GASTAR EXPLORATION LTD
Form 10-K
March 25, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2009

or

¨ Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission file number: **001-32714**

GASTAR EXPLORATION LTD.

(Exact name of registrant as specified in its charter)

Alberta, Canada	**98-0570897**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1331 Lamar Street, Suite 1080	
Houston, Texas	**77010**
(Address of principal executive offices)	(Zip Code)

(713) 739-1800

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Shares, No Par Value	NYSE Amex LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer , accelerated filer , and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the closing price of $2.00 per common share on the American Stock Exchange at the close of business on June 30, 2009 (the last business day of the registrant s most recently completed second fiscal quarter) was $71,897,694.

As of March 24, 2010, there were 50,028,592 common shares outstanding.

Documents incorporated by reference:

The information required by Part III of Form 10-K (Items 10, 11, 12, 13 and 14 thereunder) is incorporated by reference herein from portions of the registrant s definitive proxy statement relating to its 2010 annual meeting of shareholders to be filed with the Securities and Exchange Commission within 120 days of December 31, 2009.

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2009

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Cautionary Statement about Forward-Looking Statements

Some of the information included in this Annual Report on Form 10-K (Form 10-K) contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give our current expectations or forecasts of future events. These statements can be identified by the use of forward-looking words, including may , expect , anticipate , plan , project , believe , estimate , intend , will , should or ot These forward-looking statements are based on current expectations and beliefs concerning future developments and their potential effect on us. Forward-looking statements may include statements that relate to, among other things, our:

- Financial position;
- Business strategy and budgets;
- Anticipated capital expenditures;
- Drilling of wells;
- Natural gas and oil reserves;
- Timing and amount of future production of natural gas and oil;
- Operating costs and other expenses;
- Cash flow and anticipated liquidity;
- Prospect development; and
- Property acquisitions and sales.

Although we believe the expectations reflected in such forward-looking statements are reasonable, we cannot assure you that such expectations will occur. These forward-looking statements involve known and unknown risks, uncertainties and other factors, some of which are beyond our control, that may cause our actual results, performance or achievements to be materially different from our historical experience and our present expectations or projections, or actual future results expressed or implied by the forward-looking statements. These factors include, but are not limited to, among others:

- Low and/or declining prices for natural gas and oil;

Demand for natural gas and oil;

Natural gas and oil price volatility;

Uncertainties about the estimated quantities of natural gas and oil reserves, including uncertainties about the effects of the Securities and Exchange Commission s (the SEC) new rules governing reserve reporting;

The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells;

Ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;

The ability to find, acquire, market, develop and produce new natural gas and oil properties;

Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;

Operating hazards inherent to the natural gas and oil business;

Down hole drilling and completion risks that are generally not recoverable from third parties or insurance;

Potential mechanical failure or under-performance of significant wells or pipeline mishaps;

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- Adverse weather conditions;
- Availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- The number of well locations to be drilled and the time frame in which they will be drilled;
- Delays in anticipated start-up dates;
- Actions or inactions of third-party operators of our properties;
- Ability to find and retain skilled personnel;
- Strength and financial resources of competitors;
- Potential defects in title to our properties;
- Federal and state regulatory developments and approvals;
- Losses possible from pending or future litigation;
- Environmental risks; and
- Worldwide political and economic conditions.

Other factors that could affect our financial performance or cause our actual results to differ materially from our projected results are described (1) under Item 1A Risk Factors and elsewhere in this Form 10-K, including such information that we include or incorporate by reference, (2) in our subsequent reports, registration statements and other filings filed from time-to-time with the SEC and (3) other announcements we make from time to time.

You should not unduly rely on these forward-looking statements in this Form 10-K, as they speak only as of the date of this Form 10-K. Except as required by law, we undertake no obligation to publicly update, revise or release any revisions to these forward-looking statements after the date on which they are made, to reflect new information, events or circumstances occurring after the date of this Form 10-K or to reflect the occurrence of unanticipated events.

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Unless otherwise indicated or required by the context, (i) all references included in this Form 10-K to Gastar, the Company, we , us , and our refer to Gastar Exploration Ltd. and its subsidiaries and predecessors, (ii) all dollar amounts appearing in this Form 10-K are stated in United States (U.S.) dollars unless otherwise noted in Australian dollars (AU$) and (iii) all financial data included in this Form 10-K have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP).

As of the opening of trading on August 3, 2009, a common share consolidation on the basis of one (1) common share for five (5) common shares (the 1-for-5 Reverse Split) became effective. All common share and per share amounts reported in this Form 10-K have been reported on a post reverse split basis.

PART I

Item 1. *Business*

Overview

We are an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties with an emphasis on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as shale resource plays. We are pursuing natural gas exploration in the deep Bossier gas play in the Hilltop area of East Texas and the Marcellus Shale in the Appalachian area of West Virginia and central and southwestern Pennsylvania. We also conduct coal bed methane (CBM) development activities within the Powder River Basin of Wyoming and Montana.

We are a Canadian corporation, incorporated in Alberta and subsisting under the *Business Corporations Act* (Alberta). Our principal office is located at 1331 Lamar Street, Suite 1080, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is *http://www.gastar.com*. Information on our website or about us on any other website is not incorporated by reference into this Form 10-K and does not constitute a part of this report. Our common shares are listed on the NYSE Amex under the symbol GST .

Our Strategy

Continue Exploitation of Existing East Texas and Marcellus Sale Assets

Our East Texas portfolio includes 24 productive wells, which we anticipate will grow to 28 wells over the next 12 months. We have identified numerous potential drilling locations on our current East Texas acreage position of 28,200 gross (14,400 net) acres that provide opportunities under normal gas market conditions to increase production and cash flow through the drilling of high return Bossier wells. Our Marcellus Shale assets in West Virginia and Pennsylvania consist of one tested vertical Marcellus Shale well that is awaiting connection to a pipeline and 15 drilled shallow Devonian wells. We continue to increase our acreage exposure of approximately 38,800 gross (35,500 net) acres and drilling activities in the Marcellus Shale.

Actively Manage Our Domestic Drilling Program

We believe operating our East Texas and our Appalachian Marcellus Shale properties enables us to control the timing and cost of our drilling budget, as well as control operating costs and the marketing of our production. We have assembled an experienced team of operating professionals with the specialized skills needed to plan and execute the drilling and completion of the deep, high-temperature and high-pressure wells targeting the deep Bossier formation.

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Manage and Utilize Technological Expertise

We believe that 3-D seismic analysis, enhanced natural gas recovery processes, horizontal drilling, and other advanced drilling technologies and production techniques are valuable tools that improve drilling results and ultimately enhance production and returns. We believe that utilizing these technologies and production techniques in exploring for, developing and exploiting natural gas and oil properties have helped us reduce drilling risks, lower finding costs and provide for more efficient production of natural gas and oil from our properties.

Natural Gas and Oil Activities

The following provides an overview of our major natural gas and oil projects. While actively pursuing specific exploration and development activities in each of the following areas, we continue to review other opportunities. There is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled.

Hilltop Area, East Texas

The majority of our activities have been in the Bossier play in the Hilltop area of East Texas, approximately midway between Dallas and Houston in Leon and Robertson Counties, where, at December 31, 2009, we held leases covering approximately 28,200 gross (14,400 net) acres. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production and attractive long-lived per well reserves.

In May 2009, following the completion of the Wildman Trust #5 well in the Bossier play, we released our contracted drilling rig in East Texas due to low natural gas prices and to conserve capital. In late October 2009, we returned the contracted rig to drilling in East Texas with the spudding of the Donelson #4 well, a lower Bossier vertical test. The well was drilled to a total depth of 19,000 feet; however, while attempting to log the well, hole stability issues arose. The well was sidetracked, and while drilling, the well experienced a significant gas kick and will have to be plugged back to approximately 15,600 feet and re-drilled to a revised total depth of 18,700 feet. This second sidetrack operation is expected to take approximately six to eight weeks and require additional costs of approximately $4.0 million gross ($2.7 million net). The revised estimate to drill and complete the Donelson #4 well is now approximately $16.5 million gross ($11.0 million net), which may, in part, be subject to reimbursement under existing well control insurance policies. Gastar has a 67% before payout working interest and an approximate 50% before payout net revenue interest in the well.

For the year ended December 31, 2009, net production from the Hilltop area averaged 21.8 million cubic feet of natural gas equivalent (MMcfe) per day. For the three months ended December 31, 2009, net production from the Hilltop area averaged approximately 20.1 MMcfe per day. At December 31, 2009, proved reserves attributable to the Hilltop area were approximately 43.7 billion cubic feet of natural gas equivalent (Bcfe), or 89% of our total proved reserves.

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The following table provides production and operational information about the Hilltop area for the periods indicated:

	For the Years Ended December 31, 2009	2008	2007
Production:			
Natural gas (MMcf)	7,959	6,361	4,695
Oil (MBbl)	2	4	7
Total (MMcfe)	7,971	6,383	4,739
Natural gas (MMcfd)	21.8	17.4	12.9
Oil (MBod)	0.0	0.0	0.0
Total (MMcfed)	21.8	17.5	13.0
Average realized sales prices before hedging activity:			
Natural gas (per Mcf)	$ 3.04	$ 7.30	$ 5.75
Oil (per Bbl)	$ 53.64	$ 102.53	$ 66.44
Selected data per Mcfe:			
Production costs (1)	$ 0.42	$ 0.54	$ 0.62

(1) Production costs include natural gas and oil lease operating expense, gathering and workover expense and excludes ad valorem and severance taxes.

For the fiscal year 2010, we currently anticipate that we will drill approximately 4 gross (3.0 net) wells in East Texas and conduct up to 2 recompletions in existing wells.

Appalachia West Virginia and Central and Southwestern Pennsylvania

The Marcellus Shale is Middle Devonian aged shale that underlies much of the Appalachian region of Pennsylvania, New York, Ohio, West Virginia and adjacent states. The shallow depth of the Marcellus Shale and its low permeability make the Marcellus Shale an unconventional exploration target. Advancements in two technologies, hydraulic stimulation and horizontal drilling, have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. In late 2007, we began acquiring an acreage position prospective for in the Marcellus Shale in West Virginia and central and southwestern Pennsylvania. At December 31, 2009, our acreage position in the play was approximately 38,800 gross (35,500 net) acres, the majority of which is believed to be in the core, over-pressured area of the Marcellus Shale play and is in close proximity to wells being drilled by other operators.

In October 2009, we commenced drilling our first vertical Marcellus Shale well, the Yoho #1 well. We successfully drilled the well to a depth of 6,600 feet, which was completed and tested in January 2010. It tested at a stabilized gross rate of 1.5 million cubic feet of natural gas (MMcf) and 120 barrels of condensate per day, with no water production at approximately 1,000 psi of flowing tubing pressure. We currently are waiting for a connection to a pipeline and do not expect sales until late third quarter 2010.

During the year ended December 31, 2009, we drilled 8 gross (7.6 net) shallow vertical wells in shallower Devonian formations resulting in 15 gross (13.8 net) total shallow wells drilled by us in the area. Currently, eleven are on production, and the remaining wells are scheduled to be on production in the next 90 days. This shallow well drilling program continues to be conducted to hold certain expiring leases by production. For the year and three months ended December 31, 2009, net production from the Appalachian area averaged 0.4 MMcfe per day.

For the fiscal year 2010, we currently anticipate that we will drill approximately 4 gross (2.1 net) horizontal and 2 gross (2 net) vertical Marcellus Shale wells and 7 additional shallow Devonian wells.

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Coalbed Methane Powder River Basin, Wyoming and Montana

At December 31, 2009, we owned an average non-operated working interest of approximately 40% in approximately 40,700 gross (17,200 net) acres within the Powder River Basin of Wyoming and Montana. We had no drilling activity in Wyoming and Montana during 2009 due to low natural gas prices in the area. As a result, only maintenance expenditures were incurred during 2009. Drilling in 2010 is anticipated to increase slightly due to recent natural gas price increases in the area. As a result of the 2009 decrease in drilling activity and reduced compression, our 2009 Powder River Basin production averaged 3.2 MMcfe per day, down from 5.5 MMcf per day in 2008. For the three months ended December 31, 2009, our Powder River Basin production averaged 2.5 MMcfe per day, down from 5.5 MMcf per day for the same period in 2008.

Markets and Customers

The success of our operations is dependent upon prevailing prices for natural gas and oil. The markets for natural gas and oil have historically been and currently continue to be volatile. Natural gas and oil prices are beyond our control. Although some industry observers have indicated that long-term demand for natural gas will increase because of rising demand to fuel power generation and to meet increasing environmental requirements, natural gas currently is selling at significantly lower prices than oil on an energy equivalent basis due to excess natural gas in storage and excess production concerns.

Our current East Texas production has access to major intrastate and interstate pipeline systems. We contract to sell natural gas from our properties with spot market contracts that vary with market forces on a monthly basis. While overall natural gas prices at major markets, such as Henry Hub in Erath, Louisiana, may have some impact on regional prices, the regional natural gas price at our production facilities may move somewhat independently of broad industry price trends. Because some of our operations are located in specific regions, we are directly impacted by regional natural gas prices in those regions regardless of pricing at major market hubs. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. Any significant change affecting these facilities or our failure to obtain timely access to existing or future facilities on acceptable terms could restrict our ability to conduct normal operations. There are limited natural gas purchaser and transporter alternatives currently available in the Hilltop area of East Texas and, as described below, ETC Texas Pipeline, Ltd. (ETC) provides for the treating, purchase and transportation of substantially all of our natural gas production from this area. Delays in the commencement of operations of the new pipelines, the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition. Our deep Bossier production is transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase our natural gas production. Powder River Basin natural gas is sold under spot market contracts to major pipeline and natural gas marketing companies. Our shallow West Virginia production is sold on the spot market to regional pipeline companies. Our Marcellus Shale production currently is subject to pipeline infrastructure and access constraints in the area. Numerous mid-stream pipeline projects have been proposed for the area, but until such projects are completed, we will likely continue to incur delays in getting our Marcellus Shale production to sales.

Our very limited oil production in Texas and the Appalachian Basin in West Virginia is sold under spot sales transactions at market prices. The availability and price responsiveness of the multiple oil purchasers provides for a highly competitive and liquid market for oil sales.

In March 2008, we entered into formal agreements with ETC (the ETC Contract) for the treating, purchase and transportation of substantially all of our natural gas production from the Hilltop area of East Texas. The ETC Contract was effective as of September 1, 2007 and has a term of 10 years. ETC currently provides us with 50.0 MMcf per day of treating capacity and 150.0 MMcf per day of transportation capacity of production from our wells located in Leon and Robertson Counties, Texas.

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On November 16, 2009, concurrent with the sale of our Hilltop gathering system in East Texas, our wholly-owned subsidiary entered into a gas gathering agreement effective November 1, 2009 (the Hilltop Gathering Agreement), with Hilltop Resort GS, LLC for a term of 15 years. The Hilltop Gathering Agreement covers delivery of our gross production of natural gas in the Hilltop area of East Texas to certain delivery points provided under the ETC Contract, as well as additional delivery points that, from time to time, may be added. We also are obligated to connect new wells that we drill within the area covered by the agreement to the gathering system. The Hilltop Gathering Agreement provides for a minimum quarterly gathering gross production volume of 50.0 MMcf per day (35.0 MMcf per day net to us) times the number of days in the quarter for five years from the effective date of November 1, 2009. If quarterly production is less than the minimum quarterly requirement, the gathering fee is payable on such deficit. If excess quarterly production exists, such excess is carried forward to offset any future deficit quarters. The gathering fee on the initial gross 25 Bcf of production is $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reaches 300 Bcf.

For the years ended 2009, 2008 and 2007, ETC accounted for 85%, 79% and 78%, respectively, of our natural gas and oil revenues, excluding realized hedge impact. Enserco Energy, Inc. (Enserco) accounted for 13%, 19% and 20% of our natural gas and oil revenues, for the years end 2009, 2008 and 2007, respectively, excluding realized hedge impact. ETC purchases substantially all of our East Texas natural gas production and Enserco purchases substantially all of our Powder River Basin natural gas production. Management believes that the loss of either ETC or Enserco would not have a long-term material adverse impact on our financial position or results of operations, as there are other purchasers operating in the areas.

Competition

The natural gas and oil industry is intensely competitive and speculative in all of its phases. We encounter competition from other natural gas and oil companies in all areas of our operations. In seeking suitable natural gas and oil properties for acquisition, we compete with other companies operating in our areas of interest, including large natural gas and oil companies and other independent operators, many of whom have greater financial resources and in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce natural gas and oil but also market natural gas and oil and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive natural gas and oil properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Prices of our natural gas and oil production are controlled by market forces. However, competition in the natural gas and oil exploration industry also exists in the form of competition to acquire leases and obtain favorable transportation prices. We are smaller and have a more limited operating history than most of our competitors and may have difficulty acquiring additional acreage and/or projects and may have difficulty arranging for the transportation of our production. We also face competition in obtaining natural gas and oil drilling rigs and in providing the manpower to operate them and provide related services.

U.S. Governmental Regulation

In addition to the environmental regulations discussed below, our natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States. These laws and regulations, all of which are subject to change from time to time, include matters relating to land tenure; drilling and production practices, such as discharge permits and the spacing of wells; the disposal of water resulting from operations and the processing, handling and disposal of hazardous materials, such as hydrocarbons

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and naturally occurring radioactive materials; bonding requirements; ongoing obligations for licensing; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act, or SDWA, to require the disclosure of chemicals used by the natural gas and oil industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production and is critical to our East Texas and Marcellus Shale operations. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing.

Failure to comply with these rules and regulations can result in substantial penalties. Furthermore, we could be liable for personal injuries, property damage, spills, discharge of hazardous materials, reclamation costs, remediation, clean-up costs and other environmental damages as a consequence of acquiring a natural gas or oil prospect or acreage.

The regulatory burden on the natural gas and oil industry increases our cost of doing business and affects our financial condition. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because those laws and regulations are frequently amended or reinterpreted. We are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective.

Regulation of Sales of Natural Gas

The price at which we buy and sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the Federal Energy Regulatory Commission, or the FERC, and/or the Commodity Futures Trading Commission (the CFTC). See below the discussion of Other Federal Laws and Regulations Affecting Our Industry Energy Policy Act of 2005 . Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities. In addition, pursuant to Order 704 (defined below) we may be required to annually report to FERC on May 1 of each year information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted during the prior calendar year. See below the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

Regulation of Availability, Terms and Cost of Pipeline Transportation

The availability, terms and cost of transportation can significantly affect sales of natural gas. FERC regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of natural gas produced by us and the revenues received by us for sales of such natural gas. FERC requires interstate pipelines to offer available firm transportation capacity on an open access, non-discriminatory basis to all natural gas shippers. FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well.

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The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the NGC+ Work Group), or to explain how and why their tariff provisions differ. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group s interim guidelines for such an interconnecting pipeline.

State laws and regulations generally govern the gathering and intrastate transportation of natural gas. Natural gas gathering systems in the states in which we operate are generally required to offer services on a non-discriminatory basis, and 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. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. Under the Energy Policy Act of 2005, or EPAct 2005, Congress made it unlawful for any entity, including otherwise non-jurisdictional producers of natural gas, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services regulated by the FERC that violates the FERC s rules. FERC s rules implementing the provision of EPAct of 2005 make it unlawful for any entity in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, directly or indirectly, to use or employ any device, scheme, or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA and NGPA up to $1,000,000 per day per violation. While EPAct 2005 reflects a significant expansion of the FERC s enforcement authority, we do not anticipate that we will be affected by that statute any differently than other producers of natural gas.

FERC Market Transparency Rules. In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report on Form No. 552, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas companies with whom we compete.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by

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FERC and Congress will continue indefinitely into the future. We do not believe that we will be affected by any action taken in a materially different way than other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. The oil industry is also extensively regulated by numerous federal, state and local authorities. Prices for crude oil and condensate are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

In a number of instances, however, the ability to transport and sell such products on interstate pipelines is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act, or ICA. The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rate as well as the rules and regulations governing the service. The ICA requires, among other things, that rates on interstate common carrier pipelines be just and reasonable. The ICA permits challenges to existing rates and authorizes FERC to investigate such rates to determine whether they are just and reasonable. If, upon completion of an investigation, FERC finds that the existing rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation and, in some cases, reparations for the two (2) year period prior to the filing of a complaint. We do not believe, however, that these regulations affect us any differently than other producers.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Our operations are subject to extensive and continually changing regulation affecting the natural gas and oil industry. Many departments and agencies, both federal and state are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas and oil industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

Regulation of Production. The production of natural gas and oil is subject to extensive regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require, among other things, permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of the natural gas and oil properties; the establishment of maximum rates of production from natural gas and oil wells; the spacing of wells; and the plugging and abandonment of wells and removal of related production equipment. These and other regulations can limit the amount of the natural gas and oil we can produce from our wells, limit the number of wells we can drill, or limit the locations at which we can conduct drilling operations. Moreover, each state generally imposes a production or severance tax with respect to production and sale of natural gas, natural gas liquids and crude oil within its jurisdiction.

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U.S. Environmental Regulation

Our U.S. natural gas and oil exploration and production operations and similar operations that we do not operate but in which we own a working interest 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. Environmental laws are implemented principally by the United States Environmental Protection Agency, or EPA, the Department of Transportation and the Department of the Interior, as well as other comparable state agencies. 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 may result in the issuance of injunctions limiting or prohibiting operations, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as the assessment of other laws or regulations that are adopted in the future, could have a material adverse impact on our operations and other operations in which we own an interest.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws and regulations or the modification or more stringent enforcement of existing laws and regulations could have a material adverse effect on our operations and other operations in which we own an interest. 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 significant resources in order to satisfy existing applicable environmental laws and regulations. However, there is no assurance that costs to comply with existing, and any new environmental laws and regulations in the future will not be material. In addition, if substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Moreover, a serious incident of pollution may result in the suspension or cessation of operations in the affected area. 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 business operations are subject.

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 transported, 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 as well as other operations in which we own an interest 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

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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 EPA 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 and other operations in which we own an interest 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. In the past, proposals have been made to amend RCRA to rescind this exemption. Repeal or modification of the exception or similar exemptions in state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating cost, which could have a significant impact on us as well as the natural gas and oil industry in general.

We currently own, lease, own a working interest in, or operate numerous properties that for many years have been used by third parties for the exploration and production of natural gas and oil. Although we abide by standard industry operating and disposal practices, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us or in which we own an interest, or on or under other locations, including off-site locations, where such substances have been taken for disposal or recycling. In addition, many of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

Our operations and other operations in which we own a working interest 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 and state waters, including wetlands. In addition, depending on the location, discharges from or the use of water in our operations may be subject to regulation by regional or local regulatory authorities. 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 natural gas and oil production operations were to occur, we would be subject to spill notification and response requirements under the CWA or the equivalent state regulatory program. Depending on the nature and location of these operations, spill response plans may also have to be prepared.

Our natural gas and oil exploration and production operations and other operations in which we own an interest generate produced water as a waste material, which is subject to the disposal requirements of the CWA, SDWA or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by coal bed methane, or CBM, production in our operations or in other operations in which we own an interest. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to the surface, or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance

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with permits issued by regulatory agencies and in compliance with applicable environmental regulations. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the CWA or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the SDWA or an equivalent state regulatory program. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that the produced water has been discharged into the produced water disposal wells in substantial compliance with such obtained permits and applicable laws. Nonetheless, in connection with CBM production in the Powder River Basin, a concern common of many operators in the Basin is the potential for opposition by individuals or groups to the issuance of a permit for the discharge or disposal of water generated by production activities. Such opposition could result in delays, limitations or denials with respect to environmental or other approvals necessary to develop our acreage in the Powder River Basin, which could adversely affect our financial condition or results of operations. In addition, the United States Congress is considering amending the SDWA to require additional regulation of chemicals used by the oil and gas industry in the hydraulic fracturing process, and some states are considering similar regulations.

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 found at our operations or other operations in which we own an interest, 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. However, there is no assurance that in the future, we will not be required to incur capital expenditures in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues.

Our CBM production operations involve the use of gas-fired compressors to produce or transport gas that is produced. Emissions of combustible by-products from compressors at one location may be large enough to subject the compressors to CAA and comparable state air quality regulation requirements for pre-construction and operating permits. To date, we believe that such gas-fired compressors that have been operated by us or at other operations in which we own a working interest have been operated in substantial compliance with obtained permits and the applicable federal, state and local laws and regulations without undue cost to or burden on our business activities. Another air emission associated with the CBM operations that may be subject to regulation and permitting requirements is particulate matter resulting from construction activities and vehicle traffic. To date, we do not believe there has been any unusual difficulty in complying with requirements related to particulate matter.

Endangered Species Act

The federal Endangered Species Act, as amended (ESA) and similar state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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Other Laws and Regulations

Our operations and other operations in which we own a working interest are also impacted by 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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere and other climatic changes. In response to such studies, the EPA is considering regulations and Congress is considering legislation to reduce emissions of greenhouse gases.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal CAA. Accordingly, the EPA has proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including sources emitting more than 25,000 tons of greenhouse gases on an annual basis, beginning in 2011 for emissions occurring in 2010. Also, on June 26, 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances authorizing emissions of greenhouse gases into the atmosphere. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support for legislation to reduce greenhouse gas emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for our products and services. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of natural gas and oil. As a result of the sale of our Australian operations in July 2009, our current operational activities are conducted and our consolidated revenues are generated from markets exclusively in the United States, and we have no long-lived assets located outside the United States.

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Employees

As of March 25, 2010, we had 24 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, regulatory reporting, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our natural gas and oil. Our employees do not belong to a union or have a collective bargaining organization. Management considers its relationship with its employees to be good.

Corporate Offices

We lease our corporate offices at 1331 Lamar Street, Suite 1080, Houston, Texas 77010. Our office space covers 9,332 square feet at a monthly rental of $18,151 through October 2010. Additionally, we rent 1,322 square feet of office space in Parkersburg, West Virginia at a monthly rental of $881 per month through January 2012.

Internet Website Access

Our website address is *http://www.gastar.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website as soon as reasonably practicable after we have electronically filed the material with, or furnished it to, the SEC.

The public may also read and copy any materials we have filed with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website that contains our reports, proxy and information statements and our other SEC filings. The address of that site is www.sec.gov. Information is also available at www.sedar.com for our filings required by Canadian securities regulators.

None of the information on our website or filed by us on www.sedar.com should be considered incorporated into or a part of this Form 10-K.

We also make available free of charge on our internet website at www.gastar.com under the corporate governance tab our:

- Code of Ethics;
- Terms of Reference of our Audit Committee;
- Terms of Reference of our Governance Committee:
- Terms of Reference of our Remuneration Committee;
- Terms of Reference of our Nominating Committee;
- Reserves Review Committee Mandate; and
- Whistleblower Procedure.

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Item 1A. ***Risk Factors***

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following material risk factors associated with our business and the oil and gas industry in which we operate. If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected. There may be additional risks that are not presently material or known.

An investment in Gastar is subject to risks inherent in our business. The trading price of our common shares will be affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in Gastar may decrease, resulting in a loss.

Risks Related to Our Business

Future economic conditions in the U.S. and key international markets may materially adversely impact our operating results.

The U.S. and other world economies are slowly recovering from a recession, which began in 2008 and has extended into 2010. Growth has resumed, but is modest. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than what was experienced in recent years. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate will result in decreased demand growth for our natural gas production and crude oil, as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

Natural gas and oil prices are volatile and further declines in natural gas and oil prices will continue to significantly and negatively affect our financial condition and results of operations.

The success of our business greatly depends on market prices of natural gas and oil. The higher market prices are, the more likely it is that we will be financially successful. On the other hand, declines in natural gas or oil prices may have a material adverse affect on our financial condition, profitability and liquidity. Lower prices also may reduce the amount of natural gas or oil that we can produce economically. Natural gas and oil commodity prices are set by broad market forces. Historically, the natural gas and oil markets have been and will likely continue to be volatile in the future. Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas or oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- The domestic and foreign supply of natural gas and oil;
- Overall economic conditions;
- Weather conditions;
- Political conditions in the Middle East and other oil producing regions, such as Venezuela;
- Domestic and foreign governmental regulations;
- The level of consumer product demand; and

The price and availability of alternative fuels.

Our success is influenced by natural gas prices in the specific areas where we operate, and these prices may be lower than prices at major markets.

Regional natural gas prices may move independent of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional natural gas prices regardless of Henry Hub or other major market pricing. During 2009, approximately 86% of our production was priced based on the Katy Hub basis point, and 13% was priced on the Colorado Interstate Gas (CIG) basis point. In 2007, natural gas prices based on CIG were extremely volatile, and spot sales of natural gas in the region traded at prices substantially below historic levels, when compared to prices in other primary natural gas sales points in the country. This was attributed primarily to limitations in available pipeline capacity for natural gas deliveries out of the Rocky Mountain area. While this volatility has been alleviated partially by completion of a major pipeline system in January 2008, CIG natural gas prices continue to trade approximately 5% less than Henry Hub prices and may decline further if supplies of natural gas in the Rocky Mountains continue to increase. Our West Virginia natural gas production is priced using the Columbia Gas Appalachia Pool. At December 31, 2009, the Henry Hub price was $5.79 per MMBtu, compared to our key basis point pricing of $5.72 per MMBtu at the Katy Hub, $5.54 per MMBtu for CIG and $5.95 per MMBtu for the Columbia Gas Appalachia Pool. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations.

Natural gas and oil reserves are depleting assets, and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows would be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Further, we may not be successful in exploring for, developing or acquiring additional reserves, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions;
- Blowouts, fires or explosions with resultant injury, death or environmental damage;
- Pressure or irregularities in formations;
- Equipment failures or accidents;
- Adverse weather conditions;
- Compliance with governmental requirements and laws, present and future; and
- Shortages or delays in the availability of drilling rigs and the delivery of equipment.

We use available seismic data to assist in the location of potential drilling sites. Even when properly used and interpreted, 2-D and 3-D seismic data and other visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would have a material adverse affect our financial condition, future cash flows and results of operations. In addition, using seismic data and other advanced technologies involves substantial upfront costs and is more expensive than traditional drilling strategies, and we could incur losses as a result of these expenditures.

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We have incurred significant net losses since our inception and may incur additional significant net losses in the future.

With the exception of the one-time sale of our Australian properties in 2009, we have not been profitable since we started our business. Excluding after tax gains on the sale of assets, we incurred net losses of $92.4 million, $5.4 million and $69.1 million for the years ended December 31, 2009, 2008 and 2007, respectively. Our capital has been employed in an increasingly expanding natural gas and oil exploration and development program, with the focus on finding significant natural gas and oil reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this Item 1A Risk Factors and elsewhere in this Form 10-K may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. Our failure to achieve profitability in the future could materially adversely affect our ability to raise additional capital and continue our exploration and development program.

We are subject to various legal proceedings and claims. The cost of our defending these lawsuits and any future lawsuits, and any resulting judgments, could be significant and could have a material adverse effect upon our financial condition.

We are subject to various significant legal proceedings and claims arising outside of the normal course of business. These include, but are not limited to, eight civil lawsuits in which we have been named as a co-defendant arising from investor claims made in connection with brood mare leasing programs operated by ClassicStar, L.L.C. (ClassicStar), a company indirectly owned by GeoStar Corporation (Geostar), which in turn is owned by some of our former executive officers and directors and previously was our largest shareholder. In March 2010, an individual shareholder of GeoStar, who prior to April 2005 served as a director and executive officer of the Company, was charged by the United States Attorney for the District of Oregon with conspiracy to defraud the Federal government by impairing or impeding the Internal Revenue Service in the collection of incomes taxes from participants in the ClassicStar mare leasing programs. The information filed by the U.S. Attorney contains allegations that the ClassicStar mare leasing programs were used to generate fraudulent tax deductions. In those civil suits in which the Company has been named as a co-defendant, many of the plaintiffs allege that Geostar or its shareholders directly or indirectly made investments in the Company using funds fraudulently obtained from participants in the ClassicStar brood mare programs, or that GeoStar and its shareholders used funds obtained from such mare program participants to acquire or develop properties that were later sold to the Company. The plaintiffs in these proceedings seek to attribute the actions of GeoStar and these individuals to the Company. For more information on these and other significant currently outstanding legal proceedings, see Note 17, Commitments and Contingencies Litigation , to our consolidated financial statements included in this Form 10-K. No assurance can be given regarding the outcome of these legal proceedings, and additional claims may arise. We are vigorously defending the Company in these matters. This litigation, regardless of outcome or merit, however, can result in substantial costs and diversion of resources from our business. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that our management would have to appropriate to the defense of such claims. Considerable legal, accounting and other professional services expenses related to these matters have been incurred to date and significant expenditures may continue to be incurred in the future. Although we cannot predict the ultimate outcome of these matters or the liability that could potentially result, continuing defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations.

Deficiencies of title to our leased interests could significantly affect our financial condition.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is not to incur the expense of retaining lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of lease brokers and others to perform the field work in examining records in the appropriate governmental or county clerk s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to drilling an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary

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to cure those defects to the extent reasonably possible. It does happen, from time-to-time, that the examination made by the title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect, which could affect our financial condition and results of operations. We currently are involved in a title litigation matter in East Texas. See Note 17, Commitments and Contingencies Litigation .

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves.

There are many uncertainties inherent in estimating natural gas and oil reserves and their values, many of which are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas or oil that cannot be measured in an exact manner. Estimates of economically recoverable natural gas or oil reserves and of future net cash flows necessarily depend on many variables and assumptions, such as:

- Historical natural gas or oil production from that area, compared with production from other producing areas;
- Assumptions concerning the effects of regulations by governmental agencies;
- Assumptions concerning future prices;
- Assumptions concerning future operating costs;
- Assumptions concerning severance and excise taxes; and
- Assumptions concerning development costs and workover and remedial costs.

Any of these variables or assumptions could vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of natural gas or oil attributable to any particular group of properties, classifications of those reserves based on risk recovery and estimates of the future net cash flows expected from them prepared by different engineers, or by the same engineer at different times, may vary substantially. Because of this, our reserve estimates may materially change at any time.

You should not consider the present values of estimated future net cash flows referred to in this Form 10-K to be the current market value of the estimated reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect when the estimate is made. Current or actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- The amount and timing of actual production;

Supply and demand for natural gas or oil;

Actual prices received for natural gas in the future being different than those used in the estimate;

Curtailments or increases in consumption of natural gas or oil;

Changes in governmental regulations or taxation; and

The timing of both production and expenses in connection with the development and production of natural gas or oil properties.

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In this Form 10-K, the net present value of estimated future net revenues at December 31, 2009 is calculated using the 12-month unweighted arithmetic average of the first-day-of-the-month price and a 10% discount rate. This price and rate are not necessarily the most appropriate price or discount factor based on prices and interest rates in effect from time to time and risks associated with our reserves or the natural gas and oil industry in general.

Our estimates of proved reserves have been prepared under new SEC rules, which went into effect for fiscal years ending on or after December 31, 2009, and may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This Form 10-K presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The previous rules required that reserve estimates be calculated using year-end pricing. Under the new rules the pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average 12-month West Texas Intermediate posted price of $57.65 per Bbl for oil and a Henry Hub spot price of $3.87 per MMBtu for natural gas, as compared to $41.00 per Bbl for oil and $5.71 per MMBtu for natural gas as of December 31, 2008. As a result of these changes, direct comparisons to our previously-reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our acreage in the Hilltop area in East Texas and the Marcellus Shale in West Virginia and Pennsylvania. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill and develop those reserves within the required five-year timeframe.

The SEC has not reviewed our or any reporting company s reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this Form 10-K have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

The imprecise nature of estimating proved natural gas and oil reserves, future downward revisions of proved reserves and increased drilling expenditures without current additions to proved reserves may lead to write downs in the carrying value of our natural gas and oil properties.

We may experience write downs of the carrying value of our oil and gas properties in the future if the present value of our proved natural gas and oil reserves is lower than our remaining unamortized capitalized costs. Factors that can contribute to write downs include lower natural gas and oil prices, downward revisions in estimated proved natural gas and oil reserve quantities, differences in timing between the incurrence of significant costs of exploration or development activities and the recognition of significant proved reserves resulting from such activities and unsuccessful drilling activities.

Approximately 41% of our proved reserves are classified as proved developed non-producing or proved undeveloped and may ultimately prove to be less than estimated.

At December 31, 2009, approximately 41% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take substantial capital to recomplete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2009 assumes that we will spend

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significant development capital expenditures to develop these reserves, including an estimated $11.4 million and $6.7 million in 2010 and 2011, respectively. Further, our drilling efforts may be delayed or unsuccessful, and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Our inability to meet a financial covenant contained in our bank revolving credit facility may adversely affect our liquidity, financial condition or results of operations.

We are subject to certain financial covenants we are required to maintain under our revolving credit facility related to our working capital, cash flow and interest coverage ratio. If we breach a financial covenant and we are unable to cure such violation or obtain waivers from our lenders under the revolving credit facility within the applicable cure periods, such violation will constitute an event of default under the revolving credit facility, and our lenders could terminate any commitments they have to make available further funds, accelerate the due dates for the payments of all outstanding indebtedness and exercise their remedies as a secured creditor with respect to the collateral securing the revolving credit facility, which is substantially all of our natural gas and oil properties.

If the counterparties to the derivative instruments we use to hedge our business risks default or fail to perform, we may be exposed to risks we had sought to mitigate, which could materially adversely effect our financial condition and results of operations.

We use hedges to mitigate our natural gas price risk with counterparties. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty s insolvency, inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and results of operations. At the date of filing of this Form 10-K, our only counterparties were BP Corporation North America, Bank of Montreal and J.P. Morgan Ventures Energy Corporation.

We are subject to complex laws and regulations, including environmental laws and regulations that can adversely affect the cost, manner or feasibility of conducting our business.

Our exploration and production interests and operations are subject to stringent and complex federal, state and local laws and regulations governing the operation and maintenance of our facilities and the handling and discharge of substances into the environment. These existing laws and regulations impose numerous obligations that are applicable to our interests and operations including:

- Air and water discharge permits for drilling and production operations;
- Drilling and abandonment bonds or other financial responsibility assurances;
- Reports concerning operations;
- Spacing of wells;
- Access to properties, particularly in the Powder River Basin;
- Taxation; and

Other regulatory controls on operating activities.

In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of natural gas and oil.

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Failure to comply with environmental and other laws and regulations applicable to our interests and operations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of orders enjoining or limiting future operations, any of which could have a material adverse affect on our financial condition. Legal requirements are sometimes unclear or subject to reinterpretation and may be frequently changed in response to economic or political conditions. As a result, it is hard to predict the ultimate cost of compliance with these requirements or their affect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse effect on our financial condition, future cash flows and the results of operations.

The production, handling, storage, transportation and disposal of natural gas and oil, by-products of natural gas and oil and other substances produced or used in connection with natural gas and oil production operations are regulated by laws and regulations focused on the protection of human health and the environment. Joint and several, strict liability may be incurred without regard to fault or the legality of the original conduct under certain of these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties located near our storage facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. Consequently, the discharge or release of natural gas, oil or other substances into the air, soil or water, even by predecessor operators, could subject us to liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, property and natural resource damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our natural gas and oil sales and our related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and oil and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases , or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. Accordingly, the EPA has proposed regulations that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. In addition, in October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including sources emitting more than 25,000 tons of GHGs on an annual basis, beginning in 2011 for emissions occurring in 2010. On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009 , also known as the Waxman-Markey cap-and-trade legislation , or ACESA. The purpose of ACESA is to control and reduce emissions of GHGs in the United States. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs, and President Obama has indicated that he supports legislation to control and reduce emissions of GHGs through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the CFTC to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is considering whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Separately, the House of Representatives adopted financial regulatory reform

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legislation on December 11, 2009, that among other things would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace. This legislation would subject swap dealers and major swap participants to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants, and would provide the CFTC with authority to impose position limits in the OTC derivatives markets. A major swap participant generally would be someone other than a dealer who maintains a substantial net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the U.S. banking system or financial markets. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the SDWA to repeal an exemption in the SDWA for the underground injection of hydraulic fracturing fluids near drinking water sources and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production, primarily in shale formations. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas. If adopted, these regulatory initiatives and legislation could establish additional levels of regulation and other restrictions that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

The process of drilling for and producing natural gas and oil involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately.

The natural gas and oil business involves many operating hazards, such as:

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Uncontrollable flows of natural gas, oil or well fluids;
- Pipe and cement failures;
- Formations with abnormal pressures;
- Stuck drilling and service tools;

Pipeline ruptures or spills;

Natural disasters; and

Releases of toxic natural gas.

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Any of these events could cause substantial losses to us as a result of:

- Injury or death;
- Damage to and destruction of property, natural resources and equipment;
- Pollution and other environmental damage;
- Regulatory investigations and penalties;
- Suspension of operations; and
- Repair and remediation costs.

We could also be responsible for environmental damage caused by previous owners of property from whom we purchased leases. As a result, we may incur substantial liabilities to third parties or governmental entities. Although we maintain what we believe is appropriate and customary insurance for these risks, the insurance may not be available or sufficient to cover all of these liabilities. If these liabilities are not covered by our insurance, paying them could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

The CBM which we produce in the Powder River Basin may be drained by offsetting production wells.

Our drilling locations in the Powder River Basin are spaced primarily using 80-acre spacing. Producing wells located on the 80-acre spacing units contiguous with our drilling locations may drain the acreage underlying our wells. We do not operate these properties and have limited ability to exercise influence over operations for these properties. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control. Likewise, as a result of our dependence on the operator and other working interest owners for these projects, we are limited in our ability to drill wells to protect against drainage. Although there has not been a material number of offsetting wells drilled adjacent to our properties at this time, if a substantial number of productive wells are drilled on spacing units adjacent to our properties, they may decrease our revenue and could have an adverse impact on the economically recoverable reserves of our properties that are susceptible to such drainage.

Our Powder River Basin CBM wells typically have a shorter reserve life and lower rates of production than conventional natural gas wells, which may adversely affect our profitability and our ability to recognize proved reserves from this basin during periods of low natural gas prices.

The shallow coal from which we produce CBM in the Powder River Basin typically have a two to six year reserve life and have lower total reserves and produce at lower rates than most conventional natural gas wells. We depend on drilling a large number of wells each year to replace production and reserves in the Powder River Basin and to distribute operational expenses over a larger number of wells. A decline in natural gas prices could make certain wells uneconomical because production rates are lower on an individual well basis and may be insufficient to cover operational costs. The extended decline in gas prices through 2009 combined with the revised pricing methodology under the new SEC rules, described in more detail above, had a negative impact on our reserves in the Powder River Basin. As of December 31, 2009, we did not recognize any proved undeveloped reserves in the Powder River Basin because our proved undeveloped reserves in the Basin did not have a positive PV-10 value and were uneconomical as a result. Our proved developed reserves in the Basin had only nominal value at such date.

Approximately 85% of our natural gas and oil revenues and 89% of our total proved reserves as of and for the year ended December 31, 2009 were attributable to our properties in East Texas. Any disruption in production, development of proved reserves, or our ability to

process and sell natural gas from this area would have a material adverse effect on our results of operations or reduce future revenues.

Our current production is geographically concentrated in East Texas. Production of the natural gas in East Texas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Our natural gas produced from this area contains levels of carbon dioxide and hydrogen sulfide that are above levels accepted by gas purchasers. This production must be treated by the purchaser. A majority of our East Texas production is processed by the purchaser. If the purchaser s facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our East Texas production could reduce current revenues by an estimated $4.3 million to $6.4 million, before the impact of hedges, with a corresponding reduction in our cash flow. Moreover, an unexpected delay in developing proved reserves in this area due to capital constraints or changes in development plan could reduce future revenues.

There are a limited number of natural gas purchasers and transporters in the Hilltop area of East Texas. The loss of our current purchaser and transporter and an inability to locate another purchaser and transporter would have a material adverse effect on our financial condition and results of operations.

There are a limited number of natural gas transporters in the Hilltop area in East Texas. For the year ended December 31, 2009, ETC accounted for substantially all of our revenues from this area. If ETC were to cease purchasing and transporting our natural gas and we were unable to contract with another transporter, it would have a material adverse effect on our financial condition, future cash flows and the results of operations.

Our ability to market our natural gas and oil may be impaired by capacity constraints on the gathering systems and pipelines that transport our natural gas and oil.

The availability of a ready market for our natural gas production, particularly in the Appalachian area, depends on the proximity of our reserves to and the capacity of natural gas gathering systems, pipelines and trucking or terminal facilities. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. We enter into agreements with companies that own pipelines used to transport natural gas from the wellhead to contract destination. Those pipelines are limited in size and volume of natural gas flow. Our Marcellus Shale production currently is subject to pipeline infrastructure and access constraints in the area. Numerous mid-stream pipeline projects have been proposed for the area, but until such projects are completed, we will likely continue to incur delays in getting our Marcellus Shale production to sales. Our development of Marcellus Shale properties may be limited or delayed. Should production begin, other outstanding contracts with other producers and developers could interfere with our access to a natural gas line to deliver natural gas to the market. Delays in the commencement of operations of new pipelines, the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition. Further, interstate transportation and distribution of natural gas is regulated by the federal government through the FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy.

Additionally, state regulators have powers over sale, supply and delivery of natural gas and oil within their state borders. While we do employ certain companies to represent our interests before state regulatory agencies, our interests may not receive favorable rulings from any state agency, or some future occurrence may drastically alter our ability to enter into contracts or deliver natural gas to the market.

In West Virginia and southwestern Pennsylvania, key issues to development include limited pipeline infrastructure and access, water access and disposal issues to support operations, and limited industry services. All of these factors could have an adverse effect on our ability to effectively conduct exploration and development activities.

In recent years, pipeline capacity for natural gas deliveries out of the Rocky Mountain area has been, at times, significantly constrained resulting in an oversupply and creating substantial discounts on spot natural gas prices received for regional production. This has had a substantial impact on the prices received for natural gas production from Wyoming and Montana, as compared to Gulf Coast natural gas prices. While a recently completed interstate pipeline has alleviated the problem by providing access to the Midwest interstate pipelines

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and markets, the relief may be offset over time by the expected increase in supply of natural gas available in the Rocky Mountains.

Competition in the natural gas and oil industry is intense. We are smaller and have less operating history than many of our competitors, and increased competitive pressure could adversely affect our results of operations.

We operate in a highly competitive environment. We compete with other natural gas and oil companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated natural gas and oil companies, numerous independent natural gas and oil companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have substantially larger operating staffs and greater capital resources than we do and, in many instances, have been engaged in the natural gas and oil business for a much longer time than we have. These companies may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase more properties and prospects than our financial and human resources permit. In addition, these companies may be able to spend more on the existing and changing technologies that we believe are and will be increasingly important to the current and future success of natural gas and oil companies. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. Increased competitive pressure could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

Where appropriate, we may evaluate and pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves;
- Exploration potential;
- Future natural gas and oil prices;
- Operating costs;
- Potential environmental and other liabilities; and
- Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are inexact and their accuracy inherently uncertain, and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every facility or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies;

Unanticipated costs;

Diversion of resources and management attention from our exploration business;

Entry into regions or markets in which we have limited or no prior experience; and

Potential loss of key employees, particularly those of the acquired organization.

We cannot control the activities on properties we do not operate, which may affect the timing and success of our future operations.

Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could have a material adverse affect on the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures;
- The operator s expertise and financial resources;
- Approval of other participants in drilling wells; and
- Selection of technology.

Technological changes could affect our operations.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement such new technologies at substantial costs. In addition, many other natural gas and oil companies have greater financial, technical and personnel resources that may allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may be unable to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If one or more of the technologies that we currently use or may implement in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, it could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Hedging of our production may result in losses or prevent us from benefiting to the fullest extent possible from increases in prices for natural gas and oil.

We have entered into New York Mercantile Exchange (NYMEX) futures contracts as hedges on 6.8 Bcf of natural gas production in 2010. Although these hedges may partially protect us from by declines in natural gas prices, the use of these arrangements also may limit our ability to benefit from significant increases in the prices of natural gas.

Exchange rate fluctuations subject us to unique risks.

As a result of our monetary deposits in Australian dollars, we are exposed to the impact of fluctuations in the exchange rate between the Australian dollar and the U.S. dollar. Currently, we have only minimal exposure to Canadian currency fluctuations, as almost all of our current revenues and expenses are in U.S. dollars.

We depend on our key personnel, the loss of which could adversely affect our operations and financial performance.

We depend to a large extent on the services of a limited number of senior management personnel and directors. Particularly, the loss of the services of our chief executive officer and chief financial officer could negatively impact our future operations. We have employment agreements with these key members of our senior management team; although, we do not maintain key-man life insurance on any of our senior management. We believe that our success is also dependent on our ability to continue to retain the services of skilled technical personnel. Our inability to retain skilled technical personnel could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Our major shareholder may influence the activities and operations of certain jointly owned properties, which also could result in conflicts of interest.

As of December 31, 2009, Chesapeake Energy Corporation owned approximately 13.6% of our outstanding common shares. As a result, Chesapeake is in a position to heavily influence the outcome of matters requiring a

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shareholder vote, including the election of directors, the adoption of or amendment to provisions in our Amended and Restated Articles of Incorporation, Bylaws and the approval of mergers and other significant corporate transactions. Their high level of ownership may also delay, defer or prevent a change in control of us and may adversely affect the voting and other rights of other shareholders. Chesapeake has the right to have an observer present at our board of directors meetings.

Chesapeake and its subsidiaries are also engaged in the natural gas and oil business. It is possible that we may in some circumstances be in direct or indirect competition with Chesapeake, including competition with respect to certain business strategies and transactions that we may propose to undertake. These conflicts of interest may have a material adverse affect our results of operations.

Some of our directors may not be subject to suit in the United States.

Two of our directors are citizens of Canada. As a result, it may be difficult or impossible to effect service of process within the United States upon those directors, to bring suit against them in the United States or to enforce in the United States courts any judgment obtained there against them predicated upon any civil liability provisions of the United States federal securities laws. Investors should not assume that Canadian courts will enforce judgments of United States courts obtained in actions against those directors predicated upon the civil liability provisions of the United States federal securities laws or the securities or blue sky laws of any state within the United States or will enforce, in original actions, liabilities against those directors upon the United States federal securities laws or any such state securities or blue sky laws.

Risks Related to Our Common Shares

Future issuances of our common shares may adversely affect the price of our common shares.

The future issuance of a substantial number of common shares into the public market, or the perception that such an issuance could occur, could adversely affect the prevailing market price of our common shares. A decline in the price of our common shares could make it more difficult to raise funds through future offerings of our common shares or securities convertible into common shares.

Our ability to issue an unlimited number of our common shares under our articles of incorporation may result in dilution or make it more difficult to effect a change in control of the Company, which could adversely affect the price of our common shares.

Unlike most corporations formed in the United States, our Amended and Restated Articles of Incorporation chartered under the laws of the Province of Alberta, Canada permit the board of directors to issue an unlimited number of new common shares without shareholder approval, subject only to the rules of the NYSE Amex LLC or any future exchange on which our common shares might trade. The issuance of a large number of common shares could be affected by our directors to thwart a takeover attempt or offer for us by a third party, even if doing so would not benefit our shareholders, which could result in the common shares being valued less in the market. The issuance or the threat of issuance of a large number of common shares at prices that are dilutive to the outstanding common shares could also result in the common shares being valued less in the market.

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

None.

Item 2. ***Properties***

Our properties consist primarily of natural gas and oil leases in the following areas:

Hilltop area of East Texas;

Marcellus Shale in West Virginia and southwestern Pennsylvania; and

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Powder River Basin in Wyoming and Montana.

Additional information concerning our interests in these areas is described under Item 1 Business .

Production, Prices and Operating Expenses

The following table presents information regarding the production volumes, average sales prices received and selected data per Mcfe associated with our sales of natural gas and oil for the periods indicated. Oil and condensate are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil or condensate is the energy equivalent of six Mcf of natural gas.

	For the Years Ended December 31,		
	2009	**2008**	**2007**
Production:			
Natural gas (MMcf)	9,266	8,482	6,576
Oil (MBbl)	4	5	7
Total (MMcfe)	9,291	8,510	6,621
Natural gas (MMcfd)	25.4	23.2	18.0
Oil (MBod)	0.0	0.0	0.1
Total (MMcfed)	25.5	23.3	18.1
Average sales prices before hedging activity:			
Natural gas (per Mcf)	$ 3.06	$ 6.92	5.18
Oil (per Bbl)	$ 54.46	$ 98.39	66.17
Average sales prices after realized hedging activity:			
Natural gas (per Mcf) (1)	$ 4.36	$ 6.63	5.18
Oil (per Bbl)	$ 54.46	$ 98.39	66.17
Selected data per Mcfe:			
Lease operating, transportation and selling expenses and severance tax	$ 0.92	$ 1.28	1.32
General and administrative expenses	$ 1.68	$ 1.68	2.55
Depreciation, depletion and amortization of natural gas and oil properties	$ 1.77	$ 2.87	3.24

(1) We had no hedging instruments on 2007 natural gas volumes.

Drilling Activity

The following table shows our drilling activity for the periods indicated. In the table, gross wells refer to wells in which we have a working interest, and net wells refer to gross wells multiplied by our working interest in such wells.

	For the Years Ended December 31,			
	2009		**2008**	
	Gross	**Net**	**Gross**	**Net**
Exploratory wells:				
Productive	9	8.6	9	7.2
Non-productive				
Total	9	8.6	9	7.2
Development wells:				

Productive	2	1.2	9	4.6
Non-productive				
Total	2	1.2	9	4.6

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Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2009. Gross acreage represents the total number of acres in which we own a working interest. Net acreage represents our proportionate working interest resulting from our ownership in gross acres.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Hilltop area, East Texas	20,838	9,876	7,349	4,477
Appalachia, West Virginia and Pennsylvania (1)	37,166	33,842	1,641	1,618
Powder River Basin, Wyoming and Montana	22,125	9,483	18,615	7,737
Other	2,448	2,448		
Total	82,577	55,649	27,605	13,832

(1) We believe that substantially all of our Appalachia acreage is prospective for the Marcellus Shale.

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire.

As of December 31,	Net Acres	% of Total Undeveloped
2010	13,241	24%
2011	8,468	15%
2012	4,887	9%
2013	19,934	36%
2014 and later	2,068	4%

We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three years. As is customary in the natural gas and oil industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the primary term of such a lease. In the Appalachian area, we have drilled 15 wells in shallower Devonian formations, which will retain for the life of production our interest in certain undeveloped acreage for possible future deeper drilling in the Marcellus Shale. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and may allow additional acreage to expire in the future.

Of the 13,241 acres expiring in 2010, we are currently focusing on the expiring acreage in the Hilltop and Appalachia areas, where approximately 2,503 and 7,071 acres are scheduled to expire in 2010, respectively. We have already extended or in the process of extending the 2,503 acres in East Texas. In the Appalachia area, we have already extended or in the process of extending approximately 3,355 acres, with current plans of either divesting the remaining 3,716 acres or letting such leases expire. In the Powder River Basin area, 1,219 acres are expiring in 2010, of which 1,033 acres have been extended by post 2009 year-end drilling and the remaining 186 acres are scheduled to expire. We do not have any plans to retain the other 2,448 acres expiring in 2010 as such acreage is not in a focus area.

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Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2009. Gross represents the total number of wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross wells. Productive wells are wells that currently are capable of producing natural gas or oil. Wells that are completed in more than one producing horizon are counted as one well.

	Productive Wells					
	Natural Gas		Oil		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Hilltop area, East Texas	21	14.2	3	3.0	24	17.2
Appalachia, West Virginia and Pennsylvania (1)	22	19.9			22	19.9
Powder River Basin, Wyoming and Montana	505	221.9			505	221.9
Total United States	548	256.0	3	3.0	551	259.0

(1) Includes 1 gross vertical Marcellus Shale well, and remainder are primarily shallow Devonian shale wells.

Natural Gas and Oil Reserves

Reserve Estimation

In December 2008, the SEC adopted new rules related to modernizing reserve calculation and disclosure requirements for oil and natural gas companies, which became effective prospectively for annual reporting periods ending on or after December 31, 2009. The new rules expand the definition of natural gas and oil producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic natural gas or oil, and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of proved reserves, which was revised to indicate that entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than the end-of-period price, when estimating whether reserve quantities are economical to produce. Likewise, the unweighted 12-month average price is now used to compute depreciation, depletion and amortization. Another provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

The new reserve rules resulted in the use of lower prices at December 31, 2009 for both natural gas and oil than would have resulted under the previous rules. Use of the new unweighted 12-month average pricing rules at December 31, 2009 resulted in a downward adjustment of approximately 11,300 MMcfe to our total proved reserves as of December 31, 2009, as compared to the old year-end prices rule.

Third Party Review of Reserves Estimates

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. A copy of NSAI s summary reserve report is included as Exhibit 99.1 to this Form 10-K.

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Within NSAI, the technical persons primarily responsible for preparing the reserves estimates set forth in the NSAI reserves report incorporated herein are Mr. Dan Paul Smith and Mr. William (Bill) J. Knights. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. He is a Registered Professional Engineer in the State of Texas (License No. 49093) and has over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Knights has been practicing consulting petroleum geology at NSAI since 1991. He is a Certified Petroleum Geologist and Geophysicist in the State of Texas (License No. 1532) and has over 29 years of practical experience in petroleum geosciences, with over 19 years experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a Bachelor of Science Degree in Geology and in 1984 with a Master of Science Degree in Geology. Both technical principals meet or exceed the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimates

Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles.

We maintain an internal technical team consisting of our Senior Reservoir Engineer and several geoscience professionals, who work closely with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserve review and estimation process. Throughout the year, our internal technical team meets regularly with representatives of NSAI to review properties and discuss methods and assumptions used in NSAI s preparation of the year-end reserve estimates. We provide historical information to NSAI for our largest producing properties, including with respect to ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. NSAI performs an independent analysis and differences are reviewed with our senior management. In some cases, additional meetings are held to review additional reserve work performed by our technical team related to any identified reserve differences. Historical variances between our internal reserve estimates and NSAI s estimates have been less than 5%. In addition, our Board of Directors has a reserves review committee, which is chaired by an independent director. The reserves review committee meets at least once a year and is specifically designated to review the year-end reserve reporting and the reserve estimation process, while our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis. The year-end NSAI reserve report is reviewed by the reserves review committee, together with representatives of NSAI and our internal technical team.

Since 2006, all of our reserve estimates have been reviewed and approved by our Senior Reservoir Engineer, who reports directly to our Chief Financial Officer. Our Senior Reservoir Engineer attended Texas A&M University and graduated in 1978 with a Bachelor of Science degree in Reservoir Engineering and has been involved in evaluations and the estimation of reserves and resources for over 27 years. During the year, our technical team may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operation conditions. We did not file any reports during the year ended December 31, 2009 with any federal authority or agency with respect to our estimate of oil and gas reserves.

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Technologies Used in Reserves Estimation

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. The SEC s new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To achieve reasonable certainty, our technical team employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, well logs, geologic maps and available downhole and production data, seismic data, well test data and reservoir simulation modeling.

Estimated Proved Reserves

Our proved reserve information as of December 31, 2009 included in this Form 10-K was estimated by NSAI in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

In accordance with new SEC regulations, which were effective as of December 31, 2009, estimates of our proved reserves and future net revenues as of December 31, 2009 are made using benchmark prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price for natural gas and oil prices (new SEC pricing). Key natural gas prices utilized are Henry Hub price of $3.87 per MMBtu, Katy Hub price of $3.68 per MMBtu and CIG price of $3.04 per MMBtu and an oil price of $57.65 per barrel. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees, and regional price differentials. Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated significantly in recent years. All of our proved reserves are located within the United States.

The following table summarizes our estimated proved reserves as of December 31, 2009 using new SEC pricing.

	Total Proved Reserves as of December 31, 2009 (1)			
	Producing	**Non-producing**	**Undeveloped**	**Total**
Natural gas (MMcf)	28,759	6,769	13,005	48,533
Oil (MBbls)	17	17	33	67
Total proved reserves (MMcfe)	28,859	6,871	13,203	48,933
Standardized measure of discounted future net cash flow (in thousands)	$ 31,662	$ 7,095	$ 6,866	$ 45,623

(1) The above table is based on the new SEC pricing guidelines. Key natural gas prices utilized are Henry Hub price of $3.87 per MMBtu, Katy Hub price of $3.68 per MMBtu and CIG price of $3.04 per MMBtu and an oil price of $57.65 per barrel.

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Pricing Assumptions

In accordance with the new SEC pricing, our December 31, 2009 report of estimated proved reserves and future net revenues were made using prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials.

The following table summarizes our proved reserves by geographic area using the new SEC pricing as of December 31, 2009:

SEC Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	Oil (MBbls)	MMcfe	% Proved Developed	PV10 (2) (in thousands)
Hilltop area, East Texas	43,686	9	43,741	72%	$ 41,368
Appalachia, West Virginia and Pennsylvania	2,350	58	2,695	66%	$ 3,874
Powder River Basin, Wyoming and Montana	2,497		2,497	100%	381
Total	48,533	67	48,933	73%	$ 45,623

(1) The SEC Case assumptions were based on new SEC pricing guidelines. Key natural gas prices utilized are Henry Hub price of $3.87 per MMBtu, Katy Hub price of $3.68 per MMBtu and CIG price of $3.04 per MMBtu and an oil price of $57.65 per barrel.

(2) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. PV-10 is a non-US GAAP financial measure because it excludes the effects of income taxes. We believe that PV-10 is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may use the measure as a basis for comparison of the relative size and value of our reserves to other companies. PV-10 should not be considered as an alternative to standardized measure of discounted future net cash flows as defined under US GAAP. We presently have approximately $49.4 million of foreign tax credits carryforwards for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, no future taxes payable have been included in the determination of discounted future net cash flows.

In addition to the SEC Pricing Case proved reserves, NSAI also prepared estimates of our year-end proved reserves using two sets of alternative commodity price assumptions as of December 31, 2009.

Flat Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	Oil (MBbls)	MMcfe	% Proved Developed	PV10 (2) (in thousands)
Hilltop area, East Texas	48,664	11	48,729	72%	$ 99,244
Appalachia, West Virginia and Pennsylvania	2,595	58	2,947	67%	$ 7,361
Powder River Basin, Wyoming and Montana	8,584		8,584	37%	6,051
Total	59,843	69	60,260	67%	$ 112,656

(1) The December 31, 2009 Flat Pricing Case assumptions were based on the posted spot prices as of December 31, 2009 for both oil and gas, adjusted by lease in accordance with sales contracts, quality, transportation, compression and gathering fees, and regional price differentials. All prices were held constant through the lives of the properties. This pricing methodology is similar to that used by the SEC

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prior to the introduction of the new SEC pricing on December 31, 2009. Key natural gas prices utilized are Henry Hub price of $5.79 per MMBtu, Katy Hub price of $5.72 per MMBtu and CIG price of $5.54 per MMBtu and an oil price of $76.00 per barrel. We presently have approximately $49.4 million of foreign tax credits carryforwards for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, no future taxes payable have been included in the determination of discounted future net cash flows.

NYMEX Strip Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	Oil (MBbls)	MMcfe	% Proved Developed	PV10 (2) (thousands)
Hilltop area, East Texas	50,813	12	50,885	71%	$ 114,004
Appalachia, West Virginia and Pennsylvania	2,764	59	8,349	25%	$ 9,726
Powder River Basin, Wyoming and Montana	9,467		9,467	34%	9,910
Total	63,044	71	68,701	60%	$ 133,640

(1) The NYMEX Strip Pricing Case assumptions were based on the forward closing prices on the New York Mercantile Exchange for crude oil and natural gas as of December 31, 2009. For gas volumes, the price was based on a Henry Hub natural gas price, which increased from $5.79 per MMBtu to $8.51 per MMBtu over the life of the properties and was adjusted by lease in accordance with sales contracts, quality for energy content, transportation fees, and regional price differentials. For oil, the price was based on a crude oil price which increased from $81.95 per Bbl to $98.50 per Bbl during the life of the properties and was adjusted by lease for contract terms, energy content, transportation fees, and regional price differentials, (together the NYMEX Case). We presently have approximately $49.4 million of foreign tax credits carryforwards for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, no future taxes payable have been included in the determination of discounted future net cash flows.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2009, our PUDs totaled 13.2 Bcfe of natural gas equivalent. Approximately 93% of our PUDs at year-end 2009 were associated with East Texas and 7% to our Marcellus Shale area. The December 31, 2009 PUDs consisted of two gross (net 1.3) wells in East Texas and two gross (net 2.0) vertical wells in the Marcellus Shale. During 2009, we converted 6.6 Bcfe of PUD reserves to proved developed reserves, added new PUD reserves of 2.1 Bcfe and had negative revisions of PUDs of 5.7 Bcfe, primarily due to changes in commodity prices, including negative revisions of approximately 2.4 Bcf in the Powder River Basin that were rendered uneconomic under the new SEC pricing. Costs incurred relating to the development of PUDs were approximately $9.9 million in 2009. Estimated future development costs relating to the development of 2009 year-end PUDs is $15.1 million of which 2010 and 2011 expenditures are $8.5 million and $6.3 million, respectively. All PUDs are scheduled to be drilled by 2014.

Item 3. ***Legal Proceedings***

Information about our legal proceedings is set forth in Note 17, Commitments and Contingencies Litigation to our consolidated financial statements, which begin on page F-1.

Item 4. ***Removed and reserved for future use.***

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PART II

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

Market Information

Our common shares are traded on the NYSE Amex LLC under the symbol GST and until July 6, 2009 on the Toronto Stock Exchange under the symbol YGA . On July 6, 2009, we voluntarily delisted our common shares on the Toronto Stock Exchange. The following table sets forth the high and low sale prices of our common shares as reported on the NYSE Amex LLC.

	NYSE Amex	
	High	**Low**
2009:		
Fourth quarter	$ 5.06	$ 4.12
Third quarter	$ 5.13	$ 1.90
Second quarter	$ 3.20	$ 1.85
First quarter	$ 3.95	$ 2.10
2008:		
Fourth quarter	$ 6.50	$ 0.40
Third quarter	$ 13.60	$ 5.80
Second quarter	$ 13.75	$ 5.75
First quarter	$ 7.55	$ 4.50

The last reported sale price of our common shares on the NYSE Amex on March 24, 2010 was $4.98.

Shareholders

As of March 24, 2010, there were 466 shareholders of record who owned our common shares.

Dividends

We have never declared or paid any cash dividends on our common shares. We anticipate that we will retain future earnings, if any, to satisfy our operational and other cash needs and do not anticipate paying any cash dividends on our common shares in the foreseeable future. In addition, our revolving credit facility, prohibits us from paying cash dividends as long as such debt remains outstanding. Pursuant to the provisions of the *Business Corporations Act* (Alberta), we are prohibited from declaring or paying a dividend if there are reasonable grounds for believing that (1) we are, or would after the payment be, unable to pay our liabilities as they become due or (2) the realizable value of our assets would thereby be less than the aggregate of our liabilities and stated capital of all classes.

Recent Sales of Unregistered Securities; Use of Proceeds from Unregistered Securities

All of our equity securities sold during the year ended December 31, 2009 that were not registered under the Securities Act of 1933, as amended, have been previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

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

The following table presents selected historical financial data as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements.

As of and For the Years Ended December 31,		
2009	2008	2007