GeoMet, Inc.
Form S-1
February 10, 2006

As filed with the Securities and Exchange Commission on February 10, 2006

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

GeoMet, Inc.

(Exact name of registrant as specified in its charter)

Delaware	1311	76-0662382
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

J. Darby Seré

President and Chief Executive Officer

GeoMet Inc.

909 Fannin, Suite 3208

Houston, TX 77010

(713) 659-3855

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Dallas Parker

William T. Heller IV

Thompson & Knight LLP

333 Clay Street, Suite 3300

Houston, TX 77002

(713) 654-8111

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement is declared effective.

If any securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, as amended (the Securities Act), check the following box. x

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

CALCULATION OF REGISTRATION FEE

Title of each class of Securities to be registered	Amount to be registered	Proposed maximum offering price per share(1)	Proposed maximum aggregate offering price(1)	Amount of registration fee
Common stock, par value $0.001 per share	10,250,000	$13.00	$133,250,000	$14,258

(1) Estimated solely for the purpose of calculating the registration fee under Rule 457(c) under the Securities Act. No exchange or over-the-counter-market exists for registrant s common stock; however, shares of the registrant s common stock issued to qualified institutional buyers in connection with its January and February 2006 private equity placements are eligible for the PORTAL Market®. There is currently no market price for the shares of the Registrant s common stock; however, the price of the shares issued in both private placements was $13.00 per share.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until this registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and it is not soliciting offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED FEBRUARY 10, 2006

PROSPECTUS

10,250,000 Shares

Common Stock

This prospectus relates to up to 10,250,000 shares of the common stock of GeoMet, Inc., which may be offered and sold, from time to time, by the selling stockholders named in this prospectus. The selling stockholders acquired the shares of common stock offered by this prospectus in private equity placements. We are registering the offer and sale of the shares of common stock to satisfy registration rights we have granted to the selling stockholders.

We are not selling any shares of common stock under this prospectus and will not receive any proceeds from the sale of common stock by the selling stockholders. The shares of common stock to which this prospectus relates may be offered and sold from time to time directly from the selling stockholders or alternatively through the underwriters or broker-dealers or agents. Prior to this offering, there has been no public market for the common stock. The shares of common stock may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale, or at negotiated prices. Please read Plan of Distribution.

We are an independent energy company engaged in the exploration, development and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We intend to list our common stock on The Nasdaq National Market once we meet the eligibility requirements of The Nasdaq National Market.

Investing in our common stock involves risks. You should read the section entitled "Risk Factors" beginning on page 10 for a discussion of certain risk factors that you should consider before buying shares of the common stock.

You should rely only on the information contained in this prospectus or any prospectus supplement or amendment. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted.

Neither the Securities and Exchange Commission (hereinafter "SEC") nor any other regulatory body has approved or disapproved of these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2006

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WHERE YOU CAN FIND INFORMATION

We have filed with the SEC, under the Securities Act, a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other documents are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and to the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements, and other information that is filed electronically with the SEC. The web site can be accessed at www.sec.gov.

After effectiveness of the registration statement, which includes this prospectus, we will be required to comply with the informational requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and, accordingly, will file current reports on Form 8-K, quarterly reports on Form 10-Q, annual reports on Form 10-K, proxy statements, and other information with the SEC. Those reports, proxy statements and other information will be available for inspection and copying at the public reference facilities and internet site of the SEC referred to above.

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SUMMARY

This summary highlights selected information from this prospectus but does not contain all information that you should consider before investing in the shares. You should read this entire prospectus carefully, including Risk Factors beginning on page 10, and the financial statements included elsewhere in this prospectus. In this prospectus, we refer to GeoMet, Inc., its subsidiaries and predecessors as GeoMet, we, our, or our company. We own, operate, and conduct exploration, development, and production activities for natural gas from coal seams (coalbed methane) (in this prospectus we sometimes refer to coalbed methane as CBM). References to the number of shares of our common stock outstanding have been revised to reflect a four-for-one stock split that was effected in January 2006. The estimates of our proved reserves as of September 30, 2005 and December 31, 2004, 2003 and 2002 included in this prospectus are based on reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. A summary of their report with respect to estimated proved reserves as of September 30, 2005 is attached to this prospectus as Appendix A. We discuss sales volumes, per unit revenue and per unit cost data net of the royalty owner s interest in this prospectus. We only use net numbers in this prospectus, which do not include the royalty owner s interest. We have provided definitions for some of the industry terms used in this prospectus in the Glossary of Natural Gas and Coal Terms beginning on page 82 of this prospectus.

About GeoMet

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. We were originally founded as a consulting company to the coalbed methane industry in 1985 and have been active as an operator and developer of coalbed methane properties since 1993. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We are currently developing a total of approximately 77,000 net acres of coalbed methane rights in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin. We also control the balance of approximately 178,000 net acres of coalbed methane exploration and development rights primarily in north central Louisiana, British Columbia, West Virginia, and Colorado. We have conducted substantial gas desorption testing and drilling of core holes throughout our property base. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin contains a total of 610 additional drilling locations.

At September 30, 2005, we had 258.5 Bcf of estimated proved reserves with a PV-10 of approximately $1.4 billion using gas prices in effect at such date. Our estimated proved reserves at September 30, 2005 are 100% coalbed methane and 72% proved developed. For the month of December 2005, our net gas sales totaled approximately 14,700 Mcf per day. For 2005, we estimate that our total capital expenditures will be approximately $60 million, of which we had spent $49.7 million as of September 30, 2005. We estimated our development expenditures for the development of the Gurnee and Pond Creek fields to be $45 million in 2005, of which we had spent $40.3 million through September 30, 2005. We intend to increase our development expenditures by approximately 44% in 2006 to approximately $65 million to accelerate the drilling of the Gurnee and Pond Creek fields. Total capital expenditures in 2006 are estimated to be in the range of $80 million to $90 million.

Areas of Operation

Cahaba Basin

We have the development rights to approximately 41,800 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At September 30, 2005, approximately 54% of our estimated proved reserves, or 139.0 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At September 30, 2005, we had developed 23% of our

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Cahaba Basin CBM acreage. We own a 100% working interest in the area and are the operator. As of December 1, 2005, we had drilled 137 wells in the Gurnee field, of which 115 were producing (the remainder of which were pending completion or hook-up or were venting gas), with net daily sales of gas averaging approximately 4,000 Mcf for the month of December 2005. From project inception through September 30, 2005, our finding and development costs in the Cahaba Basin have averaged $0.82 per Mcf. Our undeveloped CBM acreage in the Cahaba Basin contains 381 additional drilling locations, based on 80-acre spacing. In 2006, we intend to spend approximately $45 million of our capital expenditure budget to develop and drill approximately 75 wells 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 coal. A total of 30 core holes have been drilled and over 540 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.

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 design capacity of approximately 45,000 barrels of water per day. 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 these facilities will meet all of our future water disposal requirements for the Gurnee field.

We own and operate a 9.2-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.

Appalachian Basin

In the Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 56,000 net CBM acres, approximately 35,100 of which are in our Pond Creek field. At September 30, 2005, approximately 45% of our estimated proved reserves, or 116.3 Bcf, were located within the Pond Creek field, of which approximately 65% were classified as proved developed. We own a 100% working interest in the area and are the operator. As of December 1, 2005, we had drilled 157 wells in the Pond Creek field, of which 154 were producing (the remainder of which are pending completion or hook-up), with net daily sales of gas averaging approximately 9,500 Mcf for the month of December 2005. From project inception through September 30, 2005, our finding and development costs in the Pond Creek field have averaged $0.89 per Mcf. Our undeveloped CBM acreage in the Pond Creek field contains 229 additional drilling locations based on 80-acre spacing. In 2006, we intend to spend approximately $20 million of our capital expenditure budget to develop and drill approximately 40 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 high quality, low-medium volatile bituminous coal of Pennsylvanian age. Due to mining activity, it has been long known that these coal groups are gas rich. A total of 39 core holes have been drilled in the area 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.

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Our gas is gathered into our central dehydration and compression facility and delivered into the Cardinal States Gathering System for redelivery into the Columbia Gas Transmission Corporation gas pipeline system.

British Columbia

Our Peace River Project is comprised of approximately 33,000 gross acres (16,500 net acres) along the Peace River near Hudson s Hope, British Columbia. We are conducting operations on this project through an exploration and development agreement with a third party. We will earn a 50% working interest in this leasehold by spending $7.2 million on an evaluation program. We have spent approximately $5.5 million of this amount from project inception through December 31, 2005. We expect to complete our earning obligations in 2006 and to operate this project going forward. We have drilled three core holes targeting the Lower Cretaceous Gething coal formation. Total net coal thickness ranges from 30 to 70 feet at depths from 1,000 to 3,000 feet. At these depths, coals are medium volatile bituminous rank having seams up to nine feet in thickness. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We have recently completed two wells and a water disposal well, and testing operations are in process.

North Central Louisiana

In Winn, LaSalle, and Caldwell Parishes of Louisiana, we are conducting an evaluation of the coals within the Wilcox formation. We operate the project with a 100% working interest. As of September 30, 2005, we had a total of approximately 110,000 net acres under lease, and we have subsequently exercised an option to acquire an additional 9,259 acres. The Wilcox is a thick deltaic deposit of Eocene age, composed primarily of sandstone, siltstone, shale, and coal. The coals are low rank, being classified as sub-bituminous and lignitic. Coal thickness averages 75 feet at depths from 2,000 to 3,500 feet. We have drilled 17 exploration or production test wells and two water disposal wells. We have also conducted 60 gas desorption tests from a sample of nine of these wells to determine the gas content of the coal and to define the potential gas resources. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are currently evaluating producibility issues related to zonal isolation of adjacent water sands and related water encroachment in this area.

Piceance Basin of Colorado

We also hold a total of approximately 14,600 net CBM acres of leasehold in our Cameo prospect in the southwestern portion of the Piceance Basin in Mesa County, Colorado. We are targeting the Cameo coals within a 200-foot interval of the Williams Fork formation at a depth of about 2,000 feet. We have drilled one core hole and have conducted desorption tests on the core. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are actively pursuing opportunities to increase our acreage position in this area.

Characteristics of Coalbed Methane

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. This 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 depending on well spacing.

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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. While at shallow depths of less than 500 feet these fractures are sometimes 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.

Summary of Our Properties as of September 30, 2005

Field	Estimated Proved Reserves(1)		
	Proved	Proved Developed	PV-10(2)
	(MMcf)	(MMcf)	(in millions)
Appalachia:			
Pond Creek field	116,328	75,713	$ 593.5
Alabama:			
Gurnee field	139,033	108,322	748.5
White Oak Creek field	3,155	2,922	27.6
Total	258,516	186,957	$ 1,369.6

Area	Net Wells(3)	Additional Drilling Locations	Net CBM Acres Owned or Controlled		
			Total	Developed	Undeveloped
Appalachian Basin	147	229	55,758	11,172	44,586
Cahaba Basin	123	381	41,766	9,480	32,286
North Central Louisiana(4)			119,244		119,244
British Columbia			16,500		16,500
Piceance Basin			16,949		16,949
Other (United States)			5,030		5,030
Total	270	610	255,247	20,652	234,595

(1) Based on the reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, a summary of which is attached to this prospectus as Appendix A.
(2) PV-10 was calculated using a natural gas price at September 30, 2005 of $14.70 per Mcf. See Reconciliation of Non-GAAP Financial Measures for additional information.
(3) Excludes 22 net wells pending completion at September 30, 2005.
(4) Includes an option to acquire a total of approximately 9,259 acres, which we exercised in December 2005.

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Recent Drilling Activity (net wells)

	Nine Months Ended September 30, 2005(1)	Year Ended December 31, 2004	2003	2002
Development	77.0	81.8	47.7	9.6
Exploratory	2.0	10.0	15.0	2.5
Total	79.0	91.8	62.7	12.1
Total Capital Expenditures (in thousands)	$ 49,733	$ 86,189(2)	$ 36,069	$ 12,770

(1) Excludes 22 net wells pending completion.
(2) Includes $27 million for the acquisition of producing properties.

Strategy

Our objective is to increase stockholder value by investing capital to increase our reserves, production, cash flow, and earnings. We intend to focus on the following strategies:

- Focus exclusively on coalbed methane operations where we have substantial experience and expertise.

- Exploit our existing resource base by accelerating drilling in our projects and expanding into adjacent areas, thereby leveraging our knowledge of the area and our existing infrastructure and operating base.

- Explore for large-scale CBM development opportunities both in our existing core areas and in other areas that we enter, where we intend to have operating control and the ability to reduce costs through economies of scale. We seek to be among the first companies in an area so that our costs of entry are less, large acreage positions can be established, and smaller incremental investments can be made to reduce our risk before larger expenditures are required.

- Seek out opportunistic CBM producing property acquisitions.

- Optimize financial flexibility by maintaining unused capacity under our bank revolving credit facility. We have entered into a new five-year, $150 million revolving credit facility with an initial $120 million borrowing base.

Competitive Strengths

CBM Is Our Only Business. We explore for, develop, and produce CBM exclusively. We believe that substantial expertise and experience is required to develop, produce, and operate coalbed methane fields in an efficient manner. We believe that the inherent geologic and production characteristics of coalbed methane 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 and then begins to decline at a shallow rate.

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 Finding and Development Costs. Our finding and development costs have averaged $0.92 per Mcf since January 1, 2001.

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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 have initial inclining production rates 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 24-person CBM management, professional, and project management team has an average of more than 16 years of CBM experience and has participated in the drilling and operation of more than 2,600 CBM wells worldwide since 1977.

Large Inventory of Organic Growth Opportunities. We have a total of over 255,000 net acres of CBM exploration and development rights, including almost 77,000 net undeveloped acres in our two development areas. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin provides us with a total of 610 additional 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 with low finding and development costs and low project life operating costs.

Minimal Water Disposal Issues. Unlike many CBM projects, water disposal is not a significant issue for us in the Gurnee field, where we have a pipeline in place to transport produced water for disposal into the Black Warrior River, or in the Pond Creek field, which produces comparatively low amounts of water and where we have an existing water disposal well that we believe is adequate for our needs.

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CORPORATE INFORMATION

On January 30, 2006, we completed a private equity offering of 10,000,000 shares of our common stock, consisting of 2,067,023 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 $25.0 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 the offering, together with the proceeds from the repayment of the selling stockholders loans, to repay a portion of the borrowings under our credit facility and for general corporate purposes. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers from which we received aggregate consideration of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. The net proceeds generated from this sale were used to repay a portion of the borrowings under our credit facility and for general corporate purposes.

On April 14, 2005, GeoMet, Inc., an Alabama corporation (Old GeoMet), was merged with and into GeoMet Resources, Inc., a Delaware corporation (GeoMet), and we subsequently changed our name to GeoMet, Inc. We initially acquired 80% of the common stock of Old GeoMet on December 9, 2000 and subsequently acquired an additional 0.95% of Old GeoMet s common stock on November 17, 2004. Accordingly, the equity of the minority interests in Old GeoMet was shown in the consolidated financial statements as a minority interest prior to April 14, 2005.

Our corporate headquarters are located at 909 Fannin, Suite 3208, Houston, Texas 77010 and our telephone number is (713) 659-3855. Our corporate website address is *www.geometinc.com*. Our technical and operational headquarters are located at 5336 Stadium Trace Parkway, Suite 206, Birmingham, Alabama 35244.

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THE OFFERING

Common stock offered by the selling stockholders	10,250,000 shares.
Common stock to be outstanding after this offering(1)	32,483,707 shares.
Use of proceeds	We will not receive any proceeds from sale of the shares of common stock offered in this prospectus.
Dividend policy	We do not anticipate that we will pay cash dividends in the foreseeable future. Our new credit facility prohibits the payment of cash dividends.
Risk factors	For a discussion of factors you should consider in making an investment, see Risk Factors.
Proposed Nasdaq symbol	.

(1) Includes 192,020 shares issued from the exercise of stock options in January 2006 in connection with the private offering and 250,000 sold pursuant to the initial purchaser s option to purchase additional shares. Common stock outstanding excludes options to purchase 1,901,304 shares of our common stock outstanding as of January 31, 2006, of which 1,813,304 were exercisable.

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SUMMARY OF FINANCIAL, RESERVE AND OPERATING DATA

The following table shows our historical financial, reserve and operating data for, and as of the end of, each of the periods indicated. Our historical results are not necessarily indicative of the results that may be expected for any future period. The following data should be read in conjunction with Management s Discussion and Analysis of Results of Operations and Financial Condition and the financial statements and related notes included in this prospectus.

	Nine Months Ended September 30,	Nine Months Ended September 30,	Year Ended December 31		
	2005	2004	2004	2003	2002
	(In thousands unless otherwise indicated)				
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:					
Total revenues	$ 24,615	$ 13,705	$ 20,924	$ 12,049	$ 7,008
Lease operating costs, compression and transportation costs and production taxes	9,062	5,290	7,517	3,047	1,530
Depreciation, depletion and amortization	3,378	1,666	2,691	2,120	2,151
Research and development costs	531	279	278	432	167
General and administrative	2,277	1,758	2,513	1,370	1,598
Impairment of non-operating assets				8	108
Realized losses on derivative contracts	2,289	429	815	44	
Unrealized losses (gains) from the change in market value of open derivative contracts	21,833	1,103	(542)	102	
Operating income (loss)	(14,755)	3,180	7,652	4,926	1,454
Other expenses and interest, net	2,507	499	920	144	74
Income tax provision	(5,843)	912	2,312	1,651	639
Minority interest	(442)	152	584	571	138
Cumulative effect of change in accounting method				19	
Net income (loss)	$ (10,977)	$ 1,617	$ 3,836	$ 2,541	$ 603
BALANCE SHEET DATA (at period end):					
Working capital (deficit)	$ (14,947)	$ (3,701)	$ (1,251)	$ 5,133	$ 3,940
Total assets	$ 242,261	$ 122,291	$ 142,090	$ 81,505	$ 42,261
Long-term debt	$ 93,940	$ 35,526	$ 51,513	$ 10,102	$ 6,665
Stockholders equity	$ 86,032	$ 63,471	$ 65,692	$ 52,754	$ 22,912
OTHER DATA:					
Net cash provided by operating activities	$ 8,418	$ 8,895	$ 10,580	$ 10,801	$ 4,603
Net cash used in investing activities	$ (49,272)	$ (47,777)	$ (66,193)	$ (36,341)	$ (12,773)
Net cash provided by financing activities	$ 39,635	$ 34,336	$ 50,192	$ 30,534	$ 5,372
Capital expenditures	$ 49,733	$ 47,755	$ 86,189	$ 36,069	$ 12,770
Net sales volume (Bcf)	3.3	2.3	3.2	2.5	2.1
Average sales price ($ per Mcf)	$ 7.39	$ 5.79	$ 6.12	$ 4.71	$ 3.16
Total production costs ($ per Mcf)	$ 2.76	$ 2.31	$ 2.36	$ 1.23	$ 0.72
Expenses: ($ per Mcf)					
Lease operating costs	$ 1.89	$ 1.55	$ 1.60	$ 0.66	$ 0.28
Compression and transportation costs	$ 0.71	$ 0.61	$ 0.61	$ 0.40	$ 0.31
Production taxes	$ 0.16	$ 0.15	$ 0.15	$ 0.17	$ 0.13
Research and development costs	$ 0.16	$ 0.12	$ 0.09	$ 0.17	$ 0.08
General and administrative	$ 0.69	$ 0.77	$ 0.79	$ 0.55	$ 0.75

Depreciation, depletion & amortization	$ 1.03	$ 0.73	$ 0.84	$ 0.85	$ 1.01
Estimated proved reserves (Bcf)(2)	258.5		209.9	103.9	35.5
PV-10 ($ millions)(1)(2)	$ 1,369.6		$ 481.8	$ 236.9	$ 64.4
Standardized measure of discounted future net cash flows ($ millions)			$ 349.8	$ 172.5	$ 45.4
Price used for PV-10 ($ per Mcf)(2)	$ 14.70		$ 6.21	$ 5.77	$ 4.62
EBITDA (in millions)(1)	$ (10.9)	$ 4.70	$ 9.8	$ 6.5	$ 3.5

(1) See reconciliation of non-GAAP financial measures on page 24 for additional information.

(2) Based on the reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers, at each period end. The natural gas price used to compute PV-10 is volatile and may fluctuate widely. Refer to Risk Factors for a more complete discussion.

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RISK FACTORS

You should consider carefully each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in our common stock.

Risks Related To Our Business

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 may be beyond our control. Because all of our estimated proved reserves as of September 30, 2005 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 unit 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, estimated 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

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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 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 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 and oil 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. Because total estimated proved reserves include our proved undeveloped reserves at September 30, 2005, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. 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.

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 coalbead 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 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;

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- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas and oil prices;
- pipeline ruptures; 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 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. In the future, we will require substantial capital to fund our business plan and operations. We expect to be required to meet our needs from our excess cash flow, debt financings, and additional equity offerings. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development, and other activities.

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.

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.

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, or interruption of transportation of natural gas produced from the wells in these basins or other events which impact these areas.

Our business depends on transportation facilities owned by others. Disruption of, capacity constraints in, or proximity to pipeline systems could limit our sales and increase our per unit costs of producing our gas.

We transport our gas to market by utilizing pipelines owned by others. If pipelines do not exist near our producing wells, if pipeline capacity is limited, or if pipeline capacity is unexpectedly disrupted, our gas sales

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could be limited and our transportation costs could increase, reducing our profitability. If we cannot access pipeline transportation, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales are reduced because of transportation constraints, our revenues will be reduced, which will also increase our per unit costs.

Our gas from the Pond Creek field in the Appalachian Basin is gathered to a central facility that we own and operate to be dehydrated and compressed and delivered into the Cardinal States Gathering System (Cardinal States) for redelivery into Columbia s pipeline system. Our gathering agreement with Cardinal States terminates on April 30, 2007. In the event that by April 30, 2007 we are either unable to execute a long-term gathering agreement or enter into an extension with Cardinal States, or have not completed a connection to an alternate pipeline, we may temporarily be unable to transport gas from the Pond Creek field to the market, and our revenues would be adversely affected.

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.

The coalbeds from which we produce gas frequently contain water that may hamper our ability to produce gas in commercial quantities or affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain 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.

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 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;

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- 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.

We may be unable to retain our existing senior management team and/or our key personnel that has 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, and do not expect to enter into employment agreements or non-competition agreements with any of our key employees, other than J. Darby Seré, our Chief Executive Officer and President, 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 or marketing of gas 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

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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. 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 have limited protection for our technology and depend on technology owned by others.

We use operating practices that management believes are of significant value in developing CBM resources. In most cases, patent or other intellectual property protection is unavailable for this technology. Our use of independent contractors in most aspects of our drilling and some completion operations makes the protection of such technology more difficult. Moreover, 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.

We may need to use unproven technologies to produce coalbed methane economically on some of our properties.

Our ability to produce gas economically from coal seams with lower permeability requires the use of advanced technologies that are still being developed and tested. Horizontal drilling or jet drilling are advanced technologies we may use to produce gas from coal seams that have lower permeability. Horizontal drilling, applied in coal, requires a well design that promotes simultaneous production of water and methane without significant back-pressure, and a well that will ensure wellbore integrity throughout its projected life. Jet drilling, a completion technique, is accomplished by forcing water at high pressures through a nozzle connected to a flexible hose horizontally in a coal seam. In the event that horizontal drilling, jet drilling, or any other advanced technology we may use are not effective for producing coalbed methane economically from coal seams with lower permeability, we may not be able to commercially develop areas having lower permeability coal seams even though the coal thickness and gas content data obtained from our core drilling and gas desorption testing indicate that such areas would be favorable for CBM development.

The unavailability 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 unavailability 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.

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Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our natural gas production, we have entered into 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 natural gas prices, such transactions may limit our potential gains and increase our potential losses if natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

our production is less than expected; or

the counterparties to our hedging agreements fail to perform under the contracts.

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

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

Risks Relating to Our Common Stock

One existing stockholder holds a substantial interest in our company, and insiders own a significant amount of our common stock, which could limit your ability to influence the outcome of stockholder votes, and the interests of this stockholder and these insiders could differ from those of our other stockholders.

A representative of Yorktown Energy Partners IV, L.P. (Yorktown) serves on our board of directors, and Yorktown owns approximately 49.9% of our outstanding common stock. In addition, our officers and their affiliates beneficially own or control approximately 13.6% of our outstanding common stock. Yorktown and our executive officers and directors have, and can be expected to continue to have, a significant voice in our affairs and in the outcome of stockholder voting. Under Delaware law and our certificate of incorporation, matters requiring a stockholder to vote, including the election of directors, the adoption of an amendment to our certificate of incorporation, and the approval of mergers and other significant corporate transactions require the affirmative vote of the holders of a majority of the outstanding shares or, in the case of the election of directors, a plurality of the votes cast. As a consequence, the effect of this level of share ownership by Yorktown and our officers and directors may permit them to approve certain matters by written consent and may delay or prevent a change of control of us or otherwise protect your investment.

There has been no public market for our common stock, and our stock price may fluctuate significantly.

There is currently no public market for our common stock, and an active trading market may not develop or be sustained after the sale of all of the shares covered by this prospectus. The market price of our common stock could fluctuate significantly as a result of:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;

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- changes in revenue or earnings estimates or publication of research reports by analysts about us or the exploration and production industry;
- liquidity and registering our common stock for public resale;
- actual or unanticipated variations in our reserve estimates and quarterly operating results;
- changes in oil and gas prices;
- speculation in the press or investment community;
- sales of our common stock by our stockholders;
- increases in our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any increased indebtedness we incur in the future;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market and economic conditions, including the occurrence of events or trends affecting the price of natural gas; and
- domestic and international economic, legal, and regulatory factors unrelated to our performance.

If a trading market develops for our common stock, stock markets in general experience volatility that often is unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

We may not be accepted for listing or inclusion on The Nasdaq National Market or a national securities exchange.

In connection with our filing of this registration statement, we have agreed to use commercially reasonable efforts to satisfy the criteria for listing and list or include (if we meet the criteria for listing on such exchange or market) our common stock on the New York Stock Exchange (NYSE), The American Stock Exchange, or The Nasdaq National Market as soon as practicable (including seeking to cure in our listing and inclusion application any deficiencies cited by such exchange or market), and thereafter maintain the listing on such exchange or market. We do not believe that we will meet the NYSE s requirements for listing. The American Stock Exchange and The Nasdaq National Market have initial listing criteria, including criteria related to minimum bid price, public float, market makers, minimum number of round lot holders, and board independence requirements, that we can give no assurance that we will meet. Our inability to list or include our common stock on The American Stock Exchange or The Nasdaq National Market could affect the ability of purchasers in this offering to sell their shares of common stock subsequent to the declaration of the effectiveness of this registration statement and consequently adversely affect the value of such shares. In such case, our stockholders would find it more difficult to dispose of, or to obtain accurate quotations as to the market value of, our common stock. In addition, we would have more difficulty attracting the attention of market analysts to cover us in their research.

If our common stock is approved for listing or inclusion on The American Stock Exchange or The Nasdaq National Market, we will have no prior trading history, and thus there is no way to determine the prices or volumes at which our common stock will trade. We can give no assurances as to the development of liquidity or any trading market for our common stock. Holders of shares of our common stock may not be able to resell their shares at or near their original acquisition price, or at any price.

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We do not intend to pay, and are prohibited in our ability to pay, any dividends on our common stock.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and plans for expansion. In addition, the declaration and payment of any dividends on our common stock is currently prohibited by the terms of our new credit facility.

You may experience dilution of your ownership interests due to the future issuance of shares of our common stock, which could have an adverse effect on our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. Our authorized capital stock consists of 125 million shares of common stock and 10 million shares of preferred stock with such designations, preferences, and rights as may determined by our board of directors. As of the date of this prospectus, 32,483,707 shares of common stock and no shares of preferred stock were outstanding. We have reserved 2,400,000 shares for future issuance to employees as restricted stock or stock option awards pursuant to our stock option plans, of which options to purchase 2,093,324 shares have already been granted. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes, or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

We will incur increased costs as a result of being a public company.

As a public company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. The U.S. Sarbanes-Oxley Act of 2002 and related rules of the U.S. Securities and Exchange Commission, or SEC, and the New York Stock Exchange, The Nasdaq National Market, and The American Stock Exchange regulate corporate governance practices of public companies. We expect that compliance with these public company requirements will increase our costs and make some activities more time consuming. For example, we will create new board committees and adopt new internal controls and disclosure controls and procedures. In addition, we will incur additional expenses associated with our SEC reporting requirements. A number of those requirements will require us to carry out activities we have not done previously. For example, under Section 404 of the Sarbanes-Oxley Act, for our annual report on Form 10-K for 2007 we will need to document and test our internal control procedures, our management will need to assess and report on our internal control over financial reporting and our independent accountants will need to issue an opinion on that assessment and the effectiveness of those controls. Furthermore, if we identify any issues in complying with those requirements (for example, if we or our independent auditors identified a material weakness or significant deficiency in our internal control over financial reporting), we could incur additional costs rectifying those issues, and the existence of those issues could adversely affect us, our reputation or investor perceptions of us. We also expect that it could be difficult and will be significantly more expensive to obtain directors and officers liability insurance, and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as executive officers. Advocacy efforts by shareholders and third parties may also prompt even more changes in governance and reporting requirements. We cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this prospectus, 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 statem those words are usually forward-looking statements.

The forward-looking statements contained in this prospectus 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 prospectus 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 prospectus. All forward-looking statements speak only as of the date of this prospectus. 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;
- our inability 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 inability 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.

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USE OF PROCEEDS

We will not receive any of the proceeds from the sale of the shares of common stock offered by this prospectus. Any proceeds from the sale of the shares pursuant to this prospectus will be received by the selling stockholders.

DIVIDEND POLICY

We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock, as we intend to reinvest cash flow generated by operations in our business. Our credit facility currently prohibits us from paying cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict our ability to declare or pay cash dividends on our common stock. Our Board of Directors has the authority to issue preferred stock and to fix dividend rights that may have preference to our common shares.

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CAPITALIZATION

The following table presents our capitalization as of September 30, 2005, on a pro forma as adjusted basis giving effect to our private equity offering, the exercise of 192,020 shares of stock options, and a four-for-one common stock split in January 2006. You should read this table in conjunction with our consolidated financial statements included in this prospectus.

	As of September 30, 2005 Pro Forma As Adjusted (In thousands)
Long-term debt(1)	$ 49,188
Stockholders equity:	
Common stock, $0.001 par value, 125,000,000 shares authorized; and 32,483,707 shares issued and outstanding(2)	$ 32
Preferred stock, $0.001 par value, 10,000,000 shares authorized, no shares issued or outstanding(2)	
Additional paid-in capital	133,793
Accumulated other comprehensive income	70
Retained deficit	(2,960)
Notes receivable(1)	(401)
Total stockholders equity	130,534
Total capitalization	$ 179,722

(1) Long-term debt decreased by $27,162,000 from the sale of 2,317,023 shares in our private equity offerings in January and February 2006 after offering expenses, by $17,124,000 from the proceeds received from the payment of loans with interest by selling stockholders (including $250,000 in notes receivable that was included in other assets), and by $466,279 in proceeds from the exercise of stock options in January 2006 in connection with our private equity offering.

(2) Authorized share amount reflects an increase in January 2006 our authorized capital stock from 10,000,000 shares of common stock as of September 30, 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.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA

The following table shows our summary historical consolidated financial and operating data as of and for each of the nine month periods ended September 30, 2005 and 2004, for the four years ended December 31, 2004 and for the partial period December 8, 2000 through December 31, 2000. The summary historical consolidated financial and operating data for the nine months ended September 30, 2005 and the three years ended December 31, 2004 are derived from our audited financial statements included herein and the summary historical consolidated financial and operating data for the nine month period ended September 30, 2004 are derived from our unaudited financial statement and include all adjustments consisting only of normal recurring adjustments necessary for a fair presentation of the results of this interim period**.** The summary historical consolidated financial and operating data for the year ended December 31, 2001 and the partial period December 8, 2000 through December 31, 2000 was derived from our audited financial statements which are not included herein You should read the following data in conjunction with Managements Discussion and Analysis of Results of Operations and Financial Condition: and the financial statements and related notes included elsewhere in this prospectus where there is additional 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.

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Year Ended December 31, 2004	2003	2002	2001	From inception on December 8, 2000 to December 31, 2000
			(In thousands unless otherwise indicated)				
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME DATA:							
REVENUES							
Gas sales	$ 24,240	$ 13,258	$ 19,522	$ 11,700	$ 6,731	$ 11,850	$ 718
Operating fees and other	375	447	1,402	349	277	205	48
Total revenues	24,615	13,705	20,924	12,049	7,008	12,055	766
COSTS AND OPERATING EXPENSES							
Lease operating costs	6,212	3,555	5,092	1,640	590	542	34
Compression and transportation costs	2,332	1,385	1,951	993	654	681	27
Production taxes	518	350	473	414	285	560	34
Depreciation, depletion and amortization	3,378	1,666	2,691	2,120	2,151	3,167	150
Research and development costs	531	279	279	432	168		
General and administrative	2,277	1,758	2,513	1,370	1,598	1,206	350
Impairment of other equipment and other non-current assets				8	108		
Realized losses on derivative contracts	2,289	429	815	44			
Unrealized losses (gains) from the change in market value of open derivative contracts	21,833	1,103	(542)	102			
Total costs and operating expenses	39,370	10,525	13,272	7,123	5,554	6,156	595
Operating income (loss)	(14,755)	3,180	7,652	4,926	1,454	5,899	171
Interest income	33	52	70	95	119	291	20
Interest expense (net of amounts capitalized)	(2,534)	(550)	(986)	(232)	(186)	(151)	(24)
Other expenses	(6)	(1)	(4)	(7)	(7)	(3)	
Total other income (expense)	(2,507)	(499)	(920)	(144)	(74)	137	(4)

Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	(17,262)	2,681	6,732	4,782	1,380	6,036	167
Income tax provision	(5,843)	912	2,312	1,651	639	1,152	32
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	(11,419)	1,769	4,420	3,131	741	4,884	135
Minority interest	(442)	152	584	571	138	958	24
Net income (loss) before cumulative effect of change in accounting principle, net of income tax	(10,977)	1,617	3,836	2,560	603	3,926	111
Cumulative effect of change in accounting principle, net of income tax				19			
Net income (loss)	(10,977)	1,617	3,836	2,541	603	3,926	111
Other comprehensive income, net of income taxes							
Foreign currency translation adjustment	68		2				
Comprehensive income (loss)	$ (10,909)	$ 1,617	$ 3,838	$ 2,541	$ 603	$ 3,926	$ 111

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA (continued):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Year Ended December 31, 2004	2003	2002	2001	From inception on December 8, 2000 to December 31, 2000
	(In thousands unless otherwise indicated)						
Net income (loss) per common share:							
Basic	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08	$ 0.49	$ 0.02
Diluted	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08	$ 0.49	$ 0.02
BALANCE SHEET DATA (at period end):							
Working capital (deficit)	$ (14,947)	$ (3,701)	$ (1,251)	$ 5,133	$ 3,940	$ 6,268	$ 3,732
Total assets	$ 242,261	$ 122,291	$ 142,090	$ 81,505	$ 42,261	$ 33,240	$ 29,462
Long-term debt	$ 93,940	$ 35,526	$ 51,513	$ 10,102	$ 6,665	$ 1,242	$ 1,328
Stockholders equity	$ 86,032	$ 63,471	$ 65,692	$ 52,754	$ 22,912	$ 22,310	$ 18,384
OTHER DATA:							
Net cash provided by operating activities	$ 8,418	$ 8,895	$ 10,580	$ 10,801	$ 4,603	$ 8,669	$ 827
Net cash used in investing activities	$ (49,272)	$ (47,777)	$ (66,193)	$ (36,341)	$ (12,773)	$ (5,232)	$ (14,057)
Net cash provided by (used in) financing activities	$ 39,635	$ 34,336	$ 50,192	$ 30,534	$ 5,372	$ (2,127)	$ 18,160
Capital expenditures	$ 49,733	$ 47,755	$ 86,189	$ 36,069	$ 12,770	$ 5,117	$ 153
Net sales volume (Bcf)	3.3	2.3	3.2	2.5	2.1	2.5	0.15
Average sales price ($ per Mcf)	$ 7.39	$ 5.79	$ 6.12	$ 4.71	$ 3.16	$ 4.73	$ 4.92
Total production costs ($ per Mcf)	$ 2.76	$ 2.31	$ 2.36	$ 1.23	$ 0.72	$ 0.71	$ 0.66
Estimated proved reserves (Bcf)(2)	258.5		209.9	103.9	35.5	16.7	21.6
PV-10 ($ millions)(1)(2)	$ 1,369.6		$ 481.8	$ 236.9	$ 64.4	$ 19.2	$ 101.8
Standardized measure of discounted future net cash flows ($ millions)			$ 349.8	$ 172.5	$ 45.4	$ 14.0	$ 75.0
EBITDA ($millions)(1)	$ (10.9)	$ 4.7	$ 9.8	$ 6.5	$ 3.5	$ 8.1	$ 0.3

(1) See reconciliation of non-GAAP financial measures on page 24 for additional information.

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

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL AND OPERATING DATA (continued):

Reconciliation of Non-GAAP Financial Measures

The following table shows our reconciliation of how we calculate our PV-10. Management believes 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 gas companies. However, 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 us. PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Twelve Months Ended December 31, 2004	2003	2002	2001	From inception on December 8, 2000 to December 31, 2000
			(In thousands)				
Future cash inflows	$ 3,800,977		$ 1,302,830	$ 599,501	$ 163,986	$ 45,679	$ 205,387
Less: Future production costs	526,780		290,425	125,765	48,771	14,030	29,349
Less: Future development costs	68,796		38,242	23,832	4,676	1,140	1,273
Future net cash flows	3,205,401		974,163	449,904	110,539	30,509	174,765
Less: 10% discount factor	(1,835,752)		(492,339)	(213,018)	(46,095)	(11,310)	(72,956)
PV-10	$ 1,369,649		481,824	236,886	64,444	19,199	101,809
Less: Undiscounted income taxes			(274,975)	(125,858)	(32,101)	(8,196)	(48,888)
Plus: 10% discount factor			142,906	61,520	13,084	2,969	22,056
Discounted income taxes			(132,069)	(64,338)	(19,017)	(5,227)	(26,832)
Standardized measure of discounted future net cash flows			$ 349,755	$ 172,548	$ 45,427	$ 13,972	$ 74,977

The following table reconciles our net income/(loss) before cumulative effect of change in accounting principle, net of tax to EBITDA. EBITDA is defined as earnings (loss) before deducting net interest expense, income taxes and depreciation, depletion and amortization. Although EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles (GAAP), management believes that it is useful to an investor in evaluating GeoMet because it is used as measures to evaluate a company s operating performance.

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Year Ended December 31, 2004	2003	2002	2001	From inception on December 8, 2000 to December 31, 2000
			(In thousands)				
Net income/(loss) before cumulative effect of change in accounting principle, net of tax	$ (10,977)	$ 1,617	$ 3,836	$ 2,560	$ 603	$ 3,926	$ 111
Add: Interest expense	2,534	550	986	232	186	151	24
Less: Interest income	(33)	(52)	(70)	(94)	(119)	(291)	(20)
Add (Deduct): Provision for income taxes	(5,843)	912	2,312	1,651	639	1,152	32
Add: Depreciation, depletion and amortization	3,378	1,666	2,691	2,120	2,151	3,167	150
EBITDA	$ (10,941)	$ 4,693	$ 9,755	$ 6,469	$ 3,460	$ 8,105	$ 297

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

RESULTS OF OPERATIONS AND FINANCIAL CONDITION

The following is a discussion and analysis of our financial condition and results of operations and should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this prospectus.

Overview

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia.

We have been very active in North America for over twenty years as an operator of CBM fields owned by us, as a contract operator for CBM fields in which we owned an interest, and as a consultant or contract operator for CBM fields owned by other companies. Over the last five years, we have focused on expanding the number of projects that we own and operate. This focus resulted in the initial development of our two primary producing properties, the Gurnee field in the Cahaba Basin and the Pond Creek field in the Appalachian Basin. Additionally, we own and operate several active exploration projects. This change in focus of our operations has also resulted in a significant increase in our business, ranging from capital expenditures to headcount.

Effective April 30, 2004, we acquired the working interests of our 50% partner in the Appalachian Basin, including a 50% working interest in the Pond Creek field, for cash consideration of $27 million and a contingent payment of up to $3 million, which we expect to pay in full in 2008 (the Pond Creek Acquisition). In the acquisition we acquired approximately 31.8 Bcf of estimated proved reserves at a price of $0.84 per Mcf.

Effective June 7, 2004, we sold our 10% working interest in the White Oak Creek field in the Black Warrior Basin for $21 million (the White Oak Creek Sale). We sold approximately 8.4 Bcf of our estimated proved reserves at a price of $2.50 per Mcf while retaining an approximate 3% overriding royalty interest in the field. This overriding royalty interest is presently subject to a dispute. The trial court has ruled in our favor; however, the case is currently under appeal. See Legal Proceedings for a further discussion of this lawsuit. Prior to 2003 and the start-up of the Pond Creek field, our working and overriding interests in the White Oak Creek field were our primary sources of production, revenue, and cash flow.

On January 30, 2006, we sold 2,067,023 shares of common stock in a private placement to qualified institutional buyers pursuant to Rule 144A under the Securities Act. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers under Rule 144A under the Securities Act pursuant to the initial purchaser s option to purchase additional shares.

The net proceeds from these offerings of approximately $27 million, after offering expenses, and the receipt of approximately $17.5 million from the repayment of certain stockholder loans, and from the exercise of stock options by certain of the selling stockholders were used to repay outstanding borrowings on our credit facility and for general corporate purposes.

Unlike conventional natural gas production operations, in the early stages of a CBM project, production of water is generally comparatively higher and production of gas lower. Typically, gas production from CBM projects gradually increases over time as pressure is lowered due to extraction of water and as additional wells are drilled. As water extraction continues and the maximum number of wells drilled on the project acreage is reached, production peaks and stabilizes for a period and ultimately begins to decline. Substantial capital and operating expenditures are required to fully develop a CBM field. Further, in the early years of the life of a CBM well it is common for produced water to decline substantially, while gas production increases. Additionally, a

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significant portion of operating costs are fixed, generally driven by the number of producing wells, the disposal of produced water, and the cost and maintenance of infrastructure. Over time, as gas production increases and produced water declines, lease operating costs per unit of production are generally lower. As an example, the per Mcf lease operating expense at the White Oak Creek field, a mature CBM project that reached peak gas production in 2001, was $0.60 for the first five months of 2004 (through the date of the White Oak Creek sale). Conversely, our primary producing properties, Pond Creek and Cahaba, are at much earlier stages in their lifecycles with development operations beginning on June 30, 2002 and December 31, 2003, respectively, and gas sales commencing in February 2003 and January 2004, respectively. The lease operating expense per Mcf for these fields in the quarter ended September 30, 2005 was $1.42 and $3.80, respectively. The per unit operating costs for these properties are high relative to White Oak Creek due to their earlier stages of development, but are expected to be lower as gas production increases. For the nine month period ended September 30, 2005, sales volumes from the Cahaba and Pond Creek projects accounted for approximately 88% of our total sales volumes. As a result of the concentration of sales volumes in these two projects, our gas revenues, profitability, and cash flows will be primarily dependent on the performance of these projects.

To reduce our exposure to fluctuations in natural gas prices, which have exhibited a high degree of volatility over the past several years, we periodically enter into derivative commodity instruments. Our policy is to enter into hedging transactions which increase our statistical probability of achieving our targeted level of cash flows.

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 prepare 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 financial statements. We believe the following critical accounting policies affect our more significant judgments and estimates used 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 & MacNaughton, our 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.

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.

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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 unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The 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. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

Unevaluated Properties. The costs 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.

Accrual for Future Abandonment Costs.

We have significant obligations to plug and abandon natural gas wells and related equipment and facilities. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. The related asset value is increased by the same amount. 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.

Estimating future asset retirement obligations 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

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legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the carrying cost of the related asset.

Price Risk Management Activities. We account for our price risk management activities under the provisions of SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended. We record the fair value of our derivative instruments on our balance sheet as either an asset or liability. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. We have elected not to designate any of our current price risk management activities as accounting hedges, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change. Our estimates of fair value are determined by obtaining independent market quotes from our counterparties. The fair values determined by the counterparties are based, in part, on estimates and judgments.

Revenue Recognition. We derive revenue primarily from the sale of produced gas, hence our revenue recognition policy for these sales is significant. We recognize gas revenue from our interests in producing wells as gas is produced and sold from those wells. Gas sold in production operations is not significantly different from our share of production.

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 Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under SFAS 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 Internal Revenue Code Section 382.

We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years.

Future Charges

Public Company Expenses

We believe that our general and administrative expenses will increase in connection with the filing of this registration statement. This increase will consist of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act of 2002 and other regulations. We anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company. This increase will be due primarily to the cost of accounting support services, filing annual and quarterly reports with the SEC, investor relations, directors fees, directors and officers insurance, and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for 2006 will increase significantly. Our consolidated financial statements following the completion of this offering will reflect the impact of these increased expenses and affect the comparability of our financial statements with periods prior to the completion of this offering.

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Equity Compensation Expenses

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

Derivative Instruments

Due to the historical volatility of natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our production. Currently, we use collars and fixed-price swaps as our mechanism for hedging commodity prices. We have elected not to designate any of our current derivative instruments as hedges for accounting purposes in accordance with SFAS No. 133 Derivative Instruments and Hedging Activities. As a result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized in earnings. While we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our production is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. As a result of rising commodity prices, we realized a charge in the quarter ended December 31, 2005 of approximately $5.2 million. If commodity prices increase, we may recognize additional charges in future periods.

Producing Field Operations Summary

The table below presents information on gas revenues, sales volumes, production costs and per Mcf data for the nine months ended September 30, 2005 and 2004 and the years ended December 31, 2004, 2003, and 2002. This table should be read with the discussion of the results of operations for the periods presented below.

	Nine Months Ended September 30,		Year Ended December 31		
	2005	**2004**	**2004**	**2003**	**2002**
	(In thousands except per Mcf)				
Gas sales	$ 24,240	$ 13,258	$ 19,522	$ 11,700	$ 6,731
Lease operating costs	$ 6,212	$ 3,555	$ 5,092	$ 1,640	$ 590
Compression and transportation costs	2,332	1,385	1,951	993	654
Production taxes	518	351	473	414	285
Total production costs	$ 9,062	$ 5,291	$ 7,516	$ 3,047	$ 1,529
Net sales volumes (MMcf)	3,279	2,288	3,187	2,484	2,130

Per Mcf data ($/Mcf):					
Average gas sales price	$ 7.39	$ 5.79	$ 6.12	$ 4.71	$ 3.16
Lease operating costs	1.89	1.55	1.60	0.66	0.28
Compression and transportation costs	0.71	0.61	0.61	0.40	0.31
Production taxes	0.16	0.15	0.15	0.17	0.13
Total production costs	2.76	2.31	2.36	1.23	0.72

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Results of Operations

Nine Months Ended September 30, 2005 compared with Nine Months Ended September 30, 2004

The following is a discussion of significant matters affecting the operating and financial results for the nine-month period ended September 30, 2005 compared to the nine-month period ended September 30, 2004. Significant changes in sales volumes at our major properties and the White Oak Creek Sale and the Pond Creek Acquisition, which occurred in 2004 and were discussed in detail in the Overview, result in the periods not being comparable.

Selected items presented in our Consolidated Statement of Operations and Comprehensive Income on page F-4 and their percentage changes from the comparable period are presented in the table below:

	Nine Months Ended September 30,		Percentage
	2005	2004	Change
	(In thousands)		
Gas sales	$ 24,240	$ 13,258	83%
Operating fees and other	376	447	(16)%
Total revenues	$ 24,616	$ 13,705	80%
Lease operating costs	$ 6,212	$ 3,555	75%
Compression and transportation costs	2,332	1,385	68%
Production taxes	518	351	48%
Depreciation, depletion and amortization	3,378	1,666	103%
Research and development costs	531	279	90%
General and administrative	2,277	1,758	29%
Realized losses on derivative contracts	2,289	429	434%
Unrealized losses (gains) from the change in market value of open derivative contracts	21,833	1,103	1,879%
Total costs and operating expenses	$ 39,370	$ 10,526	274%
Interest expense (net of amounts capitalized)	$ (2,534)	$ (550)	360%
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	$ (17,262)	$ 2,680	(744)%
Income tax provision	(5,843)	911	(741)%
Net Income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	$ (11,419)	$ 1,769	(745)%

Sales Volumes. Increases in wells coming on line from the ongoing drilling program and the Pond Creek Acquisition, offset partially by the White Oak Creek Sale and normal production declines, resulted in a 43% increase in sales volumes to 3.3 Bcf from 2.3 Bcf. Total net productive wells increased 54% to 270 from 175.

Gas Sales. Increases in gas prices and sales volumes resulted in an 83% increase in gas sales to $24.2 million from $13.3 million. Gas prices increased 28% to $7.39 per Mcf from $5.79 per Mcf.

Operating fees and other. A $0.1 million cash settlement from a previous joint venture partner and a $0.17 million decrease in operating fees from the termination of contract operations resulted in a slight decrease in operating fees and other.

Lease Operating costs. An increase in unit costs and higher sales volumes resulted in a 75% increase in lease operating costs to $6.2 million from $3.6 million. Lease operating costs per Mcf increased 22% to $1.89 from $1.55. The increase in per unit lease operating costs was primarily due to a change in the sales volume mix,

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which is weighted more to early stage projects with higher per unit lease operating costs in the 2005 period as compared to mature projects with lower per unit lease operating costs in the 2004 period. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit lease operating costs than the overall per unit lease operating costs.

Compression and transportation costs. An increase in unit costs and higher sales volumes at Pond Creek resulted in a 68% increase in compression and transportation costs to $2.3 million from $1.4 million. Compression and transportation costs per mcf increased 16% to $0.71 from $0.61. The increase in per unit compression and transportation costs was primarily due to the additions of compressors to handle the increase in sales volumes and increases in firm transportation fees. There are no transportation costs at Cahaba. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit compression and transportation costs than the overall per unit compression and transportation costs.

Production taxes. Increases in gas sales resulted in a 48% increase in production taxes to $0.5 million from $0.4 million. A significant portion of Pond Creek sales volumes is exempt from production taxes for five years from date of first production because of a West Virginia tax exemption.

Depreciation, depletion and amortization. A 50% increase in the depletion rate for gas reserves to $0.99 from $0.66 combined with a 43% increase in sales volumes caused depreciation, depletion and amortization to increase 103% to $3.4 million from $1.7 million. A $48 million increase in 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 was the primary cause of the increased depletion rate in 2005. The depletion rate is generally calculated by dividing the net book value of gas properties by total proved reserves.

General and administrative. Increases in employee expenses, professional fees and business taxes, partially offset by an increase in recoveries, reclassification and capitalized items, resulted in a 29% increase in general and administrative to $2.3 million from $1.8 million. An increase in the number of employees due to increased activity levels and a $0.15 million one-time payment to certain executives associated with the subsidiary merger increased employee expenses. General and administrative recoveries, reclassification and capitalized items in 2005 and 2004 amounted to $4.2 million and $4.1 million, respectively. General and administrative recoveries, reclassifications and capitalized items primarily consist of capitalized general and administrative costs related to exploration and development activities and the reclassification of costs related to field employees involved in production activities.

Realized losses on derivative contracts. Increases in gas prices during the nine month period ended September 30, 2005, combined with increases in the nominal volume of derivative contracts that settled during the period, caused the realized losses on derivative contracts to increase 434% to $2.3 million from $0.4 million. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Realized losses represent the net cash settlements paid to the derivative counterparty during the period. The realized losses are recorded in total costs and operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Unrealized losses (gains) from the change in market value of open derivative contracts. The change in the market value of open derivative contracts during the nine month period ending September 30, 2005 resulted in a 1,879% increase in unrealized losses to $21.8 million from $1.1 million. Increases in gas prices during the period and in the nominal volume of outstanding derivative contracts contributed to the increase in unrealized losses. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Under this accounting treatment, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the income statement in the period of change. The gains and losses are recorded in total costs and operating expenses in the

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Interest expense (net of amounts capitalized). Higher average levels of debt outstanding and higher borrowing rates on the credit facility caused interest expense (net of amounts capitalized) to increase 360% to $2.5 million from $0.6 million. Capitalized interest in 2005 and 2004 was $0.4 million and $0.08 million, respectively.

Income tax provision. Our income tax provision includes both state and federal taxes. Our state taxes are an insignificant portion of our income tax provision. The 741% decrease in our income tax provision to a benefit of $5.8 million from an expense of $0.9 million corresponds to the net loss in 2005 from net income in the comparable period. The effective rate in 2005 and comparable period remained at approximately 34%.

Year Ended December 31, 2004 compared with Year Ended December 31, 2003

The following is a discussion of significant matters affecting the operating and financial results for the year ended December 31, 2004 compared to the year ended December 31, 2003. Significant changes in sales volumes at our major properties and the White Oak Creek Sale and the Pond Creek Acquisition, which occurred in 2004 and were discussed in detail in the Overview, result in the periods not being comparable.

Selected items presented in the Consolidated Statement of Operations and Comprehensive Income on page F-4 and their percentage changes from the comparable period are presented in the table below:

	Year Ended December 31,		Percentage
	2004	**2003**	**Change**
	(In thousands)		
Gas sales	$ 19,522	$ 11,700	67%
Operating fees and other	1,402	349	302%
Total revenues	$ 20,924	$ 12,049	74%
Lease operating costs	$ 5,091	$ 1,640	210%
Compression and transportation costs	1,951	993	96%
Production taxes	473	414	14%
Depreciation, depletion and amortization	2,691	2,120	27%
Research and development costs	279	432	(35)%
General and administrative	2,513	1,370	83%
Impairment		8	100%
Realized losses on derivative contracts	815	44	1,752%
Unrealized losses (gains) from the change in market value of open derivative contracts	(542)	102	631%
Total costs and operating expenses	$ 13,271	$ 7,123	86%
Interest expense (net of amounts capitalized)	$ (986)	$ (232)	325%

Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	$ 6,732	$ 4,782	41%
Income tax provision	2,312	1,651	40%
Net Income (loss) before minority interest, and cumulative effect of change in accounting principle, net of income tax	$ 4,420	$ 3,131	41%

Sales volumes. Increases in wells coming on line from the ongoing drilling program at Pond Creek, the beginning of development at Cahaba and the Pond Creek Acquisition, offset partially by the White Oak Creek Sale and normal production declines, resulted in a 28% increase in sales volumes to 3.2 Bcf from 2.5 Bcf. Total net productive wells increased 96% to 220 from 112.

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Gas sales. Increases in gas prices and sales volumes resulted in a 67% increase in gas sales to $19.5 million from $11.7 million. Gas prices increased 30% to $6.12 per Mcf from $4.71 per Mcf. The sales price per Mcf in 2003 was reduced by the forward sale of 3,000 MMBtu/day of gas produced from White Oak Creek at a set price of $4.00/MMBtu for the period January 1, 2003 to December 31, 2003.

Operating fees and other. A $0.8 million White Oak Creek joint interest audit settlement and a $0.2 million increase in contract operating fees, primarily increased operating fees and other by $1.1 million to $1.4 million in 2004 from $0.3 million in 2003.

Lease operating costs. An increase in unit costs and higher sales volumes resulted in a 210% increase in lease operating costs to $5.1 million from $1.6 million. Lease operating costs per mcf increased 142% to $1.60 from $0.66. The increase in per unit lease operating costs was primarily due to a change in the sales volume mix which is weighted more to early stage projects with higher per unit operating costs in the 2004 period as compared to mature projects with lower per unit operating costs in the comparable period. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit lease operating costs than the overall per unit lease operating costs.

Compression and transportation costs. An increase in unit costs and higher sales volumes at Pond Creek resulted in a 96% increase in compression and transportation costs to $2.0 million from $1.0 million. Compression and transportation costs per mcf increased 53% to $0.61 from $0.40. The increase in per unit compression and transportation costs was primarily due to the addition of compressors to handle the increase in sales volumes. There are no transportation costs at Cahaba. The White Oak Creek Sale was the sale of a mature project with significantly lower per unit compression and transportation costs than the overall per unit compression and transportation costs.

Production taxes. Increases in gas sales resulted in a 14% increase in production taxes to $0.5 million from $0.4 million. All of Pond Creek s production in 2004 and 2003 was exempt from production taxes because the producing wells are located in West Virginia which has a production tax exemption for five years from the date of first production.

Depreciation, depletion and amortization. Increases in sales volumes and a 2.5% increase in the depletion rate to $0.80 per Mcf from $0.78 per Mcf caused depreciation, depletion and amortization to increase 27% to $2.7 million from $2.1 million. The Pond Creek Acquisition added 31.8 Bcf of proved reserves at a cost of $27 million or $0.85 per Mcf of proved reserves. The White Oak Creek Sale reduced the net book value of properties by $21 million and reduced proved reserves by 8.4 Bcf. The depletion rate is generally calculated by dividing the net book value of gas properties by total proved reserves.

General and administrative. Increases in employee expenses, professional fees and business taxes, partially offset by an increase in recoveries, reclassifications and capitalized items, resulted in an 83% increase in general and administrative to $2.5 million from $1.4 million. The hiring of additional employees due to the increase in activity levels and higher salary levels increased gross employee expenses approximately $0.9 million and a title dispute increased legal fees approximately $0.3 million. General and administrative recoveries, reclassifications and capitalized items in 2004 and 2003 were $5.4 million and $5.1 million, respectively. General and administrative recoveries, reclassifications and capitalized items primarily consist of capitalized general and administrative costs related to exploration and development activities and the reclassification of costs related to field employees involved in production activities.

Realized losses on commodity derivative contracts. Increases in gas prices during the year, combined with increases in the nominal volume of derivative contracts that settled during the year, caused the realized losses on derivative contracts to increase 1,752% to $0.8 million from $0.04 million. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Realized losses represent the net cash settlements paid to the derivative counterparty during the period. The realized losses are recorded in total costs and operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

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Unrealized losses (gains) from the change in market value of open derivative contracts. The change in the market value of open derivative contracts for the year resulted in an unrealized gain of $0.5 million from a loss of $0.1 million in the comparable period. Decreases in gas prices during the period and an increase in the nominal volume of outstanding derivative contracts contributed to the decrease in unrealized losses. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Under this accounting treatment, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the income statement in the period of change. The gains and losses are recorded in total costs and operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Interest expense (net of amounts capitalized). Increased average debt levels and higher borrowing rates on the credit facility caused interest expense (net of amounts capitalized) to increase 325% to $1.0 million from $0.2 million during the period. Capitalized interest in 2004 and 2003 was $0.1 million and $0.1 million, respectively.

Income tax provision. Our income tax provision includes both state and federal taxes. Our state taxes are an insignificant portion of our income tax provision. The 40% increase in our income tax provision to $2.3 million from $1.7 million corresponds to the increase in net income before tax in 2004. The effective rate in 2004 and comparable period remained at approximately 34%.

Year Ended December 31, 2003 compared with Year Ended December 31, 2002

The following is a discussion of significant matters affecting the operating and financial results for the year ended December 31, 2003 compared to the year ended December 31, 2002. Significant changes in the composition of our major properties that occurred in 2003 results in the periods not being comparable.

Selected items presented in the Consolidated Statement of Operations and Comprehensive Income on page F-4 and their percentage changes from the comparable period are presented in the table below:

	Year Ended December 31,		Percentage
	2003	**2002**	**Change**
	(In thousands)		
Gas sales	$ 11,700	$ 6,731	74%
Operating fees and other	349	277	26%
Total revenues	$ 12,049	$ 7,008	72%
Lease operating costs	$ 1,640	$ 590	178%
Compression and transportation costs	993	654	52%
Production taxes	414	285	45%
Depreciation, depletion and amortization	2,120	2,151	(1)%

Research and development costs	432	168	159%
General and administrative	1,370	1,598	(14)%
Impairment of other equipment and other non-current assets	8	108	(92)%
Realized losses on derivative contracts	44		100%
Unrealized losses (gains) from the change in market value of open derivative contracts	102		100%
Total costs and operating expenses	$ 7,123	$ 5,554	28%
Interest expense (net of amounts capitalized)	$ (232)	$ (186)	24%
Income (loss) before income taxes, minority interest, and cumulative effect of change in accounting principle, net of income tax	$ 4,782	$ 1,380	246%
Income tax provision	1,651	639	158%
Net income (loss) before minority interest and cumulative effect of change in accounting principle, net of income tax	$ 3,131	$ 741	322%

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Sales volumes. Increases in wells coming on line from the beginning of development at Pond Creek resulted in a 17% increase in sales volumes to 2.5 Bcf from 2.1 Bcf. Total net productive wells increase 115% to 112 from 52.

Gas sales. Increases in gas prices and sales volumes resulted in a 74% increase in gas sales to $11.7 million from $6.7 million. Gas prices increased 49% to $4.71 per Mcf from $3.16 per Mcf. The sales price in 2003 was reduced by the forward sale of 3,000 MMBtu/day of gas produced from White Oak Creek at a set price of $4.00/MMBtu for the period January 1, 2003 to December 31, 2003.

Lease operating costs. An increase in unit costs and higher sales volumes resulted in a 178% increase in lease operating costs to $1.6 million from $0.6 million. Lease operating costs per Mcf increased 136% to $0.66 from $0.28. The increase in per unit lease operating costs was primarily due to a change in the sales volume mix which is weighted more to early stage projects with higher per unit operating costs in the 2003 period as compared to mature projects with lower per unit operating costs in the comparable period. Before the addition of the Pond Creek project, White Oak Creek was our major property which was a mature project with significantly lower per unit lease operating costs than Pond Creek.

Compression and transportation costs. An increase in unit costs and higher sales volumes due to the beginning of sales at Pond Creek, resulted in a 52% increase in compression and transportation costs to $1.0 million from $0.7 million. Compression and transportation costs per mcf increased 29% to $0.40 from $0.31.

Production taxes. Increased gas sales at White Oak Creek resulted in a 45% increase in production taxes to $0.4 million from $0.3 million. All of Pond Creek s production in 2003 was exempt from production taxes because the producing wells are located in West Virginia which has a production tax exemption for five years from the date of first production.

Depreciation, depletion and amortization. A 16% decrease in the depletion rate to $0.80 from $0.96, offset by an increase in sales volumes, resulted in a 1% decrease in depreciation, depletion and amortization to $2.1 million. The Pond Creek and Cahaba projects were the primary changes to the net book value and reserves in 2003. The DD&A rate is generally calculated by dividing the net book value of gas properties by total proved reserves.

General and administrative expenses. Increases in employee expenses of $1.2 million offset by a $1.4 million increase in general and administrative recoveries, reclassifications and capitalized items, reduced general and administrative expenses by 14% to $1.4 million from $1.6 million. An increase in the number of employees to handle the increase in development and exploration efforts resulted in additional employee expense. General and administrative recoveries, reclassification and capitalized items in 2003 and 2002 were $5.1 million and $3.8 million, respectively. Increases in our development and exploration efforts in 2003 resulted in an increase in general and administrative recoveries, reclassifications and capitalized items. General and administrative recoveries, reclassifications and capitalized items primarily consist of capitalized general and administrative costs related to exploration and development activities and the reclassification of costs related to field employees involved in production activities.

Impairment of other equipment and other non-current assets. The impairment in 2003 of $8,000 was a write-down of the remaining cost in the computer software that was partially written off in 2002. The impairment in 2002 consisted of a $0.1 million write-down of a common stock investment in a technology joint venture that was discontinued and an $8,000 write-down of computer software.

Realized losses on commodity derivative contracts. Increases in gas prices during the year, combined with increases in the nominal volume of derivative contracts that settled during the year, caused realized losses on commodity derivative contracts totaling $0.04 million in 2003. We did not enter into any derivative contracts during the year ending December 31, 2002. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Realized losses represent the net cash

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settlements paid to the derivative counterparty during the period. The realized losses are recorded in total costs and operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Unrealized losses (gains) from the change in market value of open derivative contracts. The change in the market value of open derivative contracts for the year resulted in an unrealized loss of $0.1 million. We did not have any derivative contracts outstanding at December 31, 2002. Increases in gas prices during the period and an increase in the nominal volume of outstanding derivative contracts contributed to the unrealized loss. We enter into various gas swap and three-way collar transactions from time to time that we choose not to designate as accounting hedges. Under this accounting treatment, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the income statement in the period of change. The gains and losses are recorded in total costs and operating expenses in the Consolidated Statement of Operations and Comprehensive Income.

Interest expense (net of capitalized amounts). Higher average debt levels and higher borrowing rates on the credit facility caused interest expense (net of amounts capitalized) to increase 24% to $0.23 million from $0.19 million. Capitalized interest expense in 2003 and 2002 was $0.1 million and $0.05 million, respectively.

Income tax provision. Our income tax provision includes both state and federal taxes. Our state taxes are an insignificant portion of our income tax provision. The 158% increase in our income tax provision to $1.7 million from $0.6 million corresponds to the increase in net income before tax in 2003, offset partially by a 26% decrease in our effective tax rate to 34% from 46%. Our effective tax rate decreased in 2003 due to the loss of Section 29 tax credits in 2002 that resulted in a higher effective tax rate for the year.

Liquidity and Capital Resources

Cash Flows and Liquidity

As of September 30, 2005, we had a working capital deficit of approximately $14.9 million. This compares to a deficit of working capital of $1.2 million at December 31, 2004. The increase in the working capital deficit is primarily due to the $17.3 million derivative liability, offset partially by the related $5.9 million deferred tax asset. The derivative liability is directly affected by natural gas prices and may vary significantly from period to period. Our accounts payable balances at September 30, 2005 increased by approximately 26% over levels at December 31, 2004, primarily as a result of the timing of payments of expenditures for our current projects. At September 30, 2005, we had $27 million available for borrowing under our credit facility.

Cash flow from operating activities was $8.4 million and $10.6 million, respectively, for the nine months ended September 30, 2005 and the year ended December 31, 2004. In the past, cash flow from operations has been insufficient to fund our capital expenditures. In order to meet this shortfall, we have generally incurred debt under our credit facility and sold additional common stock ($9.1 million of proceeds in 2004). With the proceeds of our private equity offering in January 2006, including the repayment of loans we had made to selling stockholders and the availability under our new credit facility, we believe we will have adequate resources to meet our capital expenditure requirements for 2006 and for other working capital needs.

Cash flow from financing activities for the nine months ended September 30, 2005 includes payment of a $3 million common stock dividend by GeoMet to its stockholders prior to the merger of its subsidiary, Old GeoMet, into GeoMet.

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 common stock, we may be forced to defer planned capital expenditures.

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Price Risk Management Activities

The energy markets have historically been very volatile, and there can be no assurance that gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of natural gas on our operations, management has adopted a policy of hedging natural gas prices from time to time primarily through the use of commodity price swap agreements and costless collar arrangements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Our price risk management policy strictly prohibits the use of derivatives for speculative positions.

We enter into hedging transactions that increase our statistical probability of achieving our targeted level of cash flows. We have at times hedged forward for periods up to two years. We generally limit the amount of these hedges to no more than 50% to 60% of the then expected gas production for such future period. 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 $1.00 and $1.50 per MMBtu. Currently, our hedge strategy favors the use of three-way collars that allow us to retain more price upside. We have not designated any of our price risk management activities as accounting hedges and, therefore, have accounted for these transactions using the mark-to-market accounting method. Generally, we incur accounting losses during periods where prices rise above the level of our hedges and gains during periods where prices drop below the level of our hedges. Until 2005, the impact of this method of accounting was not significant; however, the significant increase in gas prices in 2005, particularly in the third quarter in response to Hurricanes Katrina and Rita, resulted in the incurrence of approximately $24.1 million in hedging losses. A total of $21.8 million of such losses were unrealized at September 30, 2005 and had no impact on cash flows.

We believe that the use of derivative instruments does not expose us to material risk. However, the use of derivative instruments could materially affect our results of operations depending on the future prices of natural gas. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity. For a summary of accounting policies related to derivative instruments, see Note 2 of the notes to the consolidated financial statements included in this prospectus.

As of September 30, 2005, we had the following hedge contracts outstanding:

Derivative	Volume (MMBtu)	Weighted Average Floor Range ($/MMBtu)	Fixed or Ceiling Weighted Average Price ($/MMBtu)
Swaps:			
October 1 October 31, 2005	248,000		$ 6.42
Costless Collars:			
October 1 December 31, 2005	856,000	$ 5.75 $7.17	$ 8.91
January 1 December 31, 2006	4,258,000	$ 5.99 $7.27	$ 9.05
January 1 December 31, 2007	1,756,000	$ 6.60 $7.98	$ 10.28

We have subsequently settled all of the above swap volumes and 856,000 MMBtu of the costless collar volumes for the three-month period ended December 31, 2005, resulting in a realized loss to us of approximately $5.2 million.

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Sensitivity analyses of the incremental effects on pre-tax loss for the nine months ended September 30, 2005 of a hypothetical 10% and 25% change in natural gas prices for outstanding hedge contracts as of September 30, 2005 are provided in the following table:

	Incremental (Increase)/ Decrease in pre-tax loss assuming a hypothetical price increase and decrease of(1):	
	10%	25%
	(In thousands)	
Price increase	($ 6,730)	($ 17,370)
Price decrease	6,310	14,620

(1) We remain at risk for possible changes in the market value of these derivative contracts; however, any unfavorable increases would be partly offset by higher revenues due to higher sales prices for our gas. The favorable effect of this offset is not reflected in the sensitivity analyses.

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.

Capital Expenditures and Capital Resources

	Nine Months Ended September 30,		Year Ended December 31,		
	2005	2004	2004	2003	2002
	(In thousands)				
Capital expenditures:					
Leasehold acquisition	$ 1,413	$ 1,134	$ 1,571	$ 2,109	$ 1,851
Exploration	6,334	4,923	6,759	17,374	2,318
Development	40,356	34,697	49,023	14,623	7,232
Acquisitions		27,046	27,046		
Other items (primarily capitalized overhead and interest)	1,630	1,373	1,790	1,963	1,369
Total capital expenditures	$ 49,733	$ 69,173	$ 86,189	$ 36,069	$ 12,770

Our capital expenditures for the nine month period ending September 30, 2005 were approximately 17% higher than the comparable 2004 period, exclusive of the Pond Creek Acquisition and the White Oak Creek Sale. This increase was primarily due to the increase in development activity in the Gurnee and Pond Creek fields. Increases in the 2005 period development expenditures was due to increased spending at Pond

Creek. Our capital expenditures for 2004, exclusive of the Pond Creek Acquisition and the White Oak Creek Sale, increased approximately 62% compared to 2003 as a result of increased development expenditures at the Gurnee field. Our capital expenditures increased in 2003 due to increased Pond Creek field development spending and due to exploratory spending.

We expect total capital expenditures in the last quarter of 2005 to be approximately $10 million and total capital expenditures to range from $80 million to $90 million for 2006.

Credit Facility

We have recently entered into a $150 million amended and restated credit agreement with Bank of America, N.A., as agent, and other lenders. Availability under the amended credit agreement is subject to a borrowing

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base, which is currently set at $120 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. The amended 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 increasing from a low of 100 basis points to a high of 200 basis points as loans outstanding increase as a percentage of the borrowing base. Borrowings under the amended credit agreement are secured by first priority liens on substantially all of our assets including equity interests in our subsidiaries. All outstanding borrowings under the amended credit agreement become due and payable in January 2011.

We are subject to financial covenants requiring maintenance of a minimum current ratio and a minimum interest coverage ratio. 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.

At September 30, 2005, the amount of borrowings outstanding under our then existing credit facility was $93 million, accruing interest at an average annual rate of 5.78%.

At September 30, 2005, we did not have any hedges in place to reduce our risk to increases in interest rates.

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 September 30, 2005:

		Beginning January 1, 2006(1)				
	2005 Three Months	One Year	2-4 Years	5-6 Years	More than 6 Years	Total
				(In thousands)		
Total debt(2)	$ 13	$ 86	$ 93,309	$	$ 618	$ 94,026
Interest expense on debt(3)	1,461	5,719	5,093			12,273
Operating lease obligations	293	1,182	3,052	1,282	210	6,019
Abandonment liabilities	25	28			1,419	1,472
Derivative liability	6,243	12,843	2,231			21,317
Total commitments	$ 8,035	$ 19,858	$ 103,685	$ 1,282	$ 2,247	$ 135,107

(1) Does not include a contingent payment on related to the Pond Creek Acquisition because the amount is not contractually determinable until December 31, 2007. The contingent payment, if any, will be paid March 31, 2008 and cannot exceed $3 million.

(2) Maturities based on credit agreement terms as of September 30, 2005 which had a maturity date of November 21, 2007.

(3) Assumes an annual rate on a 30-day LIBOR of 4.15% plus the current 2% margin for a total interest rate of 6.15%.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

In June 2005, the Financial Accounting Standard Board (FASB) issued FASB Statement No. 154, *Accounting Changes and Error Corrections*- a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a

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change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. This Statement also provides guidance for determining whether retrospective application of a change in accounting principle is impracticable and for reporting a change when retrospective application is impracticable. The correction of an error in previously issued financial statements is not an accounting change. However, the reporting of an error correction involves adjustments to previously issued financial statements similar to those generally applicable to reporting an accounting change retrospectively. Therefore, the reporting of a correction of an error by restating previously issued financial statements is also addressed by this Statement. This statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of this statement had no effect on our financial statements.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, Exchanges of Nonmonetary Assets, an Amendment of Accounting Principles Board (APB) Opinion No. 29, which provides all nonmonetary asset exchanges that have commercial substance must be measured based on fair value of the assets exchanged and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. SFAS No. 153 became effective for fiscal periods beginning on or after June 15, 2005. We adopted SFAS No. 153 effective July 1, 2005. The adoption of SFAS No. 153 did not have a material impact on our financial statements.

In March 2005, the Financial Accounting Standard Board (FASB) issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside our control. FIN 47 states that we must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This interpretation is intended to provide more information about long-lived assets, future cash outflows for these obligations, and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The release of this Interpretation did not affect the method we were applying to accrue asset retirement obligations, therefore, the adoption of this Interpretation had no effect on our financial statements.

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*, which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods and services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees, and carries forward without change prior guidance for share-based payments for transactions with non-employees. SFAS No. 123(R) eliminates the intrinsic value measurement objective in APB Opinion 25 and, except in certain circumstances, requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. The standard requires grant date fair value to be estimated using either an option-pricing model which is consistent with the terms of the award or a market observed price, if such a price exists. If such fair value cannot be reasonably estimated because it is not practicable to estimate the expected volatility of our share price, we are required to estimate a value calculated by substituting the historical volatility of an appropriate industry sector index for the expected volatility of our share price. Such cost must be recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The standard also requires us to estimate the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur.

We are required to adopt SFAS No. 123(R) on January 1, 2006 using the prospective transition method. Under the prospective transition method equity compensation cost will be recognized in the consolidated statement of operations based on fair value for all new awards and existing awards that are modified, repurchased or cancelled after the required effective date of January 1, 2006. For awards outstanding as of January 1, 2006,

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we will continue using the accounting principles originally applied to those awards before adoption. We have adopted SFAS No. 123(R) effective January 1, 2006 and are in the process of implementing the standard. The impact of the adoption of SFAS No. 123(R) cannot be predicted at this time because it will depend on the level of share-based awards granted in the future.

Quantitative and Qualitative Disclosures about Market Risk

For a discussion of our commodity and interest rate risks, see the discussions set forth in the subsections titled Price Risk Management Activities and Credit Facility above.

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 exploratory, the effect of changes in the exchange rate does not impact our revenues or expenses but primarily affects the costs of unproved 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.

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BUSINESS

About GeoMet

We are engaged in the exploration, development, and production of natural gas from coal seams (coalbed methane or CBM). Our principal operations and producing properties are located in the Cahaba Basin in Alabama and the Appalachian Basin in West Virginia and Virginia. GeoMet was originally founded as a consulting company to the coalbed methane industry in 1985 and has been active as an operator and developer of coalbed methane properties since 1993. We control a total of approximately 255,000 net acres of coalbed methane development rights, primarily in Alabama, West Virginia, Virginia, Louisiana, Colorado, and British Columbia. We control a total of approximately 77,000 net acres of coalbed methane development rights in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin, and we also control the balance of 178,000 net acres of coalbed methane development rights primarily in north central Louisiana, British Columbia, West Virginia, and Colorado. We have conducted substantial gas desorption testing and drilling of core holes throughout our property base. We believe our extensive undeveloped acreage position in the Gurnee field in the Cahaba Basin and in the Pond Creek field in the Appalachian Basin contains a total of 610 additional drilling locations.

At September 30, 2005, we had 258.5 Bcf of estimated proved reserves with a PV-10 of approximately $1.4 billion using gas prices in effect at such date. Our estimated proved reserves are 100% coalbed methane and 72% proved developed. For the month of December 2005, our net gas sales totaled approximately 14,700 Mcf per day. For 2005, we estimate that our total capital expenditures will be approximately $60 million, of which we had spent $49.7 million as of September 30, 2005. We estimated our development expenditures for the development of the Gurnee and Pond Creek fields to be $45 million in 2005, of which we had spent $40.3 million through September 30, 2005. We intend to increase our development expenditures by approximately 44% in 2006 to approximately $65 million to accelerate the drilling of the Gurnee and Pond Creek fields. Total capital expenditures in 2006 are estimated to be in the range of $80 million to $90 million.

Areas of Operation

Cahaba Basin

We have the development rights to approximately 41,800 net CBM acres throughout the Cahaba Basin of central Alabama, which is adjacent to the Black Warrior Basin. At September 30, 2005, approximately 54% of our estimated proved reserves, or 139.0 Bcf, were located in the Gurnee field within the Cahaba Basin, of which approximately 78% were classified as proved developed. At September 30, 2005, we had developed 23% of our Cahaba Basin CBM acreage. We own a 100% working interest in the area and are the operator. As of December 1, 2005, we had drilled 137 wells in the Gurnee field, of which 115 were producing (the remainder of which were pending completion or hook-up or were venting gas), with net daily sales of gas averaging approximately 4,000 Mcf for the month of December 2005. From project inception through September 30, 2005, our finding and development costs in the Cahaba Basin have averaged $0.82 per Mcf. Our undeveloped CBM acreage in the Cahaba Basin contains 381 additional drilling locations, based on 80-acre spacing. In 2006, we intend to spend approximately $45 million of our capital expenditure budget to develop and drill approximately 75 wells 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 30 core holes have been drilled and over 540 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.

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

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Environmental Management. This pipeline has a design capacity of approximately 45,000 barrels of water per day. 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 these facilities will meet all of our future water disposal requirements for the Gurnee field.

We own and operate a 9.2-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.

Appalachian Basin

In the Appalachian Basin of southern West Virginia and southwestern Virginia, we have the rights to develop approximately 56,000 net CBM acres, approximately 35,100 of which are in our Pond Creek field. At September 30, 2005, approximately 45% of our estimated proved reserves, or 116.3 Bcf, were located within the Pond Creek field, of which approximately 65% were classified as proved developed. We own a 100% working interest in the area and are the operator. As of December 1, 2005, we had drilled 157 wells in the Pond Creek field, of which 154 were producing (the remainder of which are pending completion or hook-up), with net daily sales of gas averaging approximately 9,500 Mcf for the month of December 2005. From project inception through September 30, 2005, our finding and development costs in the Pond Creek field have averaged $0.89 per Mcf. Our undeveloped CBM acreage in the Pond Creek field contains 229 additional drilling locations based on 80-acre spacing. In 2006, we intend to spend approximately $20 million of our capital expenditure budget to develop and drill approximately 40 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 high quality, low-medium volatile bituminous rank Pennsylvanian Age coal. Due to mining activity, it has been long known that these coal groups are gas rich. A total of 39 core holes have been drilled in the area 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 is gathered into our central dehydration and compression facility and delivered into the Cardinal States Gathering System for redelivery into the Columbia Gas Transmission Corporation gas pipeline system. Our gathering agreement with Cardinal States terminates on April 30, 2007. We have held discussions with Cardinal States about possible terms of a long term gathering agreement and negotiations are at an early stage. We expect that within the next 60 days we will have either: 1) executed a long term gathering agreement with Cardinal States or 2) initiated right-of-way acquisitions and permitting of our own 11-mile pipeline to be constructed at an estimated cost of $5 to $6 million, which we plan to interconnect with Jewell Ridge, a new interstate pipeline. East Tennessee Natural Gas, LLC, a subsidiary of Duke Energy Corporation, will construct the Jewell Ridge pipeline. The scheduled in service date for the Jewell Ridge Pipeline, which is awaiting final FERC approval, is July 1, 2006.

British Columbia

Our Peace River Project is comprised of approximately 33,000 gross acres (16,500 net acres) along the Peace River near Hudson s Hope, British Columbia. We are conducting operations on this project through an exploration and development agreement with a third party. We will earn a 50% working interest in this leasehold by spending $7.2 million on an evaluation program. We have spent approximately $5.5 million of this amount

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from project inception through December 31, 2005. We expect to complete our earning obligations in 2006 and to operate this project going forward. We have drilled three core holes targeting the Lower Cretaceous Gething coal formation. Total net coal thickness ranges from 30 to 70 feet at depths from 1,000 to 3,000 feet. At these depths, coals are medium volatile bituminous rank having seams up to nine feet in thickness. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We have recently drilled and completed two wells and a water disposal well and testing operations are in process.

North Central Louisiana

In Winn, LaSalle, and Caldwell Parishes of Louisiana, we are conducting an evaluation of the coals within the Wilcox Formation. We operate the project with a 100% working interest. As of September 30, 2005, we had a total of approximately 110,000 acres under lease, and we have subsequently exercised an option to acquire an additional 9,259 acres. The Wilcox is a thick deltaic deposit of Eocene age, composed primarily of sandstone, siltstone, shale, and coal. The coals are low rank, being classified as sub-bituminous and lignitic. Coal thickness averages 75 feet at depths from 2,000 to 3,500 feet. We have drilled 17 exploration or production test wells and two water disposal wells. We have also conducted 60 gas desorption tests from a sample of nine of these wells to determine the gas content of the coal and to define the potential gas resources. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are currently evaluating producibility issues related to zonal isolation of adjacent water sands and related water encroachment in this area.

Piceance Basin of Colorado

We also hold a total of approximately 14,600 net CBM acres of leasehold in our Cameo prospect in the southwestern portion of the Piceance Basin in Mesa County, Colorado. We are targeting the Cameo coals within a 200-foot interval of the Williams Fork formation at a depth of about 2,000 feet. We have drilled one core hole and have conducted gas desorption tests on the core. We believe that the gas content and coal thickness under our acreage position are favorable for CBM development. We are actively pursuing opportunities to increase our acreage position in this area.

History of GeoMet

Our predecessor, GeoMet, Inc., an Alabama corporation (Old GeoMet), was founded in 1985 by three geologists (the Founders) with backgrounds in the coal mining and related coal degasification industry. The Founders became directly involved with coalbed methane in 1977, working for USX Corporation in developing the first large-scale degasification field in the United States at the Oak Grove Mine in Alabama. This project became the model for subsequent coalbed methane projects in the Black Warrior basin. Our staff has been involved in the development of over thirty percent of the coalbed methane wells currently producing in the Black Warrior basin.

During our early years, our staff consulted extensively with the Gas Research Institute (GRI) in the research and development of new technology for the industry and with many of the companies involved in the early development of coalbed methane, including Taurus (now Energen), Amoco, Chevron, and River Gas Corporation (River Gas). In addition to work done in the United States, we have evaluated or consulted on coalbed methane projects in Australia, Bangladesh, Canada, China, Colombia, Czechoslovakia, Hungary, Israel, Poland, South Africa, Switzerland, the United Kingdom, Venezuela, and Zimbabwe.

In 1986, the Founders acquired a 25% equity interest in River Gas and we provided the technical expertise in connection with the development of the Blue Creek field in the Black Warrior Basin of Alabama. Dominion Energy acquired the Blue Creek field from River Gas in 1992. In 1993, following the sale of the Founders equity interest in River Gas, we ceased consulting services and began to participate in the initiation and development of coalbed methane projects. Due to capital constraints, this participation usually was in the form of relatively small earned interests. The White Oak Creek field in the Black Warrior Basin and the Apache Canyon field in the Raton Basin were developed in this manner.

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Shareholders of Old GeoMet sold 80% of their ownership in Old GeoMet in December 2000 to GeoMet Resources, Inc., a Delaware corporation (Resources), a special purpose entity formed by J. Darby Seré, William C. Rankin, and Yorktown Energy Partners IV, L.P. In connection with this purchase, Resources committed an additional $40 million to Old GeoMet to fund future coalbed methane development and Messrs. Seré and Rankin assumed the positions of President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, respectively. Old GeoMet and Resources merged in April 2005 and Resources changed its name to GeoMet, Inc.

Estimated Proved Reserves

The following tables set forth certain information with respect to our estimated proved reserves by field as of September 30, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. The reserve information as of September 30, 2005 is based on estimates made in a reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers. A summary of DeGolyer and MacNaughton s report on our estimated proved reserves as of September 30, 2005 is attached to this memorandum as Appendix A.

	Estimated Proved Reserves				
Field	**Proved Developed Producing**	**Proved Developed Non-Producing**	**Proved Undeveloped**	**Total Proved**	**PV-10**
	(MMcf)	**(MMcf)**	**(MMcf)**	**(MMcf)**	**($M)**
Appalachia:					
Pond Creek field	74,922	791	40,615	116,328	$ 593,521
Alabama:					
Gurnee field	86,864	21,458	30,711	139,033	748,551
White Oak Creek field	2,763	159	233	3,155	27,577
Total	164,549	22,408	71,559	258,516	$ 1,369,649

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 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. See Reconciliation of Non-GAAP Financial Measures.

CBM-producing natural gas reservoirs generally are not 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 are expected to decline slower than non-CBM wells. See Risk Factors and notes to the financial statements included elsewhere in this prospectus 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 September 30, 2005 used to estimate proved reserves and future net revenue was $14.70 per Mcf and was calculated using the Henry Hub cash price at September 30, 2005, of $14.55 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

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Production and Operating Statistics

The following table presents certain information with respect to our production and operating data for the periods presented.

	Nine Months Ended September 30,		Year Ended December 31,		
	2005	2004	2004	2003	2002
Gas:					
Net sales volume (Bcf)	3.3	2.3	3.2	2.5	2.1
Average sales price ($ per Mcf)	$ 7.39	$ 5.79	$ 6.12	$ 4.71	$ 3.16
Total production costs ($ per Mcf)	$ 2.76	$ 2.31	$ 2.36	$ 1.23	$ 0.72
Expenses: ($ per Mcf)					
Lease operations costs	$ 1.89	$ 1.55	$ 1.60	$ 0.66	$ 0.28
Compression and transportation costs	$ 0.71	$ 0.61	$ 0.61	$ 0.40	$ 0.31
Production taxes	$ 0.16	$ 0.15	$ 0.15	$ 0.17	$ 0.13
Depreciation, depletion & amortization (excluding impairment)	$ 1.03	$ 0.73	$ 0.84	$ 0.85	$ 1.01
Research and development costs	$ 0.16	$ 0.12	$ 0.09	$ 0.17	$ 0.08
General and administrative	$ 0.69	$ 0.77	$ 0.79	$ 0.55	$ 0.75

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 September 30, 2005. 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 capable of producing natural gas.

	Productive Wells(1)		Developed Acres		Undeveloped Acres(2)	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Cahaba Basin	123	123	9,480	9,480	32,286	32,286
Appalachian Basin	147	147	11,172	11,172	45,069	44,586
British Columbia					33,000	16,500
North Central Louisiana					113,352	109,985
Pieance Basin					17,000	16,949
Other					5,030	5,030
Total	270	270	20,652	20,652	245,737	225,336

(1) Excludes 22 net wells pending completion at September 30, 2005.
(2) Excludes an option to acquire a total of approximately 9,259 net acres, which we exercised in December 2005.

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Drilling Activity

The following table sets forth the number of completed gross exploratory and gross development wells drilled in the United States which we participated in during the nine months ending September 30, 2005 and the previous three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective periods. Productive wells are completed producing wells capable of commercial production. At September 30, 2005, we were in the process of completing 22 gross wells (22 net).

	Exploratory			Development		
Well Activity (Gross)	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Nine months ended September 30, 2005	2.0	3.0	5.0	77.0		77.0
Year ended December 31, 2004	10.0	1.0	11.0	85.0		85.0
Year ended December 31, 2003	16.0	1.0	17.0	133.0		133.0
Year ended December 31, 2002	5.0		5.0	44.0		44.0

The following table sets forth, for the nine months ending September 30, 2005 and 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.

	Exploratory			Development		
Well Activity (Net)	**Productive**	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Nine months ended September 30, 2005	2.0	3.0	5.0	77.0		77.0
Year ended December 31, 2004	10.0	1.0	11.0	81.8		81.8
Year ended December 31, 2003	15.0	1.0	16.0	47.7		47.7
Year ended December 31, 2002	2.5		2.5	9.6		9.6

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.

Marketing and Customers

We market all of our gas through Shamrock Energy LLC, a wholly owned subsidiary of Optigas, Inc., under a natural gas purchase contract that may be terminated by either party upon 90 days notice after February 2006. The contract calls for Shamrock to purchase and us to sell gas from properties covered by the contract, which includes all of our major properties. Shamrock provides several related services including nominations, gas control, gas balancing, transportation and exchange, market and transportation intelligence and other advisory and agency services. We receive the weighted average resale price for the gas less a fee for Shamrock s services

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ranging from $0.03 to $0.045 per MMBtu purchased. Proceeds from the sale of the gas are deposited into and disbursed from a trust account for our benefit and the obligations of Shamrock are guaranteed by Optigas. The parties have agreed to amend the contract to make certain technical changes including changes in the payment and reporting terms and to provide that the contract be cancelable by either party on 90 days notice.

Competition

Our operations primarily compete regionally in the northeastern and southeastern United States. Competition throughout the United States is regionalized. We believe that the gas market is highly fragmented and not dominated by any single producer. 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.

Regulation

Regulation by the 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 do not own any pipelines that provide intrastate natural gas transportation, so state regulation of pipeline transportation does not directly affect our operations. As with FERC regulation described above, however, state regulation of pipeline transportation may influence certain aspects of our business and the market for our products.

Gathering Pipeline Regulation. Section 1(b) of the NGA 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 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

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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 sales of natural gas 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 marketing 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.

Environmental Regulations

Our coalbed methane exploration and production operations are subject to significant federal, state, and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities, and concentrations of various substances that can be released into the environment as a result of natural gas and oil 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

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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 of the oil and 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.

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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 contributed 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 significant 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.

Employees

At September 30, 2005, we had 65 full-time employees. 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.

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.

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El Paso Overriding Royalty Interest Dispute

We filed a claim on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell our interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

Insurance Matters

As is common in the gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

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MANAGEMENT

Executive Officers and Directors

The following discussion sets forth as of the date of this prospectus the names and ages of our executive officers and the names and ages of the individuals that serve on our board of directors. Our executive officers are appointed by our board of directors and shall serve until the expiration of their contracts, their death, resignation, or removal by our board of directors. Our directors serve one year terms or until their successors are elected and qualified or until their death, resignation or removal in the manner provided in our bylaws. The present term of each director will expire at the next annual meeting of our stockholders.

Name	Age	Position with Company
J. Darby Seré	58	Chairman of the Board, President, and Chief Executive Officer
William C. Rankin	56	Executive Vice President and Chief Financial Officer
Philip G. Malone	57	Senior Vice President Exploration and Director
Brett S. Camp	46	Senior Vice President Operations
J. Hord Armstrong, III	64	Director
James C. Crain	57	Director
Stanley L. Graves	61	Director
Charles D. Haynes	65	Director
W. Howard Keenan, Jr.	55	Director

J. Darby Seré, *Chairman of the Board, President, and Chief Executive Officer.* Since 2000, Mr. Seré has served as a Director, President and Chief Executive Officer of GeoMet, Inc. Mr. Seré was elected Chairman of the Board in January 2006. Mr. Seré has over 34 years of experience in the oil and gas business, including 17 years as Chief Executive Officer of two publicly held exploration and production companies. Mr. Seré served as President, CEO and Director of Bellwether Exploration Company from 1988-1999, where he also served as Chairman of the Board from 1997-1999, and of Bayou Resources, Inc. from 1982-1987. Mr. Seré was Manager of Acquisitions, Vice President Acquisitions and Engineering and Executive Vice President of Howell Corporation / Howell Petroleum Corporation from 1977-1981. Mr. Seré began his career as a staff reservoir engineer for Chevron Oil Co. in 1970. Mr. Seré currently serves as a director of Gateway Energy Corporation, a publicly held gas gathering, transportation and distribution company. Mr. Seré is a registered professional engineer and holds a Bachelors degree in Petroleum Engineering from Louisiana State University and a Masters of Business Administration from Harvard University.

William C. Rankin, *Executive Vice President and Chief Financial Officer.* Since 2000, Mr. Rankin has served as Executive Vice President and Chief Financial Officer of GeoMet, Inc. Mr. Rankin has 34 years experience as an accountant and financial manager, including 27 years as a financial officer with both publicly and privately owned energy companies. He began his career as an auditor with Deloitte & Touche from 1971-1975. He served as Director of Internal Audit of Kerr-McGee Corporation from 1975-1977, Controller of Cotton Petroleum Corporation from 1977-1980 and Executive Vice President and Chief Financial Officer for Cayman Resources Corporation from 1980-1985. Mr. Rankin joined Hadson Corporation in 1985 as Vice President and Controller, became Vice President and Treasurer in 1988 and last served as Sr. Vice President and Chief Financial Officer of Hadson Resources Corporation from 1989-1993. In 1994 he became Sr. Vice President and Chief Financial Officer of Contour Energy Company (and its predecessors) where he served until 1997. In 1997, he became Sr. Vice President of Bellwether Exploration Company. Mr. Rankin is a Certified Public Accountant and holds a Bachelors degree in Accounting from the University of Arkansas.

Philip G. Malone, *Senior Vice President Exploration and Director.* Since 2000, Mr. Malone has served as our Vice President Exploration. Mr. Malone has 31 years experience as a professional geologist; one year at the Geological Survey of Alabama, ten years at USX Corporation and 20 years at GeoMet, where he participated in founding the company in 1985. From 1976 to 1985, he was a geologist with USX Corporation and served as chief geologist for the last three years of his tenure with responsibility for supervising exploration and

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development work related to coal and coalbed methane for USX Southern District. He has authored and co-authored numerous technical papers and is a recognized speaker worldwide on CBM topics. Mr. Malone holds a Bachelors degree in Geology from the University of Alabama.

Brett S. Camp, *Senior Vice President Operations*. Since 2000, Mr. Camp has been our Vice President-Operations. Mr. Camp has 24 years experience as a professional geologist; four years at USX Corporation and 20 years at GeoMet, where he participated in founding the company in 1985. Mr. Camp holds a Bachelors degree in Geology from Eastern Illinois University.

J. Hord Armstrong, III, *Director*. Mr. Armstrong was appointed to our board of directors in January 2006. Mr. Armstrong has over 30 years of financial and operational experience in varied industries. Mr. Armstrong founded D&K Healthcare Resources, Inc. in 1987, and served as its Chairman and Chief Executive Officer until October 2005. From 1977 to 1987, Mr. Armstrong was with Arch Coal Inc. last serving as its Chief Financial Officer. Mr. Armstrong was First Vice President with White Weld & Company from 1968 to 1977. Mr. Armstrong served for ten years as a member of the Board of Trustees of the St. Louis College of Pharmacy and has served as a director of Jones Pharma Incorporated. Mr. Armstrong formerly served as Chairman of the Board of Trustees of the Pilot Fund, a registered investment company, and also formerly served as a Director of BHA, Inc., based in Kansas City, Missouri. Mr. Armstrong graduated from Williams College in 1963, and attended the New York University School of Business in 1965 and 1966.

James C. Crain, *Director*. Mr. Crain was appointed to our board of directors in January 2006. Mr. Crain has been involved in the energy industry for over 30 years, both as an attorney and as an executive officer. Since 1984, Mr. Crain has held officer positions with Marsh Operating Company, including Vice President of Land and Legal, Executive Vice President, and his current position, President, which he has held since 1989. In addition, since 1997, Mr. Crain has acted as the general partner of Valmora Partners, L.P., which invests in various oil and gas businesses. Prior to joining Marsh in 1984, Mr. Crain was a Partner in the law firm of Jenkens & Gilchrist, where he was the head of the Energy Section. Mr. Crain currently serves on the board of directors of Crosstex Energy, L.P., a Delaware limited partnership that is publicly traded on the Nasdaq National Market. Mr. Crain holds a Bachelors degree in Accounting, a Masters of Professional Accounting in Taxation and a Juris Doctorate degree, all from the University of Texas.

Stanley L. Graves, *Director*. Mr. Graves was appointed to our board of directors in January 2006. Mr. Graves has over 37 years of experience in the oil and gas business. He currently serves as Chairman of the Board of Graves Service Company, Inc., as well as President of Graco Resources, Inc. From 1997-2002, Mr. Graves was the President of U.S. Clay, L.P., which mined and processed bentonite. Prior to his time at U.S Clay, L.P., Mr. Graves served as Vice President Business Development for Ultimate Abrasive Systems, Inc., as President of Eldridge Gathering System Inc., and as Vice President of Energen Corp., the largest CBM producer in Alabama. Mr. Graves currently serves on the board of directors of CapitalSouth Bancorp, a publicly traded bank holding corporation. Mr. Graves holds a Bachelors degree in Engineering from Auburn University.

Charles D. Haynes, *Director*. Dr. Haynes was appointed to our board of directors in January 2006. Dr. Haynes has over 43 years in the energy profession as an academic, researcher, and executive. He retired from The University of Alabama in May 2005, having held faculty and administrative positions since 1991. From 1977 to 1990, he was a senior executive and officer of Belden & Blake Corporation. He is a licensed professional engineer in Alabama and currently serves as Chair of the Alabama Board of Licensure for Engineers and Land Surveyors. He holds Bachelors, Masters, and Doctorate degrees from The University of Alabama, Pennsylvania State University, and the University of Texas, respectively.

W. Howard Keenan, Jr., *Director*. Mr. Keenan has served on our board of directors since December 2000. Mr. Keenan has over 30 years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private equity investment manager focused on the energy industry. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas including the founding of the first Yorktown Fund in 1991. He is or has served as a director of multiple Yorktown portfolio companies. Mr. Keenan holds a Bachelors degree from Harvard College and a Masters of Business Administration from Harvard University.

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Board of Directors; Committees of the Board

Our Board of Directors is comprised of seven members, consisting of J. Darby Seré, Philip G. Malone, J. Hord Armstrong, III, James C. Crain, Stanley L. Graves, Charles D. Haynes, and W. Howard Keenan, Jr. We expect that Messrs. Armstrong, Crain, Graves, and Haynes, being a majority of our Board, will qualify as independent directors as such term is defined by the SEC and the exchange on which our securities will be traded. We have a compensation committee, an audit committee, and a nominating, corporate governance and ethics committee, which are each composed of independent directors. We also have an executive committee that has three members, one of whom is an independent director.

Director Compensation

Each of our independent directors receive an annual retainer of $20,000 and an annual grant of 2,000 shares of non-qualified stock options. Our independent directors also receive $1,500 for each Board meeting attended and $1,000 for each committee meeting attended. In lieu of the foregoing meeting fees, if attendance is by telephone, they receive a fee of $200 per hour. The Chairman of the Audit Committee receives an additional annual retainer of $10,000. The Chairs of other committees of our Board of Directors receive an additional annual retainer of $5,000. All directors are reimbursed for reasonable expenses incurred in their service on our Board of Directors.

Indemnification

Our certificate of incorporation and bylaws provide indemnification rights to the members of our Board of Directors. Additionally, we may enter into separate indemnification agreements with the members of our Board of Directors to provide additional indemnification benefits, including the right to receive in advance reimbursements for expenses incurred in connection with a defense for which the director is entitled to indemnification.

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Executive Compensation

The Summary Compensation Table below sets forth the cash and non-cash compensation information for the years ended December 31, 2005, 2004 and 2003 for the Chief Executive Officer and our other executive officers whose salary and bonus earned for services rendered to us exceeded $100,000 for the most recent fiscal year. We have not yet determined the amounts of the annual bonuses for 2005.

Summary Compensation Table

					Long-Term Compensation			
		Annual Compensation			Awards		Payouts	
Name And Principal Position	Year	Salary ($)	Bonus ($)(1)	Other Annual Compen-sation (2)($)	Restricted Stock Award(s) ($)	Securities Underlying Options/ SARs (#)(3)	LTIP Payouts ($)	All Other Compensation (4)($)
J. Darby Seré	2005	$ 255,600	$ N/A	$ 11,305				$ 6,300
Chairman of the Board, President, and Chief Executive Officer	2004	243,360	70,574	6,881		106,660		6,150
	2003	231,840	63,756	7,448		319,980		7,000
William C. Rankin	2005	$ 211,800	$ N/A	$ 15,071				$ 6,300
Executive Vice President and Chief Financial Officer	2004	201,720	58,499	14,664		93,340		6,000
	2003	192,144	52,840	12,413		280,020		6,000
Philip G. Malone	2005	$ 119,160	$ N/A					$ 4,263
Senior Vice President Exploration	2004	109,163	22,924					4,280
	2003	121,800	33,495					4,598
Brett S. Camp	2005	$ 161,180	$ N/A					$ 5,932
Senior Vice President Operations	2004	126,000	36,540					4,765
	2003	119,400	32,835					4,506

(1) Bonuses represent the amount earned for the year indicated and are paid in the following year.
(2) Other compensation includes paid vacation time not taken by the named executives.
(3) These options were granted under the GeoMet Resources, Inc. Non-Qualified Stock Option Agreement, which allowed Messrs. Seré and Rankin collectively to be granted options to purchase up to 1.2 million shares of our common stock. These options have an exercise price of $2.50 per share and vest equally over a three-year period on each anniversary date. The unvested portion of these options vested on January 30, 2006 under the terms of the Non-Qualified Stock Option Agreement. These options expire 10 years after the date of grant.
(4) Represents employer matching contributions to our 401(k) plan.

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Option/SAR Grants in Fiscal Year 2005

There were no options/SARs granted during this period.

The following table sets forth for each of the named executive officers the number of shares subject to both exercisable and unexercisable stock options in respect of the Company s common shares, as well as the value of unexercisable in-the-money options as of the end of December 31, 2005. The Company has not granted any SARS.

Aggregated Option/SAR Exercises and December 31, 2005 Option/SAR Values

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at December 31, 2005 (shares)		Value of Unexercised In the Money Options/SARs at December 31, 2005 ($)(1)	
			Exercisable	Unexercisable(2)	Exercisable	Unexercisable
J. Darby Seré			462,200	177,760	$ 4,853,100	$ 1,866,480
William C. Rankin			404,480	155,560	$ 4,247,040	$ 1,633,380

(1) Calculated using the price of $13.00 less the applicable exercise price multiplied by the number of option shares.
(2) All stock options became immediately exercisable on January 30, 2006, the closing date of our private placement offering. Mr. Seré exercised and sold 160,000 shares in connection with the private placement offering.

The stock options granted to these executive officers were granted under the GeoMet Resources, Inc. Non-Qualified Stock Option Agreement. These options have an exercise price of $2.50 per share and vest equally over a three-year period on each anniversary date. These options expire 10 years after the date of grant. The options will automatically vest upon the occurrence of (i) an initial public offering, (ii) the date on which Yorktown and its Permitted Transferees cease to own 60% or more of the common stock, or (iii) the termination of employment of either Messrs. Seré or Rankin pursuant to a Without Cause Termination or Good Reason Termination as defined in their employment agreements.

Employment Agreements and Other Arrangements

Mr. Seré and Mr. Rankin executed employment agreements in December 2000, each agreement having initial terms that expired in December 2003. The agreements are substantially similar in form, with differences in titles, responsibilities and base salary. Following the expiration of the initial term, each agreement has been automatically extended for an additional one-year term, and will continue to be automatically extended for an additional year, unless we or the executive gives written notice to the contract party 90 days before the end of subsequent additional term.

Each agreement provides that, if the executive s employment is terminated by us without cause, or by the executive for good reason, that we will pay him, within 30 days of the date of termination, a lump sum amount equal to 18-month s base salary, plus the executive s base salary, reimbursable expenses and vacation accrued but unpaid through the date of termination. In addition, we will continue to provide group medical and dental insurance to the executive and the executive s family for a period of 18 months after the date of termination.

Description of 2005 Stock Option Plan

We have adopted the GeoMet, Inc. 2005 Stock Option Plan (the 2005 Plan). Our board of directors believes that equity-based incentive compensation plans provide an important means of attracting, retaining and motivating employees, non-employee directors, and other service providers. The 2005 Plan is intended to promote and advance our interests by providing our employees, non-employee directors and other service providers added incentive to continue in our service through a more direct interest in the future success of our operations. Our board of directors believes that employees, non-employee directors, and other service providers who have an investment in us are more likely to meet and exceed performance goals. In 2001, the Company established a stock option plan that authorizes the granting of options to key employees to acquire common stock of its majority-owned subsidiary at prices equivalent to the market value at the date of grant. The options have a term of seven years, vest evenly over four years and become exercisable on each of the first four anniversary dates of issuance. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and the options were exchanged for options to acquire common stock of GeoMet under the 2005 Plan. The following is a summary of the 2005 Plan.

Administration. The 2005 Plan provides for administration by our compensation committee. Among the powers granted to the compensation committee are (1) the authority to interpret the 2005 Plan and the options granted thereunder, (2) determine eligibility for participation in the 2005 Plan, (3) prescribe the form of the option agreements embodying options granted under the 2005 Plan, (4) make administrative guidelines and other regulations for carrying out the 2005 Plan and make changes in such guidelines and regulations as the compensation committee deems proper and (5) take any and all other actions it deems necessary or advisable for the proper operation or administration of the 2005 Plan. The compensation committee also has authority with respect to all matters relating to the discharge of its responsibilities and the exercise of its authority under the 2005 Plan. The 2005 Plan provides for indemnification of compensation committee members for personal liability incurred related to any action, interpretation or determination made in good faith with respect to the 2005 Plan and awards made under the 2005 Plan.

Eligibility. Our employees, non-employee directors and other service providers who, in the opinion of the compensation committee, are in a position to make a significant contribution to our success are eligible to participate in the 2005 Plan. The compensation committee determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the terms of the 2005 Plan.

Available Shares. The maximum number of shares available for grant under the plan is 1,200,000 shares of our common stock plus any shares of common stock that become available under the 2005 Plan for any reason other than exercise. The number of shares available for award under the 2005 Plan is subject to adjustment for certain corporate changes in accordance with the provisions of the 2005 Plan. Shares of common stock issued pursuant to the 2005 Plan may be shares of original issuance or treasury shares or a combination of those shares.

Stock Options. The 2005 Plan provides for the grant of incentive stock options intended to meet the requirements of Section 422 of the Code and nonqualified stock options that are not intended to meet those requirements. Incentive stock options may be granted only to our employees. All options will be subject to terms, conditions, restrictions and limitations established by the compensation committee, as long as they are consistent with the terms of the 2005 Plan.

The compensation committee will determine when an option will vest and become exercisable. No option will be exercisable more than ten years after the date of grant (or, in the case of an incentive stock option granted to a 10% shareholder, five years after the date of grant). Unless otherwise provided in the option award agreement, options terminate within a certain period of time following a participant s termination of employment or service for any reason other than cause (one year in the case of an incentive stock option and two years in the case of a non-qualified stock option) or for cause (three months).

The exercise price of a stock option granted under the 2005 Plan shall be determined by the compensation committee but may not, in any event, be less than the fair market value of the common stock on the date of grant. Incentive stock options must be granted at 100% of fair market value (or, in the case of an incentive stock option granted to a 10% shareholder, 110% of fair market value).

The exercise price of a stock option may be paid (i) in cash, (ii) with the consent of the compensation committee, by the execution of a promissory note and/or a combination of cash and execution of a promissory

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note, or (iii) with the consent of the compensation committee and if and to the extent provided for under the option agreement for such option, in cash and/or by delivery of shares of common stock already owned by the optionee having an aggregate fair market value (determined as of the date of exercise) equal to the purchase price.

New Plan Benefits. The number of awards that will be received by or allocated to our executive officers, non-employee directors, employees, and other service providers under the 2005 Plan is undeterminable at this time.

Corporate Change. Unless an award agreement provides otherwise, in the event of a participant s involuntary termination of employment or service other than for death, cause, or inability to perform or a voluntary termination for good reason, within one year after a corporate change (which may include, among others, the dissolution or liquidation of us, certain reorganizations, mergers or consolidations, the sale of all or substantially all our assets, or the closing of an underwritten public offering of our common stock), the board of directors serving prior to the date of the applicable event shall accelerate the exercise dates of all outstanding options, and may, in its discretion, without obtaining stockholder approval, pay cash to any or all optionees in exchange for the cancellation of their outstanding options.

Withholding Taxes. All applicable withholding taxes will be deducted from any payment made under the 2005 Plan, withheld from other compensation payable to the participant, or be required to be paid by the participant prior to the making of any payment of cash or common stock under the 2005 Plan. Payment of withholding taxes may be made by withholding shares of common stock from any payment of common stock due or by the delivery by the participant of previously acquired shares of common stock, in either case having an aggregate fair market value equal to the amount of the required withholding taxes. No payment will be made and no shares of common stock will be issued pursuant to any award made under the 2005 Plan until the applicable tax withholding obligations have been satisfied.

Transferability. No award may be sold, transferred, pledged, exchanged, or disposed of, except by will or by the laws of descent and distribution. All awards are exercisable during the lifetime of the optionee only by the optionee, or if the optionee is legally incompetent, by the optionee s legal representative. If provided in the award agreement, nonqualified stock options may be transferred by a participant to a permitted transferee. In connection with a divorce, a participant may request that we agree to observe the terms of a domestic relations order with respect to all or part of an award granted to a participant. Our decision regarding such a request will be made by the compensation committee based upon our interests. The compensation committee s decision need not be uniform between participants.

Amendment. Our board of directors may suspend, terminate, amend or modify the plan, but may not without the approval of the holders of a majority of the shares of our common stock make any alteration or amendment that operates (1) to increase the total number of shares of common stock as to which options may be granted under the 2005 Plan (other than adjustments in connection with certain corporate reorganizations and other events), (2) to extend the term of the 2005 Plan or the exercise period beyond the ten-year maximum provided in the 2005 Plan, (3) to decrease the minimum purchase price provided in the 2005 Plan, or (4) to make any other change requiring shareholder approval under any applicable rule, regulation, or procedure of any national securities exchange or securities association upon which any of our securities are listed. No suspension, termination, amendment or modification of the plan will adversely affect in any material way any award previously granted under the 2005 Plan, without the consent of the participant.

Effectiveness. The 2005 Plan became effective in April 2005. Unless terminated earlier, the 2005 Plan will terminate on the tenth anniversary of the effective date.

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Description of Proposed 2006 Long-Term Incentive Plan

We intend to submit to the compensation committee for approval the proposed GeoMet, Inc. 2006 Long-Term Incentive Plan (the 2006 Plan), under which we expect to reserve 2,000,000 shares of our common stock to be granted or which will underlie stock options granted under the 2006 Plan. If the compensation committee approves and adopts the 2006 Plan, we will submit the 2006 Plan to our stockholders for their approval. If the 2006 Plan is adopted by our stockholders, we will not grant any additional options to acquire shares under our 2005 Plan. The purpose of the 2006 Plan is to promote and advance our interests by providing our officers, non-employee directors, and technical and professional employees added incentive to continue in our service through a more direct interest in the future success of our operations. We believe that officers, non-employee directors, and technical and professional employees who have an investment in us are more likely to meet and exceed performance goals. We believe that the various equity-based incentive compensation vehicles provided for under the 2006 Plan, which may include stock options, restricted and unrestricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards, are needed to maintain and promote our competitive ability to attract, retain and motivate officers, non-employee directors, and technical and professional employees.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of February 9, 2006 with respect to the beneficial ownership of our common stock by (i) 5% stockholders, (ii) our directors, (iii) our executive officers, and (iv) our executive officers and directors as a group.

Unless otherwise indicated in the footnotes to this table each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

Name and Address of Beneficial Owner	Amount(1)	Percent of Class(2)
Yorktown Energy Partners IV, L.P. 410 Park Avenue New York, New York 10022	16,202,696	49.9%
W. Howard Keenan, Jr. 410 Park Avenue New York, New York 10022	16,202,696(3)	49.9%
J. Darby Seré 909 Fannin, Suite 3208 Houston, Texas 77010	1,440,150(4)	4.4%
William C. Rankin 909 Fannin, Suite 3208 Houston, Texas 77010	1,260,300(5)	3.8%
Philip G. Malone 5336 Stadium Trace Parkway Suite 206 Birmingham, Alabama 35244	887,368(6)	2.7%
Brett S. Camp 5336 Stadium Trace Parkway Suite 206 Birmingham, Alabama 35244	887,368(7)	2.7%

J. Hord Armstrong, III 909 Fannin, Suite 3208 Houston, Texas 77010		%
James C. Crain 909 Fannin, Suite 3208 Houston, Texas 77010		%
Stanley L. Graves 909 Fannin, Suite 3208 Houston, Texas 77010		%
Charles D. Haynes 909 Fannin, Suite 3208 Houston, Texas 77010		%
All officers and directors as a group	20,677,882	61.7%

(1) Unless otherwise indicated, all shares of stock are held directly with sole voting and investment power. Securities not outstanding, but included in the beneficial ownership of each such person are deemed to be outstanding for the purpose of computing the percentage of outstanding securities of the class owned by such person, but are not deemed to be outstanding for the purpose of computing percentage of the class owned by any other person. The total number includes shares issued and outstanding as of February 9, 2006, plus shares which the owner shown above has the right to acquire within 60 days after the date of this prospectus.

(2) For purposes of calculating the percent of the class outstanding held by each owner shown above with a right to acquire additional shares, the total number of shares excludes the shares which all other persons have the right to acquire within 60 days after the date of this prospectus, pursuant to the exercise of outstanding stock options and warrants.

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(3) Represents shares of common stock owned by Yorktown. Mr. Keenan may be deemed to share the voting and dispositive control over the shares of common stock owned by Yorktown. Mr. Keenan disclaims beneficial ownership of the reported securities owned by Yorktown.

(4) Includes options to purchase up to 479,960 shares of common stock, which are exercisable within 60 days from the date of this prospectus and 456,000 shares of common stock that are held in a family limited partnership under the control of Mr. Seré, and for which he holds voting and dispositive power.

(5) Includes options to purchase up to 560,040 shares of common stock, which are exercisable within 60 days from the date of this prospectus, and 400,000 shares of common stock that are held in a family limited partnership under the control of Mr. Rankin, and for which he holds voting and dispositive power.

(6) Includes 443,684 shares of common stock held by the spouse of Philip G. Malone.

(7) Includes 443,684 shares of common stock held by the spouse of Brett S. Camp.

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CERTAIN TRANSACTIONS WITH AFFILIATES AND MANAGEMENT

On April 14, 2005, the merger date of our majority-owned subsidiary with and into GeoMet, we issued to each minority interest owner and holder of incentive stock options of our majority-owned subsidiary an option to purchase shares of 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 shares of our common stock with cash or a loan from us, up to a certain amount of our shares of common stock to prevent any dilution that resulted from the merger. Notes issued to purchase any stock are full recourse, earn interest at an annual rate of 6%, and mature on the earlier of April 14, 2009 or 60 days after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the non-dilution option agreement. The option holders exercised non-dilution options to purchase 1,456,660 shares of our common stock. The option holders financed the exercise of these options using approximately $10.9 million in notes and $0.2 million in cash. These notes receivable are shown in our financial statements as a reduction in stockholders equity, and $10.5 million of these loans were repaid in full with interest upon the closing of our private equity offering in January 2006.

The following loans were full recourse and accrued interest at an annual rate of 5.87% and were to become due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the note agreements. Except as otherwise indicated, the loans were repaid with interest upon the closing of our private equity offering in January 2006.

On December 8, 2000, GeoMet was formed through the issuance of 7.2 million shares of common stock for $18 million in cash to Yorktown Energy Partners IV, L.P., our controlling stockholder, which is a partnership managed by Yorktown Partners LLC and organized in 1999 to make direct investments in the energy industry on behalf of certain institutional investors, and 800,000 shares of common stock to certain of our executive officers for $400,000 in cash and notes receivable in the amount of $1.6 million under the terms of a stock acquisition and stockholders agreement between us, Yorktown, and such officers. The shares of common stock issued are subject to a stockholders agreement, which, among other things, restricts the transfer and disposition of the shares of common stock. The stockholders agreement also specifies that any additional issuances of common stock to the original stockholders will be issued at a per share consideration of $2.50 up to a maximum additional funding of $40 million. The notes receivable resulting from the financing of the purchase of our common stock are shown in our financial statements as a reduction in stockholders equity.

On April 27, 2004, we issued 4,000,000 shares of common stock at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $9.1 million and notes receivable of $0.9. In 2003, we increased the authorized common shares by 8,000,000 shares and issued 4,000,000 and 8,000,000 shares of common stock on May 19 and September 22, respectively at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $27.3 million and notes receivable of $2.7 million. In connection with the closing of our private equity offering in January 2006, all of these loans were repaid in full with interest.

On July 21, 2003, we loaned Mr. Rankin, our chief financial officer, $250,000 to provide liquidity in connection with a divorce settlement so that Mr. Rankin could retain ownership of his shares of common stock. The loan is included in other assets in our financial statements and was repaid in full with interest upon the closing of our private equity offering in January 2006.

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SELLING STOCKHOLDERS

This prospectus covers shares sold in our recent private equity offering to qualified institutional buyers, as defined by Rule 144A under the Securities Act. The selling stockholders who purchased shares from us in the private equity offering may from time to time offer and sell under this prospectus any or all of the shares listed opposite each of their names below. We are required to register for resale the shares of our common stock described in the table below.

The following table sets forth information about the number of shares owned by each selling stockholder that may be offered from time to time under this prospectus. Certain selling stockholders may be deemed to be underwriters as defined in the Securities Act. Any profits realized by the selling stockholder may be deemed to be underwriting commissions.

The table below has been prepared based upon the information furnished to us by the selling stockholders as of February 9, 2006. The selling stockholders identified below may have sold, transferred, or otherwise disposed of some or all of their shares since the date on which the information in the following table is presented in transactions exempt from or not subject to the registration requirements of the Securities Act. Information concerning the selling stockholders may change from time to time and, if necessary, we will amend or supplement this prospectus accordingly. We cannot give an estimate as to the amount of shares of common stock that will be held by the selling stockholders upon termination of this offering because the selling stockholders may offer some or all of their common stock under the offering contemplated by this prospectus. The total number of shares that may be sold hereunder will not exceed the number of shares offered hereby. Please read Plan of Distribution.

The following table sets forth the name of each selling stockholder, the nature of any position, office, or other material relationship, if any, which the selling stockholder has had, within the past three years, with us or any of our predecessors or affiliates, and the number of shares of our common stock owned by such stockholder prior to the offering. We have assumed all shares reflected on the table will be sold from time to time.

Selling Stockholders	Number of Shares of Common Stock Owned Prior to the Offering(1)	Number of Shares of Common Stock Being Offered Hereby(1)	Number of Shares of Common Stock Owned After Completion of the Offering	Percentage of Shares of Common Stock Owned After Completion of the Offering
AG CNG Fund, L.P.(2)(3)	20,900	20,900		*
AG MM, L.P.(4)(5)	12,100	12,100		*
AG Princess, L.P.(6)(7)	9,200	9,200		*
AG Super Fund, L.P.(8)(9)	193,700	193,700		*
AG Super Fund International Partners, L.P.(10)(11)	46,800	46,800		*
Amaranth LLC(12)(13)	150,000	150,000		*
BBT Fund, L.P.(14)	413,000	413,000		*

Brady Retirement Fund L.P.(15).	18,000	18,000	*
Brightwater Fund LLC(16)	4,000	4,000	*
Brightwater Master Fund LP(16)	36,000	36,000	*
CAP Fund, L.P.(17)	203,000	203,000	*
Chilton Global Natural Resources Partners, L.P.(18)	184,490	184,490	*
Chilton International, LP(18)	88,443	88,443	*
Chilton Investment Partners, LP(18)	14,052	14,052	*
Chilton Opportunity International, LP(18)	13,098	13,098	*

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Selling Stockholders	Number of Shares of Common Stock Owned Prior to the Offering(1)	Number of Shares of Common Stock Being Offered Hereby(1)	Number of Shares of Common Stock Owned After Completion of the Offering	Percentage of Shares of Common Stock Owned After Completion of the Offering
Chilton Opportunity Trust, L.P.(18)	12,574	12,574		*
Chilton QP Investment Partners, LP(18)	37,343	37,343		*
Commonfund Event-Driven Company(19)(20)	8,600	8,600		*
The Dalrymple Global Resources Fund, LP(21)	15,000	15,000		*
Deephaven Relative Value Equity Trading LTD(22)	75,000	75,000		*
Eton Park Fund, L.P.(23)	563,500	563,500		*
Eton Park Master Fund, Ltd.(23)	1,046,500	1,046,500		*
GAM Arbitrage Investments Inc.(24)(25)	66,000	66,000		*
Geary Partners L.P.(26)	59,100	59,100		*
Goldman, Sachs & Co.(27)	1,700,000	1,700,000		*
Hedgenergy Master Fund LP(28)	300,000	300,000		*
Ironman Energy Capital, L.P.(29)	75,000	75,000		*
Kenmont Special Opportunities Master Fund, L.P.(30)	200,000	200,000		*
Nutmeg Partners, L.P.(31)(32)	29,000	29,000		*
PHS Bay Colony Fund, L.P.(33)(34)	9,200	9,200		*
PHS Patriot Fund, L.P.(35)(36)	4,500	4,500		*
Presidio Partners(37)	72,900	72,900		*
Prism Offshore Fund, Ltd.(38)	352,400	352,400		*
Prism Partners, L.P.(38)	151,000	151,000		*
Prism Partners QP, LP(39)	141,600	141,600		*
Royal Bank of Canada(40)	625,000	625,000		*
SDS Capital Group SPC, Ltd.(41)	50,000	50,000		*
SGB Simurgh Partners LLC(42)	50,000	50,000		*
SRI Fund, L.P.(43)	84,000	84,000		*
Straus-GEPT Partners LP(44)	62,500	62,500		*
Straus Partners LP(45)	62,500	62,500		*
Touradji Global Resources Master Fund, Ltd.(46)	1,100,000	1,100,000		*
York Capital Management, L.P.(47)	353,958	353,958		*
York Investment Limited(48)	1,536,042	1,536,042		*
TOTAL	10,250,000	10,250,000		

* Less than 0.1%

(1) Ownership is determined in accordance with Rule 13d-3 under the Securities Exchange Act of 1934.

(2) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to AG CNG Fund, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by AG CNG Fund, L.P.

(3) AG CNG Fund , L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of AG CNG Fund, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. AG CNG, Fund L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(4) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to AG MM, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by AG MM, L.P.

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(5) AG MM, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of AG MM, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. AG MM, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(6) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to AG Princess, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by AG Princess, L.P.

(7) AG Princess, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of AG Princess, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. AG Princess, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(8) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to AG Super Fund, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by AG Super Fund, L.P.

(9) AG Super Fund, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of AG Super Fund, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. AG Super Fund, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(10) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to AG Super Fund International Partners, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by AG Super Fund International Partners, L.P.

(11) AG Super Fund International Partners, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of AG Super Fund International Partners, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. AG Super Fund International Partner, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(12) Nicholas M. Maounis is the managing member of Amaranth Advisors L.L.C., which is the Trading Advisor of this selling stockholder. By virtue of his position with the Trading Advisor, Mr. Maounis exercises investment power and voting control over the shares held by the selling stockholder.

(13) Each of Amaranth Securities L.L.C. and Amaranth Global Securities Inc. is a broker-dealer registered pursuant to Section 15(b) of the Securities Exchange Act of 1934 and is a member of the National Association of Securities Dealers, Inc. (the NASD). Each such broker-dealer may be deemed to be an affiliate of the selling stockholder. Neither of such broker-dealers, however, is authorized by the NASD to engage in securities offerings either as an underwriter or as a selling group participant and neither of such broker-dealers actually engages in any such activity.

(14) BBT-FW, Inc. is the general partner of BBT Fund, L.P. Sid R. Bass exercises investment power and voting control over the shares held by this selling stockholder.

(15) William J. Brady is the general partner of Brady Retirement Fund L.P. and holds investment power and voting control over the shares held by this selling stockholder.

(16) David Zusman exercises voting control and investment power over the shares held by this selling stockholder.

(17) CAP-FW, Inc. is the general partner of CAP Fund, L.P. Sid R. Bass exercises investment power and voting control over the shares held by this selling stockholder.

(18) Chilton Investment Company, LLC is the general partner and investment adviser of this selling stockholder, and its board of directors exercises investment power and voting control over the shares held by this selling stockholder.

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(19) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to Commonfund Event-Drive Company. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by Commonfund Event-Drive Company.

(20) Commonfund Event-Drive Company is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of Commonfund Event-Drive Company was not involved in the purchase of the shares and will not be involved in the sale of the shares. Commonfund Event-Drive Company purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(21) G. Paul Ferguson exercises voting control and investment power over the shares held by this selling stockholder.

(22) Colin Smith exercises voting control and investment power over the shares held by this selling stockholder.

(23) Eton Park Capital Management, LP is the investment manager for Eton Park Fund, LP and Eton Park Master Fund, Ltd. Eton Park Capital Management LLC is the general partner of Eton Park Capital management, LP. Eric Mondich is the managing member of Eton Park Capital Management LLC. By virtue of his position with Eton park Capital Management LLC, Mr. Mondich exercises investment power and voting control over the shares held by this selling stockholder.

(24) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to GAM Arbitrage Investments Inc. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by GAM Arbitrage Investments Inc.

(25) GAM Arbitrage Investments Inc. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of GAM Arbitrage Investments Inc. was not involved in the purchase of the shares and will not be involved in the sale of the shares. GAM Arbitrage Investments Inc. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(26) William J. Brady is the general partner of Geary Partners L.P. and holds investment power and voting control over the shares held by this selling stockholder.

(27) Goldman, Sachs & Co. is a member of the National Association of Securities Dealers, Inc.

(28) B.J. Willingham is the Chief Information Officer of Moncrief Willingham Energy Advisers, L.P., the investment adviser of this selling stockholder. By virtue of his position with Hedgenergy Master Fund LP, Mr. Willingham exercises investment power and voting control over the shares held by this selling stockholder.

(29) G. Bryan Dutt has investment power and voting control over the shares held by this selling stockholder.

(30) Donald R. Kendall Jr. exercises investment power and voting control over the shares held by this selling stockholder.

(31) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to Nutmeg Partners, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by Nutmeg Partners, L.P.

(32) Nutmeg Partners, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of Nutmeg Partners, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. Nutmeg Partners, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.

(33) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to PHS Bay Colony Fund, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by PHS Bay Colony Fund, L.P.

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(34) PHS Bay Colony Fund, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of PHS Bay Colony Fund, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. PHS Bay Colony Fund, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.
(35) Angelo, Gordon & Co., L.P. (Angelo, Gordon) is the Investment Manager to PHS Patriot Fund, L.P. John M. Angelo and Michael L. Gordon are the principal executive officers of Angelo, Gordon. Each of Angelo, Gordon and Messrs. Angelo and Gordon disclaim beneficial ownership of the shares held by PHS Patriot Fund, L.P.
(36) PHS Patriot Fund, L.P. is not a broker-dealer; however, it is an affiliate of a registered broker-dealer. The broker dealer that is an affiliate of PHS Patriot Fund, L.P. was not involved in the purchase of the shares and will not be involved in the sale of the shares. PHS Patriot Fund, L.P. purchased the shares in the ordinary course of its business and is not a party to any agreement or other understanding to distribute the shares directly, or indirectly.
(37) William J. Brady is the general partner of Presidio Partners and holds investment power and voting control over the shares held by this selling stockholder.
(38) Charles Jobson is the managing member of Delta Partners LLC, which is the Investment Manager of this selling stockholder. By virtue of his position with the Investment Manager, Mr. Jobson exercises investment power and voting control over the shares held by the selling stockholder.
(39) Charles Jobson is the managing member of Delta Partners LLC, which is the Investment Manager of this selling stockholder, and he is the Managing Member of Delta Investment Partners LLC, the general partner of the selling stockholder. By virtue of his position with the Investment Manager and the general partner, Mr. Jobson exercises investment power and voting control over the shares held by the selling stockholder.
(40) Royal Bank of Canada is a controlling shareholder of RBC Capital Markets Corp and RBC Dain Rauscher, Inc., NASD Members.
(41) Steve Derby has investment power and voting control over the shares held by this selling stockholder.
(42) Vance Brown has investment power and voting control over the shares held by this selling stockholder.
(43) BBT-FW, Inc. is the general partner of SRI Fund, L.P. Sid R. Bass exercises investment power and voting control over the shares held by this selling stockholder.
(44) Melville Straus, the Managing Principal of Straus-GEPT Partners, LP, exercises investment power and voting control over the shares held by this selling stockholder.
(45) Melville Straus, the Managing Principal of Straus Partners, LP, exercises investment power and voting control over the shares held by this selling stockholder.
(46) Paul Touradji is an officer of Touradji Capital Management LP, the Investment Manager of Touradji Global Resources Master Fund, Ltd. By virtue of his position with Touradji Capital Management LP, Mr. Touradji exercises investment power and voting control over the shares held by this selling stockholder.
(47) The general partner of York Capital Management, L.P. is Dinan Management, LLC, which is controlled by James G. Dinan.
(48) The general partner of York Investment Limited is York Offshore Holdings Limited, which is controlled by James G. Dinan.

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PLAN OF DISTRIBUTION

We are registering the common stock covered by this prospectus to permit the selling stockholders to conduct public secondary trading of these shares from time to time after the date of this prospectus. Under the registration rights agreement we entered into with the selling stockholders, we agreed to, among other things, bear all expenses, other than brokers or underwriters discounts and commissions, in connection with the registration and sale of the common stock covered by this prospectus. We will not receive any of the proceeds of the sale of the common stock offered by this prospectus. The aggregate proceeds to the selling stockholders from the sale of the common stock will be the purchase price of the common stock less any discounts and commissions. A selling stockholder reserves the right to accept and, together with their agents, to reject, any proposed purchases of common stock to be made directly or through agents.

The common stock offered by this prospectus may be sold from time to time to purchasers:

- directly by the selling stockholders and their successors, which includes their donees, pledgees or transferees or their successors-in-interest; or
- through underwriters, broker-dealers or agents, who may receive compensation in the form of discounts, concessions or agents commissions from the selling stockholders or the purchasers of the common stock. These discounts, concessions, or commissions may be in excess of those customary in the types of transactions involved.

The selling stockholders and any underwriters, broker-dealers or agents who participate in the sale or distribution of the common stock may be deemed to be underwriters within the meaning of the Securities Act. The selling stockholders identified as registered broker-dealers in the selling stockholders table above under the heading Selling Stockholders are deemed to be underwriters. As a result, any profits on the sale of the common stock by such selling stockholders and any discounts, commissions or agent s commissions or concessions received by any such broker-dealer or agents may be deemed to be underwriting discounts and commissions under the Securities Act. Selling stockholders who are deemed to be underwriters with the meaning of Section 2(11) of the Securities Act will be subject to prospectus delivery requirements of the Securities Act. In addition, underwriters are subject to certain statutory liabilities, including, but not limited to, Sections 11,12, and 17 of the Securities Act.

The common stock may be sold in one or more transactions at:

- fixed prices;
- prevailing market prices at the time of sale;
- prices related to such prevailing market prices;
- varying prices determined at the time of sale; or

negotiated prices.

These sales may be effected in one or more transactions:

- on any national securities exchange or quotation on which the common stock may be listed or quoted at the time of the sale;
- in the over-the-counter market;
- in transactions on such exchanges or services or in the over-the-counter market;
- through the writing of options (including the issuance by the selling stockholders of derivative securities), whether the options or such other derivative securities are listed on an options exchange or otherwise;
- through the settlement of short sales (only after the initial effectiveness of the registration statement to which this prospectus is a part); or
- through any combination of the foregoing.

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These transactions may include block transactions or crosses. Crosses are transactions in which the same broker acts as an agent on both sides of the trade.

In connection with the sales of the common stock, the selling stockholders may enter into hedging transactions with broker-dealers or other financial institutions that in turn may:

- engage in short sales of the common stock (only after the initial effectiveness of the registration statement to which this prospectus is a part) in the course of hedging their positions;
- sell the common stock short and deliver the common stock to close out short positions;
- loan or pledge the common stock to broker-dealers or other financial institutions that in turn may sell the common stock;
- enter into option or other transactions with broker-dealers or other financial institutions that require the delivery to the broker-dealer or other financial institution of the common stock, which the broker-dealer or other financial institution may resell under the prospectus; or
- enter into transactions in which a broker-dealer makes purchases as a principal for resale for its own account or through other types of transactions.

To our knowledge, there are currently no plans, arrangements or understandings between any selling stockholders and any underwriter, broker-dealer or agent regarding the sale of the common stock by the selling stockholders.

We intend to apply for listing of the common stock on The Nasdaq National Market once we meet the eligibility requirements of The Nasdaq National Market. However, we can give no assurances as to the development of liquidity or any trading market for the common stock or that we will meet the listing requirements.

There can be no assurance that any selling stockholder will sell any or all of the common stock under this prospectus. Further, we cannot assure you that any such selling stockholder will not transfer, devise or gift the common stock by other means not described in this prospectus. In addition, any common stock covered by this prospectus that qualifies for sale under Rule 144 or Rule 144A of the Securities Act may be sold under Rule 144 or Rule 144A rather than under this prospectus. The common stock covered by this prospectus may also be sold to non-U.S. persons outside the U.S. in accordance with Regulation S under the Securities Act rather than under this prospectus. The common stock may be sold in some states only through registered or licensed brokers or dealers. In addition, in some states the common stock may not be sold unless it has been registered or qualified for sale or an exemption from registration or qualification is available and complied with.

The selling stockholders and any other person participating in the sale of the common stock will be subject to the applicable provisions of the Exchange Act and the rules and regulations promulgated thereunder. The Exchange Act rules include, without limitation, Regulation M, which may limit the timing of purchases and sales of any of the common stock by the selling stockholders and any other participating person. In addition, Regulation M may restrict the ability of any person engaged in the distribution of the common stock to engage in market-making activities with respect to the particular common stock being distributed. This may affect the marketability of the common stock and the ability of any person or entity to engage in market-making activities with respect to the common stock.

We have agreed to indemnify the selling stockholders against certain liabilities, including liabilities under the Securities Act.

We have agreed to pay substantially all of the expenses incidental to the registration, offering, and sale of the common stock to the public, including the payment of federal securities law and state blue sky registration fees, except that we will not bear any underwriting discounts or commissions or transfer taxes relating to the sale of shares of our common stock.

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If required, at the time of a particular offering of shares of common stock by a selling stockholder, a supplement to this prospectus will be circulated setting forth the name or names of any underwriters, broker-dealers or agents, any discounts, commissions or other terms constituting compensation for underwriters and any discounts, commissions or concessions allowed or reallowed or paid to agents or broker-dealers. We have no obligation to any selling stockholder to arrange an underwriting, or assist in providing for any proposed sale, of any of the shares of common stock covered by this prospectus.

We have agreed with the selling stockholders to keep the registration statement of which this prospectus forms a part effective for specified periods of time or until the occurrence of certain events. We may, under certain circumstances, suspend the use of this prospectus upon notice to the selling stockholders, to update the registration statement of which this prospectus forms a part with periodic information or material non-public information as required by the Securities Act. We have agreed with the selling stockholders to limit these suspended periods to those required by the Securities Act or limit them to contractually specified limits. See Registration Rights.

Once sold under the registration statement of which this prospectus forms a part, the shares of common stock covered hereby will be freely tradeable in the hands of persons other than our affiliates.

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DESCRIPTION OF CAPITAL STOCK

Pursuant to our certificate of incorporation, we have the authority to issue an aggregate of 135,000,000 shares of capital stock, consisting of 125,000,000 shares of common stock, par value $0.001 per share, and 10,000,000 shares of preferred stock, par value $0.001 per share.

Selected provisions of our organizational documents are summarized below. Copies of our organizational documents will be provided upon request and are available on our website, *www.geometinc.com*. In addition, you should be aware that the summary below does not give full effect to the terms of the provisions of statutory or common law which may affect your rights as a stockholder.

Common Stock

As of February 9, 2006, we had a total of 32,483,707 shares of common stock outstanding. We have reserved 2,400,000 shares for future issuance to employees as restricted stock or stock option awards pursuant to our stock option plans, of which options to purchase 2,093,324 shares have already been granted. We intend to reserve a total of 2,000,000 shares of our common stock for issuance to our officers, independent directors, and technical and professional employees pursuant to our proposed 2006 Plan, if adopted. If the 2006 Plan is adopted, we do not expect to issue any additional options under the 2005 Plan.

Voting rights. Each share of common stock is entitled to one vote in the election of directors and on all other matters submitted to a vote of our stockholders. Our stockholders may not cumulate their votes in the election of directors.

Dividends, distributions and stock splits. 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 therefor after payment of dividends required to be paid on shares of preferred stock, if any.

Liquidation. In the event of any dissolution, liquidation, or winding up of our affairs, whether voluntary or involuntary, after payment of our debts and other liabilities and making provision for any holders of our preferred stock who have a liquidation preference, our remaining assets will be distributed ratably among the holders of common stock.

Fully paid. All the shares of common stock to be outstanding upon completion of this offering will be fully paid and nonassessable.

Other rights. Holders of our common stock have no redemption or conversion rights but do have preemptive rights to subscribe for our securities, except in certain circumstances, including, but not limited to, a public offering of our stock.

Preferred Stock

Our board of directors has the authority to issue up to 10,000,000 shares of preferred stock in one or more series and to fix the rights, preferences, privileges and restrictions thereof, including dividend rights, dividend rates, conversion rates, voting rights, terms of redemption, redemption prices, liquidation preferences, and the number of shares constituting any series or the designation of that series, which may be superior to those of the common stock, without further vote or action by the stockholders. There will be no shares of preferred stock outstanding, and we have no present plans to issue any preferred stock.

One of the effects of undesignated preferred stock may be to enable our board of directors to render it more difficult to or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and as a result to protect the continuity of our management. The issuance of shares of the preferred

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stock by our board of directors as described above may adversely affect the rights of the holders of common stock. For example, preferred stock issued by us may rank prior to the common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights, and may be convertible into shares of common stock. Accordingly, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock.

Liability and Indemnification of Officers and Directors

Our certificate of incorporation contains certain provisions permitted under the Delaware General Corporation Law relating to the liability of directors. These provisions eliminate a director s personal liability for monetary damages resulting from a breach of fiduciary duty, except that a director will be personally liable:

- for any breach of the director s duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- under Section 174 of the Delaware General Corporation Law relating to unlawful stock repurchases or dividends; or
- for any transaction from which the director derives an improper personal benefit.

These provisions do not limit or eliminate our rights or those of any stockholder to seek non-monetary relief, such as an injunction or rescission, in the event of a breach of a director s fiduciary duty. These provisions will not alter a director s liability under federal securities laws.

Our certificate of incorporation and bylaws also provide that we must indemnify our directors and officers against expenses, judgments, fines, and amounts paid in settlement incurred by such director or officer if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation, and with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Our certificate of incorporation and bylaws also provide that we may advance expenses, as incurred, to our directors and officers in connection with a legal proceeding upon receipt of an undertaking by or on behalf of such director or officer to repay such amount unless it shall be ultimately determined that he is entitled to be indemnified by us as authorized by the certificate of incorporation and the bylaws.

Anti-Takeover Effects of Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws

Our certificate of incorporation and bylaws and the Delaware General Corporation Law contain certain provisions that could discourage potential takeover attempts and make it more difficult for our stockholders to change management or receive a premium for their shares.

Delaware Law

We are subject to Section 203 of the Delaware General Corporation Law, an anti-takeover provision. In general, the provision prohibits a publicly-held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder. A business combination includes a merger, sale of 10% or more of our assets, and certain other transactions resulting in a financial benefit to the stockholder. For purposes of Section 203, an interested stockholder is defined to include any person that is:

- the owner of 15% or more of the outstanding voting stock of the corporation;

- an affiliate or associate of the corporation and was the owner of 15% or more of the voting stock outstanding of the corporation, at any time within three years immediately prior to the relevant date; or

- an affiliate or associate of the persons described in the foregoing bullet points.

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However, the above provisions of Section 203 do not apply if:

- our board approves the transaction that made the stockholder an interested stockholder prior to the date of that transaction;

- after the completion of the transaction that resulted in the stockholder becoming an interested stockholder, that stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding shares owned by our officers and directors; or

- on or subsequent to the date of the transaction, the business combination is approved by our board and authorized at a meeting of our stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

Stockholders may, by adopting an amendment to the corporation s certificate of incorporation or bylaws, elect for the corporation not to be governed by Section 203, effective 12 months after adoption. Neither our certificate of incorporation nor our bylaws exempt us from the restrictions imposed under Section 203. It is anticipated that the provisions of Section 203 may encourage companies interested in acquiring us to negotiate in advance with our board.

Charter and Bylaw Provisions

Our bylaws provide that any action required or permitted to be taken by our stockholders may be effected at a duly called annual or special meeting of the stockholders or may be taken by written consent of the stockholders having not less than the number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Special meetings of stockholders may be called only by our chairman, or by our chairman, president, and secretary at the request of a majority of our board, or at the request in writing of the stockholders owning a majority-in-interest of our entire capital stock issued and outstanding and entitled to vote.

Directors may be removed with the approval of the holders of a majority of the shares then entitled to vote at an election of directors. Directors may be removed by stockholders with or without cause. Vacancies and newly created directorships resulting from any increase in the number of directors may be filled by election at an annual or special meeting of stockholders or by the affirmative vote of a majority of the directors then in office, though less than a quorum. If there are no directors in office, then an election of directors may be held in the manner provided by law.

Transfer Agent and Registrar

Our transfer agent and registrar for our common stock is American Stock Transfer & Trust Company.

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SHARES ELIGIBLE FOR FUTURE SALE

Prior to the date of this prospectus, there has been no public market for our common stock. The sale of a substantial amount of our common stock in the public market after we complete our initial offering, or the perception that such sales may occur, could adversely affect the prevailing market price of our common stock. Furthermore, because some of our shares will not be available for sale shortly after our initial offering due to the contractual and legal restrictions on resale described below and the fact that a substantial majority of our shares of common stock are registered for resale by our selling stockholders, the sale of a substantial amount of common stock in the public market after these restrictions lapse or in the future by these selling stockholders could adversely affect the prevailing market price of our common stock and our ability to raise equity capital in the future.

We currently have 32,483,707 shares of common stock outstanding. Of those shares, all of the shares of our common stock sold under this prospectus will be freely tradable without restriction or further registration under the Securities Act, unless the shares are purchased by affiliates as that term is defined in Rule 144 under the Securities Act. Any shares purchased by an affiliate may not be resold except in compliance with Rule 144 volume limitations, manner of sale and notice requirements, pursuant to another applicable exemption from registration or pursuant to an effective registration statement. The shares of common stock held by our employees are restricted securities as that term is defined in Rule 144 under the Securities Act. These restricted securities may be sold in the public market by our employees only if they are registered or if they qualify for an exemption from registration under Rule 144 or Rule 144(k) under the Securities Act. These rules are summarized below.

Rule 144

In general, under Rule 144 as currently in effect, beginning 90 days after the date of this prospectus, a person or persons whose shares are aggregated, who have beneficially owned restricted shares for at least one year, including persons who may be deemed to be our affiliates, would be entitled to sell within any three-month period a number of shares that does not exceed the greater of (i) 1% of the number of shares of common stock then outstanding, which will equal approximately 320,000 shares immediately after this offering, or (ii) the average weekly trading volume of our common stock during the four calendar weeks before a notice of the sale on SEC Form 144 is filed.

Sales under Rule 144 are also subject to certain manner of sale provisions and notice requirements and to the availability of certain public information about us.

Rule 144(k)

Under Rule 144(k), a person who is not deemed to have been one of our affiliates at any time during the 90 days preceding a sale, and who has beneficially owned the shares proposed to be sold for at least two years, including the holding period of any prior owner other than an affiliate, is entitled to sell these shares without complying with the manner of sale, public information, volume limitation or notice provisions of Rule 144.

Stock Issued Under Employee Plans

We intend to file registration statements on Form S-8 under the Securities Act to register approximately 4.4 million shares of common stock issuable, with respect to options and restricted stock units to be granted, or otherwise, under our employee plans. These registration statements are expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Shares issued upon the exercise of stock options or restricted stock after the effective date of the Form S-8 registration statements will be eligible for resale in the public market without restriction, subject to Rule 144 limitations applicable to affiliates. Under Rule 701 under the Securities Act, as currently in effect, each of our employees, officers, directors, and consultants who purchased or received shares pursuant to a written compensatory plan or contract is eligible to resell these shares 90 days after the effective date of this offering in reliance upon Rule 144, but without compliance with specific restrictions. Rule 701 provides that affiliates may sell their Rule 701 shares under Rule 144 without complying with the holding period requirement and that non-affiliates may sell their shares in reliance on Rule 144 without complying with the holding period, public information, volume limitation, or notice provisions of Rule 144.

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REGISTRATION RIGHTS

We entered into a registration rights agreement in connection with our recent private offering of common stock in January 2006. In the registration rights agreement we agreed, for the benefit of the purchasers of our common stock in the private offering, that we will, at our expense:

- file with the SEC (which occurs pursuant to the filing of the shelf registration statement of which this prospectus is a part), within 90 days after the closing date of the private offering, a registration statement (a shelf registration statement);
- use our commercially reasonable efforts to cause the shelf registration statement to become effective under the Securities Act not later than 210 days after the closing date of the private offering;
- continuously maintain the effectiveness of the shelf registration statement under the Securities Act until the earliest of:
  - the sale of all of the shares of common stock covered by the shelf registration statement pursuant to the registration statement or Rule 144 under the Securities Act or any similar provision then in effect;
  - such time as all of the shares of our common stock sold in the private offering and covered by the shelf registration statement and not held by affiliates of us are, in the opinion of our counsel, eligible for sale pursuant to Rule 144(k) (or any successor or analogous rule) under the Securities Act; or
  - the second anniversary of the issuance of the shares of common stock pursuant to the purchase agreement with the initial purchaser.

We have filed the registration statement of which this prospectus is a part to satisfy our filing obligation under the registration rights agreement. A purchaser of our common stock in connection with this prospectus will not receive the benefits of the registration rights agreement.

Notwithstanding the foregoing, we will be permitted, under limited circumstances, to suspend the use, from time to time, of the shelf registration statement of which this prospectus is a part (and therefore suspend sales under the registration statement) for certain periods, referred to as blackout periods, if, among other things, any of the following occurs:

- The representative of the underwriters of an underwritten offering of primary shares by us has advised us that the sale of shares of our common stock under the shelf registration statement would have a material adverse effect on our initial public offering;
- a majority of our Board of Directors, in good faith, determines that (1) the offer or sale of any shares of our common stock would materially impede, delay or interfere with any proposed financing, offer or sale of securities, acquisition, merger, tender offer, business combination, corporate reorganization, consolidation or other significant transaction involving us; (2) after the advice of counsel, the sale of the shares covered by the shelf registration statement would require disclosure of non-public material information not otherwise required to be disclosed under applicable law; or (3) either (x) we have a bona fide business purpose for preserving the

confidentiality of the proposed transaction, (y) disclosure would have a material adverse effect on us or our ability to consummate the proposed transaction, or (z) the proposed transaction renders us unable to comply with SEC requirements; or

a majority of our Board of Directors, in good faith, determines, that we are required by law, rule or regulation to supplement the shelf registration statement or file a post-effective amendment to the shelf registration statement in order to incorporate information into the shelf registration statement for the purpose of (1) including in the shelf registration statement a prospectus required under Section 10(a)(3) of the Securities Act; (2) including in the prospectus included in the shelf registration statement any facts or events arising after the effective date of the shelf registration statement (or the most-recent post-effective amendment) that, individually or in the aggregate, represents a fundamental change in the

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information set forth in the prospectus; or (3) including in the prospectus included in the shelf registration statement any material information with respect to the plan of distribution not disclosed in the shelf registration statement or any material change to such information.

The cumulative blackout periods in any 12 month period commencing on the closing of the private equity placement may not exceed an aggregate of 90 days and furthermore may not exceed 60 days in any 90-day period, except as a result of a review of any post-effective amendment by the SEC prior to declaring it effective; provided we have used all commercially reasonable efforts to cause such post-effective amendment to be declared effective.

In addition to this limited ability to suspend use of the shelf registration statement, until we are eligible to incorporate by reference into the registration statement our periodic and current reports, which will not occur until at least one year following the end of the month in which the registration statement of which this prospectus is a part is declared effective, we will be required to amend or supplement the shelf registration statement to include our quarterly and annual financial information and other developments material to us. Therefore, sales under the shelf registration statement will be suspended until the amendment or supplement, as the case may be, is filed and effective.

A holder who sells our common stock pursuant to the shelf registration statement or as a selling stockholder pursuant to an underwritten public offering will be required to be named as a selling stockholder in the related prospectus, as it may be amended or supplemented from time to time, and to deliver a prospectus to purchasers, will be subject to certain of the civil liability provisions under the Securities Act in connection with such sales and will be bound by the provisions of the registration rights agreement that are applicable to such holder (including certain indemnification rights and obligations). In addition, each holder of our common stock must deliver information to be used in connection with the shelf registration statement in order to have such holder s shares of our common stock included in the shelf registration statement.

Each holder will be deemed to have agreed that, upon receipt of notice of the occurrence of any event which makes a statement in the prospectus which is a part of the shelf registration statement untrue in any material respect or which requires the making of any changes in such prospectus in order to make the statements therein not misleading, or of certain other events specified in the registration rights agreement, such holder will suspend the sale of our common stock pursuant to such prospectus until we have amended or supplemented such prospectus to correct such misstatement or omission and have furnished copies of such amended or supplemented prospectus to such holder or we have given notice that the sale of the common stock may be resumed.

We have agreed to use our commercially reasonable efforts to satisfy the criteria for listing and list or include (if we meet the criteria for listing on such exchange or market) our common stock on the New York Stock Exchange, The American Stock Exchange, or The Nasdaq National Market (as soon as practicable, including seeking to cure in our listing or inclusion application any deficiencies cited by the exchange or market), and thereafter maintain the listing on such exchange.

We will bear certain expenses incident to our registration obligations upon exercise of these registration rights, including the payment of federal securities law and state blue sky registration fees, except that we will not bear any underwriting discounts or commissions or transfer taxes relating to sale of shares of our common stock. We will agree to indemnify each selling stockholder for certain violations of federal or state securities laws in connection with any registration statement in which such selling stockholder sells its shares of our common stock pursuant to these registration rights. Each selling stockholder will in turn agree to indemnify us for federal or state securities law violations that occur in reliance upon written information it provides for use in the registration statement.

Although we have agreed to use commercially reasonable efforts to cause the registration statement, of which this prospectus is a part, to become effective under the Securities Act within 210 days of the closing of our private equity offering in January 2006, there can be no assurance that the registration statement will be filed or, if filed, that it will become effective within such time period or at all.

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MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

FOR NON-UNITED STATES HOLDERS

To ensure compliance with Treasury Department Circular 230, prospective investors in our common stock are hereby notified that (1) any discussion of U.S. federal tax issues in this prospectus is not intended or written to be used, and cannot be used, for the purpose of avoiding penalties that may be imposed under the Internal Revenue Code, (2) any discussion of U.S. federal tax issues in this prospectus is written to support the promotion or marketing of the transactions or matters addressed herein and (3) prospective investors should seek advice based on their particular circumstances from an independent tax advisor.

The following is a summary of material United States federal income and, to a limited extent, estate tax considerations relating to the purchase, ownership and disposition of our common stock by persons that are non-United States holders (as defined below), but does not purport to be a complete analysis of all the potential tax considerations relating thereto. This summary is based upon the Internal Revenue Code of 1986 as amended (the Code) and regulations, administrative rulings and court decisions now in effect, all of which are subject to change, possibly on a retroactive basis. This summary deals only with non-United States holders that will hold our common stock as capital assets (generally, property held for investment) and does not address tax considerations applicable to investors that may be subject to special tax rules, including financial institutions, tax-exempt organizations, insurance companies, dealers in securities or currencies, traders in securities that elect to use a mark-to-market method of accounting for their securities holdings, persons that will hold the common stock as a position in a hedging transaction, straddle or conversion transaction for tax purposes, regulated investment companies, real estate investment trusts, or persons that have a functional currency other than the U.S. dollar. If a partnership holds the common stock, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership (including an entity treated as a partnership for United States federal income tax, purposes) holding our common stock, you should consult your tax advisor. Moreover, this summary does not discuss alternative minimum tax consequences, if any, or any state, local or foreign tax consequences to holders of the common stock. We have not sought any ruling from the Internal Revenue Service (the IRS) with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions. INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK SHOULD CONSULT THEIR OWN TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE UNITED STATES FEDERAL INCOME AND ESTATE TAX LAWS TO THEIR PARTICULAR SITUATIONS AS WELL AS ANY TAX CONSEQUENCES ARISING UNDER THE LAWS OF ANY STATE, LOCAL OR FOREIGN TAXING JURISDICTION OR UNDER ANY APPLICABLE TAX TREATY.

As used in this discussion, a non-United States holder is a beneficial owner of common stock that for United States federal income tax purposes is not:

- an individual who is a citizen or resident of the United States, including an alien individual who is a lawful permanent resident of the United States or who meets the substantial presence test under Section 7701(b) of the Code;

- a corporation or partnership, or other entity treated as a corporation or partnership for United States federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia (unless, in the case of a partnership, U.S. Treasury regulations are adopted which provide otherwise);

- an estate whose income is subject to United States federal income taxation regardless of its source; or a trust (i) if it is subject to the supervision of a court within the United States and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) that has a valid election in effect under applicable United States Treasury Regulations to be treated as a United States person.

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Dividends

We do not expect to pay any cash distributions on our common stock in the foreseeable future. However, if we do make a cash distribution on our common stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Distributions in excess of earnings and profits will constitute a return of capital that is applied against and reduces the non-United States holder s adjusted tax basis in the common stock, and any remaining excess will be treated as gain realized on the sale or other disposition of the common stock. See Gain on Disposition of Common Stock below for additional discussion of the federal tax treatment of distributions in excess of earnings and profits. Any distribution to a non-United States holder of common stock that is not effectively connected with a non-United States holder s conduct of a U.S. trade or business ordinarily will be subject to withholding of United States federal income tax at a rate of 30%, or such lower rate as may be specified under an applicable income tax treaty. To receive a reduced treaty rate, a non-United States holder must provide us with IRS Form W-8BEN or other appropriate version of Form W-8 certifying eligibility for the reduced rate.

Dividends paid to a non-United States holder that are effectively connected with a trade or business conducted by the non-United States holder in the United States (and, where a tax treaty applies, are attributable to a permanent establishment maintained by the non-United States holder in the United States) generally will be exempt from the withholding tax described above but instead will be subject to United States federal income tax on a net income basis at the regular graduated U.S. federal income tax rates in much the same manner as if the non-United States holder were a resident of the United States. In such cases, we will not have to withhold U.S. federal income tax if the non-United States holder complies with applicable certification and disclosure requirements. To claim this exemption from withholding tax, a non-United States holder must provide us with an IRS Form W-8ECI properly certifying eligibility for such exemption. Dividends received by a corporate non-United States holder that are effectively connected with a trade or business conducted by such corporate non-United States holder in the United States may also be subject to an additional branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

A non-United States holder that claims the benefit of an applicable income tax treaty generally will be required to satisfy applicable certification and other requirements. However,

- in the case of common stock held by a foreign partnership, the certification requirement generally will be applied to the partners of the partnership and the partnership will be required to provide certain information;

- in the case of common stock held by a foreign trust, the certification requirement generally will be applied to the trust or the beneficial owners of the trust depending on whether the trust is a foreign complex trust, foreign simple trust or foreign grantor trust as defined in the U.S. Treasury Regulations; and

- look-through rules will apply for tiered partnerships, foreign simple trusts and foreign grantor trusts.

A non-United States holder that is a foreign partnership or a foreign trust is urged to consult its own tax advisor regarding its status under these U.S. Treasury Regulations and the certification requirements applicable to it.

A non-United States holder that is eligible for a reduced rate of U.S. federal withholding tax under an income tax treaty may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service.

Gain on Disposition of Common Stock

A non-United States holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

the gain is effectively connected with the non-United States holder s conduct of a trade or business in the United States, and if required by an applicable tax treaty, attributable to a permanent establishment maintained by the non-United States holder in the United States;

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- the non-United States holder is a nonresident alien individual present in the United States for 183 days or more during the taxable year of the disposition and certain other requirements are met; or

- our common stock constitutes a U.S. real property interest by reason of our status as a United States real property holding corporation for U.S. federal income tax purposes (a USRPHC) at any time within the shorter of the five-year period preceding the disposition or your holding period for our common stock.

Unless an applicable tax treaty provides otherwise, gain described in the first bullet point above will be subject to U.S. federal income tax on a net income basis in the same manner as if such holder were a resident of the United States. Non-United States holders that are foreign corporations also may be subject to a branch profits tax equal to 30% (or such lower rate specified by an applicable tax treaty) of a portion of its effectively connected earnings and profits for the taxable year. Non-United States holders are urged to consult any applicable tax treaties that may provide for different rules.

Gain described in the second bullet point above will be subject to U.S. federal income tax at a flat 30% rate, but may be offset by U.S. source capital losses.

We believe that we are a USRPHC. Nonetheless, a non-United States holder generally will not be subject to United States federal income tax on any gain realized on a disposition of our common stock as a result of the third bullet point above if our common stock is considered to be regularly traded on an established securities market, within the meaning of Section 897 of the Code and the applicable Treasury Regulations, at any time during the calendar year in which the sale or other disposition occurs, and the non-United States holder does not actually or constructively own, at any time during the five-year period ending on the date of the sale or other disposition, more than 5% of our common stock. It is likely that our common stock will not be considered regularly traded on an established securities market prior to the effectiveness of the registration statement governing the resale of such stock. In addition, even after the shelf registration statement becomes effective, it is possible that our common stock will not be considered regularly traded if it is not regularly quoted by brokers or dealers making a market in our common stock.

If our common stock is not considered to be regularly traded on an established securities market, a non-United States holder may be subject to withholding at a rate of 10% of the amount realized on a disposition of our common stock, and the non-United States holder generally will be taxed on its net gain derived from the disposition at the regular graduated U.S. federal income tax rates and in much the same manner as is applicable to U.S. persons. If the non-United States holder is a foreign corporation, the additional branch profits tax described above may also apply. Similarly, if we make any distribution to a non-United States holder in excess of our current and accumulated earnings and profits, the distribution generally will be subject to withholding in the manner described above under Dividends , and the non-United States holder generally will be taxed on its net gain, if any, derived from the receipt of the distribution at the regular U.S. federal income tax rates applicable to United States persons (subject to a credit for any tax withheld). If the non-United States holder subject to tax in this manner is a foreign corporation, the additional branch profits tax described above may also apply. A non-United States holder may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service.

Non-United States holders should consult their own tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our common stock.

Federal Estate Taxes

If you are an individual, common stock owned or treated as being owned by you at the time of your death will be included in your gross estate for United States federal estate tax purposes and may be subject to United States federal estate tax, unless an applicable estate tax treaty provides otherwise.

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Information Reporting and Backup Withholding

Generally, we must report annually to the IRS and to you the amount of dividends paid to you, your name and address, and the amount, if any, of tax withheld. Copies of the information returns reporting those dividends and amounts withheld may also be made available to the tax authorities in the country in which you reside under the provisions of any applicable tax treaty or exchange of information agreement.

In general, backup withholding at the applicable rate (currently 28%) will not apply to dividends on our common stock paid by us or our paying agents, in their capacities as such, to a non-United States holder if such non-United States holder has provided the required certification and neither we nor our paying agent has actual knowledge or reason to know that the payee is a United States person.

Information reporting and backup withholding generally will not apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a foreign broker. However, information reporting requirements will apply to a payment of the proceeds of a sale of common stock effected outside the United States by a foreign office of a broker if the broker (i) is a United States person, (ii) derives 50% or more of its gross income for certain periods from the conduct of a trade or business in the United States, (iii) is a controlled foreign corporation as to the United States, or (iv) is a foreign partnership that, at any time during its taxable year, is more than 50% (by income or capital interests) owned by United States persons or is engaged in the conduct of a trade or business in the United States, unless in any such case the broker has documentary evidence in its records that the beneficial owner is a non-United States holder and certain other conditions are met, or the holder otherwise establishes an exemption. Payment of the proceeds of a sale of common stock by a United States office of a broker will be subject to both information reporting and backup withholding unless the holder certifies its non-United States holder status under penalties of perjury, or otherwise establishes an exemption and the broker does not have actual knowledge or reason to know that the payee is a United States person.

Backup withholding is not an additional tax. Any amount withheld under the backup withholding rules will be allowed as a credit against the non-United States holder s United States federal income tax liability and any excess may be refundable if the proper information is provided to the IRS.

LEGAL MATTERS

The validity of the shares offered hereby will be passed upon for us by Thompson & Knight LLP.

EXPERTS

The financial statements as of September 30, 2005, December 31, 2004 and 2003 and for the nine-months ended September 30, 2005, and for each of the three years in the period ended December 31, 2004 included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of SFAS 143, Accounting for Asset Retirement Obligations) appearing in this registration statement, and has been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The estimates of our proved reserves as of September 30, 2005 and December 31, 2004, 2003, and 2002 included in this prospectus are based on reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. A summary of their report with respect to estimated proved reserves as of September 30, 2005 is attached to this prospectus as Appendix A. These estimates are included in this prospectus in reliance upon the authority of the firm as experts in these matters.

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GLOSSARY OF NATURAL GAS AND COAL TERMS

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

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.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

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, gas, and all other minerals other than CBM.

Central Appalachia. As used in this prospectus, Central Appalachia includes Virginia and southern West Virginia.

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.

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.

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Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or 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 performance ratio, 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 ratio referred to in this prospectus is calculated for a particular time period by dividing the total capital expenditures for exploration, development and acquisition, including future development costs less the costs of any unproved properties by the change in total proved reserves before a reduction for sales volumes. Total capital expenditures is determined in accordance with the full cost method of accounting and the change in total proved reserves is based on the proved reserves determined by independent reserve engineers.

Frac well. A vertical well drilled in advance of mining and producing from zones artificially fractured or stimulated and which is capable of producing natural gas.

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 gas during the test period, corrected to standard temperature and pressure (the measured gas), (ii) the lost 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 gas, which is determined by measuring the gas released while grinding the coal sample into a powder or which is calculated mathematically using the measurements from the test period.

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

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

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

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

Northern Appalachia. As used in this prospectus, Northern Appalachia includes southwestern Pennsylvania and northern West Virginia.

NYMEX. The New York Mercantile Exchange.

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Permeability. The capacity for movement of a fluid through a reservoir.

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.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved 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. The estimated future net revenues are discounted at an annual rate of 10% in accordance with the SEC s practice, 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 gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Shut in. Stopping an oil or 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 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.

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GEOMET, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

GeoMet, Inc.

Houston, Texas

We have audited the accompanying balance sheets of GeoMet, Inc. (the Company) as of September 30, 2005, December 31, 2004 and 2003 and the related statements of operations, stockholder s equity and comprehensive income and cash flows for the nine-months ended September 30, 2005, and for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of GeoMet, Inc. as of September 30, 2005, December 31, 2004 and 2003, and the results of its operations and cash flows for the period from January 1, 2005 through September 30, 2005, and for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4 to the Financial Statements, the Company adopted Statement of Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003.

/s/ Deloitte & Touche LLP

Houston, TX

February 8, 2006

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	September 30, 2005	December 31, 2004	December 31, 2003
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	$ 1,790,807	$ 3,013,723	$ 8,437,662
Restricted cash		130,243	88,140
Accounts receivable	4,753,160	3,484,560	2,516,248
Current portion of note receivable	23,767	22,347	20,495
Derivative asset		440,585	26,609
Deferred tax asset	5,874,368		
Other current assets	494,438	404,610	368,579
Total current assets	12,936,540	7,496,068	11,457,733
PROPERTY AND EQUIPMENT:			
Gas Properties Utilizing the full cost method of accounting:			
Proved properties	220,924,653	131,190,981	66,576,545
Unproved properties	19,437,987	11,079,258	9,026,356
Other	1,839,971	1,643,934	1,151,088
Total property and equipment	242,202,611	143,914,173	76,753,989
Less accumulated depreciation, depletion, and amortization	(13,889,897)	(10,376,533)	(7,613,276)
Property and equipment net	228,312,714	133,537,640	69,140,713
OTHER NONCURRENT ASSETS:			
Note receivable	330,077	348,145	370,492
Note receivable Officer	250,000	250,000	250,000
Other	431,349	458,442	285,647
Total other noncurrent assets	1,011,426	1,056,587	906,139
TOTAL	$ 242,260,680	$ 142,090,295	$ 81,504,585
LIABILITIES AND STOCKHOLDERS EQUITY			
CURRENT LIABILITIES:			
Accounts payable	$ 9,486,248	$ 7,532,995	$ 5,393,496
Derivative liability	17,338,749		
Abandonment liability	25,362	280,569	160,579
Accrued liabilities	947,991	844,429	638,854
Current portion of long-term debt	85,295	89,392	132,018

Total current liabilities	27,883,645	8,747,385	6,324,947
LONG-TERM DEBT	93,940,211	51,512,799	10,102,109
LONG-TERM DERIVATIVE LIABILITY	3,979,140		
LONG-TERM ABANDONMENT LIABILITY	1,446,781	888,758	520,057
OTHER LONG-TERM ACCRUED LIABILITIES	211,100	303,294	283,791
DEFERRED INCOME TAXES	28,767,678	12,411,885	9,443,020
Total liabilities	156,228,555	73,864,121	26,673,924
MINORITY INTEREST		2,534,395	2,076,783
STOCKHOLDERS EQUITY:			
Common stock, $0.001 par value authorized 40,000,000, 24,000,000 and 24,000,000 shares; issued and outstanding 29,974,664, 24,000,000 and 20,000,000 at September 30, 2005, December 31, 2004 and December 31, 2003, respectively	29,975	24,000	20,000
Additional paid-in capital	106,167,055	59,848,451	49,852,450
Accumulated other comprehensive income	70,070	2,119	
Retained earnings (deficit)	(2,959,983)	11,017,209	7,181,428
Less notes receivable	(17,274,992)	(5,200,000)	(4,300,000)
Total stockholders equity	86,032,125	65,691,779	52,753,878
TOTAL	$ 242,260,680	$ 142,090,295	$ 81,504,585

See Notes to consolidated financial statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

AND COMPREHENSIVE INCOME

	Nine Months Ended September 30,		Years Ended December 31,		
	2005	2004	2004	2003	2002
		(Unaudited)			
REVENUES:					
Gas sales	$ 24,240,126	$ 13,257,579	$ 19,521,447	$ 11,700,119	$ 6,730,797
Operating fees and other	375,509	447,115	1,402,334	348,917	277,023
Total revenues	24,615,635	13,704,694	20,923,781	12,049,036	7,007,820
COSTS AND OPERATING EXPENSES:					
Lease operating costs	6,211,819	3,554,653	5,091,046	1,639,679	590,444
Compression and transportation costs	2,331,618	1,384,596	1,951,316	992,634	654,392
Production taxes	518,556	350,430	473,222	413,799	285,278
Depreciation, depletion and amortization	3,377,617	1,666,147	2,691,320	2,120,038	2,150,557
Research and development costs	531,314	279,099	278,339	431,560	166,768
General and administrative	2,277,153	1,758,161	2,513,297	1,370,908	1,598,350
Impairment of other equipment and other non-current assets				8,394	108,394
Realized losses on derivative contracts	2,288,724	428,582	814,940	44,160	
Unrealized losses (gains) from the change in market value of open derivative contracts	21,833,559	1,103,040	(542,076)	101,491	
Total costs and operating expenses	39,370,360	10,524,708	13,271,404	7,122,663	5,554,183
Operating income (loss)	(14,754,725)	3,179,986	7,652,377	4,926,373	1,453,637
OTHER INCOME (EXPENSE):					
Interest income	33,317	52,311	69,553	94,409	119,422
Interest expense (net of amounts capitalized)	(2,533,769)	(550,269)	(985,949)	(231,734)	(186,137)
Other expenses	(6,952)	(1,304)	(4,174)	(6,908)	(6,862)
Total other income (expense)	(2,507,404)	(499,262)	(920,570)	(144,233)	(73,577)
INCOME (LOSS) BEFORE INCOME TAXES, MINORITY INTEREST, AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAX	(17,262,129)	2,680,724	6,731,807	4,782,140	1,380,060
INCOME TAX PROVISION	(5,842,601)	911,447	2,312,008	1,650,928	638,829
NET INCOME (LOSS) BEFORE MINORITY INTEREST AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAX	(11,419,528)	1,769,277	4,419,799	3,131,212	741,231
MINORITY INTEREST	(442,336)	152,384	584,018	570,719	138,479
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAX	(10,977,192)	1,616,893	3,835,781	2,560,493	602,752

CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAX				19,075	
NET INCOME (LOSS)	(10,977,192)	1,616,893	3,835,781	2,541,418	602,752
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAXES					
Foreign currency translation adjustment	67,951		2,119		
COMPREHENSIVE INCOME (LOSS)	$ (10,909,241)	$ 1,616,893	$ 3,837,900	$ 2,541,418	$ 602,752
Earnings per share basic:					
Income (loss) before cumulative effect of change in accounting principle, net of income tax	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08
Cumulative effect of change in accounting principle, net of income tax					
Net income (loss) per share basic	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08
Earnings per share diluted:					
Income (loss) before cumulative effect of change in accounting principle, net of income tax	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08
Cumulative effect of change in accounting principle, net of income tax					
Net income (loss) per share diluted	$ (0.40)	$ 0.07	$ 0.17	$ 0.20	$ 0.08
Weighted average shares outstanding basic	27,555,076	22,277,372	22,710,384	12,668,492	8,000,000
Weighted average shares outstanding diluted	27,555,076	22,422,340	22,860,396	12,668,492	8,000,000

See notes to consolidated financial statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

	September 30, 2005	December 31, 2004	December 31, 2003	December 31, 2002
Common stock, $0.001 par value shares outstanding:				
Balance beginning of year	24,000,000	20,000,000	8,000,000	8,000,000
Common shares issued to certain executives		4,000,000	12,000,000	
Exercise of options, under merger agreement with majority-owned subsidiary	1,456,668			
Exercise of stock options, under incentive stock option plan	79,228			
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	4,438,768			
Balance end of period	29,974,664	24,000,000	20,000,000	8,000,000
Common stock, $0.001 par value:				
Balance beginning of year	$ 24,000	$ 20,000	$ 8,000	$ 8,000
Common shares issued to certain executives		4,000	12,000	
Exercise of options, under merger agreement with majority-owned subsidiary	1,457			
Exercise of stock options, under incentive stock option plan	79			
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	4,439			
Balance end of period	$ 29,975	$ 24,000	$ 20,000	$ 8,000
Paid-in capital:				
Balance beginning of year	$ 59,848,451	$ 49,852,450	$ 19,864,450	$ 19,864,450
Common shares issued to certain executives		9,996,001	29,988,000	
Exercise of options, under merger agreement with majority-owned subsidiary	11,131,068			
Exercise of stock options, under incentive stock option plan	98,840			
Common stock issued to acquire non-controlling interest in majority-owned subsidiary	33,918,848			
Accrued interest on all notes receivable issued to purchase common stock	1,169,848			
Balance end of period	$ 106,167,055	$ 59,848,451	$ 49,852,450	$ 19,864,450
Accumulated other comprehensive income:				
Balance beginning of year	$ 2,119	$	$	$
Foreign currency translation adjustment	67,951	2,119		

Balance end of period	$ 70,070	$ 2,119	$	$
Retained earnings:				
Balance beginning of year	$ 11,017,209	$ 7,181,428	$ 4,640,010	$ 4,037,258
Common stock dividends ($0.50 per share)	(3,000,000)			
Net income (loss)	(10,977,192)	3,835,781	2,541,418	602,752
Balance end of period	$ (2,959,983)	$ 11,017,209	$ 7,181,428	$ 4,640,010
Notes receivable:				
Balance beginning of year	$ (5,200,000)	$ (4,300,000)	$ (1,600,000)	$ (1,600,000)
Common stock issued	(10,905,144)	(900,000)	(2,700,000)	
Accrued interest on all notes receivable issued to purchase common stock	(1,169,848)			
Balance End of period	$ (17,274,992)	$ (5,200,000)	$ (4,300,000)	$ (1,600,000)
TOTAL STOCKHOLDERS EQUITY	$ 86,032,125	$ 65,691,779	$ 52,753,878	$ 22,912,460

See notes to consolidated financial statements.

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GEOMET, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,		Years Ended December 31,		
	2005	2004	2004	2003	2002
		(Unaudited)			
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:					
Net income (loss)	$ (10,977,192)	$ 1,616,893	$ 3,835,781	$ 2,541,418	$ 602,752
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:					
Depreciation, depletion and amortization	3,513,364	1,740,971	2,773,602	2,182,984	2,150,557
Minority interest	(442,336)	152,365	584,018	570,719	138,479
Deferred income taxes	(5,851,370)	886,447	2,247,008	1,625,928	1,895,577
Impairment				8,394	108,394
Unrealized losses (gains) from the change in market value of open derivative contracts (including premium amortization)	21,833,559	1,103,040	(413,976)	155,191	
Other noncash charges	206,737	111,952	164,683	98,710	33,342
Changes in assets and liabilities, excluding current maturities of notes receivable and long-term debt:					
Accounts receivable	(1,227,957)	847,584	(968,287)	(541,894)	(111,159)
Income tax refund receivable	(30,783)			1,183,807	(827,898)
Accrued income tax payable	(40,000)				
Other current assets	(89,809)	(61,314)	(36,032)	(52,951)	(367,050)
Accounts payable	1,898,020	2,481,335	2,134,223	2,667,271	750,759
Other accrued liabilities	(373,375)	16,048	259,944	361,133	229,447
Net cash provided by operating activities	8,418,858	8,895,321	10,580,964	10,800,710	4,603,200
CASH FLOWS USED IN INVESTING ACTIVITIES:					
Capital expenditures	(49,425,468)	(69,172,651)	(86,189,138)	(36,068,945)	(12,770,081)
Proceeds from sale of gas properties		21,418,809	21,418,809		
Purchase of GeoMet, Inc. common stock from minority stockholder			(1,401,250)		
Loan to officer				(250,000)	
Restricted cash	130,243	(41,926)	(42,103)	(38,140)	
Other assets	23,387	18,292	20,495	15,890	(2,467)
Net cash used in investing activities	(49,271,838)	(47,777,476)	(66,193,187)	(36,341,195)	(12,772,548)
CASH FLOWS PROVIDED BY FINANCING ACTIVITIES:					
Debt issuance costs	(114,882)	(158,303)	(275,993)	(169,709)	(31,491)
Proceeds from exercise of stock options	326,298				
Proceeds from sales of common stock		9,100,001	9,100,000	27,300,000	
Credit facility borrowings	55,000,000	103,500,000	122,500,000	35,000,000	10,500,000
Common stock dividend	(3,000,000)				
Payments on credit facility and other debt	(12,576,685)	(78,105,440)	(81,131,937)	(31,596,143)	(5,096,447)
Net cash provided by financing activities	39,634,731	34,336,258	50,192,070	30,534,148	5,372,062
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(4,667)		(3,786)		

INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,222,916)	(4,545,897)	(5,423,939)	4,993,663	(2,797,286)
CASH AND CASH EQUIVALENTS Beginning of period	3,013,723	8,437,662	8,437,662	3,443,999	6,241,285
CASH AND CASH EQUIVALENTS End of period	$ 1,790,807	$ 3,891,765	$ 3,013,723	$ 8,437,662	$ 3,443,999
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:					
Cash paid during the period for interest	$ 2,655,695	$ 485,259	$ 861,874	$ 251,789	$ 152,914
Cash paid during the period for income taxes	$ 175,000	$ 25,000	$ 25,000	$ 25,000	$
Issuance of common stock in exchange for note receivable	$ 10,905,144	$ 900,000	$ 900,000	$ 2,700,000	$
Issuance of common stock in exchange for majority-owned subsidiary s minority interest	$ 33,923,287	$	$	$	$
Acquisition of asset through a capital lease	$	$	$	$ 98,066	$

See notes to consolidated financial statements.

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GEOMET, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Nine Months Ended September 30, 2005 and 2004 (Unaudited)

and for the Years Ended December 31, 2004, 2003 and 2002

1. ORGANIZATION

GeoMet, Inc. (GeoMet) (formerly GeoMet Resources, Inc.) was incorporated under the laws of the state of Delaware on November 9, 2000. On April 13, 2005, GeoMet acquired, through a stock exchange, the non-controlling interest in its 81%-owned subsidiary and merged the subsidiary with and into GeoMet. Also, effective January 24, 2006, GeoMet s Board of Directors approved a four-for-one common stock split. Therefore, all share data in the financial statements and notes thereto has been adjusted for this split.

GeoMet exchanged 4,438,768 shares of its common stock valued at $7.64 per share for all of the common stock of the subsidiary that it did not already own, approximately 19.05%. 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. The exchange value was determined through negotiations between a special committee of GeoMet, Inc. officers and the majority shareholder of GeoMet.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the merger date. As of September 30, 2005, the purchase price allocation has not been finalized. An evaluation of unproved properties and certain intangible assets is expected to be completed by March 31, 2006.

	April 13, 2005 (Fair Value)
Natural gas properties and equipment	$ 48,229,135
Minority Interest	2,092,058
Deferred tax liability	(16,397,906)
Net assets acquired	$ 33,923,287

The following reflects the unaudited pro forma results of operations as though the acquisition had been consummated at January 1, 2004.

	Year Ended December 31, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Revenues and other income	$ 20,923,781	$ 24,615,635	$ 13,704,694
Income before income taxes and minority interest	5,998,686	(17,491,248)	2,337,525
Net income (loss)	3,938,465	(11,571,099)	1,542,766
Net income (loss) per share:			
Basic	$ 0.15	$ (0.40)	$ 0.06
Diluted	$ 0.15	$ (0.40)	$ 0.06

On November 17, 2004, GeoMet acquired 0.95 percent of the common stock of GeoMet, Inc. from a minority interest shareholder in a business combination accounted for as a purchase. The purchase price of $1,401,250 was paid in cash. The total fair value of $1,996,719 was allocated to proved properties. The acquisition was accounted for as a step acquisition 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.

Following the merger, GeoMet changed its name from GeoMet Resources, Inc. to GeoMet, Inc. GeoMet, Inc. and its subsidiaries (the Company) are engaged in exploration, acquisition, development and production of coalbed methane reserves in the United States and Canada.

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2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation For the nine months ended September 30, 2005, the consolidated financial statements include the accounts of GeoMet and its wholly owned subsidiaries. For the period December 31, 2004, the consolidated financial statements include the accounts of GeoMet and its 81% owned subsidiary. For the periods December 31, 2003 and 2002, the consolidated financial statements include the accounts of GeoMet and its 80% owned subsidiary. For the periods December 31, 2004, 2003 and 2002, the equity of the minority interests in its majority-owned subsidiary is shown in the consolidated financial statements as minority interests .

All significant intercompany accounts have been eliminated in consolidation.

Unaudited Interim Financial Statements The accompanying unaudited consolidated financial statements for the nine months ended September 30, 2004 have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information. Accordingly, they do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. In the opinion of management, all material adjustments (consisting only of normal and recurring adjustments) necessary to present a fair statement of our financial position and results of operations for the interim periods included herein have been made, and the disclosures contained herein are adequate to make the information presented not misleading. Operating results for the nine months ended September 30, 2004 are not indicative of the results for the year ended December 31, 2004.

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Net Income Per Share Basic earnings 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 earnings 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 earnings 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.

	Nine Months Ended September 30,		Year Ended December 31,		
	2005	2004	2004	2003	2002
		(Unaudited)			
Numerator					
Income (loss) available to common stockholders before cumulative effect of change in accounting principle, net of income tax	$ (10,977,192)	$ 1,616,893	$ 3,835,781	$ 2,560,493	$ 602,752
Cumulative effect of change in accounting principle, net of income tax				$ 19,075	
Net income (loss) available to common stockholders basic EPS	$ (10,977,192)	$ 1,616,893	$ 3,835,781	$ 2,541,418	$ 602,752
Effect of dilutive securities:					
Effect on minority interest from exercise of options to acquire subsidiary common stock		(14,520)	(70,023)	(7,564)	(380)
Net income (loss) available to common stockholders diluted EPS	$ (10,977,192)	$ 1,602,373	$ 3,765,758	$ 2,533,854	$ 602,372
Denominator					
Weighted average shares outstanding	27,555,076	22,277,372	22,710,384	12,668,492	8,000,000
Add dilutive securities:					
Stock Options		144,968	150,012		
Total weighted average shares outstanding and dilutive securities	27,555,076	22,422,340	22,860,396	12,668,492	8,000,000
Earnings per share basic					

Income (loss) available to common stockholders before cumulative effect of change in accounting principle, net of income tax	$	(0.40)	$	0.07	$	0.17	$	0.20	$	0.08
Cumulative effect of change in accounting principle, net of income tax										
Net income (loss) available to common stockholders per share basic	$	(0.40)	$	0.07	$	0.17	$	0.20	$	0.08
Earnings per share diluted:										
Income (loss) before cumulative effect of change in accounting principle, net of income tax	$	(0.40)	$	0.07	$	0.17	$	0.20	$	0.08
Cumulative effect of change in accounting principle, net of income tax										
Net income (loss) per share diluted	$	(0.40)	$	0.07	$	0.17	$	0.20	$	0.08

For diluted earnings per share for the nine months ended September 30, 2005, because we reported a net loss, the potential common shares for this period were excluded from the calculation because the effect would be anti-dilutive.

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For the years ended December 31, 2003 and 2002, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 1,000,000 and 400,000 shares, respectively, because the exercise price of these options was greater than the average market price for the year, which would have an antidulitive effect on earnings per share.

Gas Properties Gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of gas properties are capitalized and segregated into U.S. and Canadian cost centers. Amortization of gas properties is provided using the unit-of-production method based on estimated proved gas reserves. 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. The net carrying value of proved gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties.

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 unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. The ceiling test calculation is imposed separately for the U.S. and Canadian cost centers. 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. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling 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.

Revenue Recognition The Company recognizes gas revenues from its interests in producing wells as gas is produced and sold from those wells. Gas sold in production operations is not significantly different from the Company s share of production.

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Operating Fees The Company receives fees from operating coalbed 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 are recognized in the period in which the services are performed.

General and Administrative Costs and 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 full cost pool. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly associated with our exploration activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the periods ended September 30, 2005 and December 31, 2004, 2003 and 2002 of $1,421,107, $1,885,556, $1,910,499 and $1,193,695 respectively.

Capitalized Interest Costs The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion and amortization calculations. For the nine months ended September 30, 2005 and 2004 (unaudited), and the years ended December 31, 2004, 2003 and 2002, the Company capitalized $432,802, $81,650, $124,419, $97,227 and $53,238 of interest, respectively.

Price Risk Management Activities The Company accounts for its price risk management activities under the provisions of SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 137, No. 138 and No. 149. The statement establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The Company has elected not to designate any of its current price risk management activities as accounting hedges, and accordingly, accounted for them using the mark-to-market accounting method. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change.

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Stock Compensation Stock-based employee compensation is accounted for under the intrinsic value method of Accounting Principles Bulletin No. 25 Accounting for Stock Issued to Employees. For the nine months ended September 30, 2005 and the years ended December 31, 2004, 2003, and 2002, the exercise price of the options granted was equal to the estimated market value of the Company s stock at grant date, and therefore, no compensation costs have been recognized for its stock option plans. As allowed by SFAS No. 123, Accounting for Stock-Based Compensation issued in 1995, GeoMet has continued to apply APB Opinion No. 25 for the purpose of determining net income and to present pro forma disclosures required by SFAS No. 123. The table below shows what net income would have been had compensation cost for the Company s stock option plans been determined based on fair market value at grant date for stock options granted for the nine months ended September 30, 2005 and the years ended December 31, 2004, 2003 and 2002.

	Nine Months Ended September 30,		Years December 31,		
	2005	2004	2004	2003	2002
		(unaudited)			
Net Income (loss) as reported	$ (10,977,192)	$ 1,616,893	$ 3,835,781	$ 2,541,418	$ 602,752
Less:					
Total stock-based employee compensation expense determined under fair value based methods for all grants, net of related tax effects	60,016	47,904	63,196	87,809	76,151
Pro forma	$ (11,037,208)	$ 1,568,989	$ 3,772,585	$ 2,453,609	$ 526,601

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. See Note 9 for additional detail on stock options. The fair value of each option grant was based on the minimum value method with the following assumptions used for grants for the nine months ended September 30, 2005 and the years ended December 31, 2004, 2003 and 2002:

	Nine Months Ended		Years Ended December 31		
	September 30, 2005	September 30, 2004	2004	2003	2002

		(unaudited)			
Risk-free interest rate	3.4%	2.6%	2.6%	2.5%	3.6%
Expected years until exercise	3	3	3	4	6
Expected stock volatility					
Expected dividends					

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.

Accounts Receivable Substantially all of the Company s accounts receivable arise from sales of natural gas.

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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

Notes Receivable The Company has loaned money to officers and employees to purchase common stock in the Company. Such amounts are recorded as Notes Receivable, and are included as a component of Stockholders Equity.

Income Taxes The Company records its income taxes using an asset and liability approach in accordance with the provisions of the Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under SFAS 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.

Fair Value of Financial Instruments For cash and cash equivalents, current receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments. Debt outstanding under the 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 3 and 6 for the fair values of the receivable and other debt.

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. The Company s only foreign subsidiary is its Canadian subsidiary, Hudson s Hope Gas, Ltd.

Concentrations of Market Risk The future results of the Company 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 the control of the Company, 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 the Company to concentrations of credit risk, consist primarily of cash and accounts receivable. The Company places its cash investments with highly qualified financial institutions. Risk with respect to receivables as of September 30, 2005 was concentrated primarily in the current production revenue receivable from the purchaser of the Company s natural gas. Management does not expect there to be any significant risk of collectability of this receivable. See Note 12 for further discussion about our major customers.

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Use of Estimates in the Preparation of Financial Statements The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America 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. Actual results could differ from these estimates.

Recent Accounting Pronouncements In June 2005, the Financial Accounting Standard Board (FASB) issued FASB Statement No. 154, *Accounting Changes and Error Corrections-* a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. This Statement also provides guidance for determining whether retrospective application of a change in accounting principle is impracticable and for reporting a change when retrospective application is impracticable. The correction of an error in previously issued financial statements is not an accounting change. However, the reporting of an error correction involves adjustments to previously issued financial statements similar to those generally applicable to reporting an accounting change retrospectively. Therefore, the reporting of a correction of an error by restating previously issued financial statements is also addressed by this Statement. This statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of this statement had no effect on our financial statements.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, Exchanges of Nonmonetary Assets, an Amendment of Accounting Principles Board (APB) Opinion No. 29, which provides all nonmonetary asset exchanges that have commercial substance must be measured based on fair value of the assets exchanged and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. SFAS No. 153 became effective for fiscal periods beginning on or after June 15, 2005. The Company adopted SFAS No. 153 effective July 1, 2005. The adoption of SFAS No. 153 did not have a material impact on the Company s financial statements.

In March 2005, the Financial Accounting Standard Board (FASB) issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the Company. FIN 47 states that a Company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This interpretation is intended to provide more information about long-lived assets, future cash outflows for these obligations, and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The release of this interpretation did not affect the method we were applying to accrue asset retirement obligations, therefore, the adoption of this interpretation had no effect on our financial statements.

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*, which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods and

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services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees, and carries forward without change prior guidance for share-based payments for transactions with non-employees. SFAS No. 123(R) eliminates the intrinsic value measurement objective in APB Opinion 25 and, except in certain circumstances, requires the Company to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. The standard requires grant date fair value to be estimated using either an option-pricing model which is consistent with the terms of the award or a market observed price, if such a price exists. If such fair value cannot be reasonably estimated because it is not practicable to estimate the expected volatility of the Company s share price, the Company is required to estimate a value calculated by substituting the historical volatility of an appropriate industry sector index for the expected volatility of the Company s share price. Such cost must be recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The standard also requires the Company to estimate the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur.

We are required to adopt SFAS No. 123(R) on January 1, 2006 using the prospective transition method. Under the prospective transition method equity compensation cost will be recognized in the consolidated statement of operations based on fair value for all new awards and existing awards that are modified, repurchased or cancelled after the required effective date of January 1, 2006. For awards outstanding as of January 1, 2006, we will continue using the accounting principles originally applied to those awards before adoption. We have adopted SFAS No. 123(R) effective January 1, 2006 and are in the process of implementing the standard. The impact of the adoption of SFAS No. 123(R) cannot be predicted at this time because it will depend on the level of share-based awards granted in the future.

3. NOTE RECEIVABLE

The Company has an unsecured note receivable of $353,844, $370,492, $390,987 as of September 30, 2005 and December 31, 2004 and 2003, respectively, from a third party. The note requires payment on a semi-monthly basis, including interest at 8.25 percent, of $2,168. The fair value of the receivable as of September 30, 2005 is approximately $401,000. Scheduled maturities of the note receivable is detailed in the table below.

	Amount
2005 (remaining 3 months)	$ 5,699
2006	24,266
2007	24,943
2008	27,200
2009	29,662
Thereafter	242,074

Total note receivable	$ 353,844

4. ASSET RETIREMENT OBLIGATIONS

In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations* which is effective for fiscal years beginning after June 15, 2002. SFAS No. 143, which was adopted by the Company as of January 1, 2003, establishes accounting and reporting standards for the legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development and the normal operation of long-lived assets. It requires that the fair value of the liability for asset retirement obligations

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be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement liability, an 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.

In connection with adoption of SFAS No. 143, on January 1, 2003, the Company recognized asset retirement costs of $397,260 and asset retirement obligations of $426,160, of which $21,699 were classified as current. The cumulative-effect adjustment of $19,075 included $32,067 of depletion benefit, $9,825 for deferred tax benefits and $60,967 for accretion of the fair value of the asset retirement obligations.

The Company was required to contribute $80,000 in cash to an escrow account which is to be used to pay for a portion of the abandonment and retirement costs of a gas prospect. The balance in the escrow account is included in *Restricted Cash* on the balance sheet. The balance in the escrow account at December 31, 2004 and 2003 was $80,243 and $38,140, respectively. The retirement obligation at December 31, 2004 and 2003 for the prospect that the escrow partially funds was $167,699 and $160,579, respectively. The gas property which the escrow account was related to was sold in August 2005 and the escrow account was released in full to the Company.

The following table provides a reconciliation of the beginning and ending asset retirement obligation for the periods ending September 30, 2005 and December 31, 2004 and 2003. As of September 30, 2005, December 31, 2004 and 2003, the current portion of the obligation was $25,362, $280,569 and $160,579, respectively.

	September 30,		
	2005	2004	2003
Beginning asset retirement obligation	$ 1,169,327	$ 680,636	$ 426,160
Additional liabilities incurred	480,156	647,238	218,536
Accretion expense	82,699	66,856	44,690
Settlement of retirement costs	(260,040)	(288,929)	(7,039)
Revisions in estimates		63,526	(1,711)
Ending asset retirement obligation	$ 1,472,142	$ 1,169,327	$ 680,636

5. PRICE RISK MANAGEMENT ACTIVITIES

The Company engages in price risk management activities from time to time. These activities are intended to manage the Company s exposure to fluctuations in the price of natural gas. The Company utilizes derivative financial instruments, primarily 3-way collars and swaps, as the means to manage this price risk. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company. Under price swaps, the Company receives a fixed price on a nominal quantity of natural gas in exchange for paying a variable price based on market-based index, such as the NYMEX gas futures.

The Company has elected not to designate any of its current derivative contracts as accounting hedges and accordingly, accounted for its derivative contracts using mark-to-market accounting. During the nine months ending September 30, 2005, the Company recognized mark-to-market losses on commodity contracts of $24,122,283, which included realized losses of $2,288,704. During 2004, the Company recognized mark-to-market losses on commodity contracts of $272,864, which included realized losses of $686,840 and

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$128,100 amortization of premium payments. During 2003, the Company recognized mark-to-market losses on commodity contracts of $145,651, which included realized gains of $9,540 and $53,700 of premium payments.

Presented below is a summary of the Company s natural gas derivative contracts as of September 30, 2005 with prices expressed in dollars per million British thermal units ($/MMBtu) and notional volumes in million British thermal units per month. As of September 30, 2005 and December 31, 2004 and 2003, the fair values of the open derivative contracts were a liability of $21,317,889, an asset of $440,585 and an asset of $26,609, respectively.

Derivative		Volume (MMBtu)	Weighted Average ($/MMBtu)		
Swaps	October 1 October 31, 2005	248,000	$ 6.42		
			Floor	Range	Cap
Collars (3 way)	October 1 December 31, 2005	856,000	$ 5.75	$7.17	$ 8.91
	January 1 December 31, 2006	4,258,000	$ 5.99	$7.27	$ 9.05
	January 1 October 31, 2007	1,756,000	$ 6.60	$7.98	$ 10.28

The Company s counterparties to the open derivative contracts at September 30, 2005 are also participants in the Company s credit facility with Bank of America. The Company believes that the creditworthiness of its counterparties is sound and does not anticipate any non-performance of contractual obligations.

6. LONG-TERM DEBT

The following is a summary of long-term debt at September 30, 2005, December 31, 2004 and 2003:

	2004	2003

	September 30, 2005		
Borrowings under Bank credit facility	$ 93,000,000	$ 50,500,000	$ 9,000,000
Note payable to a third party, annual installments of $53,000 through January 2011, interest-bearing at 8.25% annually, unsecured	243,166	273,594	301,703
Note payable to an individual, semi-monthly installments of $644, through September 2015, interest-bearing at 12.6% annually, unsecured	148,459	153,779	160,137
Salary continuation payable to an individual, semi-monthly installments of $3,958, through December 2015, noninterest-bearing (less amortization discount of $572,074, with an effective rate of 8.25%), unsecured	633,881	664,838	703,359
Capital lease, monthly payments through February 2005		9,980	68,928
Total debt	94,025,506	51,602,191	10,234,127
Less current maturities included in current liabilities	(85,295)	(89,392)	(132,018)
Total long-term debt	$ 93,940,211	$ 51,512,799	$ 10,102,109

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Following are maturities of long-term debt for each of the next five years:

	Amount
2005 (remaining 3 months)	$ 12,656
2006	86,475
2007	93,094,230
2008	102,648
2009	111,768
Thereafter	617,729
Total	$ 94,025,506

In December 2001, GeoMet s subsidiary entered into a $15 million credit facility with Fleet National Bank (the Bank) as lender and administrative agent. The initial borrowing base was set at $15 million. The credit agreement, as amended, requires the borrowing base to be subject to semi-annual redeterminations on June 30 and December 31. The Bank has the right to request one additional redetermination in any fiscal year. The credit agreement, as amended, provides for interest to accrue at a rate calculated at the Company s option as either the Adjusted Base Rate, which is the greater of the Bank s Base Rate or the Federal Funds Rate plus one half of one percent or the Adjusted LIBOR Rate, which is the LIBOR rate plus a margin increasing from a low of 125 basis points to a high of 225 basis points as loans outstanding increase as a percentage of the borrowing base. The borrowings under the credit facility are secured by substantially all of the Company s gas properties.

The credit agreement was amended on November 21, 2003 and November 22, 2004, to increase the total commitment to $50 million and $150 million, respectively, and increase the borrowing base to $25 million and $80 million, respectively. On May 19, 2005 the borrowing base was increased to $120 million. Under the amended credit agreement, all outstanding borrowings become due and payable on November 21, 2007.

The credit agreement, as amended, is governed by various financial and other restrictive covenants, including requirements to maintain a current ratio of one to one and an interest coverage ratio of 2.75 to one, except during the period September 30, 2004 to March 31, 2005, when a coverage ratio of 2.50 to one is required. Additionally, the credit facility limits other borrowings, restricted payments, asset dispositions, use of proceeds, affiliate transactions and hedge transactions. As of September 30, 2005, the Company was not in default, as defined in the credit agreement, as amended.

At September 30, 2005 and December 31, 2004 and 2003, the amount of borrowings outstanding on the credit facility were $93 million, $50.5 million and $9 million, respectively, bearing interest at average annual rates of 5.78 percent, 3.89 percent and 2.38 percent, respectively.

The total fair value of the two notes payable and the salary continuation payable as of September 30, 2005 is approximately $1,241,198.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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and for the Years Ended December 31, 2004, 2003 and 2002

7. INCOME TAXES

The following is a reconciliation of federal income taxes computed at the statutory rate with income taxes recorded in the statement of income from operations and comprehensive income for the nine months ended September 30, 2005 and 2004, and the years ended December 31, 2004, 2003 and 2002.

	September 30, 2005	%	(Unaudited) September 30, 2004	%	2004	%	2003	%	2002	%
Federal income tax expense at statutory rates	$ (5,869,129)	(34%)	$ 911,447	34%	$ 2,287,497	34%	$ 1,625,928	34%	$ 469,220	34%
State income taxes net of federal benefit	16,500	.06			16,500	.2	16,500	.3		
Loss of Section 29 tax credits									137,865	9.9
Nondeductible items	10,028	.06			8,011	.1	4,874	.1	5,714	0.6
Other							3,626	.1	26,030	1.8
Total	$ (5,842,601)	(33.88%)	$ 911,447	34%	$ 2,312,008	34.3%	$ 1,650,928	34.5%	$ 638,829	46.3%

The following is a detail of the current and deferred income tax provision for the nine months ended September 30, 2005 and 2004, and the years ended December 31, 2004, 2003 and 2002.

	Nine Months September 30, 2005	(Unaudited) September 30, 2004	Year 2004	2003	2002
Current	$ 8,769	$ 25,000	$ 65,000	$ 25,000	$ (1,256,748)
Deferred	(5,851,370)	886,447	2,247,008	1,625,928	1,895,577
Income Tax Provision	$ (5,842,601)	$ 911,447	$ 2,312,008	$ 1,650,928	$ 638,829

Temporary differences giving rise to the deferred tax liability at September 30, 2005, December 31, 2004, 2003 and 2002 were as follows:

	September 30, 2005	2004	2003
Deferred tax asset:			
Compensation agreements and other	$ 370,423	$ 353,492	$ 331,228
Tax basis in excess of book basis of investment, including commodity derivative contracts	7,360,740	513,085	697,391
Accrued asset retirement obligations	467,896	385,717	231,416
Net operating loss carryforward	21,962,736	12,953,628	7,521,100
AMT tax credit carryforward	115,907	132,135	92,135
Total deferred tax assets	30,277,702	14,338,057	8,873,270
Deferred tax liability book basis of natural gas properties in excess of tax basis	(53,171,012)	(26,749,942)	(18,316,290)
Net deferred tax liability	$ (22,893,310)	$ (12,411,885)	$ (9,443,020)

As of September 30, 2005, the Company had net operating loss carryforwards of approximately $64,500,000, which begin to expire in 2022, that are available to reduce future U.S. taxable income. There was no net income or net loss for the Company s Canadian subsidiary for the nine months ended September 30, 2005 or for the year ended December 31, 2004.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the Nine Months Ended September 30, 2005 and 2004 (Unaudited)

and for the Years Ended December 31, 2004, 2003 and 2002

8. CAPITAL STOCK

At September 30, 2005, the Company had 40,000,000 share of common stock authorized, adjusted for a four-for-one stock split on January 24, 2006.

On April 13, 2005, GeoMet issued 4,438,768 shares of its common stock valued at $7.64 per share for the non-controlling interest in its majority-owned subsidiary s common stock.

On April 14, 2005, GeoMet issued to each minority interest owner and holder of incentive stock options of the majority-owned subsidiary an option to purchase common stock of GeoMet 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 GeoMet, up to a certain amount of GeoMet s common stock to prevent any dilution that resulted from the merger. 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 is shown as a reduction of stockholders equity.

All of the following notes receivable are shown as a reduction of stockholders equity. The terms of these notes to purchase common stock of GeoMet are full recourse, earn interest at an annual rate of 5.87% and become due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the note agreement.

On December 8, 2000, the Company issued 7,200,000 shares of common stock for $18 million in cash to Yorktown Energy Partners IV, L.P. and 800,000 shares to certain executive officers of the Company for $400,000 in cash and $1,600,000 note receivable under the terms of the Stock Acquisition and Stockholders Agreement between GeoMet and the officers. The common stock issued is subject to a Stockholders Agreement, which, among other things, restricts the transfer and disposition of the stock. The Stockholder s Agreement also specifies that any additional issuances of common stock to the original stockholders will be issued at a per share price of $2.50 up to a maximum additional funding of $40 million.

On April 27, 2004, the Company issued 4,000,000 common shares at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $9,100,000 and a note receivable of $900,000. In 2003, the Company increased the authorized common shares by 8,000,000 and issued 4,000,000 and 8,000,000 common shares in May and September, respectively, at $2.50 per share, to the existing stockholders in proportion to their original ownership, for cash of $27,300,000 and a note receivable of $2,700,000.

9. STOCK OPTIONS

In conjunction with the sale of common stock to certain executive officers of the Company on December 8, 2000, the Company granted these officers options to acquire 400,000 shares of common stock of GeoMet at $2.50 per share. The holders of the options also have a right to be issued additional options to acquire five percent of any additional common stock issued at a price of $2.50 per share. The executive officers were issued options to acquire 600,000 shares in conjunction with the issuance of 12,000,000 common shares in 2003 and were issued options to acquire 200,000 shares in conjunction with the issuance of 4,000,000 common shares in 2004. The options have a term of 10 years and vest ratably over three years and become exercisable on each of

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the first three anniversary dates of the agreement. The weighted average fair value of options granted during the years ended 2004 and 2003 were $0.20 and $0.24. As of September 30, 2005, December 31, 2004 and December 31, 2003, the outstanding options and weighted average remaining contractual life was 1,200,000, 1,200,000, and 1,000,000 shares and 7.1, 7.8 and 8.5 years, respectively. The Company determined the fair value of options issued using the minimum value method based on the expected life of the option.

In 2001, the Company established a stock option plan that authorizes the granting of options to key employees to acquire common stock of its majority-owned subsidiary at prices equivalent to the market value at the date of grant. The options have a term of seven years, vest evenly over four years and become exercisable on each of the first four anniversary dates of issuance. Effective with the merger of the majority-owned subsidiary into GeoMet, all of the outstanding options under this plan became fully vested and the options were exchanged for options to acquire common stock of GeoMet. The option tables for the years ended 2004 and 2003 have been converted into equivalent options of GeoMet.

As of September 30, 2005, the number of exercisable options was 805,324. The weighted average fair value of options granted during the nine months ended September 30, 2005 was $0.71. As of September 30, 2005 the 893,292 options outstanding have exercise prices between $1.07 and $7.64 and a weighted-average remaining contractual life of 4.0 years. The Company determined the fair value of options issued using the minimum value method based on the expected life of the option.

As of December 31, 2004, 2003 and 2002, the number of exercisable options was 512,600, 322,472 and 132,344,, respectively. The weighted average fair value of options granted during the years ended December 31, 2004, 2003, and 2002 were $0.14, $0.28 and $0.30, respectively. As of December 31, 2004, the 873,344 options outstanding have exercise prices between $1.07 and $4.08 and a weighted-average remaining contractual life of 3.9 years.

	Nine Months Ended September 30, 2005	
	Shares	Weighted Average Exercise Price
Stock options		
Outstanding beginning of year	873,344	$ 1.50
Granted	153,232	$ 7.36
Exercised	(79,224)	$ 1.25

Forfeited	(54,060)	$	1.07
Outstanding end of period	893,292	$	2.38

	Year 2004		Year 2003		Year 2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Stock options:						
Outstanding beginning of year	871,480	$ 1.31	759,640	$ 1.23	526,640	$ 1.08
Granted	55,920	4.08	111,840	1.80	233,000	1.59
Forfeited	(54,056)	1.07				
Outstanding end of year	873,344	$ 1.50	871,480	$ 1.31	759,640	$ 1.23

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10. PROFIT SHARING PLAN

Substantially all of the employees are covered by the Company s profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer up to 50 percent of their compensation. The Company is required to match 50 percent of total contributions up to a total of six percent which vests evenly over three years. The Company s contribution to the Plan for the nine month period ended September 30, 2005 and 2004 (unaudited), respectively; and the years ended December 31, 2004 and 2003 was $82,597, $83,845, $108,836 and $101,375, respectively.

11. RESEARCH AND DEVELOPMENT AGREEMENT

On June 13, 2002, the Company entered into a one year joint development agreement (the Agreement) with a third party to design, test and build prototype jet drilling working tools, rigs, and systems in accordance with patented inventions and technology owned by a third party, and to provide the Company an option to license the patented inventions and technology for commercial development in enhancing coalbed methane development and production. Over the term of the Agreement, the Company agreed to pay up to $250,000 in costs, excluding internal costs, associated with the joint development project.

During the term of the Agreement, the Company has an option to license the existing patent rights and any patent rights that arise as a result of the Agreement for a five year period beginning with the execution of the license agreement. Upon execution of the license agreement, the Company agrees to pay a minimum annual royalty to a third party of $50,000 and an overriding royalty interest of one percent of natural gas produced from each well utilizing the technology developed under the Agreement. The license agreement can be automatically extended for successive one year periods by paying the minimum royalty.

On May 30, 2003 the Agreement was amended to increase the costs to be paid by the Company to $350,000 and to extend the termination date to September 19, 2003. On September 17, 2003 the Agreement was amended to increase the costs to be paid by the Company to $425,000 and to extend the termination date to November 30, 2003. On November 25, 2003 the Agreement was amended to increase the costs to be paid by the Company to $475,000 and to extend the termination date to December 31, 2003. The Agreement was also amended to reduce the license fee by 50 percent of the additional costs incurred from September 19 through December 31, 2003. On February 25, 2004, the Agreement was amended to increase the costs to be paid by the Company to $565,000 and to extend the termination date to March 31, 2004. All of these costs were expensed as research and development costs. On July 9, 2004, the Company acquired a nonexclusive license to use the patented inventions and technology for enhancing coalbed methane development and production for an initial fee of $50,000. Depending on the use of the technology, additional license fees will be due in the form of per well completion fees and overriding royalties. The initial license term ends on July 8, 2006 and can be extended for indefinite annual periods for $10,000 per year.

Subsequent to the purchase of the license, the Company continues to expend money to convert the research to a commercially viable technology. All amounts expended on this research have been expensed as research and development costs.

12. COMMITMENTS AND CONTINGENCIES

Litigation From time to time the Company is 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 the financial condition, results of operations or cash flows of the Company.

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We filed a claim on June 9, 2004 against El Paso Production Company, CMV Joint Venture and CDX Minerals, LLC seeking a declaratory judgment of our rights under a joint operating agreement covering certain properties in White Oak Creek. We had previously entered into an agreement to sell our interest to CDX, subject to a preferential right to purchase held by El Paso, which El Paso subsequently exercised. A dispute arose as to whether the preferential right granted under the agreement applied to overriding royalty interests and other related interests. We have asserted that the preferential right to purchase does not include overriding royalty interests and that we are entitled to retain all overriding royalty interests we possess under the agreement. The trial court rendered judgment in our favor, and El Paso has appealed the decision of the trial court. While we believe that we are entitled to retain these interests, a judgment against us would result in our being required to sell the overriding royalty interest to El Paso for a price of approximately $10.5 million; however, this amount would be reduced by any proceeds we have received from production since the effective date of the sale.

As of September 30, 2005, there were no known environmental or other regulatory matters related to the Company s operations which are reasonably expected to result in a material liability to the Company.

Major Customers For the nine months ended September 30, 2005 and for the year ended December 31, 2004, one customer purchased approximately 99 percent of the Company s natural gas production. For the year ended December 31, 2003, one customer purchased approximately 46 percent and another customer purchased approximately 54 percent of the Company s natural gas production. Due to the availability of other purchasers, the Company does not believe that the loss of its current purchasers would adversely affect the Company s results of operations.

Operating Leases The Company leases office facilities and field compressors under operating leases expiring in various years through 2012. Minimum future rental payments under noncancelable operating leases having remaining terms in excess of one year as of September 30, 2005 for each of the next five years and in the aggregate are:

	Amount
Year Ending December 31	
2005 (remaining three months)	$ 292,851
2006	1,181,613
2007	1,163,257
2008	1,125,678
2009	763,372
Thereafter	1,492,436

Total minimum future rental payments	$ 6,019,207

Rental expense for operating leases was $739,939 and $447,424 for the nine months ended September 30, 2005 and 2004 (unaudited) respectively; and $669,579, $350,699 and $202,976 for the years ended December 31, 2004, 2003 and 2002, respectively.

Transportation Contracts In 2004 and 2005, the Company entered into firm transportation contracts with a pipeline. As of September 30, 2005 under the contracts the Company can transport maximum daily volumes of 17,000 dekatherms continuing until October 31, 2006. Beginning November 1, 2006 the maximum decreases to 7,000 continuing until October 31, 2010. As of September 30, 2005, the maximum commitment remaining under the transportation contract is approximately $3,328,632. The Company is only obligated to pay under these contracts if the gas is delivered.

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13. ACQUISITION AND DISPOSITION

On April 30, 2004, the Company acquired additional working interests in properties that it operates in West Virginia for approximately $27 million in cash. The entire purchase price was allocated to Proved Properties. The purchase price is subject to a contingent payable of up to an additional $3 million dependent on natural gas prices and production on the properties acquired. When the contingency is resolved on December 31, 2007 any amount paid will be added to Proved Properties in accordance with SFAS No. 141 Business Combinations. The acquisition was funded by borrowings from the bank credit facility.

On June 7, 2004, the Company sold all of its working interests in a non-operated field in Alabama for approximately $21 million is cash.

14. RELATED PARTY TRANSACTIONS

On July 21, 2003, GeoMet loaned the Chief Financial Officer $250,000 to provide liquidity in connection with a divorce settlement so that the executive could retain ownership of his common stock. The full recourse loan accrues interest at an annual rate of 5.87% and becomes due and payable on the earlier of April 14, 2009, six months after the holder ceases to be an employee or the occurrence of a Triggering Transaction as defined in the note agreement.

15. SUBSEQUENT EVENT

Effective January 24, 2006, GeoMet s Board of Directors approved a four-for-one common stock split and increased the authorized capital stock of the Company from 10,000,000 shares of common stock at September 30, 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.

On January 30, 2006, we completed a private equity offering of 10,000,000 shares of our common stock, consisting of 2,067,023 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 $25.0 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 the offering, together with the proceeds from the repayment of the selling stockholders loans, to repay a portion of the borrowings under our credit facility and for general corporate purposes. In connection with this offering, on February 7, 2006, we sold an additional 250,000 shares of our common stock to qualified institutional buyers from which we received aggregate consideration of approximately $3.0 million, or $12.09 per share, pursuant to the initial purchaser s option to purchase additional shares. The net proceeds generated from this sale were used to repay a portion of the borrowings under our credit facility and for general corporate purposes.

* * * * * *

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SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION ON GAS

EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES FOR THE YEARS

ENDED DECEMBER 31, 2004, 2003, AND 2002 (UNAUDITED)

This supplemental schedule provides unaudited information pursuant to Statement of Financial Accounting Standards 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 the Company s gas producing activities, all of which are conducted within the continental United States and Canada, at December 31, 2004, 2003 and 2002 are summarized below.

The Company capitalizes certain payroll and other internal costs attributable to acquisition, exploration and development activities as part of its investment in natural gas properties over the periods benefited by these activities. During the years ended December 31, 2004, 2003 and 2002, these capitalized costs amounted to $1,885,556, $1,910,499 and $1,193,695, respectively. Capitalized costs do not include any costs related to production, general corporate overhead or similar activities. For the years ended December 31, 2004, 2003 and 2002, interest costs of $124,419, $97,227 and $53,238, respectively, were capitalized. The capitalized costs below do not include the $1,996,719 recorded in Proved Properties as a result of the acquisition of common stock of the majority-owned subsidiary in November 2004.

	2004	2003	2002
Unevaluated properties United States	$ 10,370,170	$ 9,026,356	$ 4,739,033
Unevaluated properties Canada	709,088		
Properties subject to amortization Canada			
Properties subject to amortization United States	129,194,262	66,576,545	34,741,251
Capitalized costs consolidated	140,273,520	75,602,901	39,480,284
Accumulated depreciation, depletion and amortization United States	(9,762,900)	(7,276,664)	(5,328,354)
Net capitalized costs Canada	709,088		
Net capitalized costs United States	129,801,532	68,326,237	34,151,930
Net capitalized costs consolidated	$ 130,510,620	$ 68,326,237	$ 34,151,930

Cost Incurred Costs incurred in gas property acquisition, exploration and development activities for the years ended December 31, 2004, 2003 and 2002 are summarized below. The incurred costs in 2004 and 2003 exclude accrued retirement and abandonment costs of $683,888 and $588,764, respectively.

2004	2003	2002

Property acquisition costs proved	$ 27,805,246	$	$
Property acquisition costs unproved	942,623	1,582,217	1,666,145
Exploration	7,037,378	19,293,431	3,576,078
Development	49,189,196	14,658,198	7,398,739
Total costs incurred United States	84,974,443	35,533,846	12,640,962
Exploration			
Total costs incurred Canada	709,088		
Total costs incurred consolidated	$ 85,683,531	$ 35,533,846	$ 12,640,962

Reserves The following table summarizes the Company s 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.

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

	2004	2003	2002
Natural Gas (Mcf)			
Beginning of year	103,929,000	35,461,000	16,732,000
Extensions and discoveries	91,535,000	73,972,000	20,043,000
Acquisition	31,775,000		
Disposition	(8,370,000)		
Revisions of previous estimates	(5,831,000)	(3,020,000)	817,000
Production	(3,187,000)	(2,484,000)	(2,131,000)
End of year	209,851,000	103,929,000	35,461,000
Proved developed reserves beginning of year	80,780,000	29,432,000	14,410,000
Proved developed reserves end of year	160,935,000	80,780,000	29,432,000

Standardized Measure The following table presents the standardized measure of future net cash flows from 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, 2004, 2003 and 2002, 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 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.

	2004	2003	2002
Future cash inflows	$ 1,302,830,000	$ 599,501,000	$ 163,986,000
Future production costs	(290,425,000)	(125,765,000)	(48,771,000)
Future development costs	(38,242,000)	(23,832,000)	(4,676,000)
Future income tax expense	(274,975,000)	(125,858,000)	(32,101,000)
Future net cash flows	699,188,000	324,046,000	78,438,000
10% annual discount to reflect timing of cash flows	(349,433,000)	(151,498,000)	(33,011,000)

Standardized measure of discounted future net cash flows	$ 349,755,000	$ 172,548,000	$ 45,427,000

The standardized measure of discounted future net cash flows as of December 31, 2004, 2003 and 2002 was calculated using prices in effect as of that date, which averaged $6.21, $5.77 and $4.62 per mcf of natural gas, respectively.

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Changes in Standardized Measure Changes in standardized measure relating to proved gas reserves for the years ended December 31, 2004, 2003 and 2002 are summarized below:

	2004	2003	2002
Sales and transfers of oil and gas produced net of production cost	$ (12,014,000)	$ (8,654,000)	$ (5,201,000)
Net changes in prices and production cost	8,472,000	21,983,000	13,401,000
Extensions and discoveries	217,211,000	176,731,000	32,943,000
Acquisition/disposition (net)	59,308,000		
Net change in development cost	(11,772,000)	(17,822,000)	(130,000)
Revision of previous quantity estimates	(13,882,000)	(7,270,000)	1,585,000
Accretion of discount before income taxes	23,689,000	6,444,000	1,920,000
Net change in income taxes	(67,732,000)	(45,320,000)	(13,790,000)
Changes in production rates (timing) and other	(26,073,000)	1,029,000	727,000
Net change	$ 177,207,000	$ 127,121,000	$ 31,455,000

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Appendix A

DeGolyer and MacNaughton

4925 Greenville Avenue, Suite 400

One Energy Square

Dallas, Texas 75206

APPRAISAL REPORT

on

PROVED RESERVES

as of

SEPTEMBER 30, 2005

on

CERTAIN PROPERTIES

owned by

GEOMET, INC.

EXECUTIVE SUMMARY

FOREWORD

Scope of Investigation This report presents an appraisal, as of September 30, 2005, of the extent and value of the proved natural gas reserves of certain coal bed methane properties owned by Geomet, Inc. (Geomet). The reserves estimated in this report are in the White Oak Creek and Cahaba (Gurnee) fields located in Jefferson, Tuscaloosa, Walker, and Shelby Counties in Alabama and in the Pond Creek field located in McDowell County, West Virginia and Buchanan County, Virginia. The properties appraised are listed in detail in the appendix bound with our report entitled Appraisal Report on Proved Reserves as of September 30, 2005 on Certain Properties owned by Geomet, Inc.

Reserves estimated in this report are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after September 30, 2005. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Geomet after deducting royalties and interests owned by others.

This report also presents values for proved reserves using prices and costs provided by Geomet. In general, prices and costs were held constant for the life of the properties. A detailed explanation of the future price and cost assumptions is included in the Valuation of Reserves section of this report.

Values of proved reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and the estimated expenses of direct supervision, but do not include that portion of general administrative costs sometimes allocated to production. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. In this report, present worth values using a discount rate of 10 percent are reported in detail.

Estimates of gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

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Authority This report was prepared at the request of Mr. J. Darby Sere, Chief Executive Officer and President, Geomet.

Source of Information Data used in the preparation of this report were obtained from Geomet and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC; Copyright 2005 Petroleum Information/Dwights LLC. In the preparation of this report we have relied, without independent verification, upon information furnished by Geomet with respect to its property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

CLASSIFICATION of RESERVES

Petroleum reserves included in this report are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs as of the date the estimate is made, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. Proved reserves classifications used in this report are in accordance with the reserves definitions of Rules 4 10(a) (1) (13) of Regulation S X of the Securities and Exchange Commission (SEC) of the United States. The petroleum reserves are classified as follows:

Proved oil and gas reserves Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite, and other such sources.

Proved developed oil and gas reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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Proved undeveloped reserves Proved undeveloped oil and gas reserves are 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

White Oak Creek Field The properties evaluated in the White Oak Creek field in Alabama produce from the Pratt, New Castle, Mary Lee, and Black Creek coal seams and are located in the western portion of the Warrior basin. The composite thickness of these coal seams in this area varies from 10 feet to more than 15 feet. The coal in this area is water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on an 80-acre well spacing.

Production-decline curves for all of the coal bed methane wells in the immediate six township areas surrounding these properties, using production data available as of the date of the report, were analyzed to determine the typical production profile for the wells in this area. The producing rates for wells in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate original gas in place (OGIP) for each of the 80-acre tracts in which Geomet owns an interest. Isopach maps were used to estimate coal volume, and the gas content of the coal was obtained from canister tests performed on various cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on analogy with older wells in the area for which the producing trends disclosed a reliable decline that could be extrapolated to an economic limit.

Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

Proved developed nonproducing reserves were estimated for certain wells that have been drilled but are not currently on production. The volumetric method was used to estimate the reserves for these wells and the type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method and the type curves were used to project the future rates of production for the wells to be drilled on these properties.

Cahaba (Gurnee) Field All of the properties evaluated in the Cahaba (Gurnee) field in Alabama produce from the Gholson, Coke, Jones/Alice, Big Bone/J, and Big Dirty coal seams and are located in the Cahaba

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(Gurnee) basin. The composite thickness of these coal seams in this area varies from 25 feet to more than 85 feet. Average composite thickness is approximately 50 feet. The coal in this area is water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on an 80-acre well spacing.

Production-decline curves for all of the coal bed methane wells in the immediate five township areas surrounding Geomet s Cahaba (Gurnee) properties, using production data available as of the date of the report, were analyzed to determine the typical production profile for the wells in this area. The producing rates for wells in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate OGIP for each of the 80-acre tracts in which Geomet owns an interest. Isopach maps were used to estimate coal volume, and the gas content of the coal was obtained from canister tests performed on various cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on experience and general knowledge of established coal bed methane projects in the Cahaba (Gurnee) basin and adjacent Black Warrior basin.

Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

Proved developed nonproducing reserves were estimated for certain wells that have been drilled but are not currently on production. The volumetric method was used to estimate the reserves for these wells and the type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method and the type curves were used to project the future rates of production for the wells to be drilled on these properties.

Pond Creek Field All of the properties in West Virginia and Virginia evaluated in this report produce from the Pocahontas coal seams 1 through 10 in the Central Appalachian basin. The composite thickness of the coal seams in this area varies from 15 feet to more than 35 feet. The coal in this area is partially water saturated and requires stimulation and a dewatering period before maximum gas rates are achieved. This area is predominately being developed on 80-acre well spacing.

Production-decline curves for coal bed methane wells in McDowell County in West Virginia and Buchanan County in Virginia were analyzed, using production data available as of the date of the report, to determine the typical production profile for the wells in this area. The gas producing rates in this area typically incline for several years as the area is being dewatered. The rates will then either decline immediately or will remain flat for several years and then decline depending on the rate of dewatering and, consequently, the drawdown in reservoir pressure.

The volumetric method was used to estimate the OGIP for each 80-acre tract in which Geomet owns an interest. Isopach maps were used to estimate coal volume. Gas content of the coal was obtained from canister tests performed on cores taken in the area.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. Recovery factors were based on experience and general knowledge of established coal bed methane projects in the Central Appalachian basin.

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Proved developed producing reserves were estimated for the older wells by extrapolating production-decline curves to an economic limit based on current economic conditions. For producing wells where the rates of production were inclining or flat, the volumetric method was used to estimate the reserves and the type curves were used to project the future rates of production.

Proved developed nonproducing reserves were estimated for the wells that had been drilled but were not on production as of September 30, 2005, and for future coal seam completions in producing wells. The volumetric method was used to estimate the reserves, and type curves were used to project the future rates of production.

Proved undeveloped reserves were estimated using the volumetric method, and type curves were used to project the future rates of production for wells to be drilled.

In the preparation of this report, gross production estimated through September 30, 2005, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. This required that the production rates be estimated for 1 month, since production data from these properties were available only through August 2005. Data available from wells drilled on the appraised properties through September 30, 2005, are included herein. The development status represents the status applicable on September 30, 2005.

Gas volumes estimated herein are expressed as wet gas and sales gas. Wet gas is defined as the total gas to be produced before reductions for volume loss due to fuel and flare consumption and reduction for plant processing. Sales gas is defined as that portion of the wet gas to be delivered into a gas pipeline for sale after reduction for fuel usage, flare, and shrinkage resulting from field separation and plant processing. Gross gas volumes are reported as wet gas. Net gas volumes are reported as sales gas. All gas volumes are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the property is located.

Shrinkage factors, based on historic data, of 6.1 percent for production from White Oak Creek field, 6.07 percent for production from Pond Creek, and 6.38 percent for production from Cahaba (Gurnee) were used to estimate sales-gas volume.

The following table presents estimates of the proved reserves, as of September 30, 2005, of the properties appraised, expressed in millions of cubic feet (MMcf):

	Gross Reserves Wet Gas (MMcf)	Net Reserves Sales Gas (MMcf)
Proved Developed Producing	320,240	164,548
Proved Developed Nonproducing	33,734	22,408
Proved Undeveloped	102,426	71,560
Total Proved	**456,400**	**258,516**

VALUATION of RESERVES

This report has been prepared using initial prices and costs specified by Geomet. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB).

Revenue values in this report were estimated using the initial prices and costs provided by Geomet. The following assumptions were supplied by Geomet and used for estimating future prices and costs in this report:

Natural Gas Prices

Gas price differentials for each property were provided by Geomet. The prices for gas from each field were calculated using these differentials to a Henry Hub price of $14.55 per million British thermal

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units (MMBtu) and were held constant for the lives of the properties. The weighted average price over the lives of the properties in the White Oak Creek field is $14.67 per Mcf. The weighted average price over the lives of the properties in the Cahaba (Gurnee) field is $14.51 per Mcf. The weighted average price over the lives of the properties in the Pond Creek field is $14.94 per Mcf.

Operating Expenses and Capital Costs

Estimates of operating expenses and capital costs based on current costs were used for the life of the properties with no increases in the future based on inflation. In certain cases future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating conditions. Future capital expenditures were estimated using 2004 values and were not adjusted for inflation.

The estimated future revenue to be derived from the production and sale of the proved reserves, as of September 30, 2005, of the properties appraised is summarized as follows:

	Proved			
	Developed Producing	Developed Nonproducing	Undeveloped	Total Proved
Future Gross Revenue, M$	2,419,864	325,421	1,055,692	3,800,977
Production and Ad Valorem Taxes, M$	112,498	17,434	46,059	175,991
Operating Expenses, M$	237,660	8,527	104,602	350,789
Capital Costs, M$	0	7,076	61,720	68,796
Future Net Revenue*, M$	2,069,708	292,385	843,308	3,205,401
Present Worth at 10 Percent*, M$	989,911	98,550	281,188	1,369,649

* Future income taxes have not been taken into account in the preparation of these estimates.

Table 1 presents a summary of estimated net proved reserves by field and reserves classification and in total. Table 2 presents a summary of estimated revenues and expenditures from net proved reserves by field and reserves classification and in total.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved gas reserves contained in this report has been prepared in accordance with Paragraphs 10 13, 15, and 30(a) (b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the FASB and Rules 4 10(a) (1) (13) of Regulation S X and Rule 302(b) of Regulation S K of the SEC; provided, however, that (i) certain estimated data have not been provided with respect to changes in reserves information (ii) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (iii) the as of date of the report is September 30, 2005 instead of December 31, 2005.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature or information beyond the scope of our report, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

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SUMMARY and CONCLUSIONS

Geomet owns interests in certain properties located in Jefferson, Tuscaloosa, Walker, and Shelby Counties in Alabama, McDowell County in West Virginia, and Buchanan County in Virginia. The estimated net proved reserves of the properties appraised, as of September 30, 2005, are summarized as follows, expressed in millions of cubic feet (MMcf):

	Net Reserves Sales Gas (MMcf)
Proved Developed Producing	164,548
Proved Developed Nonproducing	22,408
Proved Undeveloped	71,560
Total Proved	258,516

Estimated revenue and costs attributable to Geomet s interests in the proved reserves, as of September 30, 2005, of the properties appraised under the aforementioned assumptions concerning future prices and costs are summarized as follows:

	Proved			
	Developed Producing	Developed Nonproducing	Undeveloped	Total Proved
Future Gross Revenue, M$	2,419,864	325,421	1,055,692	3,800,977
Production and Ad Valorem Taxes, M$	112,498	17,434	46,059	175,991
Operating Expenses, M$	237,660	8,527	104,602	350,789
Capital Costs, M$	0	7,076	61,720	68,796
Future Net Revenue*, M$	2,069,708	292,385	843,308	3,205,401
Present Worth at 10 Percent*, M$	989,911	98,550	281,188	1,369,649

* Future income taxes have not been taken into account in the preparation of these estimates.

All gas reserves in this report are expressed at a temperature base of 60°F and the legal pressure base of the state in which the property is located.

Submitted,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON

SIGNED: December 19, 2005

[State of Texas Registered Professional

Engineer Seal Appears Here]

/s/ James Terracio, P.E.
James Terracio, P.E.
Senior Vice President
DeGolyer and MacNaughton

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TABLE 1

ESTIMATED NET PROVED RESERVES

as of

SEPTEMBER 30, 2005

from

CERTAIN PROPERTIES

owned by

GEOMET, INC.

	Proved			
Field	**Developed Producing Sales Gas (MMcf)**	**Developed Nonproducing Sales Gas (MMcf)**	**Undeveloped Sales Gas (MMcf)**	**Total Proved Sales Gas (MMcf)**
Cahaba (Gurnee)	86,864	21,458	30,711	**139,033**
Pond Creek	74,922	791	40,615	**116,328**
White Oak Creek	2,763	159	233	**3,155**
Grand Total	**164,549**	**22,408**	**71,559**	**258,516**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 2

ESTIMATED PROVED REVENUE from NET RESERVES

as of

SEPTEMBER 30, 2005

from

CERTAIN PROPERTIES

owned by

GEOMET, INC.

Field Reserves Classification	Future Gross Revenue (M$)	Production and Ad Valorem Taxes (M$)	Total Operating Expenses (M$)	Capital Costs (M$)	Future Net Revenue (M$)	Present Worth at 10 Percent (M$)
Cahaba (Gurnee)						
Developed Producing	1,260,081	68,297	92,041	0	1,099,745	528,516
Developed Nonproducing	311,278	16,871	7,446	6,880	280,081	93,182
Undeveloped	445,504	24,146	36,774	28,534	356,049	126,853
Total Proved	**2,016,863**	**109,314**	**136,261**	**35,414**	**1,735,875**	**748,551**
Pond Creek						
Developed Producing	1,119,262	42,005	145,619	0	931,638	436,567
Developed Nonproducing	11,813	437	1,081	196	10,100	4,160
Undeveloped	606,766	21,728	67,828	33,186	484,023	152,794
Total Proved	**1,737,841**	**64,170**	**214,528**	**33,382**	**1,425,761**	**593,521**
White Oak Creek						
Developed Producing	40,521	2,196	0	0	38,325	24,828
Developed Nonproducing	2,330	126	0	0	2,204	1,208
Undeveloped	3,422	185	0	0	3,236	1,541
Total Proved	**46,273**	**2,507**	**0**	**0**	**43,765**	**27,577**
Total Developed Producing	**2,419,864**	**112,498**	**237,660**	**0**	**2,069,708**	**989,911**
Total Developed Nonproducing	**325,421**	**17,434**	**8,527**	**7,076**	**292,385**	**98,550**
Total Undeveloped	**1,055,692**	**46,059**	**104,602**	**61,720**	**843,308**	**281,188**
Grand Total Proved	**3,800,977**	**175,991**	**350,789**	**68,796**	**3,205,401**	**1,369,649**

Note: Future income tax expenses were not taken into account in the preparation of these estimates.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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Dealer Prospectus Delivery Obligation

Until (25 days after the date of this prospectus), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer s obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. ***Other Expenses of Issuance and Distribution***

The following table sets forth estimates of all expenses payable by the registrant in connection with the sale of common stock being registered. The selling shareholders will not bear any portion of such expenses. All the amounts shown are estimates except for the registration fee.

SEC registration fee	$ 14,258
NASD filing fee	
Listing application and listing fees	
Legal fees and expenses	
Printing and engraving expenses	
Directors and officers insurance expense	
Engineering fees and expenses	
Transfer agent s and registrar s fees	
Blue sky fees and expenses	
Accounting fees and expenses	
Miscellaneous	
Total	$

Item 14. ***Indemnification of Officers and Directors***

Our certificate of incorporation provides that a director will not be liable to the corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (1) for any breach of the director s duty of loyalty to the corporation or its stockholders, (2) for acts or omissions not in good faith or which involved intentional misconduct or a knowing violation of the law, (3) under section 174 of the Delaware General Corporate Law (DGCL) for unlawful payment of dividends or improper redemption of stock or (4) for any transaction from which the director derived an improper personal benefit. In addition, if the DGCL is amended to authorize the further elimination or limitation of the liability of directors, then the liability of a director of the corporation, in addition to the limitation on personal liability provided for in our charter, will be limited to the fullest extent permitted by the amended DGCL. Our bylaws provide that the corporation will indemnify, and advance expenses to, any officer or director to the fullest extent authorized by the DGCL.

Section 145 of the DGCL provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses, including attorneys fees, judgments, fines and amounts paid in settlement in connection with specified actions, suits and proceedings whether civil, criminal, administrative, or investigative, other than a derivative action by or in the right of the corporation, if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification extends only to expenses, including attorneys fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation. The statute provides that it is not exclusive of other indemnification that may be granted by a corporation s charter, bylaws, disinterested director vote, stockholder vote, agreement, or otherwise.

Our charter also contains indemnification rights for our directors and our officers. Specifically, the charter provides that we shall indemnify our officers and directors to the fullest extent authorized by the DGCL. Further, we may maintain insurance on behalf of our officers and directors against expense, liability or loss asserted incurred by them in their capacities as officers and directors.

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We have obtained directors and officers insurance to cover our directors, officers and some of our employees for certain liabilities.

We intend to enter into written indemnification agreements with our directors and executive officers. Under these agreement, if an officer or director makes a claim of indemnification to us, either a majority of the independent directors or independent legal counsel selected by the independent directors must review the relevant facts and make a determination whether the officer or director has met the standards of conduct under Delaware law that would permit (under Delaware law) and require (under the indemnification agreement) us to indemnify the officer or director.

The registration rights agreement and purchase agreement we entered into in connection with our earlier financings provide for the indemnification by the investors in those financings of our officers and directors for certain liabilities.

Item 15. ***Recent Sales of Unregistered Securities***

During the last three years, we have sold the following unregistered securities:

1. On May 19, 2003, we issued 4,000,000 shares of our common stock at a price of $2.50 per share to certain of our existing stockholders in exchange for cash of $9.1 million and notes receivable of $0.9 million. We relied on the exemption under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act), in connection with the offer and sale of those shares.

2. On September 22, 2003, we issued 8,000,000 shares of our common stock at a price of $2.50 per share to certain of our existing stockholders in exchange for cash of $18.2 million and notes receivable of $1.8 million. We relied on the exemption under Section 4(2) of the Securities Act in connection with the offer and sale of those shares.

3. On April 27, 2004, we issued 4,000,000 shares of our common stock at a price of $2.50 per share to certain of our existing stockholders in exchange for cash of $9.1 million and notes receivable of $0.9 million. We relied on the exemption under Section 4(2) of the Securities Act in connection with the offer and sale of those shares.

4. On April 13, 2005, we issued 4,438,768 shares of our common stock at a price of $7.64 per share to the remaining minority stockholders of GeoMet Inc. (Old GeoMet) in exchange for the remaining shares of Old GeoMet, which was subsequently merged with and into us. We relied on the exemption under Section 4(2) of the Securities Act in connection with the offer and sale of those shares.

5. On April 14, 2005, we issued 1,456,660 shares of our common stock at a price of $7.64 per share to certain of our existing stockholders in exchange for promissory notes in the aggregate amount of $11.1 million. The purchasers paid off these promissory notes in connection with the private placement discussed below. We relied on the exemption under Section 4(2) of the Securities Act in connection with the offer and sale of those shares.

6. On January 30, 2006 we completed a private placement of 10,000,000 shares of common stock, 2,067,023 shares of which were issued and sold by us and 7,932,977 shares of which were sold by certain of our existing stockholders. All of the shares were offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act. Banc of America Securities LLC (BofA) served as the initial purchaser. We sold the securities to BofA at a price of $12.09 per share, which was a $0.91 per share discount to the gross offering price to the investors of $13.00 per share. Aggregate net proceeds to us for the total offering, after deducting discounts of $1,880,991, was $24,990,308. We did not receive any proceeds from the shares sold by the selling stockholders. All net proceeds of the above offering that we received were used for paying down our existing debt and for general corporate purposes.

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7. On February 7, 2006, following the exercise by BofA of an option to purchase up to 1,500,000 additional shares of our common stock in connection with the above referenced private placement, we completed the sale of 250,000 shares of common stock, all of which were offered and sold to qualified institutional buyers pursuant to Rule 144A under the Securities Act. BofA served as the initial purchaser. We sold the securities to BofA at a price of $12.09 per share, which was a $0.91 per share discount over the gross offering price to the investors of $13.00 per share. Aggregate net proceeds to us for the total offering, after deducting discounts of $227,500, was $3,022,500. All net proceeds of the above offering were used to repay a portion of the borrowings under our credit facility and for general corporate purposes.

8. Additionally from January 1, 2003 through September 30, 2005, we have granted to our employees, including executive officers, options to purchase 1,120,992 shares of our common stock at exercise prices ranging from $1.80 per share to $7.35 per share. During that same period our employees, including executive officers exercised options to purchase 79,224 shares of our common stock. All such issuances were made in reliance on Rule 701 as promulgated under the Securities Act relating to issuances of securities under compensatory plans.

We intend to comply with all applicable state securities laws and regulations relating to the private placement.

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Item 16. ***Exhibits and Financial Statement Schedules***

(a) Exhibits.

The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

Exhibit No.	Description
3.1*	Amended and Restated Certificate of Incorporation of GeoMet Inc.
3.2*	Bylaws of GeoMet Resources, Inc.
3.3*	Amendment No. 1 to Bylaws of GeoMet Resources, Inc. dated March 30, 2005.
3.4*	Amendment No. 2 to Bylaws of GeoMet, Inc. dated April 14, 2005.
4.1*	Registration Rights Agreement between GeoMet, Inc. and Banc of America Securities LLC, dated as of January 30, 2006.
5.1*	Opinion of Thompson & Knight LLP.
10.1*	Agreement and Plan of Merger between GeoMet Resources Inc. and GeoMet Inc., dated as of March 31, 2005.
10.2*	2005 Stock Option Plan of GeoMet Inc., dated April 15, 2005.
10.3*	Form of Incentive Stock Option Agreement for the 2005 Stock Option Plan of GeoMet, Inc.
10.4*	Federal Income Tax Allocation Agreement among the Members of the GeoMet Resources, Inc. Consolidated Group, dated as of January 1, 2001.
10.5*	Incentive Bonus Pool Plan, dated as of May 29, 2001.
10.6*	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin.
10.7*	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré.
10.8*	Amended and Restated Credit Agreement dated January 6, 2006, between GeoMet Inc. and Bank of America.
21.1*	List of Subsidiaries of GeoMet Inc.
23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of DeGolyer and MacNaughton.
23.3*	Consent of Thompson & Knight LLP (included in Exhibit 5.1).
24	Power of Attorney (included in the signature page of this Registration Statement).

* Filed herewith

(b) Financial Statements Schedules

All schedules have been omitted because they are not required, are not applicable, or the information is included in the Financial Statements or Notes thereto.

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Item 17. ***Undertakings***

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933, as amended;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement; and

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, as amended, each such post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers, and controlling persons of the registrant pursuant to the provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer, or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer, or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on February 9, 2006.

GEOMET, INC.

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

POWER OF ATTORNEY

We, the undersigned directors and officers of GeoMet, Inc., a Delaware corporation, do hereby constitute and appoint J. Darby Seré and William C. Rankin, and each of them, our true and lawful attorney-in-fact and agent, to do any and all acts and things in our names and on our behalf in our capacities as directors and officers and to execute any and all instruments for us and in our name in the capacities indicated below, which said attorney and agent may deem necessary or advisable to enable said Registrant to comply with the Securities Act of 1933 and any rules, regulations and requirements of the Securities and Exchange Commission, in connection with the registration statements, or any registration statement for this offering that is to be effective upon filing pursuant to Rule 462 under the Securities Act of 1933, including specifically, but without limitation, power and authority to sign for us or any of us in our names in the capacities indicated below, any and all amendments (including post-effective amendments) hereof; and we do hereby ratify and confirm all that said attorneys and agents shall do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Act of 1933, this Registration Statement has been signed by the following persons in the capacities indicated below on February 9, 2006.

Signature	Capacity	Date
/s/ J. DARBY SERÉ **J. Darby Seré**	Chairman of the Board President, Chief Executive Officer (Principal Executive Officer)	February 9, 2006
/s/ WILLIAM C. RANKIN **William C. Rankin**	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 9, 2006
/s/ J. HORD ARMSTRONG, III **J. Hord Armstrong, III**	Director	February 9, 2006

/s/ JAMES C. CRAIN **James C. Crain**	Director	February 9, 2006
/s/ STANLEY L. GRAVES **Stanley L. Graves**	Director	February 9, 2006
/s/ CHARLES D. HAYNES **Charles D. Haynes**	Director	February 9, 2006
/s/ W. HOWARD KEENAN, JR. **W. Howard Keenan, Jr.**	Director	February 9, 2006
/s/ PHILIP G. MALONE **Philip G. Malone**	Director	February 9, 2006

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INDEX TO EXHIBITS

Exhibit No.	Description
3.1*	Amended and Restated Certificate of Incorporation of GeoMet Inc.
3.2*	Bylaws of GeoMet Resources, Inc.
3.3*	Amendment No. 1 to Bylaws of GeoMet Resources, Inc. dated March 30, 2005.
3.4*	Amendment No. 2 to Bylaws of GeoMet, Inc. dated April 14, 2005.
4.1*	Registration Rights Agreement between GeoMet, Inc. and Banc of America Securities LLC, dated as of January 30, 2006.
5.1*	Opinion of Thompson & Knight LLP.
10.1*	Agreement and Plan of Merger between GeoMet Resources Inc. and GeoMet Inc., dated as of March 31, 2005.
10.2*	2005 Stock Option Plan of GeoMet Inc., dated April 15, 2005.
10.3*	Form of Incentive Stock Option Agreement for the 2005 Stock Option Plan of GeoMet, Inc.
10.4*	Federal Income Tax Allocation Agreement among the Members of the GeoMet Resources, Inc. Consolidated Group, dated as of January 1, 2001.
10.5*	Incentive Bonus Pool Plan, dated as of May 29, 2001.
10.6*	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and William C. Rankin.
10.7*	Employment Agreement dated as of December 7, 2000 between GeoMet Resources, Inc. and J. Darby Seré.
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21.1*	List of Subsidiaries of GeoMet Inc.
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