.

During 2005, we issued 4,438,768 shares of our common stock valued at $7.64 per share for the minority interest in our majority-owned subsidiary's common stock. In connection with this acquisition We issued to each minority interest owner and holder of incentive stock options of the majority-owned subsidiary an option to purchase our common stock at the per share exchange value of $7.64 (the "non-dilution option"). Within 30 days of issuance, the holder of the non-dilution option could exercise the option to purchase, with cash and/or loan from us, up to the amount of our common stock necessary to prevent any dilution that resulted from the merger. The 2005 notes issued to purchase any stock are secured by the stock, with full recourse, earn interest at an annual rate of 6% and mature on the earlier of April 14, 2009, sixty days after the holder ceases to be an employee or the occurrence of a "Triggering Transaction" as defined in the non-dilution option agreement. Non-dilution options were exercised to purchase 1,456,668 shares of GeoMet common stock. The purchases were financed with $10,905,144 in notes and $227,380 in cash. The notes receivable, including accrued interest, is shown as a reduction of stockholders' equity, and approximately $10,500,000 of these notes were repaid in full with interest in January 2006.

Note 13—Share-Based Awards

Prior to January 1, 2006, stock-based employee compensation was accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25, *Accounting for Stock Issued to Employees* ("APB 25"). The exercise price of the options granted was equal to the estimated market value of our common stock at grant date, and therefore, no compensation costs have been recognized. We used the income method on a semi-annual basis to estimate the market value of our common stock at grant date.

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123R, *Share-Based Payment*, using the prospective transition method. 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.

As of December 31, 2007, we have two stock-based award plans authorized, our 2005 Stock Option Plan and our 2006 Long-Term Incentive Plan. However, no additional awards under our 2005 Stock Option Plan will be granted after the adoption of the 2006 Long-Term Incentive Plan, but we will continue to issue shares of our common stock upon exercise of awards that were previously granted under the 2005 Stock Option Plan.

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 2,000,000 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 interest of our employees and directors interests with the interests of our stockholders, and to closely link compensation with our performance. Generally, the exercise price of a stock option 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, vest evenly over three years, except for awards that are performance based and options issued to directors. Performance based awards granted under the 2006 Long-Term Incentive Plan vest once the performance criterion has been met. Options issued to our directors vest immediately.

In March 2007, we granted 168,975 share-based stock option awards and in June 2007 we granted 138,000 restricted stock awards to certain of our non-executive employees with time vesting criteria. In September 2007 we granted 219,279 share-based stock option awards and we also granted 30,145 restricted stock awards, including 20,145 with performance-based vesting to our four named executive officers and two other officers. In November 2007 we granted 19,841 incentive stock options, 20,000 restricted stock awards and 40,159 non-qualified stock options to an officer that vest on March 15, 2010. During 2007, we recorded a compensation expense accrual of $526,576 which was allocated among lease operating expenses ($118,830), general and administrative expenses ($118,830), and capitalized to unevaluated gas properties ($215,093). The future compensation cost of all the outstanding awards is $2,170,448 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 2.5 years.

Significant assumptions used in determining the compensation costs included a dividend yield of 0%, expected volatility of 40.20%, risk-free interest rate of 4.02%, an expected term of 4.5 years, and a forfeiture rate of 10%. The forfeiture rate was changed to 10% in the second quarter.

Incentive Stock Options

The table below summarizes incentive stock option activity for the year ended December 31, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	572,838	$ 6.32		
Granted	329,216	$ 7.75		
Forfeited	(71,988)	$ 9.05		
Incentive stock options converted to non-qualified stock options	(42,224)	$13.00		
Exercised	(105,565)	$ 2.13		
Outstanding at December 31, 2007	682,277	$ 6.77	4.61	$610,027
Options exercisable at December 31, 2007	299,763	$ 4.79	2.80	$602,933

The weighted average grant-date fair value of incentive stock options granted during the years 2007, 2006, and 2005 was $2.32, $4.85, and $0.60, respectively. The total intrinsic value of incentive stock options exercised during the years ended December 31, 2007, 2006, and 2005 was $0.5 million, $5.2 million, and $0.6 million, respectively.

Non-Qualified Stock Options

The table below summarizes non-qualified stock option activity for the year ended December 31, 2007:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2006	1,113,865	$ 3.20		
Granted	154,966	$ 7.46		
Forfeited	—			
Incentive stock options converted to non-qualified stock options	42,224	$13.00		
Exercised	—			
Outstanding at December 31, 2007	1,311,055	$ 4.02	5.36	$2,814,000
Options exercisable at December 31	1,070,376	$ 2.80	5.22	$2,814,000

During the year ended December 31, 2007, no non-qualified stock options were exercised The weighted average grant-date fair value of non-qualified stock options granted during the years 2007 and 2006 was $1.18 and $4.96, respectively. There were no non-qualified stock options granted in 2005. The total intrinsic value of non-qualified stock options exercised during the year ended December 31, 2006 was $1.7 million. There were no non-qualified stock options exercised or forfeited in 2007 or 2005.

Restricted Stock Awards

The table below summarizes non-vested restricted stock awards activity for the year ended December 31, 2007:

	Non-Vested Restricted Stock Awards	Weighted Average Value At Grant Date
Non-vested restricted stock at December 31, 2006	21,436	8.61
Granted	188,145	7.21
Forfeited	(31,500)	8.05
Vested	(4,083)	8.05
Non-vested restricted stock at December 31, 2007	173,998	7.21

In April 2006, we granted 12,249 performance based restricted stock awards to our four named executive officers and two other officers. The restricted stock awards are subject to performance-based vesting for our four named executive officers and two other officers and time-based vesting for all other employees. The restricted stock awards will vest as a result of a triggering event such as a corporate change of control or merger. The fair value of the restricted stock awards at December 31, 2007 is approximately $926,021. In June 2007, we granted 138,000 restricted stock awards to non-executive employees. In September 2007 we granted 30,145 restricted stock awards, including 20,145 to our four named executive officers and two other officers. In November 2007 we granted 20,000 restricted stock awards to an officer. No restricted stock awards vested in 2006 or 2005.

Prior to July 27, 2006, before we became a public company, there was no active public market for our common stock. Therefore, our compensation committee established the fair value of our common stock for incentive stock option awards based on the recommendation of senior management using the best information available on the date of grant. We used the income method except when there was other, more conclusive evidence of fair value, such as a recent arms-length event or transaction involving the acquisition or exchange of our common stock. Determining the fair value of our common stock required making complex and subjective judgments regarding a number of variables and data points. We used the income method in lieu of other acceptable methods because the income method applies cash flow modeling and assumptions similar to those used in determining the PV-10 of our proved gas reserves. We did not obtain a contemporaneous valuation by an unrelated valuation specialist for the options granted during 2005 because we believed that both our senior management and the management of our majority stockholder had adequate expertise and experience in valuing gas properties and entities with gas exploration, production, and development activities. We believe our methodology and valuations represented the estimated fair value of our common stock at that time.

Information on stock option grants during the year ended December 31, 2005 is summarized as follows:

Date of Issuance	Type of equity issuance	Number of options granted	Exercise price	Fair market value estimate per common share	Intrinsic value per share
January 24, 2005	Employee Options	65,244	$6.98	$6.98	$—
June 1, 2005	Employee Options	88,000	$7.64	$7.64	$—

The following table illustrates the approximate pro forma effect on net income and earnings per share assuming the stock-based compensation expense under APB 25 had been recorded using fair value methods at date of grant for the following prior periods:

	2005
Net (loss) income as reported	$(1,573,281)
Less: Total stock-based employee compensation expense determined under fair value based methods for all grants, net of related tax effects	61,178
Pro forma	$(1,634,459)

Note 14—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 50 percent of total contributions up to a total of six percent of their annual compensation. Our matching contribution vests evenly over three years. Our contribution to the Plan for the years ended December 31, 2007, 2006 and 2005 was $170,062, $137,357, and $122,286, respectively.

Note 15—Commitments and Contingencies

Litigation—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.

CNX Surface Use Dispute

We constructed a 12-mile gathering line in the Pond Creek field, a portion of which traverses a right-of-way granted to us by Pocahontas Mining Limited Liability Company ("PMC"). The Pond Creek gathering line connects with and transports our gas production from the Pond Creek field to the Jewell Ridge Pipeline. CNX Gas Company LLC ("CNX"), the lessee of certain minerals underlying the PMC property, has claimed that it has the exclusive right to transport gas across the PMC property and that our right-of-way is invalid. We, along with PMC, filed a complaint in the Circuit Court of Buchanan County, Virginia on May 26, 2006 against CNX seeking a temporary and permanent injunction, as well as a declaration of our rights under the right-of-way agreement that we entered into with PMC. On June 30, 2006, CNX filed a counterclaim against PMC and us seeking a declaratory judgment from the court that CNX has superior rights to our rights to the surface of the PMC property and that CNX has the exclusive right to construct pipelines, transport gas, and use roads on the PMC property. On May 23, 2007, the Circuit Court of Buchanan County, Virginia issued an interlocutory order declaring that the lease between CNX and PMC also included the exclusive right of CNX to transport gas across the PMC property and enjoined us from transporting gas through the Pond Creek gathering line over the PMC property.

On June 20, 2007, the Virginia Supreme Court vacated the injunctive portion of the order, allowing us to continue to transport gas through our Pond Creek gathering line. Also vacated was the portion of the decision that obligated us to deposit into a trust account all net proceeds from any sales of gas transported over the PMC property. On November 5, 2007, the Virginia Supreme Court accepted PMC's and our petition for appeal of the remaining portion of the May 23rd order, which held that CNX has the exclusive right to build a pipeline and transport gas across the PMC property. We believe that our right-of-way agreement across the PMC property is valid and enforceable and that we will ultimately prevail in this case.

On January 19, 2007, CNX obtained a temporary injunction against our construction of the same 12-mile pipeline across 1,450 feet of a 32-acre tract in Tazewell County, Virginia. The tract of land in dispute has been owned by a large number of extended family members, from whom we have obtained approximately 81% control of the tract, either through purchases of undivided surface interests in the tract or by entering into surface use and right-of-way easement agreements. During our pipeline construction process, CNX purchased a minority undivided surface interest in the property and filed a lawsuit seeking to enjoin the construction of our Pond Creek gathering line across the tract. On February 16, 2007, the Virginia Supreme Court vacated the temporary injunction, which allowed us to complete construction of our Pond Creek gathering line across the 32-acre tract. Both we and CNX have filed complaints to partition the 32-acre tract, and we believe that we will obtain full ownership of the portion of the tract that our Pond Creek gathering line traverses.

Our Pond Creek gathering line is connected to the Jewell Ridge Pipeline and is fully operational. In the event we are unsuccessful in obtaining favorable judgments in the CNX surface disputes, we may be required to seek an alternative way to transport our gas to market. If such an alternative is unavailable, we may be unable to deliver our gas from the Pond Creek field to market for an extended period of time.

CNX Antitrust Action

We filed a complaint against CNX and Island Creek Coal Company ("Island Creek"), an affiliate of CNX, in the Circuit Court of Tazewell County, Virginia on February 14, 2007, seeking damages arising from alleged violations of the Virginia Antitrust Act, tortious interference with contractual relations with third parties and statutory and common law conspiracy. The suit seeks $561 million for compensatory and consequential damages for alleged violations of the Virginia Antitrust Act, including alleged anticompetitive efforts of CNX to dominate and maintain its control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in Buchanan County, Virginia and for CNX's alleged efforts to conspire and act in concert with Island Creek and others to dominate and maintain control over the market for the production and transportation of coalbed methane gas from the Oakwood Field in violation of the Virginia Antitrust Act and Virginia statutory and common law. The suit also alleges CNX's intentional interference with our existing and prospective third-party business relationships in efforts to harm us and improve CNX's position and corporate and financial interests. We seek to have any damages awarded for alleged violations of the Virginia Antitrust Act tripled under Virginia statutes permitting a court to award treble damages, as well as injunctive relief to prevent CNX and other parties from continuing these alleged anticompetitive activities. In accordance with an opinion issued by the Tazewell Circuit Court in December 2007, we are preparing to file an amended petition which will re-state our claims against CNX and Island Creek with specificity.

As of December 31, 2007, 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 2012. Future minimum lease commitments as of December 31, 2007 under non-cancelable operating leases having remaining terms in excess of one year are as follows:

Year Ended December 31,	Amount
2008	$1,629,301
2009	1,420,895
2010	1,293,887
2011	1,293,887
2012	605,346
Thereafter	476,684
Total future minimum lease commitments	$6,720,000

Total rental expenses under operating leases were approximately $1,542,660, $1,591,027, and $1,048,083 for the years ended December 31, 2007, 2006 and 2005, respectively.

Transportation Contracts—In 2004 and 2005, we entered into firm transportation contracts with a pipeline. As of December 31, 2007 under the contracts we can transport maximum daily volumes of 17,000 dth's continuing until October 31, 2010. Beginning November 1, 2010, unless the annual contract is extended, the maximum decreases to 10,000 continuing until October 31, 2011."). We have a right to extend each of these contracts, in five-year increments, at the maximum tariff rate. In January 2007, we entered into two firm transportation contracts with a pipeline which became effective when our pipeline went in service on April 1, 2007, with total maximum daily quantities of 15,000 dth and 10,000 dth and primary terms of 15 years and 10 years, respectively. As of December 31, 2007, the maximum commitment remaining under the transportation contracts is approximately $19.9 million.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION ON GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

This supplemental schedule provides unaudited information pursuant to SFAS No. 69, *Disclosures About Oil and Natural Gas Producing Activities*, ("SFAS 69") and certain other information.

Capitalized Costs—Capitalized costs and accumulated depreciation, depletion and amortization relating to our gas producing activities, all of which are conducted within the continental United States and Canada, at December 31, 2007, 2006 and 2005 are summarized below.

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, 2007, 2006 and 2005, these capitalized costs amounted to $1,991,760, $1,174,148, and $1,777,566, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. Capitalized costs in 2007 include a $3.0 million purchase price adjustment for a 2004 acquisition. For the years ended December 31, 2007, 2006 and 2005, interest costs of $587,884, $1,037,576, and $714,070, respectively, were capitalized.

	For the Years Ended December 31,		
	2007	2006	2005
Unevaluated properties—United States	$ 6,651,594	$ 13,680,374	$ 14,789,928
Unevaluated properties—Canada	18,523,170	12,717,608	5,890,784
Properties subject to amortization—United States	370,404,336	310,011,154	229,519,222
Capitalized costs—consolidated	395,579,100	336,409,136	250,199,934
Accumulated depreciation, depletion and amortization—United States	(30,661,248)	(21,836,904)	(14,455,583)
Net capitalized costs—consolidated	$364,917,852	$314,572,232	$235,744,351
Net capitalized costs—Canada	$ 18,523,170	$ 12,717,608	$ 5,890,784
Net capitalized costs—United States	343,394,682	301,854,624	229,853,567
Net capitalized costs—consolidated	$364,917,852	$314,572,232	$235,744,351

Capitalized Costs Incurred

The following table discloses costs incurred in gas property acquisition, exploration and development activities for the years ended December 31, 2007, 2006 and 2005.

	For the Years Ended December 31,		
	2007	2006	2005
Acquisition costs:			
Proved	$ 3,827,641	$ 428,729	$ 540,767
Unproved	4,883,982	9,113,502	1,242,621
Exploration costs	1,937,858	2,559,745	5,621,775
Development costs	42,561,606	62,654,438	47,414,118
Total costs incurred—United States	53,211,087	74,756,414	54,819,281
Acquisition costs-unproved—Canada	435,133	1,717,097	—
Exploration costs incurred—Canada	5,523,744	5,119,289	4,876,703
Total costs incurred—Canada	5,958,877	6,836,386	4,876,703
Total costs incurred—consolidated	$59,169,964	$81,592,800	$59,695,984

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 United States. Reserve estimates for natural gas contained below were prepared by DeGolyer and MacNaughton, 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.

	2007	2006	2005
Natural Gas Reserves (Mcf)			
Proved reserves at beginning of year	325,663,000	262,512,000	209,852,000
Revisions of previous estimates	(15,343,000)	28,417,000	(5,152,000)
Extensions and discoveries	46,982,000	39,138,000	62,406,000
Acquisition	—	1,824,000	—
Disposition	—	—	—
Production	(7,126,000)	(6,228,000)	(4,594,000)
Proved reserves at end of year	350,176,000	325,663,000	262,512,000
Proved developed reserves at beginning of year	242,918,000	195,139,000	160,935,000
Proved developed reserves at end of year	238,023,000	242,918,000	195,139,000

The following table presents the standardized measure of future net cash flows related to proved gas reserves in accordance with SFAS No. 69. All components of the standardized measure are from proved reserves, all of which are located entirely within the continental United States. As prescribed by this statement, the amounts shown are based on prices and costs at December 31, 2007, 2006 and 2005, 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.

Standardized Measure	2007	2006	2005
Future cash inflows	$2,654,214,000	$1,858,104,000	$2,536,279,000
Future production costs	(725,272,000)	(501,955,000)	(463,416,000)
Future development costs	(106,356,000)	(101,777,000)	(76,297,000)
Future income taxes	(602,319,000)	(410,391,000)	(579,689,000)
Future net cash flows	1,220,267,000	843,981,000	1,416,877,000
10% annual discount to reflect timing of cash flows	(724,399,000)	(484,494,000)	(784,212,000)
Standardized measure of discounted future net cash flows	$ 495,868,000	$ 359,487,000	$ 632,665,000

Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2007, 2006 and 2005 are summarized below:

Changes in Standardized Measure	2007	2006	2005
Standardized measure at beginning of year	$ 359,487,000	$ 632,665,000	$ 349,755,000
Sales and transfers of oil and gas produced—net of production cost	(29,340,000)	(27,705,000)	(28,952,000)
Net changes in prices and production cost	248,627,000	(412,865,000)	276,690,000
Extensions and discoveries	58,936,000	63,721,000	197,336,000
Acquisition/disposition (net)	—	1,278,000	—
Net change in development cost	(43,181,000)	(4,187,000)	(31,196,000)
Revision of previous quantity estimates	(35,222,000)	49,362,000	(17,705,000)
Accretion of discount before income taxes	52,563,000	88,015,000	48,182,000
Net change in income taxes	(8,678,000)	81,343,000	(115,420,000)
Changes in production rates (timing) and other	(107,324,000)	(112,140,000)	(46,025,000)
Subtotal net change	136,381,000	(273,178,000)	282,910,000
Standardized measure at end of year	$ 495,868,000	$ 359,487,000	$ 632,665,000

The weighted average prices of gas used with the above tables at December 31, 2007, 2006 and 2005 were $7.58, $5.63, and $9.66 per Mcf, respectively.

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, 2007 and 2006 (in thousands):

	Quarter Ended			
	Mar. 31	Jun. 30	Sept. 30	Dec. 31,
Fiscal Year 2007:				
Total revenues	$12,140	$13,763	$11,644	$13,437
Operating income from continuing operations	$ (702)	$ 6,085	$ 3,465	$ 4,284
Net income (loss)	$(1,025)	$ 2,998	$ 1,588	$ 1,608
Net income (loss) per share				
Basic	$ (.03)	$ .08	$ .04	$ .04
Diluted	$ (.03)	$ .08	$ .04	$ .04
Fiscal Year 2006:				
Total revenues	$12,311	$10,140	$10,968	$11,528
Operating income from continuing operations	$13,680	$ 4,614	$ 7,706	$ 5,268
Net income	$ 7,163	$ 2,291	$ 4,228	$ 3,614
Net income per share				
Basic	$ 0.23	$ 0.07	$ 0.11	$ 0.09
Diluted	$ 0.22	$ 0.07	$ 0.11	$ 0.09

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

None.

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

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

Under the supervision and with the participation of management , we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2007, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance 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 year ended December 31, 2007 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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, our management has conducted an assessment, including testing, using the criteria in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the 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.

Based on the assessment, our management has concluded that we maintained effective internal control over financial reporting as of December 31, 2007, based on criteria in Internal Control-Integrated Framework issued by COSO.

Our management, including our chief executive officer and chief financial officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected.

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

None.

PART III

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007. Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2007.

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	Form of 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	Form Amended and Restated Bylaws of GeoMet, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company's 8-K filed on November 13, 2007 (Registration No. 000-52155)).
4.1	Registration Rights Agreement between GeoMet, Inc. and Banc of America Securities LLC, dated as of January 30, 2006 (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.1	Agreement and Plan of Merger between GeoMet Resources Inc. and GeoMet Inc., dated as of March 31, 2005 (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.2	2005 Stock Option Plan of GeoMet Inc., dated April 15, 2005 (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.3	Form of Incentive Stock Option Agreement for the 2005 Stock Option Plan of GeoMet, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).

Exhibit No.	Description
10.4	Federal Income Tax Allocation Agreement among the Members of the GeoMet Resources, Inc. Consolidated Group, dated as of January 1, 2001 (incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.5	Incentive Bonus Pool Plan, dated as of May 29, 2001 (incorporated herein by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.6	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.7	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1 filed on February 10, 2006 (Registration No. 333-134070)).
10.8	Third Amended and Restated Credit Agreement dated June 9, 2006, among GeoMet, Inc., Bank of America, N.A., as Administrative Agent, and BNP Parisbas, as Syndication Agent (incorporated herein by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 filed on June 21, 2006 (Registration No. 333-131716)).
10.9	GeoMet, Inc. 2006 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)).
10.10	Precedent Agreement dated March 28, 2006 between East Tennessee Natural Gas, LLC and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on May 12, 2006 (Registration No. 333-131716)) (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment in accordance with Rule 406 under the Securities Act).
10.11	Option Agreement dated June 13, 2006 between Jon M. Gipson and GeoMet, Inc. (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on June 21, 2006 (Registration No. 333-131716)).
10.12	Amendment No. 1 to 2006 Long-Term Incentive Plan dated effective as of March 13, 2007 (incorporated herein by reference to Exhibit 10.12 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.13	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and J. Darby Seré (incorporated herein by reference to Exhibit 10.13 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.14	Amendment to Employment Agreement dated March 13, 2007 between GeoMet, Inc. and William C. Rankin (incorporated herein by reference to Exhibit 10.14 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.15	GeoMet, Inc. Executive Officer Severance Plan dated March 13, 2006 (incorporated herein by reference to Exhibit 10.15 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.16	GeoMet, Inc. Severance Plan dated March 13, 2006 (incorporated herein by reference to Exhibit 10.16 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
10.17	Form of GeoMet, Inc. Retention Bonus Agreement (incorporated herein by reference to Exhibit 10.17 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).

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10.18	Stock Acquisition and Stockholders Agreement dated December 7, 2000 by and among GeoMet Resources, Inc., Yorktown Energy Partners IV, L.P., J. Darby Seré, and William C. Rankin (incorporated by reference to Exhibit 4.3 of the Company's Registration Statement on Form S-8, File No. 333-136924 filed on August 28, 2006).
14.1	Corporate Code of Business Conduct and Ethics (incorporated herein by reference to Exhibit 14.1 to the Company's 10-K filed on March 20, 2007 (Registration No. 000-52155)).
21.1*	List of Subsidiaries of GeoMet, Inc.
23.1*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 14, 2008.

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 March 14, 2008.

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

INDEX TO EXHIBITS

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32*	Certification pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

EXHIBIT 21.1

List of GeoMet, Inc. Subsidiaries

GeoMet Operating Company, Inc. (Parent)

Hudson's Hope Gas, Ltd. (Wholly-Owned)

GeoMet Gathering Company, LLC (Wholly-Owned)

GeoMet Gathering Virginia, Inc. (Wholly-Owned)

Shamrock Energy LLC (Wholly-Owned effective January 1, 2007)

Exhibit 23.1

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

CONSENT of INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to DeGolyer and MacNaughton, to the incorporation of information contained in our "Appraisal Report as of December 31, 2003 on Certain Properties Owned by Geomet, Inc.," "Appraisal Report as of December 31, 2004 on Certain Properties Owned by Geomet, Inc.," "Appraisal Report as of December 31, 2005 on Certain Properties Owned by Geomet, Inc.," "Appraisal Report on Proved Reserves as of December 31, 2006 on Certain Properties Owned by Geomet, Inc.," and "Appraisal Report on Proved Reserves as of December 31, 2007 on Certain Properties owned by Geomet, Inc." (our Reports), and to references to our Reports in "Part I, Item 2, Properties," "Part II, Item 6, Selected Financial Data," "Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Part II, Item 8, Financial Statements and Supplementary Data" in the Annual Report on Form 10–K of Geomet, Inc. for the year ended December 31, 2007.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON

Dallas, Texas
March 13, 2008

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William C. Rankin, certify that

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2007 of GeoMet, Inc. ("registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 14, 2008

By /s/ WILLIAM C. RANKIN

William C. Rankin,
Chief Financial Officer

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, J. Darby Seré, certify that

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2007 of GeoMet, Inc. ("registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 14, 2008

By /s/ J. DARBY SERÉ

J. Darby Seré,
Chief Executive Officer

Exhibit 32

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of GeoMet, Inc. (the "Company") for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. Darby Seré, Chief Executive Officer, and I, William C. Rankin, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. DARBY SERÉ	/s/ WILLIAM C. RANKIN
J. Darby Seré	**William C. Rankin**
Chief Executive Officer	**Chief Financial Officer**
March 14, 2008	**March 14, 2008**

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CORPORATE HEADQUARTERS
909 Fannin, Suite 1850
Houston, Texas 77010
(713) 659-3855

TECHNICAL HEADQUARTERS
5336 Stadium Trace Parkway, Suite 206
Birmingham, Alabama 35244
(205) 425-3855

ANNUAL MEETING

The 2008 Annual Meeting of Stockholders will be held on May 9, 2008, at 10:00 a.m., local time, in the Governor's Room at the Houston Center Club, located at 1100 Caroline Street, 1st City Tower Parking Building, 11th Floor, Houston, Texas 77002.

STOCK EXCHANGE LISTING

GeoMet's common stock trades on the Nasdaq Global Select Market under the symbol GMET.

TRANSFER AGENT & REGISTRAR

For registered shareholders, communication regarding name and address changes, lost certificates, stock transfer requirements and other administrative matters should be directed to:

American Stock Transfer & Trust
Attn: Shareholder Services
59 Maiden Lane
New York, NY 10038
(877) 777-0800
www.amstock.com

ADDITIONAL INVESTOR INFORMATION

Earnings and other financial information, news releases, filings with the Securities and Exchange Commission and other information are available on GeoMet's website at www.geometinc.com.

Shareholders, investment professionals and members of the news media who have questions or need additional information about GeoMet should contact Investor Relations at (713) 287-2251.

INDEPENDENT ACCOUNTANTS
Deloitte & Touche LLP

EXECUTIVE OFFICERS

J. Darby Seré
Chairman, President & Chief Executive Officer

William C. Rankin
Executive Vice President & Chief Financial Officer

Brett S. Camp
Senior Vice President – Operations

Philip G. Malone
Senior Vice President – Exploration

BOARD OF DIRECTORS

J. Darby Seré
Chairman, President & Chief Executive Officer
Executive Committee – Chairman

Philip G. Malone
Senior Vice President – Exploration

J. Hord Armstrong, III
Audit Committee – Chairman & Financial Expert
Nominating, Corporate Governance &
Ethics Committee – Chairman

James C. Crain
Audit Committee
Compensation Committee
Executive Committee

Stanley L. Graves
Audit Committee
Compensation Committee
Nominating, Corporate Governance
& Ethics Committee

Charles D. Haynes
Compensation Committee – Chairman
Nominating, Corporate Governance
& Ethics Committee

W. Howard Keenan, Jr.
Executive Committee

RESERVE DISCLOSURE

The Securities and Exchange Commission ("SEC") permits oil and gas companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. GeoMet and the independent petroleum engineering firm that GeoMet engaged use the term "probable reserves" to describe volumes of reserves potentially recoverable through additional drilling that the SEC's guidelines do not allow to be included in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves. All estimates of probable reserves in this annual report have been prepared by an independent petroleum engineering firm.

FINDING AND DEVELOPMENT COST DISCLOSURE

Finding and development cost is not a measure of performance calculated in accordance with accounting principles generally accepted in the United States of America and, thus, may be calculated differently by different companies; however, we believe that it is useful to GeoMet and to an investor in evaluating our company versus other companies in the industry because it is a widely used measure within the oil and gas industry.

FORWARD-LOOKING STATEMENTS

This annual report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our estimate of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, and the operating hazards attendant to the oil and gas business. In particular, careful consideration should be given to cautionary statements made in the various reports the Company has filed with the SEC. GeoMet undertakes no duty to update or revise these forward-looking statements.

Photography By: **Executives,** Michael Hart; **Location,** Michael Hart and Philip Malone

GeoMet

909 Fannin, Suite 1850
Houston, Texas 77010
www.geometinc.com

END