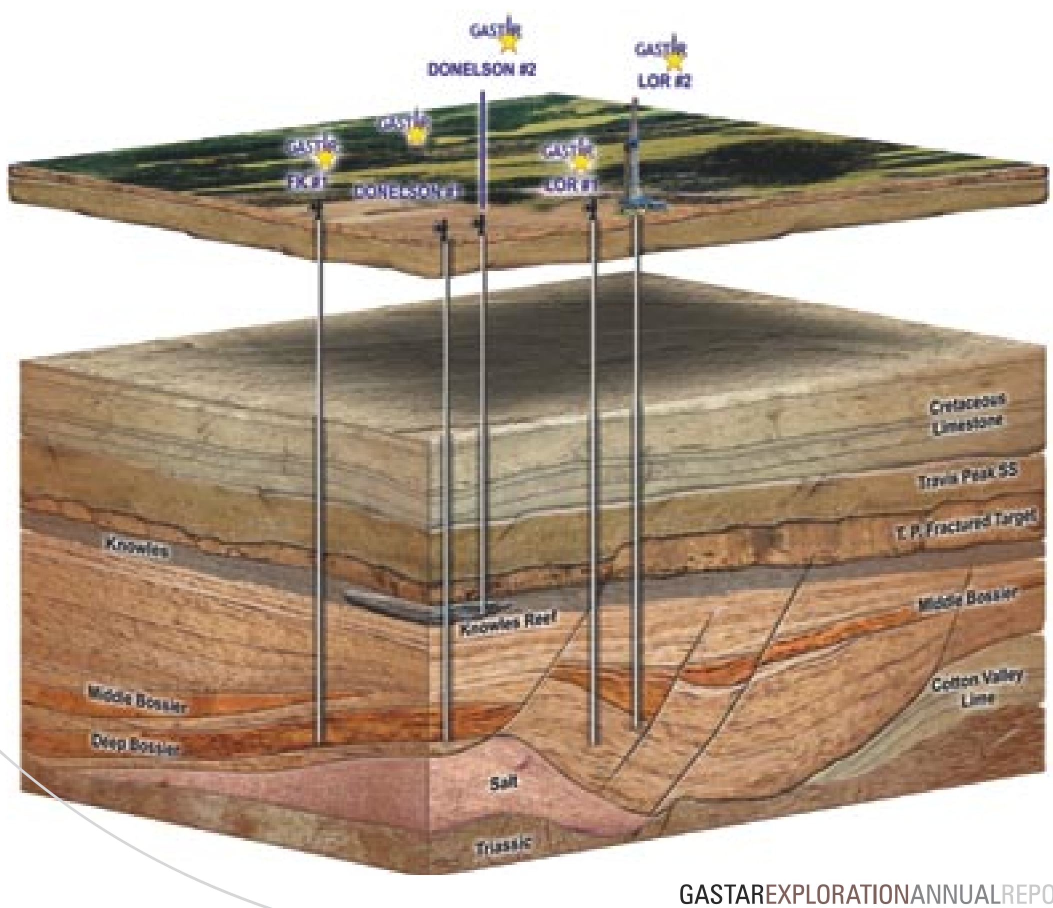
GASTAR

2005 Annual Report

Corporate Profile

Gastar Exploration Ltd. is an independent exploration and production company focused on finding and developing natural gas assets in North America and Australia. The Company pursues a balanced strategy combining select higher risk, deep natural gas exploration prospects with lower risk coalbed methane (CBM) development projects. Gastar owns and operates exploration and development acreage in the Deep Bossier natural gas play of East Texas and in the deep Trenton-Black River play in the Appalachian Basin. Gastar's CBM activities are conducted within the Powder River Basin of Wyoming and upon the approximate 3.4 million gross acres controlled by Gastar and its joint development partners in PEL 238, located in the Gunnedah Basin of New South Wales, and in EL 4416, located in the Gippsland Basin of Victoria, Australia.

Deep Hilltop, East Texas



Letter to Shareholders

Dear Shareholders,

Opportunity. Challenges. Success. We believe the following words summarize 2005 and preview 2006 for Gastar and its shareholders.

We saw an **OPPORTUNITY** to exploit higher natural gas prices and capitalize on an asset base with multiple potential productive formations.

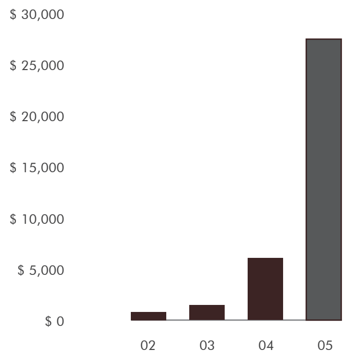
We overcame **CHALLENGES** such as competition for people, equipment, services and capital, and

We achieved **SUCCESS** with:

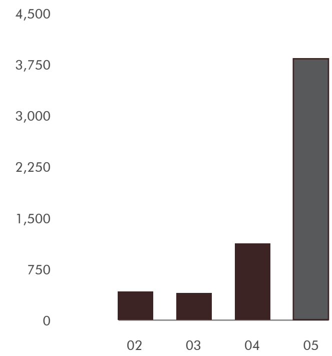
- A 242% increase in annual production to a 2005 average of 10.5 MMcfe per day compared to 3.1 MMcfe per day in 2004;
- Record cash flow from operating activities of $8.2 million;
- The drilling of the 6th successful well in our Deep Bossier play in East Texas and 36 (net) successful wells in our CBM project in the Powder River Basin;
- Confirmation of multiple geologic objectives on our East Texas leasehold;
- A joint venture agreement with Chesapeake Energy Corporation that should allow us to accelerate our drilling program in East Texas;
- Technical advances on our Australian CBM concession that should accelerate commercial production; and
- A U.S. listing on the American Stock Exchange.

For the energy industry and for natural gas focused companies in particular, higher commodity prices created unprecedented opportunity. The average natural gas price at the Henry Hub in South Louisiana for 2005 increased to $8.64 per million BTU (MMBtu) up from an average of $3.05 per MMBtu just four years ago. For Gastar, the timing was fortunate, as our East Texas development began to pay off with increasing production. These two factors combined to generate record revenue for the Company of $27.4 million on 3,821 MMcfe of sales, versus $6.1 million on 1,119 MMcfe of sales in 2004. For 2005, we reported a net loss of $25.7 million, or $0.20 per share, versus a net loss of $12.8 million, or $0.12 per share in 2004. Cash flow from operating activities was $8.2 million, an increase of $9.3 million over the $1.1 million of cash used in operating activities in 2004. We believe that 2005 was a pivotal year for Gastar, as we began accelerating the development of our large resource base.

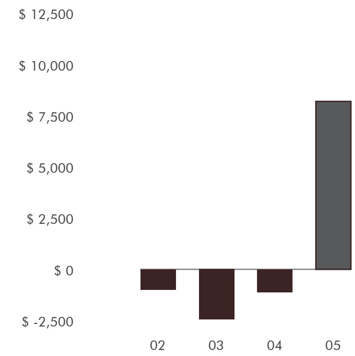
Of course, higher natural gas prices and the associated increased levels of industry activity brought significant challenges, as Gastar, like other smaller companies in our industry, had to compete for scarce equipment and services. In spite of these challenges, we made meaningful accomplishments in 2005. As we publish this letter, Gastar has recently completed its sixth deep Bossier well and its first shallower Knowles well in its Hilltop area in East Texas. During 2005, perhaps the most exciting development for Gastar in East Texas was the confirmation that we have multiple geologic objectives on our existing leasehold position. Our Donelson #1 well was not only a successful Bossier well with over 140 feet of pay in the lower and middle Bossier formations but also was a potentially significant new regional discovery in the Knowles limestone formation. We immediately drilled a twin to that well, the Donelson #2, which confirmed the Knowles discovery. We have also encountered productive



Revenues
($ thousands)



Production
(MMcfe)



Operating Cash Flow
($ thousands)

zones in the shallower Pettet formation, and we will be evaluating its potential along with other shallower zones during the course of 2006.

Our success in the Deep Bossier play also has created challenges. Lease expirations, competition from larger, better capitalized E&P companies and the desire to accelerate value creation for our shareholders brought us to the realization that we needed a strategic partner to assist with the development of our many projects. In November 2005, we entered into an agreement with Chesapeake Energy Corporation in which Chesapeake became an equity owner and joint venture partner in East Texas with Gastar. Chesapeake is one of the most respected E&P companies in America, and as such, our relationship with Chesapeake has been interpreted as a vote of confidence and a validation of Gastar's assets and business plan.

In Australia during 2005, Gastar and its partners made significant strides in solving the completion issues that had plagued previous operations on our approximately 2 million gross acre PEL 238 coalbed methane (CBM) concession. During 2006, our goal is to confirm commercial production rates by drilling a nine-well CBM pod and, if successful, to enter into initial gas transportation and marketing agreements. We are also in the process of completing and testing the first two initial CBM wells on EL 4416, our 1.4 million gross acre Gippsland Basin property. The Gippsland Basin coal is believed to be similar to the coal found in the Powder River Basin in Wyoming and Montana; however, we are very early in the process of understanding the dynamics of CBM production from this basin.

The final area of significant activity for Gastar during 2005 was our 55,000 gross acre Powder River Basin property in Wyoming. Gastar participated in the drilling of 82 CBM wells in 2005 through its joint venture activities with Pinnacle Gas Resources, Inc. We currently have approximately 353 wells on production that produced approximately 3.8 MMcfe per day net to Gastar during 2005. We anticipate continuing our active drilling program in 2006.

One of Gastar's more important successes came just after the end of 2005 when our registration statement with the U.S. Securities and Exchange Commission was declared effective, and we were approved for listing on the American Stock Exchange. We believe that the dual listing of our common stock on the AMEX and the Toronto Stock Exchange will afford our shareholders better liquidity and make Gastar an attractive investment for a wider range of investors.

Finally, we wish to sincerely thank all of our shareholders, old and new, for their continued support. We will continue to strive to maximize the potential from our existing assets and identify new opportunities consistent with our goal of increasing shareholder value.

Sincerely,

J. Russell Porter
President & Chief Executive Officer
March 31, 2006

Property Overview

Deep Bossier Play, East Texas

Gastar has accumulated approximately 54,000 gross acres (25,000 net acres) in the Deep Bossier play located in the Hilltop area of Leon and Robertson Counties, Texas. Gastar has drilled six successful lower and middle Bossier wells and plans to drill one lower and five middle Bossier wells during 2006. The Deep Bossier play is one of the very active new exploration areas in the United States and gives Gastar significant near-term production and reserve growth potential.

The lower Bossier formation is a Jurassic age series of sands found at depths of 17,400 feet to 19,000 feet. Gastar's recent successful Donelson #1 well found pay in the lower Bossier formation between 17,800 feet and 19,000 feet along with additional pay in the upper and middle Bossier intervals. Gastar is planning the drilling of additional lower Bossier wells to develop the up-thrown fault blocks in the area of the Hilltop structure.

The middle Bossier is a series of younger Jurassic age sands deposited on the flanks of the Hilltop structure and along the shelf edge, down-thrown to a series of regional growth faults. The middle Bossier formation is being successfully explored and developed both north and south of Gastar's leasehold position by other companies. Gastar's 2006 middle Bossier drilling program will test locations that have been developed using the same depositional model as the recent successful wells drilled by other operators.

In addition to the lower and middle Bossier formations, Gastar is testing several shallower formations, the Pettet, Knowles limestone and Travis Peak, with meaningful reserve potential.

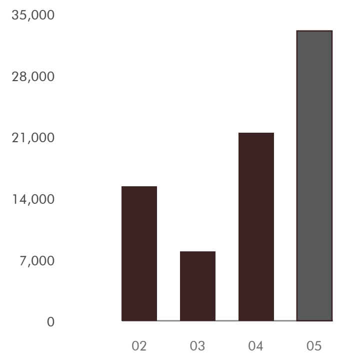
Coalbed Methane – Powder River Basin

We own an approximate 40% average working interest in 55,000 gross acres (21,900 net acres) in the Powder River Basin of Wyoming. Our primary areas of activity in the Powder River Basin are the Squaw Creek, Ring of Fire and adjacent fields, all of which are located north of Gillette, Wyoming in the heart of the development fairway. The majority of the remaining working interest is owned by the operator, Pinnacle Gas Resources, Inc.

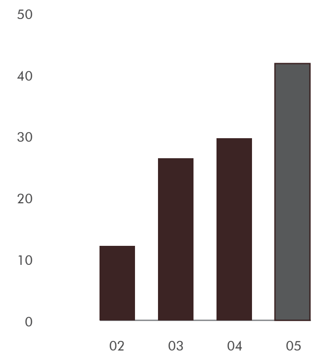
We currently have approximately 353 producing CBM wells in the Powder River Basin. During 2005, we participated in the drilling of 82 gross wells (36 net wells), all of which were successful. We anticipate continuing an active drilling program in 2006.

Coalbed Methane – New South Wales, Australia

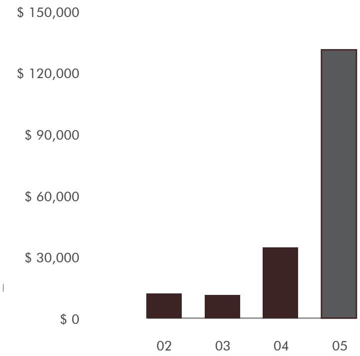
Gastar holds a 35% working interest in the CBM rights under a 2.0 million gross acre exploration license in New South Wales, Australia. The property, PEL 238, is located approximately 250 miles northwest of Sydney near the town of Narrabri. The recent installation of a pipeline that terminates near our CBM development area has enhanced the potential for commercial success on PEL 238. Gastar believes that the strategic location of these potential reserves near Sydney, Newcastle and other large gas markets will create a competitive advantage for the placement of the natural gas reserves developed on PEL 238.



Reserves
(MMcfe)



Net Wells Drilled



Capital Expenditures
($ thousands)

Extensive coring of the coal on PEL 238 by the Australian government has provided a thorough understanding of the coal resources and potential CBM resource in place on our license. Two primary coal seams are found on the PEL 238 license, the Late Permian aged Hoskisson coal formation and the Early Permian aged Maules Creek coal formation. From a coal characteristics perspective, the Maules Creek coals are similar to the coals located in the San Juan Basin in the western United States. As a result of the earlier testing, the planned 2006 activities will be focused on the Maules Creek formation.

During 2006, Gastar and its partners plan a nine-well drilling program around a well drilled and tested in 2004, the Bibbliwindi-10 well. The nine-well pod should accelerate dewatering and achieve commercial gas production sooner than would be achieved by the Bibbliwindi-10 well producing on an unconfined basis. If commercial natural gas production rates are achieved, Gastar and its joint venture partners will proceed with development of the CBM resources and commit to natural gas sales contracts.

Coalbed Methane – Victoria, Australia

Gastar owns a 75% working interest in the approximately 1.4 million acre EL 4416 exploration license located in the Gippsland Basin of Victoria, Australia, located 65 miles east of Melbourne. The EL 4416 license covers a large portion of the onshore expression of the Gippsland Basin. Offshore, the Gippsland Basin is a prolific oil and natural gas producing region. The EL 4416 property is well situated with three existing natural gas transmission lines running through the license area from productive offshore fields to a large natural gas processing facility and onto markets near Sydney, Melbourne and in Tasmania.

The coal located on EL 4416 is classified as low-rank brown coal and is expected to have characteristics similar to the coal found in the Powder River Basin of Wyoming and Montana. However, unlike the Powder River Basin, the coal located on EL 4416 is contained in individual seams that can reach thicknesses of more than 200 feet. The Victorian government has extensively evaluated the potential coal resources through detailed coal resource studies. Due to our large acreage position and the fact that this thick coal is present over a large percentage of the license area, the CBM resource potential is believed to be significant.

Gastar, along with its partner, recently completed the drilling and equipping of the first two initial CBM wells on EL 4416. While we are encouraged by the amount of coal encountered in the wells and by the initial indications of pressure and natural gas in the coal seams, we have not placed the wells on production for a long enough period of time to speculate on the probability of commercial CBM production rates being achieved from this property. The purpose of these initial production tests is to gather information on potential CBM and water rates with follow up activity to determine coal characteristics (density, permeability, ash content and contaminants), gas composition and natural gas content in order to begin the process of assessing the commercial CBM potential.

In addition to the CBM activities on EL 4416, we have begun a program to explore for and evaluate the potential for mineral sands deposits in which we have a 75% interest across our license area. Mineral sands are deposits of heavy minerals comprised of zircon (zirconium silicate), rutile (titanium dioxide) and ilmenite (titanium iron oxide). There are substantial global markets for all of these minerals. While not currently a core business for Gastar, we believe that the potential future development of minerals sands could be an attractive and important new segment to our exploration and development activities.

Corporate Information

Corporate Office

Gastar Exploration Ltd.
1331 Lamar, Suite 1080
Houston, Texas 77010
(713) 739-1800
(713) 739-0458 Fax

Web Site: www.gastar.com

Shareholder Information

The annual general meeting will be held at 2:00 pm (CDT) on Thursday June 1, 2006 at the Four Seasons Hotel at 1300 Lamar Street, Houston, Texas 77010

Transfer Agent

CIBC Mellon Trust Company
320 Bay Street, Box 1
Toronto, Ontario M5H 4A6

Common Share Listing Information

American Stock Exchange: Symbol "GST"
Toronto Stock Exchange: Symbol "YGA"

Independent Auditors

BDO Seidman, LLP
700 N. Pearl Street, Suite 2000
Dallas, Texas 75201

Reservoir Engineers

Netherland Sewell & Associates, Inc.
4500 Thanksgiving Tower
1601 Elm Street
Dallas, Texas 75201

Legal Counsel

Vinson & Elkins. L.L.P.
1001 Fannin, Suite 2300
Houston, Texas 77002

Officers

J. Russell Porter
President & Chief Executive Officer

Michael A. Gerlich
Vice President & Chief Financial Officer

Dr. Frederick E. Beck
Vice President of Drilling

Henry J. Hansen
Vice President of Land

R. David Rhodes
Vice President of Completion & Production

Sara-Lane Sirey
General Corporate Canadian Counsel and Corporate Secretary

Board of Directors

Thomas E. Robinson
Chairman of the Board
President of Geostar Corporation

Abby Badwi
Chairman of the Audit Committee
President & CEO of Rally Energy Corp.

Thomas L. Crow
Retired, Private Investor
Founder of Cobra Golf Inc.

Matthew J.P. Heysel
Former Chairman & CEO of Big Sky Energy Corporation

Richard A. Kapuscinski
Director of Sales and Marketing of Turbo Genset Inc.

J. Russell Porter
President & CEO of Gastar Exploration Ltd.

Gastar Exploration Ltd.
1331 Lamar Street, Suite 1080
Houston, Texas 77010
Tel: (713) 739-1800
www.gastar.com

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

FORM 10-K

☒ Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2005

☐ 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	**38-3324634**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1331 Lamar Street, Suite 1080 **Houston, Texas 77010**	**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 Stock, No Par Value	American Stock Exchange

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 ☒

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the closing price of $4.06 per common share on the American Stock Exchange at the close of business on March 15, 2006 was $542,832,852. As of March 15, 2006, there were 164,748,380 common shares of the registrant's common stock outstanding.

Documents incorporated by reference. None

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2005

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PART III

PART IV

Cautionary Statement About Forward-Looking Statements

Some of the information included in this Form 10-K contains “forward-looking statements”. These statements can be identified by the use of forward-looking words, including “may”, “expect”, “anticipate”, “plan”, “project”, “believe”, “estimate”, “intend”, “will”, “should” or other similar words. 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 that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These factors include among others:

- Low and/or declining prices for natural gas and oil;
- Natural gas and oil price volatility;
- The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes;
- Ability to raise capital to fund capital expenditures;
- 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 attendant 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;
- Weather conditions;
- Availability and cost of material and equipment;
- 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;
- Federal and state regulatory developments and approvals;
- Environmental risks;
- Worldwide economic conditions; and
- Operational and financial risks associated with foreign exploration and production.

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 release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this Form 10-K or to reflect the occurrence of unanticipated events. See the information under the heading "Item 1A. Risk Factors" for some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in forward-looking statements.

Unless otherwise indicated or required by the context, (i) "we", "us", and "our" refer to Gastar Exploration Ltd. and its subsidiaries and predecessors, (ii) "GeoStar acquisition" refers to our June 2005 acquisition from GeoStar Corporation ("GeoStar") of additional reserves and working interests in the Powder River Basin and in East Texas, (iii) "convertible debentures" refers to our $30.0 million principal amount of 9.75% convertible senior unsecured debentures, (iv) "warrants" refers to the warrants to purchase common shares issued to investors in connection with certain financing transactions or to our placement agents in connection with the offering of convertible debentures and certain other subordinated notes as partial compensation for their services, (v) "senior secured notes" refers to our $73.0 million principal amount of senior secured notes issued in 2005, (vi) all dollar amounts appearing in this Form 10-K are stated in U.S. dollars unless specifically noted in Canadian dollars ("CDN$"), and (vii) all financial data included in this Form 10-K has been prepared in accordance with generally accepted accounting principles in the United States of America. We have provided definitions for some of the natural gas and oil industry terms used in this Form 10-K in the "Glossary of Natural Gas and Oil Terms" on page 46.

General information about us can be found on our website at www.gastar.com. Our Annual Reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, will be available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission ("SEC"). Information is also available at www.sec.gov for United States filings and at www.sedar.com for Canadian filings.

PART I

Item 1. *Business*

Overview

We are an independent exploration and production company focused on finding and developing natural gas assets in North America and Australia. We pursue a balanced strategy combining select higher risk, deep natural gas exploration prospects with lower risk CBM development projects. We own and operate exploration and development acreage in the Deep Bossier natural gas play of East Texas and in the deep Trenton-Black River play in the Appalachian Basin. Our coal bed methane, or CBM, activities are conducted within the Powder River Basin of Wyoming and upon the approximate 3.5 million acres controlled by us and our joint development partners in PEL 238, located in the Gunnedah Basin of New South Wales, and in EL 4416, located in the Gippsland Basin of Victoria, Australia. We derive all of our revenues from production of natural gas and oil located in the United States. We derive no revenues from Canadian or Australian sources. We see no risks other than normal business risks attendant to our CBM activities in Australia.

Corporate History

In 2000, we completed a reverse takeover of CopperQuest, Inc., a company originally incorporated in 1987 pursuant to the *Business Corporations Act (Ontario)*. On May 16, 2000, we continued from the Province of Ontario into the Province of Alberta and changed our name to Gastar Exploration Ltd. Gastar Exploration Ltd .is a Canadian corporation that is subsisting under the *Business Corporations Act (Alberta)*.

Our Strategy

Management believes that:

- Natural gas is an environmentally friendly fuel that will be increasingly valued in the United States and Australia;
- CBM projects provide us with lower risk exposure to long-lived natural gas production and reserves;
- We have made an important natural gas discovery in the Deep Bossier play in the Hilltop area of East Texas that will require additional exploration and development;

- We have the ability to assemble the technical and commercial resources needed to pursue these projects; and
- Our successful development of one or more large potential natural gas projects will create substantial shareholder value.

Based on these beliefs, we have pursued a strategy that includes:

- Accelerating exploration and development drilling on our Deep Bossier play in East Texas;
- Combining lower risk CBM projects with higher risk conventional natural gas exploration;
- Assembling a portfolio of natural gas exploration and development projects in the East Texas and Appalachian Basins; and
- Limiting capital commitments and reducing risk by maintaining financial flexibility through accessing various sources of capital and participating in certain assets through joint venture arrangements with industry participants.

Natural Gas and Oil Operations

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

Hilltop Area, East Texas

General. The majority of our activities in 2005 were undertaken in the Deep Bossier play in the Hilltop area of East Texas. As of December 31, 2005, we have approximately 53,591 gross acres (25,072 net) in the Deep Bossier play in the Hilltop area, located approximately midway between Dallas and Houston. For the year ended December 31, 2005, our net production from the Hilltop area averaged approximately 6.5 MMcfed. Wells in this area target multiple potentially productive natural gas geologic horizons. Deep Bossier sand wells are typically characterized by high initial production, significant decline rates and long-lived reserves. The development of effective hydraulic formation fracturing, or “frac”, techniques appear to allow operators to develop significant reserves in the Deep Bossier sand intervals.

We have recently completed our sixth deep Bossier well and its first shallower Knowles well. We believe these wells have confirmed that we have multiple geologic objectives, each with meaningful reserve potential, on our existing leasehold position. Our Donelson #1 well was not only a successful Bossier well in the lower and middle Bossier formations, but also is a potentially significant new regional discovery in the Knowles limestone formation. A twin well, the Donelson #2, has confirmed the Knowles discovery. Additionally, we have encountered apparently productive zones in the shallower Pettet formation. We will look to evaluate its potential along with other shallower zones during 2006.

Geology. The East Texas Basin is characterized by numerous shallow and deeper productive horizons. The basin has been the site of natural gas and oil activity since the earliest days of the U.S. natural gas and oil industry. The Deep Bossier sand formation that we are targeting was not considered prospective until our activities together with the drilling of a nearby well ignited a high level of interest in this formation. To our knowledge, prior to our initial drilling activities in 2001, no wells had been drilled specifically for Deep Bossier sand production in East Texas. Our geoscientists developed the Deep Bossier sand prospect focusing on two deep wells drilled in the early 1980s. Those wells encountered over-pressured, gas-charged reservoirs in the Bossier shale section but were unable to reach their intended targets. Our geoscientists formulated a depositional model to explain the presence of these high quality sands in an area previously believed to be too remote from the traditional sand sources for the East Texas Basin.

Gas Transportation. Given the high level of traditional natural gas and oil activities in the East Texas Basin, the area has extensive natural gas pipeline infrastructure in place. In July 2004, a new one Bcf per day natural gas transmission pipeline was constructed by a third party within approximately three miles from our initial drilling activities. We have contracted with this third party for an initial 50.0 MMcfd of capacity and are negotiating an increase in that amount. Our current production from the Hilltop area is being processed at the well sites and is being transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase the natural gas.

We recently executed a Letter of Intent with ETC Texas Pipeline, Ltd., which calls for ETC to provide all gas gathering, processing and transportation services for our production from the Hilltop area. As a part of the agreement, ETC has agreed to dedicate 150 MMcfd of capacity in its nearby gas transmission line to Gastar and to construct a central processing facility capable of handling up to 180 MMcfd of natural gas.

Activities. In 2001, we participated in the 21,000 foot Belin Trust A-1 well. In January 2003, GeoStar took over as operator of the Belin Trust A-1 well. GeoStar attempted a completion in a Deep Bossier sand (approximately 18,512 feet to 18,610 feet) and was encouraged by the initial test results. A fracture stimulation and other down hole treatment techniques were performed. The well briefly tested pipeline quality natural gas at short term rates up to 5.0 MMcfd before experiencing mechanical casing problems. The well was ultimately plugged and abandoned due to safety concerns.

Due to the encouraging results from the Belin Trust A-1 well and the results of several earlier wells drilled in the area, we announced in September 2003 that we had begun site operations on the Fridkin-Kaufman #1 well, or the F-K #1, in Leon County, Texas. We drilled the F-K #1 well to a total depth of 19,175 feet, and in September 2004, the F-K #1 well began producing natural gas. As a result of the GeoStar acquisition, our working interest in the F-K #1 well increased from 75% to 98%.

The Cheney #1 well was drilled in the Hilltop area to test the Deep Bossier sand encountered in the F-K #1 well. This well is approximately one mile north of the F-K #1 well. The Cheney #1 well encountered approximately 400 net feet of potential pay based on natural gas shows while drilling and on logs. The well commenced production in mid-February 2005. As a result of the GeoStar acquisition, our working interest in the Cheney #1 increased from 75% to 98%.

In early May 2005, we completed the drilling of our third Deep Bossier sand well in East Texas, the Lone Oak Ranch #1 well. The well is located approximately three miles north northwest of the F-K #1 well and approximately two miles northwest of the Cheney #1 well. The Lone Oak Ranch #1 well was drilled to target expanded Upper and Middle Bossier sections and also test for the deeper Bossier sand encountered on the Hilltop structure in the F-K #1 and Belin Trust #1-A wells. As a result of the GeoStar acquisition, our working interest in the Lone Oak Ranch #1 increased from 75% to 98%, subject to resolution of a dispute with potential lessor, as described in "Item 3. Legal Proceedings". An unrelated private exploration and production company has a 25% after payout back-in interest in the Lone Oak Ranch #1 well. We will hold an after payout working interest of 69% in the Lone Oak Ranch #1 well. In addition to exploring additional acreage in the Hilltop area, this well completed our obligations to earn an approximate 75% working interest in approximately 8,000 gross acres in the Hilltop area of East Texas, including acreage that directly offsets the F-K #1 well.

We began drilling the Greer #1 well, our fourth Deep Bossier sand well in the Hilltop area, in January 2005. The Greer #1 well is located approximately one mile from the F-K #1 well. We drilled the Greer #1 well to a total depth of 17,800 feet and, based on natural gas shows during drilling and electric logs, the well encountered approximately 57 net feet of apparent pay. As a result of the GeoStar acquisition, we increased our working interest in this well from 73% to 98%. The well commenced production in July 2005.

Drilling commenced in February 2005 on the Fridkin-Kaufman #2 well, or F-K #2, which was drilled to a total depth of 18,700 feet. The well is located approximately 2,200 feet northeast of the F-K #1 well. Based on electric logs, the well encountered approximately 74 net feet of apparent pay in the Bossier lower "K" sand below 18,000 feet. The well also encountered over 120 feet of indicated pay in the shallower Travis Peak formation. The completion attempt in the Bossier sands was not successful, and an unsuccessful completion attempt in the Travis Peak was made in October 2005. Based on the information obtained from subsequent wells, the F-K #2 well also is being evaluated as a possible candidate to be side-tracked to test the Knowles formation. Further, the F-K #2 could provide the possibility of an additional Travis Peak test, based on information obtained from subsequent wells indicating that the previous Travis Peak test was made in Travis Peak sands that were later determined to be less attractive than the Travis Peak sands encountered deeper in the F-K #2 well. Our working interest in the F-K #2 is 100%.

We commenced drilling the Donelson #1 well in May 2005. This sixth Deep Bossier well in the Hilltop area of East Texas was drilled to a total depth of 19,200 feet. The Donelson #1 well encountered a productive interval within the Knowles limestone. The Knowles was tested productive even after being damaged by heavy drilling fluids required to control the well during drilling. The Donelson #1 well also encountered approximately 140 net feet of pay in the lower and middle Bossier formations between 17,000 feet to 19,000 feet in depth and was placed on production in March 2006 from a series of three lower Bossier sands. The lower Bossier sands appear to correlate to a similar series of sands discovered by Gastar in the earlier Belin Trust A-1 well.

The Donelson #2 well was drilled to a total depth of 14,690 feet to test and produce the Knowles formation that was encountered in the Donelson #1 well. The Donelson #2 well encountered approximately 50 feet of Knowles pay and was placed on production in early March 2006.

In January 2006, the Wildman Trust #1 well was spudded approximately 4,000 feet north of the Donelson #2 to further test the Knowles formation. We also expect to evaluate Travis Peak potential on the Wildman Trust #1. The Wildman Trust #1 well is expected to reach a projected total depth of 14,500 feet in April 2006.

We have contracted with a third party to provide us with two 20.0 MMcfd on-site processing facilities for our East Texas properties. For a monthly rental fee of approximately $35,000 per facility, the third party constructs and operates the natural gas processing plants. To date, our natural gas processing plants have operated with mechanical downtime of less than 12 hours per month. Current natural gas processing plant capacity is not anticipated to be reached until later 2006.

We are currently conducting extensive seismic analysis of the available Hilltop seismic data and continue to refine our geologic model of the area. We have also begun permitting a large scale 3-D seismic survey that will cover the majority of our acreage in the Hilltop area in order to better define and understand the complex geology associated with the deposition of the Deep Bossier sand in the area. We are also planning the drilling of additional deep wells, and we plan to continue to acquire new leases in the area.

GeoStar Acquisition

Concurrently with the private placement of senior secured notes on June 17, 2005, we closed the acquisition from GeoStar of additional leasehold and working interest properties in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana, or the GeoStar Acquisition Properties. We paid, before purchase price adjustments and acquisition costs, $68.5 million for the interests acquired from GeoStar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006. Based on a third party evaluation, the GeoStar acquisition included 3.0 Bcfe of proven developed reserves and 12.6 Bcfe of proven undeveloped reserves and additional working interest in unproven acreage in the Hilltop and Powder River Basin areas. The acquisition increased our working interest position in the Hilltop area from an average of over 70% to an average of over 90% and gave us operational control of the properties. The acquisition of additional Powder River Basin interests increased our average working interest position from approximately 17% to approximately 40% in properties currently being developed through an existing joint venture.

On August 11, 2005, we executed an agreement with GeoStar whereby the GeoStar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we issued GeoStar 6,373,694 common shares valued at $17.0 million based on a per share price of CDN$3.25 and a new unsecured subordinated note for $15.0 million. The interest rate on the new GeoStar note was the three-month London Interbank Offered Rate, or LIBOR, plus 4.5%, payable monthly commencing February 15, 2006. As required by agreement, the new GeoStar note was paid in full on November 28, 2005 in conjunction with the transaction with Chesapeake Energy Corporation.

In connection with Gastar's purchase of the GeoStar Acquisition Properties in June 2005, a final purchase price adjustment of $4.2 million payable to GeoStar was made, 50% in cash that was paid in 2006 and 50% to be settled with the issuance of 548,128 Gastar common shares valued at CDN$4.50 per share.

Transaction with Chesapeake Energy Corporation

On November 4, 2005, we closed an integrated transaction with Chesapeake Energy Corporation whereby Chesapeake:

- Acquired approximately 27.2 million newly issued common shares from us equal to 19.9% of our then outstanding common shares for $76.0 million (CDN$89.9 million or CDN$3.31 per share) in cash before fees and expenses;
- Acquired a 33.33% working interest in our Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

Chesapeake has been granted registration rights for the shares issued pursuant to this transaction. Chesapeake also has the right, with certain exceptions, to maintain its percentage ownership on a fully diluted basis by participating in future stock issuances and has the right to an observer being present at meetings of the Board of Directors.

As part of this transaction, Chesapeake agreed to pay approximately $7.8 million, before fees and expenses, to reimburse us for Chesapeake's pro rata share of leasehold interests acquired. Further, Chesapeake agreed to pay a disproportionate amount of future drilling costs described below, in exchange for an undivided 33.33% of our leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each of our existing well bores. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. Further, Chesapeake has agreed to provide assistance in procuring one to two additional drilling rigs in 2006 if needed to accelerate drilling in the Hilltop Prospect.

The transaction also provided for the formation of an area of mutual interest, or AMI, covering all of Leon, Robertson, Houston, Cherokee, Madison, Anderson, Angelina, Nacogdoches, Trinity, Polk, Shelby, San Augustine and Sabine Counties in East Texas (the "AMI Area"). For a period of three years from November 4, 2005, we will offer Chesapeake the exclusive first right to purchase up to an undivided 50% of any leasehold/working interest rights acquired by us in the AMI Area on pre-determined terms. The AMI is "one-way"—Chesapeake will not be obligated to present us any interests it now owns or acquires in the future in the AMI Area.

In connection with the transaction, we notified Chesapeake of a claim made by a third party that it has a right to purchase 33.33% of our interests in certain natural gas and oil leases located in Leon and Robertson Counties, Texas pursuant to a preferential right provision of an operating agreement dated July 7, 2000. On October 31, 2005, the third party filed a related petition for breach of contract and declaratory judgment in a legal action, as Navasota Resources, L.P. vs. First Source Texas, Inc., First Source Gas L.P., and Gastar Exploration Ltd. (Cause No. 0-05-451), in the District Court of Leon County, Texas, 12th Judicial District. We contend, among other things, that the claimant neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent transactions. Accordingly, we intend to vigorously defend the claims.

Pursuant to the terms of the GeoStar agreement, we utilized a portion of the proceeds of the Chesapeake transaction to pay the $15.0 million GeoStar note in full.

Appalachian Basin, West Virginia

General. The Appalachian Basin is a proven hydrocarbon basin with substantial production history. The well developed infrastructure and proximity to major natural gas markets in this area result in gas prices generally exceeding Henry Hub gas prices, the standard for pricing NYMEX natural gas contracts. While numerous potential hydrocarbon horizons exist, we are focusing our West Virginia plans primarily on three potentially productive horizons: shallow conventional sands; the deep Trenton-Black River and fractured medium depth Devonian shale.

Shallow Conventional Gas. We have participated in 11 pilot wells drilled into shallow conventional gas sands. The Venango (Upper Devonian age) hydrocarbon horizon, including the primary targets of the Fifty-foot Sand, the Fifth Sand and the Gordon Sand, is a multiple horizon sand located at depths of generally less than 5,000 feet. The drilling of these horizons is relatively fast and inexpensive.

Trenton-Black River Deep Gas. The Trenton-Black River play was discovered in western New York, where natural gas wells drilled to the Trenton-Black River formations produced at reported initial rates of approximately 5.0 to 8.0 MMcfd. The play was extended to southern central West Virginia when Trenton-Black River wells were drilled in the Roane County Cottontree Field.

The deep Trenton-Black River prospective formations and other deep geologic horizons can only be identified through the use of acquired or reprocessed seismic data. GeoStar, the operator of the properties, has acquired and reprocessed available 2-D seismic data as well as acquired additional proprietary 2-D seismic data to identify these deep features. We control significant lease positions over several of these seismically defined features.

Fractured Devonian Shale. Since the beginning of Appalachian natural gas production, natural gas has been produced from various shale formations. Devonian shale is generally considered to be an unconventional natural gas reservoir. We are combining experience gained from CBM production with our seismic acquisition and processing analysis to attempt to determine areas where naturally occurring fracture systems potentially increase shale well productivity.

Activities. As part of our ongoing business activities, we regularly reassess the technical and commercial potential of our exploration acreage. As of December 31, 2005, we had approximately 26,633 gross acres (13,267 net) in the Appalachian Basin in West Virginia. For the year ended December 31, 2005, our net production from the Appalachian Basin averaged 0.2 MMcfed.

Coal Bed Methane

Our acreage positions in the Powder River Basin and in Australia are primarily CBM plays. CBM is methane gas that is formed and stored in coal beds. The presence of methane in coal seams has been known since the mining of coal began. Historically, CBM was considered a safety problem, and coal had to be “degasified” before subsurface coal mining could occur. In the last two decades, however, the natural gas industry has dramatically improved its technical understanding of CBM production techniques, and CBM has come to be viewed as a major source of low cost methane.

CBM production is dissimilar to conventional natural gas production in several notable ways. Coal seams produce nearly pure methane gas, while conventional natural gas wells normally produce natural gas that contains small portions of ethane, propane and other heavier hydrocarbon gases. Methane normally constitutes more than 90% of the total gases in the production from conventional natural gas wells. Also, because coal beds often contain substantial amounts of water, it is first necessary to produce water to lower the reservoir pressure to allow the CBM to be produced. Producing and properly handling the water from the coal beds is an important part of CBM production. Once produced, CBM is dried to remove any residual moisture, compressed to pipeline pressures and ultimately transported in the same interstate pipelines as natural gas from conventional natural gas fields. CBM is also sold to the same consumers and used in the same applications as natural gas produced from conventional wells.

Since the late 1970s, CBM has been produced commercially by drilling conventional well bores into coal beds. The first commercial CBM fields were developed in the high rank bituminous hard coal beds of Alabama, the Appalachian Mountains of Pennsylvania, Virginia, West Virginia, the San Juan Basin of Colorado and New Mexico. Limited commercial CBM production was established in 1989 in the lower rank, sub-bituminous soft coal of the Powder River Basin of Wyoming. CBM production from the Powder River Basin has increased substantially since that date.

CBM plays differ from conventional natural gas plays in several significant ways. The large size of coal beds tends to reduce geologic risks, while the generally shallow depths of the coal can result in simple wells with relatively low drilling costs. CBM wells typically produce at lower rates and may have lower reserves per well than conventional wells. The combination of large CBM deposits, relatively low geologic risk and low drilling costs make CBM plays attractive investment opportunities. Although the actual finding and development costs vary for each individual gas field, significant technical strides have been made in lowering CBM costs.

We are actively developing CBM properties in the Powder River Basin of Wyoming. We are also investigating CBM development plans in the Appalachian Basin of West Virginia on Petroleum Exploration License 238, or PEL 238, in the Gunnedah Basin in New South Wales, Australia and in the Gippsland Basin in Victoria, Australia.

Powder River Basin, Wyoming and Montana

General. The Powder River Basin encompasses approximately 26,000 square miles of eastern Wyoming and southeastern Montana. The Wyoming Powder River Basin has been an important natural gas and oil producing area for nearly 100 years. Likewise, Wyoming has been a top producer of low-sulfur soft coal for many years. Only recently has a connection been made between the large coal reserves of the basin and natural gas production. Beginning in about 1989, Powder River Basin CBM development began in earnest and has increased dramatically in recent years. The drilling activity began about 40 miles south of Gillette, Wyoming and extended northward along the east flank of the basin and westward into the basin. Generally, CBM wells are shallow and less costly than conventional natural gas wells. Because of the widespread nature of multiple coal horizons, the geologic success rates reported by some operators in the Powder River Basin have been high. Due to these and other factors, the Powder River Basin CBM play has developed into one of the most active drilling areas in the United States. However, there is no assurance that we will achieve comparable cost or similar success rates.

Geology. Coal in the Powder River Basin is found in the relatively shallow Paleocene Fort Union Formation. This coal forms some of the thickest known coal seams in North America. During the 1960s and 1970s, exploration wells being drilled to deeper conventional natural target horizons encountered this coal and commonly experienced gas flows from the shallow coal formations. These wells generally yielded large volumes of water and little commercial natural gas. In some cases, blowouts occurred due to unexpected natural gas flows from the shallow coal zones.

High micro-permeability helps explain why natural gas from the Powder River Basin coal is readily produced without costly artificial stimulation. Microscopic pathways facilitate the movement of CBM to open fractures, and through these fractures, CBM finds its way to the borehole. Fracturing of the coal is apparently common throughout the Powder River Basin. This is exemplified by the large and growing area of CBM production and the large number of natural gas flows from water wells drilled into or through coal formations. The fracturing of the coal beds is critical since it is the fractures in coal that provide pathways for natural gas migration and production. Gas produced from Powder River Basin coal generally has very high methane content, usually requiring no treatment to remove carbon dioxide or nitrogen.

Drilling Techniques. One of the main reasons for the rapid pace of activity in the Powder River Basin is the low cost of drilling to shallow depths, generally less than 1,200 feet, and the fact that the coal there normally does not require expensive fracture treatments to produce at economic rates. The standard procedure has been to drill to just above a coal formation, set casing, then air drill into the coal, under-ream the hole, circulate out cuttings, set a pump or install gas lift if water volumes dictate, and place the well on production. CBM wells are drilled in “units” or projects, with each well in the unit connected to a low-pressure gathering pipeline. The gathering line delivers produced natural gas and water to a central facility where water is disposed of and natural gas is compressed and metered for delivery through a sales line to a main gas transport pipeline. The water production from CBM wells varies substantially. Although subject to regulatory review and approval, produced water is usually fresh and has generally been disposed of in holding ponds and surface streams. Other disposal techniques, which are somewhat more expensive, such as re-injection into non-producing formations, have also been used to dispose produced water. Gathering and processing costs vary by well location, system design and take-away capacity. Properties that are close to major pipelines should have substantially lower gathering costs than more remote properties.

CBM Production. The typical CBM well in the Powder River Basin initially produces significant quantities of water. As the water is produced, natural gas production begins slowly. Typically, after a considerable amount of water is produced over a three to six-month period or longer, gas production increases and water production decreases. In some cases, wells do not produce any significant amounts of water and begin producing gas immediately. This free gas is produced from fractures in the coal that are attributable to subtle structural folding or compaction of coal after they were deposited. As the development expands, the productive area increases as water is produced from these areas. Water production can also be reduced near the edges of the basin, especially near massive open pit coal mines. These shallow coal near the outcrops appears to be partially de-watered naturally due to the extensive surface mining and its associated water production.

Gas Transportation. Of critical importance to the success of a CBM project in the Powder River Basin is natural gas transportation to market. Major natural gas pipelines have been built into the basin to transport CBM to major interstate gas markets. The Thunder Creek, Fort Union, Bighorn and Western Gas Resources pipelines are the major pipelines flowing out of the south end of the basin. The Williston Basin Interstate pipeline runs north to Montana, then east to North Dakota, eventually connecting to the Northern Border pipeline and eastern markets. Western Gas Resources’ pipelines have access to both the south and north flowing pipelines. Each of our Powder River Basin properties has access to one or several of these pipelines. Additional pipeline capacity to both the north and south has been proposed to be built.

Natural gas sales prices vary with the market, but historically have been based on the prices posted by Colorado Interstate Gas. While prices generally track this index, when transportation capacity is fully utilized, Powder River Basin gas prices can be substantially depressed.

Activities. We now own an approximate 40% average working interest in approximately 54,966 gross acres (21,854 net) in the Powder River Basin of Wyoming following the GeoStar acquisition. Our main focus of activity is the Squaw Creek and adjacent areas, notably the Ring of Fire field. We currently have 353 (142.8 net) CBM wells producing in the Basin. For the year ended December 31, 2005, our average net production from our CBM properties in the Powder River Basin was approximately 3.8 MMcfed.

In 2003, we closed a Powder River Basin Earn-In Joint Venture with a third party, who paid approximately $6.7 million and made a spending commitment of $14.5 million and became operator. We assigned the operator

66% of our interest in all of our existing producing and non-producing leases within the area of mutual interest. Under the agreement, the operator acquired an interest equal to 50% of the combined interests of Gastar and GeoStar. The operator receives 60% of all pre-tax cash flow as defined in the agreement until it recovers its share of the $14.5 million spending commitment amount. We are 50/50 joint venture partners with the operator for new CBM exploration and development activity within the AMI. In the third quarter of 2004, we exercised our option to invest additional funds to maintain our working interest ownership in any wells drilled after the spending commitment was met and will continue to invest in the Powder River Basin. During 2004 and 2005, approximately 199 wells were drilled under the joint venture, and the operator plans to continue drilling under the joint venture agreement. We have chosen to fund our working interest ownership in wells drilled after the spending commitment was met.

Gunnedah Basin, New South Wales, Australia

General. PEL 238 is an approximately 2.0 million gross acres (700,000 net acres) CBM property, located approximately 250 miles northwest of Sydney, Australia, in the Gunnedah Basin of New South Wales. The Gunnedah Basin's characteristics include porous permeable quartzose sandstones at several stratigraphic levels that are adjacent to mature organic reservoir rocks that are age equivalents of producing formations in the other producing regions of Eastern Australia. CBM potential is also high, as previous wells and coreholes have penetrated aggregate coal thickness of up to 250 feet.

The geology of the PEL 238 area is characterized by buried ridges and troughs and coal gas accumulations considered to be associated with structurally high positions. Coal was deposited throughout the Lower Permian in various parts of the Gunnedah Basin. There are over 500 miles of seismic data available over the PEL 238 area. The coal is dull, blocky and relatively uncleated.

The primary coal objective of the PEL 238 area is Maules Creek at depths of 2,500 to 3,000 feet, and the secondary coal objective is the Hoskisson coal at depths of 1,500 to 2,000 feet. The Maules Creek coal is Permian age coal and is a closed coal system that is not mined in the area and thus should not be subject to rapid re-charge of the hydro system. The Hoskisson coal has not been tested but is mined to the east of the PEL 238 area.

The Australian Department of Mines and Resources has drilled over 200 core wells in the eastern portions of PEL 238 and outside the concession area that are useful in delineating the coal.

PEL 238, which includes substantial forest lands, was a part of a New South Wales government-sponsored bioregion study evaluating various land use options for the forests. While there was a wide range of possible land use options proposed, some of which could restrict our access to portions of PEL 238, the final designation of the land within the Bohena project area, covering the planned CBM development area, as Community Conservation Area Zone 4 (forestry, recreation and mineral extraction) should have no material impact on the project. Management and our joint venture partners actively participated in the bioregion process to ensure that our position was well represented and to ensure that our leasehold interests continue to be available for exploration and production.

Activities. In 2003, we were the 100% coal bed methane working interest owner on the approximate 2.0 million acre PEL 238 concession. In 2004, we entered into a joint venture and reduced our CBM ownership to 70%. Over 18 conventional and CBM wells and over 200 coal core holes have previously been drilled within PEL 238. Several PEL 238 CBM wells have demonstrated brief periods of gas production ranging from 200 to 400 Mcfd. However, these wells were not able to sustain these rates, potentially from formation damage caused while drilling. The low sustained gas and water production rates may be due in part, to suboptimal completion techniques. The joint venture is attempting to define the optimum completion technique for the PEL 238 coal that will allow sustained high flow rates to dewater the coal and to support commercial development and tie-ins to surrounding natural gas markets. Additional issues that are being studied include variable carbon dioxide content in the range of 5% to 50% thought to be caused by tertiary volcanics underlying the coal sections in certain areas, correlation of individual coal seams from well to well, variable ash contents, and natural gas marketing issues. Based on these uncertainties, PEL 238 has no proven natural gas reserves.

In 2004, we and our joint venture partners drilled and fracture stimulated two coal seams in two additional vertical CBM wells on PEL 238 to attempt to establish sustained commercial production rates. While we were obligated to drill these wells under a work commitment to New South Wales government to maintain the leases, our joint venture partners have funded the work plan under their earn-in agreement, having increased their ownership interests to 65% during 2005. Surface facilities were installed, and these new vertical CBM wells were placed on production in October 2004 and have produced at very high water rates, indicating good permeability in the coal and an effective stimulation. The wells have also shown early gas production with gas production rising to the anticipated rates for these unconfined wells. The results of all of these wells indicate that commercial gas rates should be achievable with the de-watering of a sufficient area. Management believes that the activities to date have substantially fulfilled the work plan requirements provided in the leases.

Current Drilling Program. We and our joint venture partners had committed to spend approximately $1.4 million during the permit year that ended August 2, 2005. The joint venture has spent approximately $2.3 million during the period. The joint venture is currently seeking approval from the New South Wales government, proposing to spend an additional $1.4 million in each of the two work program years ending August 2, 2006 and 2007. The proposed work program calls for the drilling of two CBM well in each of the two years, together with continued geological and geophysical activities and ongoing production management. We will bear 35% of these expenditures. PEL 238 will be due for renewal in August 2007. Although there is no assurance that the PEL 238 license will be renewed in 2007, the New South Wales government has typically ruled to extend such licenses.

In March 2006, the operator of the PEL 238 joint venture spudded the first of nine new vertical coal seam gas wells to be drilled within the Bohena Project Area. The drilling and completion program is expected to continue until mid-year and consist of:

- Drilling and fracture stimulation of eight closely spaced new production wells in proximity to an existing production well to form a 40-acre spaced “nine-spot” production pilot; and
- Drilling of a pressure monitoring well at some distance from the production pilot to determine the extent of in-seam permeability communication at approximately 160-acre well spacing. This larger spacing aims to increase the area over which reserves can be attributed and provide information that is expected to allow future development on 160-acre or greater spacing.

The first well in the drilling program is located 2.2 kilometers (1.4 miles) north of the existing production well and will be the pressure monitoring well. The Bibbliwindi-10 well will be drilled to approximately 1,020 meters (3,350 feet) total depth and perforated across the Bohena coal seam. The Bohena coal seam is expected to be intersected at depth of approximately 910 meters (3,000 feet) and to be more than six (6) meters (approximately 20 feet) thick. This well will be completed so that it can be fracture stimulated and put on production tests as part of a subsequent program.

The other eight new wells will be drilled to a total depth of approximately 1,000 meters (3,300 feet). They will be perforated in the Bohena coal seam and then hydraulically fracture stimulated before being placed into test production.

The closely spaced “nine-spot” production pilot is designed to accelerate dewatering of the 6.5 to 15 meter (21 to 49 feet) thick Bohena coal seam and to achieve commercial gas production rates in a shorter period than would be possible for an isolated well or for wells drilled on wider spacing.

Gippsland Basin, Victoria, Australia

General. The Gippsland property is located on our EL 4416 license in the onshore portion of Gippsland Basin in Victoria, Australia. The Gippsland Basin is a proven hydrocarbon province that has produced substantial volumes of oil, natural gas and coal. Our project area covers almost all of the onshore part of the Gippsland Basin. The coal in the Gippsland Basin is primarily brown and subbituminous coal, which is similar in composition and age to the coal in the Powder River Basin of Wyoming and Montana. As in the Powder River Basin, very large open pit coal mines are operated in the Gippsland Basin. The mines are located on a relatively small part of the basin near our acreage. Substantial information on the physical properties of the Gippsland Basin coal has been developed due to the extensive mining operations.

Although there has been no organized attempt to date to produce CBM from the Gippsland coal, the stratigraphy and structure of the coal is well known due to extensive core bores, water bores, coal mining operations, petroleum exploration, and other geotechnical evaluations of the coal. While no data on coal gas content and permeability is currently available, natural gas has been measured in the coal and observed coming to the surface during conventional natural gas and oil exploration. The basin has multiple coal sequences at depths of less than 3,000 feet with total coal thicknesses as great as 1,000 feet and with individual seams over several hundred feet thick. We anticipate using CBM techniques developed in the Powder River Basin and other CBM fields to evaluate Gippsland Basin CBM potential.

Activities. We have an interest in mineral licenses that encompass approximately 1.4 million gross (1.1 million net) acres on our EL 4416 license area. We own a 75% working interest in the Gippsland CBM rights and mineral sands rights, with GeoStar owning the remaining 25% working interest in the CBM and mineral sands rights.

No Gippsland Basin CBM production has been established to date; however, we have recently completed the drilling of two dedicated CBM wells on a site near several conventional wells that penetrated the targeted coal and encountered evidence of both permeability in the coal formation and the presence of CBM. Both of these new dedicated CBM wells have been drilled using drilling and completion techniques commonly used in the Powder River Basin. Each well was drilled to the top of the coal section and casing was cemented into place. Following the installation of the casing, the wells were then drilled through the coal and, if necessary, the coal is under reamed to create a large diameter cavity in the coal section. We recently completed operations on the Burong #2 well and placed it on production. We will monitor the production of the well to evaluate the potential for commercial production and future drilling activity. The Burong #3 well is awaiting a completion rig to run production tubing and a down hole pump.

If the pilot program is successful, access to gas markets is available through three major pipelines that cross our Gippsland properties: one northeast to Sydney, one south to Tasmania and one west to Melbourne. Additional potential gas markets for Gippsland Basin CBM production include mining projects located near our mineral licenses that potentially could use large amounts of natural gas in value-adding heating and roasting processes. Gas marketing agreements would need to be negotiated with potential customers.

In the fourth quarter of 2004, in accordance with common government leasing practices, we relinquished approximately 382,000 gross acres to the Government of Victoria. During the first and second quarters of 2005, we drilled the first two dedicated CBM test wells on our EL 4416 license. We recently placed the Burong #2 well on production and will begin monitoring initial de-watering results. The Burong #5 well is expected to be on production by April 2006. We hold a 75% working interest in the CBM and Mineral Sands rights on the 1.4 million gross acre concession with the balance owned and operated by GeoStar.

While coal bed methane has been the primary focus of our efforts on the Gippsland property, our exploration license is not limited to CBM only. The Gippsland exploration licenses also include mineral rights on the properties. Our partner and we are conducting a technical assessment of the mineral potential of these properties. While the assessment of the various minerals potential is in its early stages, the initial focus is on mineral sands, a major natural resource in other basins within Victoria. We have designed a mineral sands ground magnetic exploration program to further evaluate mineral sands potential. The coring portion of this program was recently completed and the data acquired is currently being evaluated.

In March 2006, we filed our application to renew EL 4416 license for another five years. Through February 2006, we have spent approximately $4.6 million, in excess of our five-year spending requirement. The license process is designed to reduce by 50% the area that the licensee is originally granted. We have discussed with the Government of Victoria if we will be required to surrender any of our current acreage upon license. Although we do not believe that we will have to relinquish 50% of the area, we believe that we will have to relinquish some percentage of the license acreage.

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 volatile and may continue to be volatile in the future. Natural gas and oil prices are beyond our control. However, rising demand for natural gas to fuel power generation and meet increasing environmental requirements has led some industry observers to indicate that long-term demand for natural gas is increasing.

Our current United States production has access to major intrastate and interstate pipeline systems. We contract to sell natural gas from our properties with spot-market based contracts that vary with market forces on a monthly basis. While overall natural gas prices at major markets, such as Henry Hub in 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. The East Texas Basin area has an extensive natural gas pipeline infrastructure in place. 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. These companies purchase essentially all of our current production.

The initial gas market for PEL 238 natural gas is anticipated to be an electricity generation facility owned and operated by one of our joint venture partners and located near the town of Narrabri, New South Wales, Australia. Although there currently is no existing pipeline from the existing and planned CBM project areas, we and our joint venture partners are finalizing plans for a gathering system and pipeline to transport our CBM gas to the electricity generation facility. The longer term market for PEL 238 natural gas is considered to be future gas-fired power generation facilities in New South Wales and the industrial and residential markets in the Sydney and Newcastle areas of New South Wales. While there are currently no pipelines connecting our project areas within PEL 238 to the Sydney and Newcastle natural gas markets, a new 190 mile pipeline that will terminate within approximately 75 miles of our PEL 238 project areas has been announced and is expected to be operational later in 2006.

Australian natural gas markets and infrastructure exist and are viable markets; however, they are not as developed as the markets and infrastructure in the United States. Specifically, the PEL 238 concession is currently not served by natural gas infrastructure. Gastar and its joint venture partners have recently entered into discussions with a third party entity that is constructing an approximate 190-mile pipeline in the vicinity of the PEL 238 concession. This pipeline would provide access to local markets in New South Wales and eventually to larger gas markets in the Sydney and Newcastle areas. These discussions involve negotiations outlining preliminary terms under which the third party would extend the pipeline currently under construction to the area of PEL 238, which is currently scheduled for further evaluation. Gastar expects that these discussions will lead to a formal agreement prior to the time that the planned development wells will be ready to enter production.

The EL 4416 license in the Gippsland Basin of Victoria, the site of recent pilot CBM drilling and planned production testing, is served by three existing natural gas transmission pipelines. The existing pipelines have capacity to transport natural gas from the EL 4416 license to markets in the area of Sydney, Melbourne and Tasmania. If Gastar's efforts result in commercial CBM production from this license, minimal infrastructure expenditures would be necessary to connect to existing pipelines.

Our very limited oil production 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.

We have not pre-sold any natural gas or oil and have no future volume delivery commitments of any kind.

During 2005, ETC Texas Pipeline Ltd. and Western Gas Reserves accounted for 66% and 32% of our natural gas and oil revenues. During 2004, ETC Texas Pipeline Ltd. and Western Gas Resources, Inc. accounted for 59% and 35%, respectively, our natural gas and oil revenues. During 2003, Western Gas Resources, Inc. and Equitable Gas Company, a division of Equitable Resources, Inc., accounted for 79% and 17%, respectively, of the Company's natural gas and oil revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

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, which 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.

The 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 relatively small 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 sourcing the manpower to run them and provide related services.

Governmental Regulation

In addition to the environmental regulations discussed below under the heading "Environmental Regulation", our natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States and Australia. 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 and naturally occurring radioactive materials; bonding requirements; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

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 opportunity.

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.

U.S. Regulation

Transportation and Sale of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

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 provide open-access transportation on a non-discriminatory basis for 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.

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 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. Our sales of crude oil and condensate are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by FERC in recent years could result in an increase in the cost of pipeline transportation service. We do not believe, however, that these regulations affect us any differently than other producers.

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 the natural gas and oil is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most 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 oil and natural gas wells, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Many states also restrict production to the market demand for the natural gas and oil and several states have indicated interests in revising applicable regulations. These regulations can limit the amount of the natural gas and oil we can produce from our wells, limit the number of wells, 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.

Australian Regulation

Commonwealth of Australia Laws and Regulations. The regulation of the natural gas and oil industry in Australia is similar to that of the United States, in that regulatory controls are imposed at both the state and commonwealth (federal) levels. Specific commonwealth regulations impose environmental, cultural heritage and native title restrictions on accessing resources in Australia. These regulations are in addition to any state level regulations. Foreign investment in Australia is regulated by the commonwealth through its foreign investment legislation and policy. In some circumstances, Australian foreign investment regulation and policy requires foreign interests to obtain prior approval from the Australian Government before investing in specific industry sectors. The Foreign Investment Review Board administers the regulation of foreign investment on behalf of the commonwealth. Its functions include analyzing proposals by foreign interests for investment in Australia and making recommendations to the Government on the compatibility of those proposals with Government policy and the relevant legislation. In some circumstances the acquisition of or formation of a new business will require review and approval under the commonwealth foreign investment policy and regulations. Australian law recognizes that in some instances native title, that is the laws and customs of the Aboriginal inhabitants, has survived European settlement. Native title will only survive if it has not been extinguished. Native title may be extinguished by an Act of Government, such as the creation of a title that is inconsistent with native title. This may include a grant of the right to exclusive possession through freehold title or lease. Native title may also be extinguished if the connection between the land and the group of Aboriginal people claiming native title has been lost. Native title legislation was enacted in 1993 in order to provide a statutory framework for deciding questions such as where native title exists, who holds native title and the nature of native title which were left unanswered by a 1992 Australian High Court decision. Native title claims by aboriginal groups' can include claims over existing and potential natural gas and oil exploration and development areas. The commonwealth government has passed amendments to this legislation to clarify uncertainty in relation to the evolving native title legal regime in Australia created by the decision in another High Court case decided in 1996. Since 1998, the native title legislation has provided for interested parties to negotiate and register indigenous land use agreements with registered native title claimants in the early stages of development. Our Australian operations could be affected by native title claims by Aboriginal groups. Each authority to prospect, lease and pipeline license must be examined individually in order to determine validity and native title claim vulnerability.

Australia Gas Markets. Several statutory mechanisms regulate access rights to a range of infrastructure in Australia including gas transmission pipelines. These involve generic access regulations contained in the *Trade Practices Act 1974 Cth.* and industry specific schemes contained in specific legislative instruments, industry codes and schemes. Objectives of this regulatory regime include providing a process for establishing third party access to natural gas pipelines, facilitating the development and operation of a national natural gas market, promoting a competitive market for natural gas in which customers are able to choose their supplier, and providing a right of access to transmission and distribution networks on fair and reasonable terms and conditions. We cannot currently ascertain the impact of the regime objectives but believe it could benefit us.

Environmental Regulation

Our natural gas and oil exploration and production operations and similar operations that we do not operate but in which we own a working interest in the United States are subject to significant federal, state and local environmental laws and regulations governing environmental protection as well as the discharge of substances into the environment. These laws and regulations may restrict the types, quantities and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that are adopted in the future, could have a material adverse impact on our operations and other operations in which we own an interest. As discussed below, our Australian operations are similarly subject to regulation by Australian authorities.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws or regulations or the modification of existing laws or regulations could have a material adverse effect on our operations 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 extraordinary resources in order to satisfy existing applicable environmental laws and regulations. However, costs to comply with existing and any new environmental laws and regulations could become material. 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.

U.S. Environmental Laws

In the United States, 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.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes strict, joint and several liability without regard to fault or legality of conduct, on persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes “petroleum” and “natural gas, natural gas liquids, liquefied natural gas or synthetic gas useable for fuel,” from the definition of “hazardous substance”, our operations 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 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, which could have a significant impact on us as well as of 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. 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, including wetlands. Under the CWA and OPA, any unpermitted release of pollutants from operations could cause us to become subject to the costs of remediating a release; administrative, civil or criminal fines or penalties; or OPA specified damages, such as damages for loss of use and natural resource damages. In addition, in the event that spills or releases of produced water from 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, Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by 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 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.

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 Clean Air Act 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, in the future, we may be required to incur capital expenditures in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues.

CBM production operations involve the use of gas-fired compressors to transport gas that is produced. Emissions of combustible by-products from compressors at one location may be great 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 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 these 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.

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.

There has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from certain greenhouse gas emission sources, primarily power plants. The natural gas and oil exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations and other operations in which we own an interest currently are not adversely impacted by current state and local climate change initiatives; however, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Finally, legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations and the operations of the natural gas and oil industry in general may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Australian Environmental Laws

Australia has environmental laws and regulations that are similar in scope and impact to United States environmental laws and regulations. Similar approval, licensing and operational impacts apply at a commonwealth, state and local government level. As a result, environmental laws and regulations can result in similar licensing and operational impacts in Australia that are similar to those discussed above with respect to the United States.

The legislation regulating environmental assessment at a commonwealth level is the *Environmental Protection and Biodiversity Conservation Act 1999 (Cth.)*. This Commonwealth Act establishes a regime for protecting the environment, flora and fauna biodiversity and Australian national heritage. It requires any person taking an action which could have a significant impact on one of these values to refer it to the commonwealth

Minister for the Environment for consideration and potential assessment. The Act only applies to matters of national environmental or heritage significance. These are matters which impact on a world heritage site, Ramsar wetlands, species which are listed as threatened under the Act, migratory species, nuclear actions and commonwealth marine areas or places listed on the commonwealth heritage list. Operators are required to assess their projects to determine whether an action is likely to have a significant impact on matters of national environmental significance, and make a decision respecting submission of that assessment to a public referral process. The referral is expected to add some time to the existing approval process but have little impact on most routine activities and operations. In addition, see the discussion in "Business—Gunnedah Basin, New South Wales, Australia" for a discussion of the New South Wales government's bioregion study involving PEL 238. Environmental protection is also regulated in each state and territory by specific legislation enacted by each state or territory. The governments of New South Wales and Victoria both have a suite of legislation regulating environmental matters in their states. The legislation imposes a licensing approval and contamination management scheme which may impact on our operations and impose a liability which may extend beyond the time period during which properties are operated, occupied or owned. The laws and regulations also restrict emissions to air, land and water and may control or regulate substances which can be released into the environment and the manner in which they are transported and disposed of. Environmental laws and regulations protecting archeological relics, natural and built heritage as well as native flora and fauna can also impact on our operations and impose obligations in respect of restitution or replacements well as liability in respect of damage.

Australia Gas Markets. Several statutory mechanisms regulate access rights to a range of infrastructure in Australia including gas transmission pipelines. These involve generic access regulations contained in the *Trade Practices Act 1974 Cth.* and industry specific schemes contained in specific legislative instruments, industry codes and schemes. Among the objectives of this regulatory regime are to provide a process for establishing third party access to natural gas pipelines; to facilitate the development and operation of a national natural gas market; to promote a competitive market for natural gas in which customers are able to choose their supplier; and to provide a right of access to transmission and distribution networks on fair and reasonable terms and conditions. We cannot currently ascertain the impact of the regime objectives but believe it could benefit us.

Employees

As of March 15, 2006, we had 15 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, 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 employees to be good.

Corporate Offices

We lease our corporate offices 1331 Lamar Street, Suite 1080, Houston, Texas 77010. Effective in March 2006, we increased our office space from 5,634 square feet to 9,332 square feet. Our amended agreement provides for a monthly rental of $8,943 per month through October 2010.

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 offering of shares of our common stock when evaluating Gastar. An investment in Gastar will be subject to risks inherent in our business. The trading price of the common shares of Gastar 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.

Natural gas and oil prices are volatile and a decline in natural gas and oil prices can significantly 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 materially adversely affect 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 are commodities whose prices are set by broad market forces. Historically, the natural gas and oil markets have been volatile. We do not see any reason why natural gas or oil prices will not 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;
- Domestic and foreign governmental regulations;
- The level of consumer product demand; and
- The price and availability of alternative fuels.

Rising demand for natural gas to fuel power generation and to meet increasingly stringent environmental requirements has led some observers to believe that long-term demand for natural gas is increasing.

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

Even though overall natural gas prices at major markets, such as Henry Hub in Louisiana, may be high, regional natural gas prices may move somewhat 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. For example, surplus natural gas supplies relative to available transportation in the Powder River Basin in 2002 caused local natural gas prices to be much less than national natural gas prices, and we, therefore, were unable to take advantage of those higher national natural gas prices. 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 other successful exploration and development activities or acquire properties containing proved reserves, or both. 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. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

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 materially and adversely 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.

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

We have not been profitable since we started our business. We incurred net losses of $25.7 million, $12.8 million and $4.9 million for the years ended December 31, 2005, 2004 and 2003, 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 an oil reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this section may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Our level of indebtedness reduces our financial and operational flexibility, and our level of indebtedness may increase.

As of December 31, 2005, the principal amount of our long-term debt was $106.3 million. Our level of indebtedness affects our operations in several ways, including the following:

- A significant portion of our cash flow must be used to service our indebtedness;
- A high level of debt increases our vulnerability to general adverse economic and industry conditions;
- The covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends, sell common shares below certain prices and make certain investments;
- Although we have the ability, subject to the limitations specified in the agreement, to borrow an additional $10.0 million of senior secured notes through June 2007, the terms of our senior secured notes prohibit us from borrowing funds senior or *pari passu* to the senior secured notes and may limit our ability to borrow subordinated funds;

- Our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy or in our industry;
- A high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate purposes; and
- A default under our senior loan covenants could result in required principal payments that we may not be able to meet, resulting in higher penalty interest rates and/or debt maturity acceleration.

We may incur additional debt, including significant additional secured indebtedness, in order to make future acquisitions or to develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

If we are unable to raise substantial amounts of additional capital, we may not be able to maximize our business plan.

In order to maximize our business plan, we will need to raise substantial amounts of new capital. If we experience difficulties in raising equity or debt capital, we may be required to scale back our business plan by limiting acquisitions and our drilling and development program. Restrictions imposed under our senior secured notes may limit our ability to borrow additional funds.

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;
- The assumed 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 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 generally based on prices and costs in effect when the estimate is made. However, 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;
- Curtailments or increases in consumption by natural gas or oil purchasers;
- 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.

In this Form 10-K, the net present value of future net revenues is calculated using a 10% discount rate. This rate is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the natural gas and oil industry in general.

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.

Due to the imprecise nature of estimating natural gas and oil reserves as well as the potential volatility in natural gas and oil prices and their effect on the carrying value of our natural gas and oil properties, write downs in the future may be required as a result of factors that may negatively affect the present value of proved natural gas and oil reserves. These factors can include volatile natural gas and oil prices, downward revisions in estimated proved natural gas and oil reserve quantities, limited classification of proved reserves associated with successful wells and unsuccessful drilling activities.

A majority of our proved reserves are classified as proved developed non-producing and proved undeveloped and may ultimately prove to be less than estimated.

At December 31, 2005, approximately 79% of our total proved reserves were classified as proved developed non-producing and proved undeveloped. It will take substantial capital to recomplete or drill our non-producing and undeveloped locations. 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 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 the drilling of an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease and/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 to cure those defects to the extent reasonably possible. However, such deficiencies may have been cured by the operator of any such wells. 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 may experience shortages of equipment and personnel, which could significantly disrupt or delay our operations.

From time to time, there has been a general shortage of drilling rigs, equipment, supplies and oilfield services in North America and Australia, which we believe may intensify because of current increased industry activity. In addition, the costs and delivery times of rigs, equipment and supplies have risen. Shortages of drilling rigs, equipment, supplies or trained personnel could delay and adversely affect our operations and drilling plans, which could have an adverse effect on our results of operations. While we intend to enter into contracts for the services of drilling rigs in North America and Australia, we may not be successful in doing so. The demand for, and wage rates of, qualified rig crews have begun to rise in the drilling industry due to the increasing number of active rigs in service. Personnel shortages have occurred in the past during times of increasing demand for drilling services. If the number of active drilling rigs increases, we may experience shortages of qualified personnel to operate our drilling rigs, which could delay our drilling operations and adversely affect our business.

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.

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 requirements, 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 and are 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 affect on our financial condition and 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. Consequently, the discharge or release of natural gas, oil or other substances into the air, soil or water could subject us to liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property 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.

Our Australian operations are subject to unique risks relating to Aboriginal land claims and government licenses.

Our Australian operations could be affected by native title claims by Aboriginal groups. Australian law recognizes that in some instances native title, that is the laws and customs of the Aboriginal inhabitants, has survived European settlement. Native title will only survive if it has not been extinguished. Native title may be extinguished by an Act of Government, such as the creation of a title that is inconsistent with native title. This may include a grant of the right to exclusive possession through freehold title or lease. Native title may also be extinguished if the connection between the land and the group of Aboriginal people claiming native title has been lost. Each authority to prospect, and license in areas in which we desire to engage in exploration or production activities must be examined individually in order to determine the validity of any native title claim. We may be required to negotiate with any Aborigines who can make a valid claim to having ancestral ties to the areas in which we desire to engage in exploration or production activities. These negotiations could both delay the timing of our exploration or production activities, as well as add an additional layer of cost or a requirement to share revenues if any Aboriginal claimants are proved to have native title rights in the exploration areas. Approximately 27.5% of our Gippsland Basin property in Victoria may be subject to native title claims. We have been informed by the government of New South Wales that the proportion of land within PEL 238 in the Gunnedah Basin, New South Wales, which is potentially subject to native title claims, cannot be readily determined.

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.

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 that we purchase or lease. 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.

Approximately 66% of our revenues for the year ended December 31, 2005 was from the production of wells located in our Deep Bossier play in East Texas. Any disruption in production or our ability to process and sell our natural gas production from this area would have an adverse effect on our results of operations.

Production of natural gas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Additionally, a majority of our East Texas production is processed through two on-site processing facilities. If these facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace either one or both of these facilities. A 60 to 90 day curtailment of our east Texas production could reduce current revenues by $4.0 to $6.0 million, with a corresponding reduction in our cash flow.

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 depends on the proximity of our reserves to and the capacity of natural gas gathering systems, pipelines and trucking or terminal facilities. 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. 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. We do not own or operate any natural gas lines or distribution facilities. Further, interstate transportation and distribution of natural gas is regulated by the federal government through the Federal Energy Regulatory Commission, or FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy. Among FERC's powers is the ability to dictate sale and delivery of natural gas to any markets it oversees.

Additionally, state regulators have vast 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.

Competition in the natural gas and oil industry is intense. We are smaller and have a more limited operating history than most 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 that, 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 adversely affect our financial condition and 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. In particular, we expect to pursue acquisitions that have the potential to economically increase our natural gas and oil reserves. 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 platform 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 materially adversely affect 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, 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. One or more of the technologies that we currently use or may implement in the future may become obsolete.

Rapid growth could result in a strain on our resources.

Because of our size, our growth, if achieved, will likely place a significant strain on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the recruitment and retention of experienced managers, geoscientists and engineers, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Our ability to successfully execute our business plan is dependent on our ability to obtain adequate financing.

Our business plan, which includes participation in 3-D seismic shoots, the drilling of exploration prospects and development projects and producing property acquisitions, has required and will continue to require substantial capital expenditures. We may require additional financing to fund our planned growth. Our ability to raise additional capital will depend on the results of our operations and the status of various capital and industry markets at the time we seek such capital. Accordingly, we cannot be certain that additional financing will be available to us on acceptable terms, if at all. In particular, the terms of our senior secured notes limit our ability to incur additional indebtedness. In the event additional capital resources are unavailable, we may be required to curtail our exploration and development activities or be forced to sell some of our assets in an untimely fashion or on less than favorable terms.

Not hedging our production may result in losses.

We currently do not hedge our natural gas and oil production. By not hedging our production, we may be more adversely affected by declines in natural gas and oil prices than our competitors who engage in hedging arrangements. Further, should we elect to hedge in the future, such hedges may result in us receiving lower than current prevailing market prices and place additional financial strains on us due to having to post margin calls on our hedges.

Exchange rate fluctuations subject us to unique risks.

As our Australian activities increase, we will be increasingly exposed to the impact of fluctuations in the exchange rate between the Australian dollar and the U.S. dollar. 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 contracts 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 business.

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

As of December 31, 2005, Chesapeake and GeoStar owned approximately 16.5% and 10.9% of our outstanding common shares, respectively. As a result, Chesapeake and GeoStar are in a position to heavily influence the outcome of matters requiring a shareholder vote, including the election of directors, the adoption or amendment of provisions in our Articles of Incorporation and 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.

The chairman of our board of directors is also a director and chief executive officer of GeoStar. Chesapeake has the right to have present an observer at our board of directors meetings. In accordance with the laws of Alberta, our directors are required to act honestly and in good faith with a view to our best interests. The GeoStar director on our board of directors also has fiduciary duties to manage GeoStar, including its investments in companies such as us, in a manner beneficial to GeoStar and its shareholders. In some circumstances, these duties may conflict with his duties as a director of Gastar. Addressing matters, such as board of director conflicts, are subject to the procedures and remedies as provided under the Business Corporations Act (Alberta).

Each of Chesapeake and GeoStar and their subsidiaries are also engaged in the natural gas and oil business. Although we have entered into the Participating and Operating Agreement, or POA, with GeoStar in 2001, and a joint operating agreement with Chesapeake, it is possible that we may in some circumstances be in direct or indirect competition with Chesapeake or GeoStar, including competition with respect to certain business strategies and transactions that we may propose to undertake. These conflicts of interest may materially adversely affect our results of operations.

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

Three of our directors reside in 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 (a) 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 (b) 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.

If we are unable to meet the SEC's requirements related to the assessment, attestation and effectiveness of our internal controls, we may suffer a loss of investor confidence, and the price of our common shares may be adversely affected.

Under the Exchange Act, we will be required to include in our annual report a report on internal controls over financial reporting. This report must state management's responsibility for establishing and maintaining an adequate internal control structure and procedures for financial reporting. The report must also contain an assessment as of the end of the year of the effectiveness of those internal controls. The Exchange Act also requires our registered public accounting firm to test and report on the assessment made by management. These new rules could become effective for us for the year ending December 31, 2007. In order to meet these requirements, we must document and test the effectiveness of our internal controls and then allow time for our registered public accounting firm to audit our internal control structure. The amount of work required by us to prepare, maintain and test our internal control structure could be extensive. In the event that management is unable to complete its assessment of the effectiveness of our internal controls over financial reporting or our auditors are unable to attest to management's assessment or do their own assessment, or if these internal controls are not effective, we might experience an adverse reaction in the financial marketplace due to a loss of investor confidence in the reliability of our financial statements, which could negatively impact the market price of our common shares.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Our properties consist primarily of oil, gas and mineral lease and concession interests in the following areas:

- Deep Bossier play in East Texas;
- Powder River Basin in Wyoming and Montana;
- Appalachian Basin in West Virginia;
- Gunnedah Basin in New South Wales, Australia; and
- Gippsland Basin in Victoria, Australia.

Additional information concerning our activities and interests in these areas is described in this report under "Item 1. Business".

Production, Prices and Operating Expenses

The following table presents information regarding the production volumes, average sales prices received and average production costs 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,	
	2005	2004
Production:		
Natural gas (MMcf)	3,810.0	1,108.0
Oil (MBbl)	1.9	1.8
Total (MMcfe)	3,821.5	1,118.8
Natural gas (MMcfd)	10.5	3.0
Oil (MBod)	0.0	0.0
Total (MMcfed)	10.5	3.1
Average sales prices:		
Natural gas (per Mcf)	$ 7.18	$ 5.40
Oil (per Bbl)	$ 50.85	$ 40.08
Selected data per Mcfe:		
Lease operating, transportation and selling expenses	$ 1.81	$ 1.78
General and administrative expenses	$ 2.28	$ 3.60
Depreciation, depletion and amortization of natural gas and oil properties	$ 3.63	$ 2.89

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. "Undecided" wells are wells for which permanent equipment was installed for the production of natural gas or oil but that as of each respective period end were in the process of de-watering.

	For the Years Ended December 31,			
	2005		2004	
	Gross	Net	Gross	Net
Exploratory wells:				
Productive	3	2.9	2	1.3
Non-productive	1	1.0	—	—
Undecided	3	1.9	3	1.5
Total	7	5.8	5	2.8
Development wells:				
Productive	82	36.0	113	25.7
Non-productive	—	—	—	—
Undecided	—	—	5	1.1
Total	82	36.0	118	26.8

Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped acreage and developed acreage in the areas indicated where we own a working interest as of December 31, 2005. Gross represents the total number of acres in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross acres.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Powder River Basin, Wyoming	33,917	11,992	21,049	9,862
Appalachian Basin, West Virginia	25,446	12,532	1,187	735
California	3,040	3,040	—	—
Texas	51,571	23,532	2,020	1,540
Total United States	113,974	51,096	24,256	12,137
Gunnedah Basin, New South Wales	1,997,800	699,230	2,200	770
Gippsland Basin, Victoria	1,400,000	1,050,000	—	—
Total Australia	3,397,800	1,749,230	2,200	770

Productive Wells

The following table sets forth our ownership interest in productive wells in the areas indicated where we own a working interest as of December 31, 2005. 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 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
Powder River Basin, Wyoming	353	142.8	—	—	353	142.8
Appalachian Basin, West Virginia	7	4.4	21	15.8	28	20.2
Texas	4	3.9	—	—	4	3.9
Total United States	364	151.1	21	15.8	385	166.9

As of December 31, 2005, we had no productive wells in Australia.

Natural Gas and Oil Reserves

Our estimated total net proved reserves of natural gas and oil as of December 31, 2005, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following table. These estimates were prepared by Netherland, Sewell & Associates, Inc., independent reservoir engineers, and are part of their reserve reports on our natural gas and oil properties. Netherland, Sewell & Associates' estimates were based on a review of geologic, economic, ownership and engineering data that we provided. In estimating the reserve quantities that are economically recoverable, end-of-period natural gas and oil prices, held constant, were utilized. In accordance with SEC regulations, no price or cost escalation or reduction was considered.

	Total Proved Reserves as of December 31, 2005			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	7,095	7,545	18,383	33,023
Oil (MBbls)	1	—	—	1
Total proved reserves (MMcfe)	7,101	7,545	18,383	33,029
Pre-tax net present value (in thousands) (1)	$28,946	$32,853	$29,496	$91,295
Standardized measure of discounted future net cash flow				$91,295

(1) The SEC views year end pre-tax present value of future net revenues from proved reserves as a non-GAAP financial measure that differs from standardized measure of discounted future net cash flows which is required to be disclosed on a year end basis under generally accepted accounting principles. The sole difference in the two measures is that standardized measure reduces future net cash flows by an estimated amount of future income tax expense. However, under our current tax position, our two measures do not differ as of December 31, 2005 because we are not projecting future income tax expense to arise from production of currently estimated proved reserves. Management uses year end pre-tax present value as one measure of the value of our current proved reserves and to compare relative values among peer companies without regard to income taxes. While future pre-tax present value are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows will be dependent on the unique tax situation of each individual company.

The weighted average natural gas and oil prices after basis adjustments used in the reserve valuation as of December 31, 2005 were $56.00 per barrel and $7.39 per Mcf.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues are made using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Estimated quantities of proved reserves and future net revenues therefrom are affected by natural gas and oil prices, which have fluctuated significantly in recent years. Our estimated proved reserves have not been filed with or included in reports to any U.S. federal agency.

Pricing Assumptions

SEC regulations require that the natural gas and oil prices used in Netherland, Sewell & Associates' reserve reports are the period-end prices for natural gas and oil at December 31, 2005. 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 for energy content, quality, transportation, compression and gathering fees, and regional price differentials. The pricing assumptions are listed below:

	As of December 31, 2005	
	Gas ($/MMBtu)	Oil ($/Bbl)
Production:		
Hilltop Area (East Texas)	$ 7.96	$ —
Powder River Basin (Wyoming and Montana)	$ 7.72	$ —
Appalachian Basin (West Virginia)	$10.42	$57.25
Cherokee Basin (Kansas)	$10.08	$ —

The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and gas production sold subsequent to December 31, 2005. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices. Accordingly, the foregoing prices should not be interpreted as a prediction of future prices.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

For additional information concerning our estimated proved reserves, the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2005, 2004 and 2003, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, see Note 24 to our consolidated financial statements contained in this report.

Item 3. *Legal Proceedings*

The Company is party to various litigation matters arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from an adverse outcome be reasonably estimated at this time.

Estate of Virgil Sparks and Oil Wells of Kentucky, Inc. vs. First Sourcenergy Group Inc .and Geostar Corporation Arbitration. In August 2002, FSG, a wholly owned Company subsidiary, was a named party to this arbitration proceeding. The dispute involves historical dealings with the development of an Authority to Prospect ("ATP") Area in Queensland, Australia, as well as an ancillary agreement. The formal arbitration is in discovery stages. FSG and GeoStar have moved to dismiss the arbitration on the grounds of a claimed prior settlement and release agreement. FSG and GeoStar are vigorously defending the arbitration, and firmly believe that its position is sound and intends to continue to defend vigorously against the claim. Further, FSG's interest in ATP 560 were transferred from FSG to a third party in 2001, the result of which means that, although FSG is a named defendant, the third party and GeoStar would bear primary liability from this arbitration action and not FSG.

Western Gas Resources, Lance oil and Gas Company, Inc. and Williams Production RMT Company vs. First Sourcenergy Wyoming, Inc. and First Sourcenergy Group, Inc. On May 3, 2005, FSW and FSG, both wholly owned Company subsidiaries, were party to a complaint concerning a June 2002 Lease Exchange and Purchase Agreement between certain of the parties. The issue involves a certain gas gathering agreement and its applicability to some of the properties exchanged under the June 2002 Agreement. A formal response to the complaint was filed in June 2005. Discovery on this matter is just beginning, and as such it is premature to assess a probability of success in defense of this action or of the Company's exposure if liability were to be found. The Company believes that it has multiple strong defenses to this action and intends to continue to vigorously defend against the claim.

Navasota Resources L.P. vs. First Source Texas, Inc., First Source Gas L.P. and Gastar Exploration Ltd. (Cause No. 0-05-451) District Court of Leon County, Texas 12th Judicial District. This lawsuit contends that the Company breached Navasota's preferential right to purchase 33.33% of the Company's interest in certain oil and gas leases located in Leon and Robertson Counties, Texas sold to Chesapeake Energy Corporation pursuant to a transaction that closed on November 4, 2005. The preferential right claimed is under an operating agreement dated July 7, 2000. The Company contends, among other things, that Navasota neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent Chesapeake transaction. This litigation matter is currently in the discovery stage and the Company intends to vigorously defend against the claim.

East Texas Lease Dispute. Certain members of a family from which leases were obtained claim to own unleased mineral interests in the same tract covering approximately 2,600 gross acres (1,500 net disputed acres) in Leon County, Texas on which Gastar's Lone Oak Ranch Well No. 1 is drilled. These family members have demanded an accounting of the revenue and expenses on the drilled well. Based on the accounting, there does not appear to be a basis for any adverse claim against us that would give rise to a monetary damage award at this time. However, the existence of unleased mineral interests in this tract could adversely impact future development of the tract. We intend to vigorously defend against this claim.

Item 4. *Submission of Matters to a Vote of Security Holders*

During the quarter ended December 31, 2005, no matters were submitted to a vote of security holders.

PART II

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

Market for Registrant's Common Equity

Our common shares are listed on the American Stock Exchange under the symbol "GST" and the Toronto Stock Exchange under the symbol "YGA". Prior to our listing on the American Stock Exchange on January 5, 2006, our common shares traded in the United States over-the-counter market under the symbol "GSREF.PK".

The following table sets forth the high and low sale prices of our common shares as quoted in the United States over-the-counter market and as reported on The Toronto Stock Exchange (CDN$) for the periods presented. The prices in the table below have been adjusted for stock splits.

	U.S. Over-the-Counter		Toronto Stock Exchange	
	High	Low	High	Low
2005				
Fourth quarter	$4.22	$3.22	CDN$4.62	CDN$3.85
Third quarter	$4.01	$2.25	CDN$4.72	CDN$2.75
Second quarter	$3.85	$2.74	CDN$4.48	CDN$3.38
First quarter	$3.92	$3.02	CDN$4.95	CDN$3.64
2004				
Fourth quarter	$4.24	$3.00	CDN$5.50	CDN$3.65
Third quarter	$3.52	$2.11	CDN$4.50	CDN$3.28
Second quarter	$3.17	$2.61	CDN$4.35	CDN$3.40
First quarter	$3.19	$1.87	CDN$4.50	CDN$2.40

As of March 15, 2006, there were 578 shareholders of record of our common shares. The last reported sale prices of our common shares on the American Stock Exchange and The Toronto Stock Exchange on March 15, 2006 were $4.06 and CDN$4.74, respectively.

Dividends

We have never declared or paid any cash dividends on our common shares. We anticipate that we will retain any 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 current senior secured notes contain covenants that prohibit 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

During the year ended December 31, 2005, we sold the following securities without registration under the Securities Act:

On June 17, 2005, we issued $63.0 million of senior secured notes bearing interest at three month LIBOR plus 6% due 2010. In conjunction with the note placement, we issued 1,217,269 common shares to the purchasers of the notes, for no additional consideration, and also issued subscription receipts to the purchasers entitling the purchasers to receive, for no additional consideration, common shares in CDN$4.5 million increments on each of the six, twelve and eighteen-month anniversaries of the closing date. The common shares issued in the transaction represented an aggregate value of CDN$4.5 million based upon the five day weighted average trading price of CDN$3.6968 per share for the five trading days immediately prior to closing. The issuance of the senior secured notes and the common shares together with subscription receipts were exempt from registration pursuant to Rule 506 of Regulation D under the Securities Act.

On June 17, 2005, concurrent with the private placement of our senior secured notes, we issued 1,650,133 common shares having an aggregate value of $6.0 million, valued at CDN$4.50 per share, the market price on the date the acquisition was announced, and $32.0 million in unsecured subordinated notes maturing on January 31, 2006 to GeoStar representing a portion of the purchase price in connection with the acquisition of additional leasehold and working interest properties from GeoStar. The issuance of the shares and unsecured subordinated notes to GeoStar was exempt from registration pursuant to Section 4(2) under the Securities Act.

On June 30, 2005, we issued 6,617,736 common shares at CDN$3.31 per share in a private offering. Pritchard Capital, LLC and Westwind Partners Inc. acted as placement agents for this offering. The issuance of the shares was exempt from registration pursuant to Rule 506 of Regulation D and Regulation S under the Securities Act.

On August 11, 2005, we executed an agreement with GeoStar whereby the previously issued $32.0 million unsecured subordinated note to us was cancelled. In conjunction with the note cancellation, we issued GeoStar 6,373,694 common shares having an aggregate value of $l7.0 million, valued at CDN$3.25 per share, the market price at the date of debt renegotiation, and a new unsecured subordinated note in a principal amount of $15.0 million. The issuance of the shares and new note upon cancellation of the previously issued notes was exempt from registration under Section 3(a)(9) of the Securities Act.

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders. We also issued subscription receipts to the purchasers entitling the purchasers to receive, for no additional consideration, common shares in CDN$714,286 increments on each of the six, twelve and eighteen-month anniversaries of the closing date. The common shares issued in the transaction represented an aggregate value of CDN$714,286 based upon the five day weighted average trading price of CDN$3.4615 per share for the five trading days immediately prior to closing. The issuance of the senior secured notes and the common shares together with subscription receipts were exempt from registration pursuant to Rule 506 of Regulation D under the Securities Act.

On November 4, 2005, we issued 27,151,641 common shares to Chesapeake for approximately $76.0 million in cash. The issuance was exempt under Section 4(2) of the Securities Act.

On December 19, 2005, pursuant to the senior secured notes, we issued to the senior secured notes holders, for no additional consideration, an additional 1,082,105 common shares having an aggregate value of CDN$4.5 million, valued at CDN$4.1586, the five day weighted average trading price immediately prior to the date of issuance. The issuance of the common shares was exempt from registration under Section 3(a)(9) of the Securities Act.

As of December 31, 2005, we had granted options outstanding to purchase 17,500,600 common shares pursuant to the 2002 Stock Option Plan, of which 12,783,350 common shares were vested but have not been exercised. These issuances were exempt under Section 4(2) of the Securities Act and Rule 701 issued under the Securities Act.

Item 6. *Selected Financial Data*

The following table presents selected historical financial and operational information as of and for the periods indicated. The selected consolidated financial data as of and for the years ended December 31, 2005, 2004, 2003, 2002 and 2001 are derived from our audited consolidated financial statements.

You should read the following selected consolidated financial and operational information in conjunction with our audited consolidated financial statements, the accompanying notes and the section entitled, "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Form 10-K.

	As of and For the Years Ended December 31,				
	2005	2004	2003	2002	2001
	(in thousands, except per share data)				
Consolidated Statements of Loss:					
Revenues	$ 27,442	$ 6,059	$ 1,461	$ 783	$ 228
Loss from operations	$ (10,963)	$ (9,587)	$ (2,368)	$ (2,657)	$ (4,960)
Net loss	$ (25,692)	$ (12,776)	$ (4,947)	$ (4,599)	$ (4,793)
Basic and diluted loss per share	$ (0.20)	$ (0.12)	$ (0.05)	$ (0.05)	$ (0.05)
Shares used in the calculation of basic and diluted loss per share	129,398	111,374	104,958	98,618	94,648
Consolidated Balance Sheet:					
Property plant and equipment, net	$165,347	$ 56,564	$ 37,725	$34,467	$23,082
Total assets	$240,128	$ 84,442	$ 38,757	$36,034	$24,458
Long-term debt	$ 90,631	$ 57,878	$ —	$ —	$ —
Total shareholders' equity	$120,776	$ 21,976	$ 23,669	$22,430	$17,656

	For the Years Ended December 31,				
	2005	2004	2003	2002	2001
Production Data:					
Production:					
Natural gas (MMcf)	3,810.0	1,108.0	385.0	393.2	81.7
Oil (MBbl)	1.9	1.8	1.0	3.1	2.8
Natural gas equivalents (MMcfe)	3,821.5	1,118.8	391.0	411.6	98.5
Natural gas (MMcfd)	10.5	3.0	1.1	1.1	0.2
Oil (MBod)	0.0	0.0	0.0	0.0	0.0
Natural gas equivalents (MMcfed)	10.5	3.1	1.1	1.1	0.3
Average Price:					
Natural gas (per Mcf)	$ 7.18	$ 5.40	$ 3.72	$ 1.33	$ 1.83
Oil (per Bbl)	$ 50.85	$ 40.08	$ 27.89	$ 20.15	$ 20.55

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis should be read in conjunction with accompanying consolidated financial statements and related notes included elsewhere in this Form 10-K. It contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this Form 10-K, particularly in "Risk Factors" and "Cautionary Notes Regarding Forward Looking Statements", all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward looking events discussed may not occur.

Overview

We are an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties. Our emphasis is on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as coal bed methane. We currently are pursuing conventional natural gas exploration in the Deep Bossier play in the Hilltop area in East Texas and the Appalachian Basin in West Virginia. Our primary CBM properties are in the United States in the Powder River Basin and in the Gunnedah and Gippsland Basins of Australia.

Results of Operations

The following is a comparative discussion of the results of operations for the years ended December 31, 2005, 2004 and 2003. It should be read in conjunction with the consolidated financial statements and the related notes and other information included elsewhere in this Form 10-K.

Year Ended December 31, 2005 compared to Year Ended December 31, 2004.

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. We reported revenues of $27.4 million for the year ended December 31, 2005, up from $6.1 million for the year ended December 31, 2004. This increase was attributable to the commencement of production of natural gas from our East Texas Bossier Field in late 2004 and continued 2005 field development and related production increases coupled with additional production from new CBM wells drilled in the Powder River Basin. The acquisition of additional leasehold and working interests in East Texas and the Powder River Basin from Geostar and higher prices for both natural gas and oil also contributed to the increase. Of the increase in revenues, 68% was attributed to higher production rates and 32% resulted from price increases.

Natural Gas and Oil Production and Average Sales Prices. Natural gas represents substantially all of our production. The table below sets forth production and sales information for the periods indicated.

	For the Years Ended December 31,	
	2005	2004
Production:		
Natural gas (MMcf)	3,810.0	1,108.0
Oil (MBbl)	1.9	1.8
Total (MMcfe)	3,821.5	1,118.8
Natural gas (MMcfd)	10.5	3.0
Oil (MBod)	0.0	0.0
Total (MMcfed)	10.5	3.1
Average sales prices:		
Natural gas (per Mcf)	$ 7.18	$ 5.40
Oil (per Bbl)	$ 50.85	$ 40.08

Lease operating, transportation and selling expenses. Our lease operating, transportation and selling expenses were $6.9 million for the year ended December 31, 2005, up from $2.0 million for the year ended December 31, 2004. This increase was due to higher production volumes and an increased number of producing wells, which was partially offset by a reduction in severance and property taxes. Our lease operating, transportation and selling expenses per Mcfe were $1.81 during the year ended December 31, 2005, compared to $1.78 for the comparable period in 2004.

Depreciation, depletion and amortization. Depreciation, depletion and amortization was $13.9 million for the year ended December 31, 2005, up from $3.2 million for the year ended December 31, 2004. This increase was attributable to the commencement of natural gas production from the wells in East Texas and the acquisition of additional leasehold and working interest properties in East Texas and the Powder River Basin from Geostar. Of the increase in DD&A expense, 73% was attributed to higher production rates and 27% was due to an increase in DD&A rate per unit. The DD&A rate for the year ended December 31, 2005 was $3.63 per Mcfe, as compared to prior comparable period of $2.89 per Mcfe. The increase in the DD&A rate is primarily due to higher capital expenditures in East Texas.

Impairment of natural gas and oil properties. Impairment of natural gas and oil properties was $8.7 million for the year ended December 31, 2005, down from $6.3 million for 2004. The impairment is the result of net natural gas and oil property costs, as adjusted for related deferred income taxes and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at June 30, 2005, the date of the impairment, held constant at $5.32 per Mcf for natural gas and $52.33 per barrel for oil, discounted at 10%, and unproven properties at historical costs of $93.3 million, which was lower than estimated fair market value, as adjusted for related deferred income taxes and other adjustments. The impairment was primarily the result of limited reserve additions during the current interim period and higher costs incurred to drill and complete the East Texas wells.

General and administrative. General and administrative expenses were $8.7 million for the year ended December 31, 2005, up from $4.0 million for 2004. This increase in general and administrative expenses was primarily due to personnel increases, higher contract staff and professional service charges, costs associated with our Form S-1 Registration Statement and non-cash compensation expense due to the issuance of stock options. Stock-based compensation expense for 2005 was $2.3 million, up from $1.4 million for 2004.

Interest expense. Interest expense was $15.3 million for the year ended December 31, 2005, up from $3.2 million for the year ended December 31, 2004. This increase was due to higher debt outstanding as a result of the sale in 2004 of $3.25 million of subordinated unsecured notes payable, the sale in 2004 of $30.0 million of convertible senior debentures, the private placement in 2005 of $73.0 million of senior secured notes and the issuance in June 2005 of $32.0 million in unsecured subordinated notes to Geostar. Interest expense includes deferred financing cost and debt discount amortization of $4.8 million for 2005, an increase of $4.0 million from 2004. In addition in June 2005, the senior unsecured notes were paid in full and a call premium of $622,000 was paid.

Year Ended December 31, 2004 compared to Year Ended December 31, 2003.

Revenues. Substantially all of our revenues are derived from the production of natural gas in the United States. Revenues were $6.1 million for the year ended December 31, 2004, up from $1.5 million for the year ended December 31, 2003. This increase was attributable to the commencement of production of natural gas in East Texas in the third quarter of 2004, additional production from new CBM wells drilled in the Powder River Basin, and higher commodity prices for both natural gas and oil. Of the increase in revenues, 59% was attributed to higher production rates and 41% resulted from price increases.

Natural Gas and Oil Production and Average Sales Prices. Natural gas represents substantially all of our production. The table below sets forth production and sales information for the periods indicated.

	For the Years Ended December 31,	
	2004	**2003**
Production:		
Natural gas (MMcf)	1,108.0	385.0
Oil (MBbl)	1.8	1.0
Total (MMcfe)	1,118.8	391.0
Natural gas (MMcfd)	3.0	1.1
Oil (MBod)	0.0	0.0
Total (MMcfed)	3.1	1.1
Average sales prices:		
Natural gas (per Mcf)	$ 5.40	$ 3.72
Oil (per Bbl)	$ 40.08	$27.89

Lease operating, transportation and selling expenses. Lease operating, transportation and selling expenses were $2.0 million for the year ended December 31, 2004, up from $712,000 for the year ended December 31, 2003. This increase was due to higher production volumes and an increased number of producing wells. Our lease operating, transportation and selling expenses per Mcfe decreased to $1.78 during the year ended December 31, 2004 from $1.82 for the comparable period in 2003.

Depreciation, depletion and amortization. Depreciation, depletion and amortization was $3.2 million for the year ended December 31, 2004, up from $572,000 for the year ended December 31, 2003. This increase was attributable to the commencement of production of natural gas from East Texas in the third quarter of 2004 and additional production from new CBM wells drilled in the Powder River Basin. Of the increase in DD&A expense, 40% was attributed to higher production rates and 60% was due to an increase in DD&A rate per unit. The DD&A rate for the year ended December 31, 2004 was $2.89 per Mcfe, as compared to $1.46 for the comparable period in 2003.

Impairment of natural gas and oil properties. Impairment of natural gas and oil properties was $6.3 million for the year ended December 31, 2004, up from $552,000 for the comparable period ended 2003. The 2004 year impairment was the result of net natural gas and oil property costs, as adjusted for related deferred income taxes and other adjustments, exceeding the sum of estimated future net revenues using prices in effect at the end of the period held constant of $4.98 per Mcf for natural gas and $27.36 per barrel for oil, discounted at 10%, and unproven property at historical cost of $29.8 million, which was lower than the estimated fair market value, as adjusted for related income taxes and other adjustments. The 2004 impairment was primarily due to the result of high initial drilling and completion costs on our Deep Bossier wells in East Texas coupled with limited production history that limited the recording of proven reserves.

General and administrative. We reported general and administrative expenses of $4.0 million for the year ended December 31, 2004, up from $1.9 million for the year ended December 31, 2003. This increase in general and administrative expenses was primarily due to higher contract staff and professional service charges and the recording of non-cash compensation expense due to the issuance of stock options in April and August 2004. Stock-based compensation expense for 2004 was $1.4 million. We recorded no stock-based compensation in 2003.

Interest expense. We reported interest and debt related items of $3.2 million for the year ended December 31, 2004, up from $2.6 million for the year ended December 31, 2003. This increase was due to higher debt outstanding as a result of the issuance of $15.0 million and $10.0 million senior unsecured notes, $3.25 million of subordinated unsecured notes and $30.0 million of convertible debentures in 2004. Interest expense includes deferred financing cost amortization of $808,000 for 2004, a decrease of $555,000 from 2003.

Liquidity and Capital Resources

For the years ended December 31, 2005 and 2004, cash expenditures on natural gas and oil properties totaled $88.1 million and $34.2 million, respectively. During 2005, our cash flow from operations was $8.2 million, and we had a deficit of $1.1 million for 2004. We also raised $161.2 million, after fees and expenses, from various debt and equity financings and repaid $41.5 million of outstanding senior and related party notes during 2005. We raised $58.2 million from various debt financings and repaid $2.2 million of notes during 2004. At December 31, 2005, approximately $61.1 million remained in available cash and cash equivalents for future capital commitments.

On June 17, 2005, the Company completed the private placement of $63.0 million of senior secured notes bearing interest at three month LIBOR plus 6%. The notes mature on June 18, 2010. Concurrently with the private placement of senior secured notes, we closed the acquisition of additional leasehold and working interest properties from GeoStar in the Hilltop area of East Texas and in the Powder River Basin of Wyoming and Montana. We paid a total of $68.5 million for the interests acquired from GeoStar consisting of $30.5 million in cash, 1,650,133 common shares valued at CDN$4.50 per share and $32.0 million in unsecured subordinated notes maturing on January 31, 2006.

On June 30, 2005, we completed a private placement of 6,617,736 common shares at CDN$3.31 per share. The estimated net proceeds from this placement were $16.4 million (CDN$20.5 million), after deducting placement fees and expenses.

On August 11, 2005, we executed an agreement with GeoStar whereby the GeoStar $32.0 million unsecured subordinated note was cancelled. In conjunction with the note cancellation, we issued GeoStar 6,373,694 common shares valued at $17.0 million based on a per share price of CDN$3.25 and a new unsecured subordinated note for $15.0 million. The interest rate on the new GeoStar note was the three-month LIBOR plus 4.5%, payable monthly commencing February 15, 2006. As required by the agreement, the $15.0 million GeoStar note was paid in full on November 28, 2005 with proceeds realized in the Chesapeake transaction.

On September 19, 2005, we issued to the holders of our senior secured notes an additional $10.0 million of senior secured notes on substantially the same terms as the original June 2005 private placement, including the issuance of 206,354 common shares to the note holders.

We have the right, exercisable quarterly to June 16, 2007, to require the original purchasers of the senior secured notes to purchase additional notes in an amount limited to an aggregate of $10.0 million in principal, provided that we comply with proved plus probable reserve present value discounted at 10%, or PV(10), to net senior secured debt coverage ratio of 2.0:1 and other general covenants and conditions. The PV(10) value is to be based on a third party independent reserve report utilizing constant pricing based on the lower of current natural gas and oil prices, adjusted for area basis differentials, or $6.00 per Mcf of natural gas and $40.00 per barrel of oil. Utilizing the same reserve pricing criteria above, the proved plus probable reserves PV(10) ("2P PV(10)") to net senior secured notes debt reserve maintenance ratio covenant must be a minimum of 1.5:1 from date of issuance of the notes up to the first anniversary date. On the first anniversary date of the senior secured notes, the 2P PV(10) reserve ratio maintenance covenant increases to a minimum of 2.5:1, on the second anniversary to 3.0:1 and on the third anniversary and for all test periods thereafter until maturity to 3.5:1. We must maintain compliance with the reserve ratio covenants at all future quarterly and annual covenant determination dates or be subject to mandatory principal redemptions under certain conditions. The senior secured notes prohibit us from issuing any debt senior or *pari passu* to the senior secured notes and may limit our ability to borrow subordinated funds and payment of dividends.

On November 4, 2005, we closed the Chesapeake transaction resulting in us receiving approximately $83.8 million, before fees and expenses, in conjunction with the issuance of approximately 27.2 million common shares at CDN$3.31 per share and Deep Bossier partial leasehold working interest sale. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. We plan to use the proceeds from the transaction as well as other sources to accelerate drilling activities, to reduce short term debt and for general corporate purposes.

We continually evaluate our capital needs and compare them to our capital resources. To execute our operational plans, particularly our drilling plans in East Texas, additional funds will be needed for acreage acquisition, seismic and other geologic analysis, drilling, undertaking completion activities and for general corporate purposes. As described below, our current budgeted capital expenditures for the next twelve months are approximately $66.0 million. We may have to significantly reduce our drilling and development program if our internally generated cash flow from operations and cash flow from financing activities are not sufficient to pay debt service and expenditures associated with our projected drilling and development activities. We expect to fund these expenditures from internally generated cash flow, cash on hand, the issuance of additional senior secured notes or the issuance of additional equity. We may also attempt to balance future capital expenditures through joint venture development of certain properties with industry partners. We are in the early stages of exploration and development of our East Texas properties. Amounts and timing of future cash flows is dependent on confirmation of production from recently completed wells, together with the success of currently drilling and to be drilled wells. We cannot be certain that future funds will be available to fully execute our business plan. During 2004 and continuing into 2005, the availability of capital for companies in the energy industry has been high.

Our 2006 capital expenditure budget is estimated at $66.0 million, of which $56.0 million is estimated to be spent on natural gas and oil exploration and development operations, $4.0 is estimated to be spent on CBM projects in the United States and $6.0 is estimated to be spent on CBM projects in Australia. Given the continued forecasts for high natural gas and oil prices and our recent debt and equity financings and our ability to issue up to an additional $10.0 million of senior secured notes, we believe that sufficient cash will be available to execute our business and operational plans for at least the next 12 months.

We are highly dependent upon natural gas pricing. A material decrease in current and projected natural gas prices could impair our ability to raise additional capital on acceptable terms and result in a financial covenant default under the senior secured notes. Likewise, a material decrease in current and projected natural gas prices could also impact our ability to divest ourselves of certain non-core assets. This could impact our ability to fund future activities. Under the terms of our senior secured notes, the proceeds from asset sales must first be offered to the holders of the senior secured notes as repayment of outstanding debt.

We currently have no natural gas price financial instruments or hedges in place. Similarly, we have no financial derivatives. Our natural gas marketing contracts use "spot" market prices. Given the uncertainty of the timing and volumes of our natural gas production this year, we do not currently plan to enter into any long-term fixed-price natural gas contracts, swap or hedge positions, other gas financial instruments or financial derivatives in 2006. Further, the senior secured notes covenants restrict us from hedging more than 50% of future production.

At December 31, 2005, we were in compliance with all debt covenants.

Impairment of Natural Gas and Oil Properties

At December 31, 2005, our ceiling limitation exceeded capitalized costs by approximately $286,000. Based on current prices for natural gas, it is likely that we will report an impairment expense for the quarter ended March 31, 2006.

Contractual Obligations and Contingencies

The following table summarizes our future contractual obligations under these arrangements as of December 31, 2005:

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
Long-term debt, including related current portion	$106,250	$—	$—	$106,250	$—
Operating leases	1,260	804	256	200	—
Total	$107,510	$804	$256	$106,450	$—

Off-Balance Sheet Arrangements

As of December 31, 2005, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying consolidated financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

All other significant accounting policies that we employ are presented in the notes to the consolidated financial statements. The following discussion presents information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate.

Natural Gas and Oil Reserves

Nature of Critical Estimate Item. Our estimate of proved reserves is based on the quantities of natural gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our proved reserve volumes and values are used to calculate depletion and impairment provisions, respectively.

Assumptions/Approach Used. Units-of-production method to amortize our natural gas and oil properties—The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

"Ceiling" Limitation Test—The full-cost method of accounting for natural gas and oil properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full-cost ceiling calculation. The ceiling is the discounted present value of our estimated total proved reserves adjusted for taxes using a 10% discount rate. To the extent that our capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of natural gas and oil properties is not reversible at a later date even if natural gas and oil prices increase. Impairments were required in the years ended December 31, 2005, and 2004. The calculation of our proved reserves could significantly impact our ceiling limitation used in determining whether an impairment of our capitalized costs is necessary. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the period. The weighted average natural gas and oil prices after basis adjustments used in the reserve valuations as of December 31, 2005 and 2004 were $56.00 per barrel and $7.39 per Mcf and $27.38 per barrel and $4.98 per Mcf, respectively.

Effect if different assumptions used. Units-of-production method to amortize our natural gas and oil properties—A 10% increase in reserves would have decreased our depletion expense for the year ended

December 31, 2005 by approximately 9%, while a 10% decrease in reserves would have increased our depletion expense by approximately 11% with an offsetting adjustment to ceiling impairment.

"Ceiling" Limitation Test—The most likely factor to contribute to a ceiling test impairment is the price used to calculate the reserve limitation threshold. A significant reduction in the prices at a future measurement date could trigger a full-cost ceiling impairment. At December 31, 2005, our ceiling limitation exceeded capitalized costs by approximately $286,000. A 10% increase in prices used would have increased our ceiling cushion by $16.1 million. A 10% decrease in prices would have resulted in the recognition of additional 2005 impairment expense of $15.3 million. Based on current prices for natural gas, it is likely that we will report an impairment expense for the quarter ended March 31, 2006. Another likely factor to contribute to a ceiling test impairment is a revised estimate of reserve volume. A 10% increase in reserve volume would have increased our ceiling cushion by approximately $8.7 million at December 31, 2005. A 10% decrease in reserve volume would have reduced our ceiling cushion resulting in the recognition of additional 2005 ceiling impairment expense of $8.3 million.

Unproved Property Impairment

Nature of Critical Estimate Item. We have elected to use the full-cost method to account for our natural gas and oil activities. Investments in unproved properties are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. Unproved properties are evaluated quarterly for impairment on a field basis. If the results of an assessment indicate that an unproved property is impaired, the amount of impairment is added to the proved natural gas and oil property costs to be amortized.

Assumptions/Approach Used. At December 31, 2005, we had $73.6 million allocated to unproved property costs which was comprised primarily of unevaluated acreage costs. The unproven property costs are evaluated by the technical team and management of whether the property has potential attributable reserves. Therefore, the assessment made by our technical team and management of the potential reserves will determine whether costs are moved from the unproved category to the full-cost pool for depletion or whether an impairment is taken.

Effect if different assumptions used. A 10% increase or decrease in the unproved property balance would have increased or decreased our depletion expense by approximately 5% for the year ended December 31, 2005. A 10% decrease in unproved property balance would have increased 2005 impairment expense by approximately $7.3 million.

Asset Retirement Obligation

Nature of Critical Estimate Item. We have certain obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Previously, the costs associated with this activity were capitalized to the full-cost pool and charged to income through depletion. We adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*" effective January 1, 2003, as discussed in Note 2 to our Consolidated Financial Statements. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets ("asset retirement obligations" or "ARO"). Primarily, the new statement requires us to estimate asset retirement costs for all of our assets, inflation adjust those costs to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our capitalized cost. We then accrete the liability quarterly using the period-end effective credit-adjusted-risk-free rate. As new wells are drilled or purchased, their initial asset retirement cost and liability is calculated and recorded. Should either the estimated life or the estimated abandonment costs of a property change upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost (included in the full-cost pool); therefore, abandonment costs will almost always approximate the estimate. When wells are sold the related liability and asset costs are removed from the balance sheet.

Assumptions/Approach Used. Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free-rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if different assumptions used. Since there are so many variables in estimating AROs, we attempt to limit the impact of management's judgment on certain of these variables by using input of qualified third parties. We engage independent petroleum engineers, who have consented to the use of their name and reports in this Form 10-K, to evaluate our properties annually. We use the remaining estimated useful life from the year end reserve reports by our independent reserve engineer in estimating when abandonment could be expected for each property. We expect to see our calculations impacted significantly if interest rates move from their current lows, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis. Our technical team developed a standard cost estimate based on historical costs, industry quotes and depth of wells. Unless we expect a well's plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and some significant calculations, could differ from actual results, despite all our efforts to make an accurate estimate.

New Accounting Prouncements

In December of 2004, the Financial Accounting Standards Board ("FASB") issued SFAS 123R, "Share Based Payments" which addresses the accounting for transactions in which an entity exchanges its equity instruments for goods and services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This statement is a revision of FASB No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). This statement supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees". Among other things, this statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost is recognized over the period during which an employee is required to provide service in exchange for the award – the requisite service period (usually the vesting period). This statement is to be applied as of the beginning of the first interim or annual period that begins after December 15, 2005, but earlier adoption is encouraged. Because the Company has adopted SFAS123 and recorded the fair value of stock options granted after January 1, 2003, this new standard will have minimal impact.

In December of 2004, FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets – An Amendment of APB Opinion No. 29" ("SFAS No. 153"). The guidance in APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB Opinion No. 29") is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in that APB Opinion No. 29; however, included certain exceptions to that principle. This statement amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date this Statement is issued. The provisions of this statement shall be applied prospectively. The adoption in 2005 of SFAS No. 153 did not have any impact on our financial statements.

Glossary of Natural Gas and Oil Terms

AUD$. Australian dollars.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bod. One stock tank barrel per day.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, which approximates the relative energy content between crude natural gas and oil.

Bcf. One billion cubic feet of natural gas.

Bituminous coal. Higher rank coal.

Bwd. Barrels of water per day.

CBM. Coal bed methane.

CDN$. Canadian dollars.

Completion. The installation of permanent equipment for the production of natural gas and oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Developed well. A well drilled within the proved area of a natural gas and oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Exploration. The search for accumulations of natural gas and oil reserves by any geologic, geophysical, or other means.

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

Farmout agreement. An agreement between a leaseholder and a party willing to drill natural gas and oil wells on a leasehold property in exchange for assignments from the leaseholder of part or all of the leasehold interests. The agreement is an executory contract in that performance will take place in the future. A farmout agreement will typically (1) outline the future drilling obligations and (2) provide the framework in which the leaseholder will effect the future leasehold assignments, assuming the drilling obligations are met. The leaseholder typically reserves overriding royalty interests at the time that the leaseholder finally executes an assignment.

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

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

Horizon. A geological layer or strata that may or may not contain natural gas and oil.

MBod. One thousand stock tank barrels per day.

Mcf. One thousand cubic feet of natural gas.

Mcfd. One thousand cubic feet of natural gas per day.

Mcfe. One thousand cubic feet of natural gas equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content between natural gas and oil.

MBbl. One thousand stock tank barrels, or 42,000 U. S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet of natural gas.

MMcfd. One million cubic feet of natural gas per day.

MMcfe. One million cubic feet of natural gas equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content between natural gas and oil.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net smelter return. An interest in a mining property held by the vendor on the net revenues generated from the sale of metal produced by the mine.

NYMEX. The New York Mercantile Exchange, which is the primary exchange on which natural gas futures contracts are traded.

Present Value of PV(10). When used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Productive well. A well that is, or is capable of, producing hydrocarbons in sufficient quantifies such that proceeds from the sale of such production exceed production expenses and taxes.

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

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

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

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

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

(iii) Estimates of proved reserves do not include the following:

(A) Oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) Crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) Crude oil, natural gas, and natural gas liquids that may be recovered from oil shale, coal, gilsonite and other such sources.

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

Rank. A measure of the maturity, or age and degree of carbonization, of coal.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty interest. An interest in an natural gas and oil property entitling the owner to a share of gas production free of costs of production.

Subbituminous coal. Lower rank coal.

Tcf. Trillion cubic feet of natural gas.

3-D (three dimensional) seismic. Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

2-D (two dimensional) seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflected seismic data collected along a single source profile.

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

Vitrinite reflectance. Technical test of the reflectivity of a coal surface, generally associated with the rank of a coal.

Working interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production. A working interest pays its share of the costs of drilling and production, as compared to an overriding royalty or royalty interest, which does not pay any costs associated with drilling or production.

Workover. Operations on a producing well to restore or increase production from the currently producing formation.

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

Commodity Risk

Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas in the region produced. Prices received for natural gas are volatile and unpredictable and are beyond our control. For the year ended December 31, 2005, a 10% change in the prices received for natural gas production would have had an approximate $2.7 million impact on our revenues. To date, we have not entered into hedge transactions to mitigate our commodity pricing risk.

Interest Rate Risk

The carrying value of our debt approximates fair value. At December 31, 2005, we had approximately $106.3 million in principal amount of long-term debt of which $73.0 million of the senior secured notes was subject to a floating interest rate of LIBOR plus 6% (10.08% at December 31, 2005). A 10% fluctuation in interest rates would have an approximate $337,000 impact on annual interest expense.

Currency Translation Risk

Because our revenues and expenses are primarily in U.S. dollars, we have little exposure to currency translation risk, and, therefore, we have no plans in the foreseeable future to implement hedges or financial instruments to manage international currency changes.

Item 8. *Financial Statements and Supplementary Data*

The reports of our independent registered public accounting firms and our consolidated financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented beginning on Page F-1 of this Form 10-K.

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

On January 10, 2006, the Board of Directors determined, upon the recommendation of its Audit Committee, to appoint BDO Seidman, LLP as the Company's independent registered public accounting firm to audit the Company's consolidated financial statements for the year ending December 31, 2005, replacing BDO Dunwoody LLP, which resigned as auditors effective on the same date. During the two most recent fiscal years and any subsequent interim period preceding such resignation, there were no disagreements with the former accountant on any matter of accounting principles or practices, financial statement disclosure, or auditing scope of procedure, which disagreement(s), if not resolved to the satisfaction of the former accountant, would have caused it to make reference to the subject matter of the disagreement(s) in connection with its report. On January 10, 2006, the Company filed a current report on Form 8-K with the SEC reporting the event.

Item 9A. *Controls and Procedures*

Management's Conclusion on the Effectiveness of Disclosure Controls and Procedures

Our Chief Executive Officer and the Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to permit us to effectively identify and timely disclose important information. They concluded that the Company's disclosure controls and procedures were effective as of December 31, 2005 to provided reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended December 31, 2005, that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

Directors, Executive Officers and Certain Other Officers

Our directors, executive officers and certain other officers and their ages as of March 15, 2006 are as follows:

Name	Age	Position
Thomas E. Robinson	50	Chairman of the Board
J. Russell Porter	44	President, Chief Executive Officer, Chief Operating Officer and Director*
Michael A. Gerlich	51	Vice President and Chief Financial Officer*
Frederick E. Beck, PhD	46	Vice President of Drilling
R. David Rhodes	47	Vice President of Completion and Production
Henry J. Hansen	50	Vice President of Land
Sara-Lane Sirey	37	General Corporate Canadian Counsel and Corporate Secretary
Abby F. Badwi	59	Director
Thomas L. Crow	74	Director
Matthew J. P. Heysel	49	Director
Richard Kapuscinski	43	Director

* Executive Officer.

Thomas E. Robinson has been the Chairman of our Board of Directors since February 2001. Mr. Robinson has more than 20 years of experience investing in various areas in the natural gas and oil industry, both as an investor in and developer of exploration projects. During this period, he directed natural gas and oil drilling and production activities for GeoStar and individually in the United States (including the states of Michigan, Illinois, Texas, Kansas, Kentucky and Wyoming) and New South Wales, Victoria and the Cooper Basin in Australia. Mr. Robinson is the Chief Executive Officer of GeoStar, a position he has held since January 1994. From May 2000 to February 2004, Mr. Robinson also served as our President and Chief Executive Officer.

J. Russell Porter has been a member of our Board of Directors and has served as our Chief Executive Officer and President since February 2004. From September 2000 to February 2004, he served as our Chief Operating Officer. Mr. Porter has a unique background, with approximately 14 years of natural gas and oil exploration and production experience and five years of banking and investment experience specializing in the natural gas and oil industry. From April 1994 to September 2000, Mr. Porter served as an Executive Vice President of Forcenergy, Inc., a publicly traded exploration and production company, where he was responsible for the acquisition and financing of the majority of its assets across the United States and Australia. Mr. Porter holds a bachelor of science degree in Petroleum Land Management from Louisiana State University and a MBA from the Kenan-Flagler School of Business at the University of North Carolina at Chapel Hill.

Michael A. Gerlich joined Gastar in May 2005, as Vice President and Chief Financial Officer. From 1994 until joining Gastar, Mr. Gerlich served as Senior Vice President – Accounting and Finance for Calpine Natural Gas L.P., formerly known as Sheridan Energy, Inc., where he served as Vice President and Chief Financial Officer. Over a 10 year period prior to joining Sheridan Energy, Mr. Gerlich held various accounting and finance positions with Trinity Resources, Ltd., with his last position being Executive Vice President and Chief Financial Officer. Mr. Gerlich was also with a Big Four accounting firm, where the focus of his practice was with energy related clients. Mr. Gerlich is a Certified Public Accountant and graduated with honors from Texas A&M University with a bachelor degree in accounting.

Frederick E. Beck, PhD joined Gastar in April 2002, as Vice President of Drilling. Dr. Beck has over twenty-two years of diversified experience in the oil and gas business. He has held positions with a major operator as a drilling engineer and drilling supervisor and as an assistant professor of petroleum engineering at the New Mexico School of Mines. From 1996 and prior to joining Gastar as Vice President of Operations, Dr. Beck was Vice President of the turnkey drilling division of Nabors Drilling USA LP. Dr. Beck holds a B.S. degree in Geology Master of Science degree in Petroleum Engineering and Doctor of Philosophy Degree in Petroleum Engineering all from Louisiana State University in Baton Rouge.

R. David Rhodes joined Gastar in March 2006, as Vice President of Completion and Production. Mr. Rhodes has over 20 years of petroleum engineering experience, focused primarily in the supervision and management of completion and production operations. Prior to joining Gastar, he managed Oil & Gas Operations and Consulting, Inc., an independent consulting firm he established in May, 2001. There, he worked as a petroleum engineering consultant for numerous natural gas and oil operators including Gastar. From 1984 to 2001, Mr. Rhodes held various engineering and management/supervisory positions at Marathon Oil Company (formerly Texas Oil & Gas Company). His last position was Operations Manager for East Texas and Northern Louisiana. Mr. Rhodes holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University.

Henry J. Hansen joined Gastar in September 2005, as Vice President of Land. Prior to joining Gastar, Mr. Hansen was Rocky Mountain Land Manager with El Paso Corporation from 1999 until January, 2003. He returned to El Paso Corporation in June of 2004, where he was senior landman until joining Gastar in September 2005. Mr. Hansen graduated from the University of Texas at Austin, Texas with a Bachelor of Business Administration.

Sara-Lane Sirey, LLB is an independent contractor, who has served as the Corporate Secretary of Gastar and General Corporate Canadian Counsel since May 2000. From July 1993 to April 2001, she served as an attorney at the law firm of Armstrong Perkins Hudson LLP (formerly Ogilvie and Company) in Calgary, Alberta, Canada, becoming a partner in 1999. Focusing on corporate/securities law, she has acted for issuers, in all industry segments, in Canada, the United States and internationally, focusing on corporate reorganizations, commercial transactions and initial public offerings of junior emerging companies as well as equity and debt financings, mergers and acquisitions and commercial transactions of senior established companies. Ms. Sirey obtained her Bachelor of Laws degree at the University of Saskatchewan.

Abby F. Badwi has been a member of our Board of Directors since February 2004. Mr. Badwi is an international energy executive with more than 30 years of experience in the exploration, development and production of natural gas and oil fields in North America, South America, Asia and the Middle East. He has been President and CEO of Rally Energy Corp., a natural gas and oil company publicly traded on the Toronto Stock Exchange with operations in Egypt, Pakistan and Canada, since July 2005. Prior to joining Rally Energy, he was the President of Corrundum Energy Ltd, a private natural gas and oil investment and advisory firm from 2003 until 2005. From 2000 until 2003, he was President and CEO of Geodyne Energy Inc., a natural gas and oil venture publicly traded on the Toronto Stock Exchange. Mr. Badwi has been an officer of several Canadian public and private companies, including President and COO of Carmanah Resources Ltd., a Calgary, Alberta-based company with oil holdings in Canada, Indonesia and Venezuela, and Vice President International Exploration of Sceptre Resources Limited, an oil and gas exploration and production company. He is currently a director of Rally Energy Corp., Arpetrol Inc., Sustainable Energy Technologies Ltd., and Fairmount Energy Inc. Mr. Badwi holds a Bachelor of Science degree in petroleum geology from the University of Alexandria, Egypt.

Thomas L. Crow has been a member of our Board of Directors since April 2002. Mr. Crow was the founder and President of Cobra Golf Inc. (a worldwide leading manufacturer of golf clubs which was listed on NASDAQ) from 1973 to 1994 and served as Vice President from 1994 to 1996 when Cobra Golf Inc. was acquired to be a subsidiary of Fortune Brand Inc. (a significant NYSE conglomerate). From 1997 to 2002, Mr. Crow remained as Chairman Emeritus of Cobra Golf Inc. Since 2002, Mr. Crow has been an independent businessman.

Matthew J. P. Heysel has been a member of our Board of Directors since January 2002. From 2000 until his resignation in May, 2005, Mr. Heysel served as Chairman of the Board of Directors and Chief Executive Officer of Big Sky Energy Corporation, an international oil and gas company. Mr. Heysel was also Chairman of Big Sky Energy Corporation's subsidiaries, Big Sky Energy Kazakhstan Ltd. and Big Sky Energy Atyrau Ltd. He also serves as the Chairman of both Big Sky Network Canada Ltd., a Canadian company located in Chengdu, China, to provide high speed internet technology services, and Chengdu Big Sky Technology Services Ltd., a Canadian company located in Calgary, Alberta to provide high speed internet technology services. From 1997 to 1999, Mr. Heysel served as an investment banker at Yorkton Securities, a Canadian independent securities firm, where he was responsible for corporate finance in the oil and gas sector. From 1987 to 1997, Mr. Heysel was with Sproule Associates Limited, Canada's largest petroleum engineering and geological consulting firm, holding the positions of Engineering Manager, Senior Associate, and Manager of International Projects. Mr. Heysel served as a Director of Canada's Petroleum Society from 1989 to 1992 and also sits as a board member of public and private oil and gas companies active in North America. Mr. Heysel obtained an Honours Bachelor's Science Degree from the University of Western Ontario in 1979, and a Bachelor of Science-Chemical Engineering from the University of Toronto in 1982 and has been a practicing professional Petroleum Engineer since that date. Mr. Heysel obtained an Honours Bachelor's Science Degree from the University of Western Ontario in 1979, and a Bachelor of Science—Chemical Engineering from the University of Toronto.

Richard A. Kapuscinski has been a member of our Board of Directors since July 2000. Since 1999, Mr. Kapuscinski is Director of Marketing at Turbo Genset Inc., responsible for North American business development. Turbo Genset is a designer and manufacturer of products for power generation and power conditioning. From 1986 to 1999, he worked as a Sales Marketing Manager with Tyco International (US) Inc. (formerly Keystone Valve). Mr. Kapuscinski is a Certified Mechanical Engineering Technologist and is a member of the Ontario Association of Certified Engineering Technicians and Technologists and the Instrument Society of America. He studied Mechanical Engineering at Lambton College in Sarnia, Ontario, Canada concentrating on the petroleum and petrochemical industry.

Messrs. Robinson, Crow and Porter are citizens of the United States, while Messrs. Badwi, Heysel and Kapuscinski are citizens of Canada. There are no family relationships between any of our directors or executive officers.

Audit Committee

The company has a standing Audit Committee, which has the authority and power to act on behalf of the board of directors with respect to the appointment of our independent auditors and with respect to authorizing all audit and other activities performed for us by our internal and independent auditors. Messrs. Badwi, Crow and Heysel are members of the Audit Committee. Under rules of the American Stock Exchange ("AMEX"), the Board of Directors is required to make certain findings about the independence and qualifications of the members of the Audit Committee of the Board. In addition to assessing the independence of the members under AMEX rules, the Board also considered the requirements of Section 10A(m)(3) and Rule 10A-3 under the Securities Exchange Act of 1934. As a result of its review, the Board determined that all of the members of the Audit Committee are independent. In addition, the Board has determined that Mr. Badwi qualifies as an audit committee financial expert under the applicable rules promulgated pursuant to the Exchange Act.

Section 16(a) Beneficial Ownership Reporting Compliance

As a result of our Registration Statement on Form S-1 being declared effective on January 4, 2006, we became subject to the rules and regulations of the SEC. Section 16(a) of the Exchange Act of 1934 requires our officers and directors and persons who own more than 10% of our common shares to file reports of ownership and changes in ownership with the SEC. These persons are required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. During the year ended December 31, 2005, no Section 16(a) reports were required to be filed.

Code of Ethics

We adopted a Code of Ethics for senior management including our principle executive officer and principle financial officer on December 15, 2005. A copy of our Code of Ethics was filed as an exhibit to our Registration Statement on Form S-1 and is also available on our website at **www.gastar.com**. A copy of our Code of Ethics will be provided to any person without charge, upon request. Such requests should be directed to J. Russell Porter, Chief Executive Officer, 1331 Lamar Street, Suite 1080, Houston, Texas 77010.

Item 11. *Executive Compensation*

Summary Compensation Table

The following tables and discussion below set forth information about the compensation awarded to, earned by or paid to our principal executive officer and principal financial officer ("Named Executive Officer") during the fiscal years ended December 31, 2005, 2004 and 2003.

					Long-Term Compensation		
		Annual Compensation			Awards	Payouts	
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation (1)**	**Securities Underlying Options**	**LTIP Payouts**	**All Other Compensation**
J. Russell Porter (2)	2005	$450,000	$337,500	$—	—	$—	$—
President, Chief Executive	2004	$350,000	$150,000	$—	1,000,000	$—	$—
Officer and Chief	2003	$350,000	$ —	$—	—	$—	$—
Operating Officer							
Michael A. Gerlich (3)	2005	$168,173	$ 79,063	$—	250,000	$—	$—
Vice President and Chief							
and Financial Officer							

(1) As permitted by the rules promulgated by the SEC, no amounts are shown with respect to perquisites and other personal benefits, securities or property for each individual named in the table above that did not exceed the lesser of $50,000, or 10% of the sum of the amounts in the annual salary and bonus columns reported for such individual.

(2) From September 2000 until February 17, 2004, Mr. Porter served as our Chief Operating Officer. On February 17, 2004, Mr. Porter was appointed our Chief Executive Officer of Gastar. Mr. Porter's bonus for 2004 was paid in 2005. For 2005, $225,000 of his 2005 bonus was paid in 2006. The amounts reflected show the aggregate amounts earned during each fiscal year. Under the terms of his current employment agreement, he receives an annual base salary of $450,000, plus bonus of not less than 20% of his base salary as determined by the Board of Directors.

(3) Mr. Gerlich joined us in May 2005 as Vice President and Chief Financial Officer. Under the terms of his current employment agreement, he receives an annual base salary of $275,000, plus a bonus as determined by the Board of Directors. For 2005, $51,563 of his 2005 bonus was paid in 2006. The amounts reflected show the aggregate amounts earned during each fiscal year.

Option Grants in 2005

The following table shows certain information about the number of stock options granted to Named Executive Officer during the year ended December 31, 2005.

Name	Number of Shares Underlying Options Granted (1)	% of Total Options Granted to Employees During Year	Exercise Price (2)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
					5% (3)	10% (3)
J. Russell Porter	—	—	—	—	—	—
Michael A. Gerlich	250,000	35.2%	CDN$3.50	06/24/10	$207,418	$458,340

(1) The options granted are exercisable over four years, one-quarter after one year and one-quarter on each of the next three anniversaries of the grant.
(2) Options are granted at an exercise price equal to the closing price of Gastar's common shares on the Toronto Stock Exchange on the day of the grant.
(3) Amounts have been converted from Canadian dollars to U.S. dollars at CDN$1.00 equals $0.8580, the exchange rate on December 31, 2005. Amounts represent hypothetical gains that could be achieved for the options if they are exercised at the end of the option term. Those gains are based on assumed rates of stock price appreciation of 5% and 10% compounded annually from the date such options were granted, through the expiration date. For the option term ending June 24, 2010, based on a strike price of CDN$3.50 on June 24, 2010, a common share would have a value on the ending date of the option term of approximately CDN$4.47 at an assumed appreciation rate of 5% and approximately $5.64, at an assumed appreciation rate of 10%. For the option term ending September 10, 2010, based on a strike price of CDN$3.25 on June 24, 2010, a common share would have a value on the ending date of the option term of approximately CDN$4.15 at an assumed appreciation rate of 5% and approximately $5.23, at an assumed appreciation rate of 10%.

Aggregate Option Exercises in 2005 and Fiscal Year End Values

The following table shows certain information about the number of stock options and warrants exercised during the year ended December 31, 2005 and the number of stock options owned by the Named Executive Officer at December 31, 2005. Options in the columns marked "unexercisable" are subject to vesting and will be forfeited if employment with us is terminated for certain reasons.

Name	Shares Acquired on Exercise (1)	Value Realized (1)	Number of Unexercised Stock Options At December 31, 2005 (1)		Value of Unexercised In-the-Money Stock Options At December 31, 2005 (2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
J. Russell Porter	—	—	650,000	750,000	$691,548	$540,540
Michael A. Gerlich	—	—	—	250,000	$ —	$160,875

(1) There were no stock options exercised by Named Executive Officers during the year ended December 31, 2005.
(2) The exercise prices of our stock option grants are specified in Canadian dollar. The value of each unexercised in-the-money stock option in the table above has been converted from CDN$ to U.S. dollars at CDN$1.00 equals $0.8580, the exchange rate on December 31, 2005. The values calculated are equal to the difference between the closing price of our common shares on the Toronto Stock Exchange on December 30, 2005 of CDN$4.25 per share and the exercise price of the stock option.

Equity Compensation Plans

Our 2002 Stock Option Plan, our only equity compensation plan, was approved and ratified by our shareholders on July 5, 2002. The 2002 Stock Option Plan superseded and replaced our prior stock-based compensation plans. Unexercised stock options granted under our prior stock option plans that had not expired or been cancelled on the effective date of the 2002 Stock Option Plan were ratified and confirmed as included under the 2002 Plan. Consequently, all currently outstanding stock options are subject to the terms of the 2002 Stock Option Plan. In April 2004, our Board of Directors amended the provisions of the 2002 Stock Option Plan to specifically incorporate a provision to provide for stock options to be exercised on a cashless basis whereby we issue the optionee the number of common shares equal to the stock option exercised, less the number of common shares which when multiplied by the market price at the date of exercise equals the aggregate exercise price for all of the common shares exercised.

We have authorized to issue, and have reserved, a maximum of 25.0 million common shares for awards under the 2002 Stock Option Plan. If any option granted under the 2002 Stock Option Plan expires or terminates for any reason in accordance with the terms of the 2002 Stock Option Plan without being exercised, the unpurchased shares subject to that option will become available for other option grants under the 2002 Stock Option Plan.

The 2002 Stock Option Plan is administered by our Board of Directors. Pursuant to the 2002 Stock Option Plan, our Board of Directors may allocate non-transferable options to purchase common shares to directors, officers, employees and consultants of Gastar and its subsidiaries. At the time of granting options under the 2002 Stock Option Plan, the aggregate number of common shares underlying all options granted under the 2002 Stock Option Plan and the aggregate number of common shares underlying the options granted to each individual under the 2002 Stock Option Plan may not exceed the maximum number permitted by any stock exchange on which our common shares are listed or by any other regulatory body having jurisdiction. Options issued pursuant to the 2002 Stock Option Plan have an exercise price determined by the Board of Directors, but that exercise price cannot be less than the price permitted by any stock exchange on which our common shares are then listed.

As of December 31, 2005, we had options outstanding to purchase 17,500,600 common shares pursuant to the 2002 Stock Option Plan, 12,783,350 shares of which are vested but have not been exercised.

The following table provides information as of December 31, 2005 about our common shares that may be issued upon the exercise of stock options and warrants under (i) all compensation plans previously approved by security holders and (ii) individual compensation arrangements not approved by security holders.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of Remaining Available for Future Issuance
Equity compensation plans approved by security holders	17,500,600	$3.02	1,106,900
Equity compensation plans not approved by security holders	—	—	—
Total	17,500,600	$3.02	1,106,900

There are no warrants or rights related to our equity compensation plans as of December 31, 2005.

Employment Agreements and Termination of Employment and Change of Control Arrangements

We have entered into an employment agreement with our Chief Executive Officer and Chief Financial Officer. Each employment agreement shall continue unless terminated in accordance with the provisions of his respective agreement. Each employment agreement provides for a base salary, a bonus, participation in our health plans and other fringe benefits. The agreements also include confidentiality provisions.

Mr. Porter's 2006 annual base salary is $450,000, with an annual bonus not to be less than 20% of his annual salary. Additionally, Mr. Porter will receive reimbursement for club and organizational membership used in furtherance of the Company's business. We will pay Mr. Porter severance benefits if his employment is terminated by death, disability, or if he or Gastar terminates his employment with proper notice. Severance benefits will be equal to two times his total compensation, as shown on his most recent Form W-2. Severance benefits will be payable over the "Severance Pay Period", as set forth in his employment agreement. Mr. Porter will receive no severance payment if his termination is due to "Reasonable Cause".

Mr. Gerlich's base salary for 2006 is $275,000. Annual bonuses are at the discretion of the Company's board of directors. Upon becoming Chief Financial Officer in 2005, Mr. Gerlich was granted a stock option to acquire 250,000 shares of our common shares. Additionally, Mr. Gerlich was granted an additional 250,000 options in 2006. We will pay Mr. Gerlich severance benefits if his employment is terminated by any reason other than "Reasonable Cause". Severance benefits will be equal to two times his most recent annual compensation (exclusive of bonuses received or other non-cash compensation) if notice is received after May 17, 2006. If notice is received prior to May 17, 2006, the severance amount equal to one times his most recent annual compensation (exclusive of bonuses received or other non-cash compensation). Severance benefits will be payable over the "Severance Pay Period", as set forth in his employment agreement.

Compensation of Directors

Commencing November 2005, the independent, non-employee and non-executive directors are to receive the following fees:

- $7,500 for all meetings attended in person;
- $1,500 per meeting attended telephonically; and
- $500 per committee meeting attended in person.

The Chairman of the Board of Directors has elected to waive his future director meeting fees. All directors are reimbursed for certain expenses incurred in connection with their attendance of Board and committee meetings in accordance with company policy.

Directors are eligible to receive stock option grants under our Stock Option Plan. During the fiscal year ended December 31, 2005, no stock options were issued to the Chairman of the Board or directors who were not employees.

Compensation Committee Interlocks and Insider Participation

The compensation committee of our Board of Directors, which we refer to as the Remuneration Committee, is comprised of Messrs. Badwi, Crow, Kapuscinski and Heysel. No member of the Remuneration Committee was during the 2005 fiscal year or at any time prior to the 2005 fiscal year an officer or employee of us or any of our subsidiaries. None of our executive officers serves as a member of the board of directors or compensation committee (or committee performing similar functions) of any entity that has one or more executive officers who serve on our Board of Directors or Remuneration Committee.

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

Security Ownership Table

The following table sets forth certain information about the beneficial ownership of common shares as of March 31, 2006 by:

- Each of our directors;
- Our Named Executive Officers set forth in the Summary Compensation Table above;
- All of our Named Executive Officers and directors as a group; and
- Each person known to us to be the beneficial owner of more than 5% of our outstanding common shares.

For purposes of the following table, a person is deemed to be the beneficial owner of securities that can be acquired by that person within 60 days from March 31, 2006 upon the exercise of warrants or options or upon the conversion of convertible securities. Each beneficial owner's percentage is determined by assuming that options, warrants or conversion rights that are held by that person regardless of price, but not those held by any other person, and which are exercisable within 60 days from March 31, 2006, have been exercised.

Unless otherwise indicated and subject to community property laws where applicable, we believe that all persons named in the following table have sole voting and investment power over all shares reported as beneficially owned by them. The address for our directors and Named Executive Officers is 1331 Lamar Street, Suite 1080, Houston, Texas 77010. The address for Chesapeake Energy Corporation is 6100 North Western Avenue, Oklahoma City, OK 73118. The address for GeoStar Corporation and Mr. Ferguson is 2480 W. Campus Drive, Building C, Mt. Pleasant, Michigan 48858. The address for FMR Corp. is 82 Devonshire Street, Boston MA 02109.

The information in the following table is based upon information supplied by officers, directors, certain named individuals, principal shareholders and from documents filed with the SEC. Applicable percentages are based on 164,748,380 Gastar common shares outstanding on March 15, 2006, subject to adjustment for each beneficial owner as described above.

	Common Shares Beneficially Owned			
	Outstanding Shares	**Issuable Upon Exercise of Stock Options (1)**	**Total**	**Percent of Total Common Stock Outstanding**
Our 5% Shareholders				
Chesapeake Energy Corporation	27,151,641	—	27,151,641	16.5%
GeoStar Corporation	17,936,138	—	17,936,138	10.9%
Tony Ferguson	6,960,000	2,048,200	9,008,200	5.4%
FMR Corp.	8,345,018	—	8,345,018	5.1%
Our Directors Who Are Not Employees				
Thomas E. Robinson (2)	10,299,658	2,048,200	12,347,858	7.4%
Abbi F. Badwi	—	75,000	75,000	*
Thomas L.Crow	300,000	212,500	512,500	*
Matthew J. P. Heysel	78,078	175,000	253,078	*
Richard A. Kapuscinski	146,833	225,000	371,833	*
Our Executive Officers				
J. Russell Porter, President, Chief Executive and Chief Operating Officer and Director	2,280,000	650,000	2,930,000	1.8%
Michael A. Gerlich, Vice President and Chief Financial Officer	5,000	—	5,000	*
Directors and executive officers, as a group (7 persons)	13,109,569	3,385,700	16,495,269	9.8%

* Less than 1%.

(1) Includes shares underlying options to purchase shares that currently are vested or will vest or be exercisable within 60 days of March 15, 2006.

(2) Mr. Robinson resigned as Chief Executive Officer of the Company on February 17, 2004 but continues to hold the title of Chairman of the Board.

Item 13. *Certain Relationships and Related Transactions*

GeoStar is the beneficial owner of approximately 10.9% of our common shares. Our Chairman of the Board of Directors is an officer and director of GeoStar. Except as disclosed elsewhere in this Form 10-K, we had the following related party transactions with GeoStar:

(a) In 2001, we entered into a Participation and Operating Agreement (“POA”) with GeoStar. For the East Texas properties, the POA was replaced effective January 1, 2005 with a Joint Operating Agreement (“JOA”), as detailed below. Pursuant to the terms of the original POA, which still governs the Company’s West Virginia and certain Australian assets, we have the option to participate as a working interest partner in properties in which GeoStar and its subsidiaries have interests in on an “at cost” basis, subject to our full due diligence review prior to our participation election. Upon agreeing to participate, we are responsible for our proportionate share of actual costs expended by GeoStar and its subsidiaries to third parties on an “at cost” basis. The $601,000 due to related parties at December 31, 2004 represented the amount owed to GeoStar and its subsidiaries for natural gas and oil property development. In 2004, pursuant to the terms of the POA, GeoStar billed the Company $27,000 (2003 - $369,000) for administrative overhead.

(b) On June 1, 2000, we entered into an agreement with GeoStar to settle accounts payable related to the development of natural gas and oil properties with the issuance of a floating convertible debenture for up to CDN$25.0 million. Under the debenture agreement, GeoStar would continue to provide funds for development and operations by allowing us to draw on the debenture. Advances under the debenture were subject to GeoStar's availability of funds and the approval of the requested advances by GeoStar's board of directors. The debenture was payable in cash or convertible into common shares, at prevailing market prices, at our option.

(c) Effective January 1, 2005, we and GeoStar entered into a JOA covering an Area of Mutual Interest ("AMI") in East Texas, with the Company as non operator and GeoStar as operator. Under the terms of the JOA, GeoStar would receive overhead reimbursement equal to 12.5% of development costs for the first 10 wells drilled after the effective date, 10% of the development costs for the 11^{th} through 20^{th} wells and 8.5% of the developments costs for all subsequent wells. As a result of the JOA, GeoStar ceased charging us a proportionate amount of direct salary and shared premises rent expense for GeoStar employees providing administrative and technical support services to the Company. In conjunction with the execution of the JOA, we terminated the convertible debenture arrangement with GeoStar and are required to finance our share of future joint venture costs.

During 2005, GeoStar billed us $1.4 million, which was equal to 12.5% of development costs for two wells drilled in East Texas. These costs have been capitalized to property and equipment and were paid in 2005. The GeoStar Acquisitions Properties agreement provides for certain post closing adjustments relating to expenditures incurred on the acquired properties, which may include additional agreed upon drilling overhead charges.

At December 31, 2005, we had a due from related parties receivable of $2.3 million primarily relating to revenues earned on GeoStar operated properties and property cost advances. Pursuant to the GeoStar Acquisition Properties agreement, the final purchase price adjustments are to be settled 50% in cash and 50% in Company common shares valued at CDN$4.50 per share. At December 31, 2005, we had a due to related parties payable of $2.1 million with a corresponding $2.1 million included in the liability to be settled by issuance of 548,128 common shares related to purchase price adjustments. The GeoStar Acquisitions Properties agreement provides for certain post closing adjustments relating to expenditures incurred on the acquired properties, which may include additional agreed upon drilling overhead charges.

(d) In 2004, we recorded $1.3 million in general and administrative costs for administrative and technical support provided by GeoStar to the Company. The consolidated financial statements also include approximately $1,000 and $115,000 and $33,000 in seismic reprocessing fees paid to GeoStar at December 31, 2005, 2004 and 2003, respectively. The seismic reprocessing fees were capitalized to natural gas and oil properties.

(e) Effective January 1, 2005, we agreed to hire and employ directly certain GeoStar employees as members of the management team.

All related party transactions in the normal course of operations have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

Item 14. *Principal Accountant Fees and Services*

Fees

BDO Seidman, LLP, our principal auditors were engaged to perform the audit for the year ended December 31, 2005. Aggregate fees billed for professional services rendered to us by BDO Seidman, LLP and our predecessor principal auditors, BDO Dunwoody LLP, Calgary, Alberta, for the years ended December 31, 2005 and 2004 were:

Category of Service	For the Years Ended December 31, 2005	2004
Audit fees:		
BDO Seidman, LLP	$175,000	$ —
BDO Dunwoody LLP	234,977	73,719
Other audit fees	—	—
Tax	17,247	—
All other	—	—
Total	$427,224	$73,719

The audit fees for the years ended December 31, 2005 and 2004 were primarily for professional services rendered in connection with the audit of our consolidated financial statements, fees related to our S-1 Registration Statement declared effective by the SEC on January 4, 2006, together with services rendered in connection with quarterly reviews of financial statements and various documents filed with various governmental agencies. Fees for tax services were for services related to tax compliance, including the preparation of tax returns.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee pre-approves all audit and non-audit services provided by our independent registered public accounting firm prior to its engagement with respect to such services. In addition to separately approved services, the Audit Committee's pre-approval policy provides for pre-approval of all audit and non-audit services provided by our independent registered public accounting firm.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

(a) Financial Statements and Schedules:

The financial statements are set forth beginning on Page F-1 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

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

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of Gastar Exploration Ltd. (1)
3.2	Bylaws of Gastar Exploration Ltd. (1)
4.1	Indenture dated November 12, 2004 between Gastar Exploration Ltd. and CIBC Mellon Trust Company as trustee. (1)
4.2	Form of 9.75% Convertible Senior Unsecured Subordinated Debenture of Gastar Exploration Ltd. (1)

Exhibit Number	Description
4.3	Form of placement agent warrant to purchase common shares of Gastar Exploration Ltd. in connection with issuances of 9.75% Convertible Senior Unsecured Subordinated Debenture of Gastar Exploration Ltd. (1)
4.4	Agency Agreement dated as of November 12, 2004 between Gastar Exploration Ltd. and Westwind Partners Inc. in connection with issuances of 9.75% Convertible Senior Unsecured Subordinated Debenture of Gastar Exploration Ltd. (1)
4.5	Form of Subscription Agreement for U.S. purchasers of 9.75% Convertible Senior Unsecured Subordinated Debenture of Gastar Exploration Ltd. (1)
4.6	Form of Subscription Agreement for U.S. purchasers of 9.75% Convertible Senior Unsecured Subordinated Debenture of Gastar Exploration Ltd. (1)
4.7	Securities Purchase Agreement dated as of June 17, 2005, by and among Gastar Exploration Ltd. and the purchasers named therein for the purchase of $63.0 million in principal amount of Senior Secured Notes. (1)
4.8	Form of Senior Secured Note dated as of June 17, 2005. (1)
4.9	Registration Rights Agreement dated as of June 17, 2005, by and among Gastar Exploration Ltd. and the purchasers named therein. (1)
4.10	Form of Subscription Agreement for U.S. purchasers of common shares of Gastar Exploration Ltd. in a private placement dated June30, 2005. (1)
4.11	Form of Subscription Agreement for U.S. purchasers of common shares of Gastar Exploration Ltd. in a private placement dated June30, 2005. (1)
4.12	Placement agent warrant to purchase 510,525 common shares of Gastar Exploration Ltd. in connection with the sale of $15.0 million in principal amount of 15% subordinated notes in October 2004. (1)
4.13	Placement agent warrant to purchase 1,989,475 common shares of Gastar Exploration Ltd. in connection with the sale of $10.0 million in principal amount of 15% subordinated notes in October 2004. (1)
4.14	Form of 10% subordinated note issued June 2004. (1)
4.15	Form of warrant to purchase common shares of Gastar Exploration Ltd. issued in connection with the sale of 10% subordinated notes in June 2004. (1)
4.16	Form of warrant to purchase common shares of Gastar Exploration Ltd. issued in connection with a private placement of working interests in 2002. (1)
4.17	Agreement between Gastar Exploration Ltd. and GeoStar Corporation dated August 11, 2005. (1)
4.18	First Amendment dated September 6, 2005 to Securities Purchase Agreement dated as of June 17, 2005, by and among Gastar Exploration Ltd. and the purchasers named therein for the purchase of $63.0 million in principal amount of Senior Secured Notes. (1)
4.19	Common Share Purchase Agreement between Gastar Exploration Ltd. and Chesapeake Energy Corporation dated November 4, 2005. (1)
4.20	Registration Rights Agreement between Gastar Exploration Ltd. and Chesapeake Energy Corporation dated November 4, 2005. (1)
4.21	Facsimile of common share certificate of the Company. (1)

Exhibit Number	Description
10.1*	The Gastar Exploration Ltd. 2002 Stock Option Plan, dated February 14, 2004, as amended. (1)
10.2*	Employment Agreement dated March 23, 2005 by and among First Sourcenergy Wyoming, Inc., Gastar Exploration Ltd. and J. Russell Porter. (1)
10.3*	Employment Agreement dated April 26, 2005 by and among First Sourcenergy Wyoming, Inc., Gastar Exploration Ltd. and Michael A. Gerlich. (1)
10.4	Purchase and Sales Agreement between GeoStar Corporation and Gastar Exploration Ltd. covering Wyoming and Montana producing properties dated June 16, 2005. (1)
10.5	Purchase and Sales Agreement between GeoStar Corporation and Gastar Exploration Ltd. covering Wyoming and Montana non-producing properties dated June 16, 2005. (1)
10.6	Purchase and Sales Agreement between GeoStar Corporation and Gastar Exploration Ltd. covering Texas producing properties dated June 16, 2005. (1)
10.7	Purchase and Sales Agreement between GeoStar Corporation and Gastar Exploration Ltd. covering Texas non- producing properties dated June 16, 2005. (1)
10.8	Participation and Operating Agreement between GeoStar Corporation and Gastar Exploration Ltd. dated June 15, 2001. (1)
10.9	Promissory Note for $15.0 million between GeoStar Corporation and Gastar Exploration Ltd. dated August 11, 2001. (1)
10.10*	Form of Gastar executive stock option agreement. †
14.1	Gastar Exploration Ltd. Code of Ethics, adopted effective December 15, 2005. (1)
21.1	Subsidiaries of Gastar Exploration Ltd. †
23.1	Consent of BDO Seidman, LLP, dated March 30, 2006. †
23.2	Consent of BDO Dunwoody LLP, dated March 31, 2006. †
23.3	Consent of Netherland, Sewell and Associates, Inc., dated March 27, 2006. †
31.1	Certification of chief executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. †
31.2	Certification of chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. †
32.1	Certification of chief executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of chief financial officer pursuant Section 906 of the Sarbanes-Oxley Act of 2002. †

† Filed herewith.

* Management contract or compensatory plan or arrangement.

1. Filed as an exhibit to the Company's Registration Statement on Form S-1 (Registration No. 333-127498), as filed with the Securities and Exchange Commission on January 4, 2006.

SIGNATURES

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

GASTAR EXPLORATION LTD.

/s/ J. RUSSELL PORTER

J. Russell Porter
President, Chief Executive Officer,
Chief Operating Officer and Director
(principal executive officer)

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ J. RUSSELL PORTER **J. Russell Porter**	President, Chief Executive Officer, Chief Operating Officer and Director (Principal Executive Officer)	March 31, 2006
/s/ MICHAEL A. GERLICH **Michael A. Gerlich**	Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 31, 2006
/s/ THOMAS E. ROBINSON **Thomas E. Robinson**	Chairman of the Board of Directors	March 31, 2006
/s/ ABBY F. BADWI **Abby Badwi**	Director	March 31, 2006
/s/ THOMAS L. CROW **Thomas Crow**	Director	March 31, 2006
/s/ MATTHEW J. P. HEYSEL **Matthew J. P. Heysel**	Director	March 31, 2006
/s/ RICHARD A. KAPUSCINSKI **Richard Kapuscinski**	Director	March 31, 2006

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Gastar Exploration Ltd.
Houston, Texas

We have audited the accompanying consolidated balance sheet of Gastar Exploration Ltd. and subsidiaries as of December 31, 2005 and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gastar Exploration Ltd. and subsidiaries at December 31, 2005, and the results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO Seidman, LLP

Dallas, Texas
March 21, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Gastar Exploration Ltd.

We have audited the accompanying consolidated balance sheet of Gastar Exploration Ltd. and subsidiaries (the "Company") as of December 31, 2004 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the two years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gastar Exploration Ltd. and subsidiaries at December 31, 2004 and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Company, effective January 1, 2003, adopted SFAS No. 143 regarding asset retirement obligation recognition.

/s/ BDO Dunwoody LLP

BDO Dunwoody LLP

Calgary, Alberta
March 18, 2005 (December 21, 2005 as to Notes 5, 13, 14, 22 and 25)

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2005	As of December 31, 2004
	(in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 61,144	$ 15,842
Revenues receivable	4,416	1,693
Accounts receivable, net	40	38
Due from related parties	2,317	—
Prepaid expenses	1,551	307
Total current assets	69,468	17,880
DEFERRED CHARGES	4,922	3,680
CASH CALL RECEIVABLE	391	6,318
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, full cost method of accounting:		
Unproved properties, not being amortized	73,580	29,759
Proved properties	129,592	42,363
Total natural gas and oil properties	203,172	72,122
Furniture and equipment	360	8
Total property, plant and equipment	203,532	72,130
Accumulated depreciation, depletion and amortization	(38,185)	(15,566)
Total property, plant and equipment, net	165,347	56,564
TOTAL ASSETS	$240,128	$ 84,442
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,935	$ 128
Accrued interest and debt related items	2,418	807
Accrued drilling and operating costs	3,008	—
Other accrued liabilities	2,465	262
Due to related parties	2,116	601
Total current liabilities	13,942	1,798
LONG-TERM LIABILITIES:		
Long-term debt	90,631	57,878
Accrued liabilities	—	77
Drilling advance liabilities	—	1,002
Asset retirement obligation	3,558	1,711
Liability to be settled by issuance of common shares	11,221	—
Total long-term liabilities	105,410	60,668
COMMITMENTS AND CONTINGENCIES (Note 19)		
SHAREHOLDERS' EQUITY:		
Common stock, no par value, unlimited shares authorized, 164,674,266 and 113,390,183 shares issued and outstanding at December 31, 2005 and 2004, respectively	167,456	45,347
Additional paid-in capital	6,509	4,221
Accumulated other comprehensive loss	—	(95)
Accumulated deficit	(53,189)	(27,497)
Total shareholders' equity	120,776	21,976
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$240,128	$ 84,442

The accompanying notes are an integral part of these consolidated financial statements.

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2005	2004	2003
	(in thousands, except share and per share data)		
REVENUES	$ 27,442	$ 6,059	$ 1,461
EXPENSES:			
Lease operating, transportation and selling expenses	6,910	2,000	712
Depreciation, depletion and amortization	13,914	3,233	572
Impairment of natural gas and oil properties	8,697	6,306	552
Accretion of asset retirement obligation	109	52	54
Mineral resource properties	65	32	30
General and administrative expenses	8,710	4,023	1,909
Total expenses	38,405	15,646	3,829
LOSS FROM OPERATIONS	(10,963)	(9,587)	(2,368)
OTHER (EXPENSES) INCOME:			
Interest expense	(15,261)	(3,248)	(2,567)
Investment income and other	492	56	18
Foreign exchange gain	40	3	91
LOSS BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	(25,692)	(12,776)	(4,826)
Provision for income taxes	—	—	—
LOSS BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	(25,692)	(12,776)	(4,826)
Cumulative effect of a change in accounting principle	—	—	(121)
NET LOSS	$ (25,692)	$ (12,776)	$ (4,947)
NET LOSS PER SHARE:			
Basic and diluted	$ (0.20)	$ (0.12)	$ (0.05)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic and diluted	129,398,548	111,374,446	104,958,180

The accompanying notes are an integral part of these consolidated financial statements.

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Accumulated Paid-in Capital	Accumulated Other Comprehensive Loss	Accumulated Deficit	Total Shareholders' Equity	Comprehensive Loss
	Shares	Amount					
	(in thousands, except share data)						
Balance at December 31, 2002	103,068,293	$ 31,802	$ 425	$ (23)	$ (9,774)	$ 22,430	$ —
Repurchase of shares	(1,391,500)	(2,141)	—	—	—	(2,141)	—
Settlement of debentures	5,206,100	8,399	—	—	—	8,399	—
Foreign currency translation loss	—	—	—	(72)	—	(72)	(72)
Net loss	—	—	—	—	(4,947)	(4,947)	(4,947)
Total comprehensive loss							$ (5,019)
Balance at December 31, 2003	106,882,893	38,060	425	(95)	(14,721)	23,669	$ —
Repurchase of shares	(340,000)	(894)	—	—	—	(894)	—
Conversion of convertible debentures	6,847,215	8,181	—	—	—	8,181	—
Issuance of shares purchase warrants	—	—	2,422	—	—	2,422	—
Stock based compensation	—	—	1,374	—	—	1,374	—
Net loss	—	—	—	—	(12,776)	(12,776)	(12,776)
Total comprehensive loss							$(12,776)
Balance at December 31, 2004	113,390,108	45,347	4,221	(95)	(27,497)	21,976	$ —
Exercise of stock options – cash	3,721,300	707	—	—	—	707	—
Exercise of stock options – cashless	2,214,888	—	—	—	—	—	—
Issuance of shares – cash	33,769,377	90,096	—	—	—	90,096	—
Issuance of shares – acquisitions	8,023,827	23,000	—	—	—	23,000	—
Issuance of shares – senior secured debt	2,505,728	7,893	—	—	—	7,893	—
Exercise of stock purchase warrants – cash	207,814	413	—	—	—	413	—
Exercise of stock purchase warrants – cashless	841,224	—	—	—	—	—	—
Stock based compensation	—	—	2,288	—	—	2,288	—
Foreign currency translation gain	—	—	—	95	—	95	95
Net loss	—	—	—	—	(25,692)	(25,692)	(25,692)
Total comprehensive loss							$(25,597)
Balance at December 31, 2005	164,674,266	$167,456	$6,509	$—	$(53,189)	$120,776	

The accompanying notes are an integral part of these consolidated financial statements.

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2005	2004	2003
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(25,692)	$(12,776)	$(4,947)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	13,914	3,233	572
Impairment of natural gas and oil properties	8,697	6,306	552
Amortization of deferred lease costs	416	33	—
Cumulative effect of a change in accounting principle	—	—	121
Stock based compensation	2,288	1,374	—
Amortization of deferred financing costs and debt discount	4,805	2,291	1,363
Accretion of asset retirement obligation	109	52	54
Changes in operating assets and liabilities, exclusive of effects of acquisition:			
Accounts receivable	(5,042)	(1,494)	(179)
Prepaid expenses	(1,244)	(716)	(45)
Accounts payable and accrued liabilities	9,951	575	62
Net cash provided by (used in) operating activities	8,202	(1,122)	(2,447)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash call receivable	5,927	(5,098)	(1,220)
Development and purchases of natural gas and oil properties	(59,305)	(34,221)	(4,763)
Purchase of natural gas and oil properties from related parties	(28,784)	—	—
Proceeds from sale of natural gas and oil properties	2	3,000	8,618
Purchase of furniture, equipment and other	(352)	(2)	—
Site restoration bond cancellation	—	263	30
Other	(143)	(4)	(80)
Net cash provided by (used in) investing activities	(82,655)	(36,062)	2,585
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayment of contract payable	—	(688)	—
Repayment of commitments payable	—	(1,342)	—
Repayment of convertible notes payable	—	(100)	—
Repayment of senior notes	(26,483)	—	—
Repayment of note payable	—	—	(630)
Repayment of related party note	(15,000)	—	—
Proceeds from issuance of convertible debentures	—	30,000	—
Proceeds from issuance of senior notes	—	25,000	—
Proceeds from issuance of subordinated, unsecured notes payable	—	3,250	—
Proceeds from issuance of senior secured notes	73,000	—	—
Proceeds of issuance of common shares, net of share issue costs	91,216	—	—
Advances on (repayments of) convertible debentures	—	(39)	3,054
Deferred financing charges	(2,978)	(2,846)	—
Repurchase of common shares	—	(894)	(2,141)
Net cash provided by financing activities	119,755	52,341	283
NET INCREASE IN CASH AND CASH EQUIVALENTS	45,302	15,157	421
FOREIGN EXCHANGE GAIN ON CASH HELD IN FOREIGN CURRENCY	—	4	4
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	15,842	681	256
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 61,144	$ 15,842	$ 681
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for taxes	$ —	$ —	$ —
Cash paid for interest	$ 8,689	$ 600	$ 1,272

The accompanying notes are an integral part of these consolidated financial statements.

GASTAR EXPLORATION LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Gastar Exploration Ltd. (the "Company") is an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States and Australia. The Company's principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties. The Company's emphasis is on prospective deep structures identified through seismic and other analytical techniques as well as unconventional natural gas reserves, such as coal bed methane. The Company continues to incur losses and has significant cash flow requirements in order to continue the process of exploring and developing its oil and gas properties.

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Company (in United States ("U.S.") dollars unless otherwise noted) have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved natural gas and oil reserve quantities and the related present value of estimated future net cash flows (See "Supplemental Oil and Gas Disclosures").

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and the consolidated accounts of all its subsidiaries. The entities included in these consolidated accounts are all wholly owned: New Energy West Corporation; 616694 Alberta Ltd.; Monterey Resources, Inc.; New Energy West (U.S.A.) Corporation; 1075191 Ontario Ltd.; First Sourcenergy Wyoming, Inc. ("FSW"); First Source Development, Inc.; First Texas Development, Inc.; First Source Gas LP; Bossier Basin LLC; First Sourcenergy Group, Inc. ("FSG"); First Sourcenergy Kansas, Inc.; First Sourcenergy Victoria, Inc.; Squaw Creek, Inc.; First Appalachian Development, Inc. and Oil and Gas Services Inc. All significant intercompany accounts and transactions have been eliminated in consolidation.

Foreign Currency Translation and Exchange

A majority of the Company's operations are conducted by its U.S. subsidiaries in U.S. dollars. The operations outside of the U.S. are primarily natural gas and oil property development in Australia, which are conducted in Australian dollars ("AUD$"). The Australian properties are in the exploration stage, and there are no current production operations in Australia. Limited operations are conducted in Canadian dollars ("CDN$"). Foreign operations are translated using rates in effect at the period end for the balance sheet, while the income statement is translated at the average rates prevailing during the period. Adjustments resulting from financial statement translations are included in cumulative translation adjustments in Accumulated Other Comprehensive Loss and were immaterial at December 31, 2005.

Foreign currency balances and non-monetary assets and liabilities are translated at the rates of exchange on the particular transaction date. Monetary assets and liabilities denominated in foreign currencies that remain outstanding at the balance sheet date are translated at period end exchange rates with resulting gains (losses) being recognized in the period. The accounts of all active subsidiaries are maintained in U.S. dollars. Translation losses recorded on investments in subsidiaries that are of a permanent nature are not tax effected.

Cash Equivalents

Cash equivalents include short-term investments, such as money market deposits or highly liquid debt instruments, with a maturity of three months or less when purchased, which amounted to $54.0 million as of December 31, 2005. The Company had no cash equivalents as of December 31, 2004. The Company maintains its cash in bank deposit accounts, which, at times, may exceed federally insured limits. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant risk of loss.

Allowance for Doubtful Accounts

At December 31, 2005 and 2004, the Company had no allowance for doubtful accounts recorded. The allowance for doubtful accounts is determined based on a quarterly review of Company receivables. Receivable accounts would be charged off when collection efforts have failed and the account is deemed uncollectible.

Deferred Financing Costs

Deferred financing costs include costs of debt financings undertaken by the Company including commissions, legal fees, value attributed to warrants issued in conjunction with a financing and other direct costs of the financing. Using the interest method, the deferred financing costs are amortized over the term of the related debt instrument.

Natural Gas and Oil Properties

The Company follows the full cost method of accounting for natural gas and oil operations, whereby all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are initially capitalized into cost centers on a country-by-country basis. The Company's current cost centers are located in the United States and Australia. Such costs include land acquisition costs, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition, exploration and development activities.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated net proved reserves, as determined by independent petroleum engineers, converting one barrel of oil to one thousand cubic feet of natural gas equivalents (Mcfe) by multiplying barrels by a factor of 6. The percentage of total reserve volumes produced during the year is multiplied by the net capitalized investment plus future estimated development costs in those reserves.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether an impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Reserves, future production profiles and net cash flows are estimated by an independent professional reservoir engineering firm. While the Company has hired a qualified reservoir engineering firm, its estimates are inherently uncertain, involve numerous assumptions that may not be realized, and predicted asset values that may not be indicative of the true market value of the assets evaluated. As a result of the inherent uncertainties and changing technical and economic assumptions, reserve estimates are subject to revisions that can materially impact the Company's financial position and results of operations.

In applying the full cost method, the Company performs a quarterly ceiling test on the cost center properties whereby the net cost of natural gas and oil properties, net of related deferred income taxes ("net cost"), is limited to the sum of the estimated future net revenues from proved reserves using prices in effect at the end of the period held constant, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("ceiling"). If the net cost exceeds the ceiling, an impairment loss is recognized for the amount by which the net cost exceeds the ceiling and is shown as a reduction in natural gas and oil properties and as additional depletion. Proceeds from a sale of natural gas and oil properties will be applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion or amortization.

Furniture, Equipment and Other

Furniture, equipment and other are recorded at historical cost and are depreciated over their estimated useful lives, which ranges from three to seven years on a straight-line basis.

Fair Value of Financial Instruments

The carrying amounts of the Company's short-term financial instruments, including cash equivalents, trade accounts receivable and trade accounts payable, approximate their fair values based on the short maturities of those instruments. The Company's Senior Secured Notes are variable rate debt and, as such, approximates fair value, as interest rates are variable based on prevailing market rates. The Company's Convertible Senior Debentures and Subordinated Unsecured Notes Payable are fixed rate debt, but the interest rates are not materially different than current prevailing market rates and, as such, their carrying value approximates fair value.

Revenue Recognition

The Company records revenues from the sale of natural gas and oil when delivery to the customer has occurred and title has transferred. This recording of revenues occurs when natural gas or oil has been delivered to a pipeline or a tank lifting has occurred. Revenues from natural gas and oil production are recorded using the sales method. Under this method, revenues are recorded based on the Company's net revenue interest, as delivered. The Company had no material gas imbalances at December 31, 2005.

Accretion on Convertible Notes

Using the interest method, the debt discount of the convertible notes is amortized over the term of the related debt.

Asset Retirement Obligation

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143") using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. Asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets are initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements as the present value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations.

Upon adoption, the Company recorded a cumulative-effect-type adjustment for an increase to net loss of $121,000 (no tax benefit). Additionally, the Company established an asset retirement obligation of $769,000, an increase to property and equipment of $667,000 and an increase to accumulated depreciation, depletion and amortization of $19,000.

Mineral Resource Properties

Mineral resource properties are properties that may hold mineral deposits of rutile (titanium dioxide), zircon (zirconium silicate) and other resource minerals. All exploration and related direct and indirect overhead expenditures for mineral resources are expensed. Capitalized acquisition costs, if any, are written off when the decision to abandon the mineral resource property is made.

Deferred Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized as income in the period that includes the enactment date. No deferred tax asset has been recorded as it is more likely than not that the Company will be unable to realize this benefit.

Loss per Share

In accordance with the provisions of SFAS No. 128, “Earnings per Share” (“SFAS No. 128”), basic earnings per share is computed on the basis of the weighted average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted average number of common shares outstanding plus the incremental effect of the assumed issuance of common shares for all potentially dilutive securities. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and warrants and the “as if converted” method for the Senior Convertible Debentures.

Stock-Based Compensation

The Company reports compensation expense for stock options granted to officers, directors and employees using the fair value method. Compensation costs are recorded over the vesting period.

Effective January 1, 2003, the Company adopted the provisions of SFAS No. 123, “Accounting for Stock-Based Compensation” (“SFAS No. 123), using the prospective method of SFAS No. 148 and is expensing the fair value of new employee option grants awarded subsequent to 2002. This statement requires the Company to record compensation costs for options granted under the Company’s stock option plan in accordance with the fair value method prescribed in SFAS No. 123.

Prior to January 1, 2003, the Company accounted for stock options under the intrinsic value method of Accounting Principles Board (“APB”) Opinion No. 25, “Accounting for Stock Issued to Employees” and its related interpretations. No compensation expense was recognized for stock options that had an exercise price equal to the market value of the underlying common stock on the date of grant.

The weighted average fair value of the Company’s stock options granted was $1.01 (CDN$1.33) for 2005 and $0.88 (CDN$1.16) for 2004. No options were granted in 2003. The fair values were determined by using the Black-Scholes-Merton valuation model that uses the assumptions noted below. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by employees who receive equity awards, and subsequent events are not indicative of the reasonableness of the original estimates of fair value made by the Company. The Company used the following weighted average assumptions for all periods: expected dividend yield of 0%, expected volatility of 30%—55%, risk free interest rate of 5% and expected option life of four years.

The table below reflects the pro-forma impact of stock-based compensation on the Company's net loss and loss per share had the Company applied SFAS No, 123 to options granted prior to January 1, 2003 that vested in 2003 and subsequent periods:

	For the Years Ended December 31,		
	2005	2004	2003
	(in thousands, except per share data)		
Net loss, as reported	$(25,692)	$(12,776)	$(4,947)
Cost of compensation expense using fair value (not tax effected)	(569)	(1,883)	(3,743)
Net loss, pro forma	$(26,261)	$(14,659)	$(8,690)
Net loss per share, as reported	$ (0.20)	$ (0.12)	$ (0.05)
Net loss per share, pro forma	$ (0.20)	$ (0.13)	$ (0.08)

Joint Venture Operation

The majority of the Company's natural gas and oil exploration activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of natural gas and oil. The Company's operational activities are conducted in the United States and Australia with only the United States currently having revenue generating operating results. See Note 24 for capitalized costs relating to natural gas and oil producing activities by geographic area.

Treasury Stock

The Company's common shares are without par value. Treasury stock purchases are recorded at cost as a reduction to common stock. Common shares are cancelled upon repurchase.

Reclassifications

Certain information provided for the prior years have been reclassified to conform to the presentation adopted in 2005.

New Accounting Pronouncements

In December of 2004, the Financial Accounting Standards Board ("FASB") issued SFAS 123R "Share Based Payments" which addresses the accounting for transactions in which an entity exchanges its equity instruments for goods and services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This statement is a revision of FASB statement SFAS No. 123. This statement supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees". Among other things, this statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost is recognized over the period during which an employee is required to provide service in exchange for the award – the requisite service period (usually the vesting period). This statement is to be applied as of the beginning of the first interim or annual period that begins after December 15, 2005, but earlier adoption is encouraged. Because we have adopted SFAS 123 and recorded the fair value of stock options granted after January 1, 2003, this new standard will have minimal impact upon adoption in 2006.

In December of 2004, FASB issued SFAS No. 153, “Exchanges of Non-monetary Assets—An Amendment of APB Opinion No. 29” (“SFAS No. 153”). The guidance in APB Opinion No. 29, “Accounting for Non-monetary Transactions” (“APB Opinion No. 29”) is based on the principle that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB Opinion No. 29, however, included certain exceptions to that principle. This statement amends APB Opinion No. 29 to eliminate the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. A non-monetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for non-monetary asset exchanges occurring in fiscal periods beginning after the date this statement is issued. The provisions of this statement shall be applied prospectively. The adoption in 2005 of SFAS No. 153 did not have any impact on the Company’s financial statements.

3. Deferred Charges

Deferred financing charges include costs of debt financings undertaken by the Company including commissions, legal fees and other direct costs of the financing. Using the interest method, the deferred financing charges are amortized over the term of the related debt. Deferred leasing charges represent future demobilization and transportation costs of leased natural gas treatment plants in East Texas. The deferred leasing charges are amortized into lease operating expense over the term of the agreements.

The following table sets forth information regarding deferred charges for the periods indicated:

	Deferred Financing Charges	Deferred Leasing Charges	Total
		(in thousands)	
Balance as of December 31, 2002	$ 849	$ —	$ 849
Amortization	(449)	—	(449)
Balance as of December 31, 2003	400	—	400
Additions	3,204	542	3,746
Amortization	(433)	(33)	(466)
Balance as of December 31, 2004	3,171	509	3,680
Additions	2,978	252	3,230
Amortization	(1,572)	(416)	(1,988)
Balance as of December 31, 2005	$ 4,577	$ 345	$ 4,922

4. Cash Call Receivable

Cash call receivable represents the Company's proportionate share of planned authorized expenditures payable to the operator upon execution of the final drilling authorization of expenditures. For the year ended December 31, 2004, all cash calls were paid to GeoStar Corporation ("GeoStar"). Of the total cash calls paid during the year ended December 31, 2005, $8.2 million was paid to GeoStar, and the remainder was paid to other outside parties.

	Total
	(in thousands)
Balance as of December 31, 2003	$ 1,220
Cash call, advances	21,534
Amounts spent/refunded	(16,436)
Balance as of December 31, 2004	6,318
Cash call, advances	15,269
Amounts spent/refunded	(21,196)
Balance as of December 31, 2005	$ 391

5. Property, Plant and Equipment

The amount capitalized as natural gas and oil properties was incurred for the purchase and development of various properties in the states of California, Montana, Texas, West Virginia and Wyoming in the United States and in New South Wales and Victoria in Australia. The following schedule represents natural gas and oil property costs by country:

	United States	Australia	Total
	(in thousands)		
From inception to December 31, 2005:			
Cost:			
Unproved properties	$ 70,519	$3,061	$ 73,580
Proved properties	128,549	1,043	129,592
	199,068	4,104	203,172
Impairment of proved natural gas and oil properties	(19,414)	(604)	(20,018)
Accumulated depreciation, depletion and amortization	(18,123)	—	(18,123)
Net book value of natural gas and oil properties at December 31, 2005	161,531	3,500	165,031
Furniture, equipment and other, net	311	5	316
Total property and equipment at December 31, 2005, net	$161,842	$3,505	$165,347
From inception to December 31, 2004:			
Cost:			
Unproved properties	$ 27,666	$2,093	$ 29,759
Proved properties	41,748	615	42,363
	69,414	2,708	72,122
Impairment of natural gas and oil properties	(10,716)	(604)	(11,320)
Accumulated depreciation, depletion and amortization	(4,246)	—	(4,246)
Net book value of natural gas and oil properties at December 31, 2004	54,452	2,104	56,556
Furniture, equipment and other, net	—	8	8
Total property and equipment at December 31, 2004, net	$ 54,452	$2,112	$ 56,564

As of December 31, 2005, unproved properties not being amortized consisted of acreage acquisition costs of $73.6 million. At December 31, 2004, unproved properties not being amortized consisted of drilling in progress costs and acreage acquisition costs of $12.9 million, and $16.9 million, respectively.

As of December 31, 2005 and 2004, the results of management's ceiling test evaluation resulted in an impairment of the U.S. proved properties of $8.7 million and $6.3 million, respectively. Management determined that an impairment was not required on the Australian properties at December 31, 2005 or 2004.

For the years ended December 31, 2005 and 2004, cash expenditures on natural gas and oil properties totaled $88.1 million and $34.2 million, respectively. In 2005, non-cash expenditures related to the GeoStar Acquisition Properties were $25.1 million for issuance of common shares and $15.0 million for repayment of New GeoStar Subordinated Note. Proceeds from the sale of assets of $2,000 and $3.0 million during 2005 and 2004, respectively, were credited to natural gas and oil properties. Natural gas and oil properties were reduced by $1.0 million and $2.0 million during 2005 and 2004, respectively, upon reclassification of drilling advances and further adjusted by $313,000 in 2004 for a settlement.

In 2004, the Company entered into a farm-in agreement in which the Company received $3.0 million in 2004 for 30% of its Australian PEL 238 CBM rights. The joint venture partners could earn an additional 35% by spending up to AUD$7.0 million of development costs. As of December 31, 2004, the joint venture partners had earned an additional 20% (i.e. a total 50% working interest) by spending an additional AUD$4.0 million. As of December 31, 2005, the joint venture partners had spent the entire AUD$7.0 million of development costs and have earned the remaining additional 15% for a total 65% working interest resulting in the Company having a working interest of 35%. The Company has a 75% working interest in the CBM and Mineral Sands rights in EL 4416 in the Gippsland Basin, Victoria, Australia property.

6. GeoStar Acquisition

On June 17, 2005, the Company completed the acquisition of additional leasehold and working interests from GeoStar, a significant shareholder, in the Deep Bossier Hilltop prospect of East Texas and in the Powder River Basin of Wyoming and Montana (the "GeoStar Acquisition Properties"). The Company paid a total of $73.1 million, after acquisition costs of $400,000 and purchase price adjustments of $4.2 million for the interest acquired from January 1, 2005 ("Effective Date") to June 17, 2005 ("Acquisition Date"). This amount consisted of $30.9 million in cash, 1,650,133 common shares valued at $6.0 million based on a per share price of CDN$4.50 (market price of the Company's common shares on the date the acquisition was announced) and $32.0 million in unsecured subordinated notes maturing on January 31, 2006 and bearing interest at the rate of 3.42% ("GeoStar Subordinated Notes") plus purchase price adjustment cost to be settled in 2006. The acquisition was accounted for using the purchase method in which the cost of the acquisition is allocated first to identifiable assets acquired based on estimated fair values. The results of operations are included in the accompanying consolidated financial statements only from Acquisition Date. The purchase price adjustments are to be settled 50% in cash and 50% in Company common shares valued at CDN$4.50 per share. This results in a liability of $2.1 million (CDN$2.5 million) that is to be settled by the issuance of Company common shares upon completion of the final settlement statement.

The carrying values of the GeoStar Acquisition Properties as of June 17, 2005 was entirely allocated to natural gas and oil properties, of which $14.5 million was for proved developed properties, $8.7 million was for proved undeveloped properties and $49.9 million was for unproved properties.

In addition, GeoStar may receive additional common shares at prevailing market prices based on look-backs at June 30, 2006 and June 30, 2007 on the East Texas assets, based on a required number of drilled wells, and net reserve additions valued at $1.50 per Mcf less attributable development expenditures to GeoStar's acquired interest.

On August 11, 2005, the Company executed an agreement with GeoStar whereby the GeoStar Subordinated Notes were cancelled. In conjunction with the cancellation of the GeoStar Subordinated Notes, the Company issued GeoStar 6,373,694 common shares valued at $17.0 million based on a per share price of CDN $3.25 (market price of the Company's common shares on the date of debt renegotiation) and a new unsecured subordinated note ("New GeoStar Subordinated Note") for $15.0 million. The New GeoStar Subordinated Note was to bear interest, payable monthly commencing February 15, 2006, at three-month LIBOR plus 4.5%. As required by the agreement, the New GeoStar Subordinated Note was paid in full on November 28, 2005 in conjunction with the transaction with Chesapeake Energy Corporation ("Chesapeake").

The following unaudited pro forma results for the years ended December 31, 2005 and 2004 show the effect on the Company's consolidated results of operations as if the GeoStar acquisition had occurred on January 1, 2005 and 2004, respectively. The pro forma results are the result of combining the statement of operations of the Company with the statements of revenues and direct operating expenses for the properties acquired from GeoStar adjusted for the financing and share issuance directly attributable to the acquisition and additional depreciation, depletion and amortization expense as a result of the Company's increased ownership in the acquired properties. The statements of revenues and direct operating expenses for the GeoStar assets exclude all other historical expenses of GeoStar. As a result, certain estimates and judgments were made in preparing the pro forma adjustments. Further, the pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations.

	For the Years Ended December 31,	
	2005	2004
	(in thousands, except per share data)	
Revenues	$ 31,370	$ 9,425
Net loss	$(27,862)	$(19,653)
Loss per share:		
Basic and diluted	$ (0.21)	$ (0.17)

7. Transaction with Chesapeake Energy Corporation

On November 4, 2005, the Company completed an integrated transaction with Chesapeake whereby Chesapeake:

- Acquired approximately 27.2 million newly issued Company common shares equal to 19.9% of the then outstanding common shares for $76.0 million, before fees and expenses;
- Acquired a 33.33% working interest in the Company's Deep Bossier play in the Hilltop prospect area of Leon and Robertson Counties of East Texas; and
- Formed an area of mutual interest to explore jointly in 13 counties in East Texas.

As part of this transaction, Chesapeake agreed to pay an additional $7.8 million, before fees and expenses, to reimburse the Company for Chesapeake's pro rata share of leasehold interests acquired and to pay a disproportionate amount of future drilling costs described below, in exchange for an undivided 33.33% of the Company's leasehold working interests in the Deep Bossier Hilltop prospect, less and except 160 acres surrounding each existing well bore. Chesapeake agreed to pay 44.44% of the drilling costs through casing point in the first six wells drilled by the parties in the Hilltop prospect to a depth sufficient to test the Deep Bossier formation (an approximate depth of 19,000 feet) in order to earn its 33.33% leasehold working interest. The leasehold reimbursement was recorded as a reduction to natural gas and oil property cost.

Chesapeake has the right, with certain exceptions, to maintain its percentage ownership of the Company, on a fully diluted basis, by participating in future stock issuances and has the right to an observer being present at meetings of the Board of Directors.

The Company utilized a portion of the proceeds of the Chesapeake transaction to pay the New GeoStar Subordinated Note in full.

8. Long-Term Debt

The following shows the Company's long-term debt as of the dates indicated:

	As of December 31,	
	2005	2004
	(in thousands)	
Senior secured notes	$ 57,546	$ —
Senior notes	—	24,840
Subordinated unsecured notes payable	3,085	3,038
Convertible senior debenture	30,000	30,000
Total net carrying value of long-term debt	90,631	57,878
Debt discount costs to be accreted	15,619	1,855
Total long-term debt at maturity	$106,250	$59,733

Senior Secured Notes

On June 17, 2005, the Company issued $63.0 million in principal amount of senior secured notes ("Senior Secured Notes"). On September 19, 2005, the Company issued to the holders of the Senior Secured Notes an additional $10.0 million of Senior Secured Notes on substantially the same terms as the original June 2005 private placement. The Senior Secured Notes are secured by substantially all of the Company's assets, bear interest at the sum of the three-month LIBOR rate plus 6% (10.08% at December 31, 2005), payable quarterly, and mature five years and one day from the date of issuance. The Senior Secured Notes are redeemable in whole or in part prior to maturity at the Company's option at any time after the first anniversary date of issuance upon payment of the principal and accrued and unpaid interest plus a premium ranging from 5% to 3% of redeemed principal; provided that, a redemption at the Company's option is not permitted following the public announcement of certain pending, proposed or intended change of control transactions.

In connection with the Senior Secured Notes issuances, the Company agreed to issue to the note holders, for no additional consideration, common shares in increments valued at $3.6 million (CDN$4.5 million) with respect to the $63.0 million of Senior Secured Notes and additional common shares in increments valued at $606,000 (CDN$714,286) with respect to the $10.0 million of Senior Secured Notes at closing and on each of the six, twelve and eighteen-month anniversaries of the closing date, valued on a five day weighted average trading price immediately prior to the date of issuance. The Company initially recorded a liability of $17.0 million to be settled by the issuance of common shares and a corresponding amount was recorded as a debt discount to be amortized to interest expense using the effective interest method. On June 17, 2005, the Company issued 1,217,269 common shares valued at $3.6 million (CDN$4.5 million) and on September 19, 2005 issued 206,354 common shares valued at $606,000 (CDN$714,286) in conjunction with the initial Senior Secured Notes issuances. On December 19, 2005, the six month anniversary of the first Senior Secured Notes issuance, the Company issued to the note holders an additional 1,082,105 common shares valued at $3.6 million (CDN$4.5 million). The issuance of common shares was recorded based on their fair values with $7.9 million recorded to common shares issued and a corresponding reduction in the liability to be settled by the issuance of common shares resulting in a balance of $9.1 million as of December 31, 2005. The Company recorded debt discount amortization of $1.5 million in 2005. The Company also incurred an estimated $3.0 million of direct financing costs for legal fees and fees paid to an agent as deferred charges and will amortize these costs over the term of the Senior Secured Notes.

The Company has the right on a quarterly basis to require the note holders to purchase up to an aggregate of $10.0 million principal amount of additional Senior Secured Notes through June 16, 2007. If additional Senior Secured Notes are issued, the note holders will be entitled to receive, for no additional consideration, additional common shares on similar terms as those issued with the original Senior Secured Notes in a pro rata amount based on the additional principal amount of the Senior Secured Notes.

The issuance of additional Senior Secured Notes is contingent upon compliance with reserves to net Senior Secured Notes debt coverage ratios and other general covenants and conditions. Under the Senior Secured Notes, the PV(10) valuation is to be based on a third party independent reserve report utilizing constant pricing based on the lower of current natural gas and oil prices, adjusted for area basis differentials, or $6.00 per Mcf of natural gas and $40.00 per barrel of oil discounted at 10% ("PV(10)"). From the first anniversary of the issuance of the Senior Secured Notes up to the second anniversary of the issuance of the notes, proved reserves PV(10) ("1P (PV10)") to net Senior Secured Notes debt must be a minimum of 1.0:1. On the second anniversary date of the Senior Secured Notes, the 1P PV(10) reserve ratio covenant increases to a minimum of 1.5:1 and it increases to 2.0:1 on the third anniversary date and for all test periods thereafter until maturity. Utilizing the same reserve pricing criteria above, the proved plus probable reserves PV(10) ("2P PV(10)") to net Senior Secured Notes debt reserve maintenance ratio covenant must be a minimum of 1.5:1 from date of issuance of the notes up to the first anniversary date and 2.0:1 to issue additional notes. On the first anniversary date of the Senior Secured Notes, the 2P PV(10) reserve ratio maintenance covenant increases to a minimum of 2.5:1, on the second anniversary to 3.0:1 and on the third anniversary and for all test periods thereafter until maturity to 3.5:1. The Company must maintain compliance with the reserve ratio covenants at all future quarterly and annual covenant determination dates or be subject to mandatory principal redemptions under certain conditions and is restricted from paying dividends on common shares while the notes are outstanding.

On January 4, 2006, the Company's registration statement was declared effective by the United States Securities and Exchange Commission to register common shares including those issued (and to be issued) in conjunction with the Senior Secured Notes.

Senior Notes

In 2004, the Company issued $25.0 million of unsecured senior notes ("Senior Notes") to a private investment company. The Senior Notes mature on July 1, 2009 and bear an annual interest rate of 15% payable semi-annually. The Company may elect to pay interest due before December 31, 2005 in-kind through the issuance of additional Senior Notes. Interest payable in 2004 in the amount of $1.5 million was paid in-kind via the issuance of additional Senior Notes. The Senior Notes are callable at any time by the Company at a call premium of 104% (decreasing ½% every six months) of the principal outstanding.

The note holder of the Senior Notes was issued Company common share warrants totaling 510,525 and 1,989,475 with exercise prices of $3.23 and $3.63, respectively. The warrants expire on October 13, 2007. A value of $1.8 million was ascribed to the warrants and deducted from the debt and the value credited to additional paid-in capital. Interest expense relating to the amortization of the debt discount value for the years ended December 31, 2005 and 2004 was $1.6 million and $184,000, respectively. No additional warrants were issued on the paid-in-kind Senior Notes.

As part of the financing, the Senior Note holder additionally received a 2% overriding royalty interest ("ORRI") in four future wells and a smaller ORRI in one additional future well, all to be drilled in the Company's East Texas Bossier field. The Company has a right of first refusal on any sale of the ORRI granted to the note holder.

The Company incurred an estimated $750,000 of direct financing costs for legal fees and fees paid to the lender as deferred charges, which are amortized over the term of the Senior Notes.

In June 2005, as a condition to the issuance of the Senior Secured Notes, the Senior Notes were called and repaid in full, including a call premium of $662,000 and the remaining unamortized deferred costs of $694,000 were expensed.

Convertible Senior Debentures

In November 2004, the Company issued $30.0 million aggregate principal amount of convertible senior unsecured debentures (“Convertible Senior Debentures”). The Convertible Senior Debentures have a term of five years and will be due November 20, 2009 and bear interest at 9.75% per annum, payable quarterly and mature on November 20, 2009. The Convertible Senior Debentures are convertible by the holders into common shares at a conversion price of $4.38 per share. The Convertible Senior Debentures are not redeemable by the Company on or before November 12, 2006, except in the event of the satisfaction of certain conditions after a “change of control”, as defined in the Trust Indenture. After November 12, 2006, the Convertible Senior Debentures may be redeemed at any time by the Company at a redemption price equal to par plus accrued and unpaid interest; provided that, the volume weighted average trading price of the common shares of the Company, for at least 20 trading days in any consecutive 30-day period, equals or exceeds $5.69.

The Company incurred an estimated $1.9 million of direct financing costs for legal fees and other expenses as deferred charges, which are being amortized over the term of Convertible Senior Debentures. The Company also issued 259,740 broker warrants with an exercise price of $3.87 and a fair value of $359,000. Interest expense relating to the amortization of the deferred charges of approximately $72,000 and $6,000 was recorded for the years ended December 31, 2005 and 2004, respectively. There was no beneficial conversion feature associated with the Convertible Senior Debentures.

On January 4, 2006, the Company’s registration statement was declared effective by the United States Securities and Exchange Commission to register common shares including those be issued upon conversion of the Convertible Senior Debentures.

Subordinated Unsecured Notes Payable

In July 2004, the Company completed a $3.25 million subordinated unsecured note financing (“Unsecured Notes”). The Unsecured Notes mature between April 2009 and September 2009, bear interest at 10% per annum and are callable by the Company after two years at 108% of the principal amount. The call premium reduces to 105% after three years and 101% after four years. The subscribers were issued 232,521 warrants exercisable at prices ranging from $2.76 to $3.03 expiring at varying dates between April 2009 and September 2009. A value of $235,000 was ascribed to the warrants and recorded as a debt discount to be amortized to interest expense using the effective interest method. Interest expense relating to the amortization of the debt discount of approximately $47,000 and $24,000 was recorded for the years ended December 31, 2005 and 2004, respectively. Cash commissions of $196,000 were incurred, which have been capitalized and are being amortized over the term of the Unsecured Notes.

Long-term Debt Maturities

The following table represents the maturities of the Company's long-term debt agreements (in thousands):

Year Ending December 31,	Amount
2006	$ —
2007	—
2008	—
2009	33,250
2010	73,000
Total	$106,250

9. Drilling Advances Liability

On September 23, 2002, the Company pre-sold working interests to third parties in four wells for $4.0 million to be used for the planned drilling program on the Company's East Texas Bossier field. The amount was classified as a "drilling advances liability", with 25% being credited to natural gas and oil properties when a well was drilled. One well was drilled in 2003, two in 2004 and one well in 2005. A total of 2,005,027 common share purchase warrants (the "Bossier Warrants") were issued to subscribers on a pro-rata basis and were fully vested and non-forfeitable at the date of issuance. The Bossier Warrants had a three year term, expiring on September 23, 2005, entitling the holder to acquire one common share of Company at a cash price of $1.49 per share or on a cashless exercise basis. Under the cashless exercise basis, the holder does not pay cash consideration at the time the warrants are exercised but agrees to surrender the required number of shares (based on the trading price as of the exercise date) to settle the amounts due on the exercise. In September 2005, the 2,005,027 Bossier Warrants were exercised and converted into common shares of the Company. Of the warrants exercised, 207,814 were exercised for cash proceeds of $413,000 and 1,797,213 were exercised on a cashless basis. The Bossier Warrants exercised on a cashless basis resulted in the issuance of 841,224 net Company common shares.

The Company paid to the working interest owners an advance on production revenue equal to 10% per annum of the amount invested on a quarterly basis for the first 12 months of the investment ("Interest Advances"). The Interest Advances have been recorded as interest expense and will be deducted against future working interest revenue earned by the working interest owners.

The Company determined the fair value of the share purchase warrants relating to the private placement offering for drilling advances liability using the Black-Scholes-Merton option pricing model, using weighted average assumption of a nil dividend yield, expected volatility of 30%, a risk-free interest rate of 5% and a term of one year, after the hold period. As such, the Company recorded a deferred charge of $425,000 as additional paid-in capital, which was amortized once drilling commenced and on the same basis as the release of the drilling advances liability.

On January 4, 2006, the Company's registration statement was declared effective by the United States Securities and Exchange Commission to register common shares including those issued upon exercise of the Bossier Warrants.

10. Asset Retirement Obligation

Effective January 1, 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its natural gas and oil properties pursuant to the provisions of SFAS No. 143. The undiscounted amount of expected cash flows required to settle the asset retirement obligations as of December 31, 2005 and 2004 is estimated at $4.6 million and $4.0 million, respectively. Of these payments, 70% are expected to be made over the next 5 years, 28% is expected to be made in years 6-10, with the remainder being paid in years 11-19. The liability for the expected cash flows, as reflected below, has been discounted for the years ended December 31, 2005 and 2004 at 6.4% and 6.8%, respectively.

	For the Years Ended December 31,	
	2005	2004
	(in thousands)	
Asset retirement obligation, beginning of year	$1,711	$ 984
Liabilities incurred	1,738	109
Accretion expense	109	52
Revision in estimated cash flows	—	566
Asset retirement obligation, end of year	$3,558	$1,711

11. Liability to be Settled by the Issuance of Common Shares

The liability to be settled by the issuance of Company common shares is comprised of future issuance obligations in connection with the Senior Secured Notes and the GeoStar acquisition.

In conjunction with the issuance of Senior Secured Notes, the Company agreed to issue to the note holders, for no additional consideration, common shares in designated value increments at initial closing and on each of the six, twelve and eighteen-month anniversaries of closing. The additional common share value increments for the June 17, 2005 and September 19, 2005 closings are $3.6 million (CDN$4.5 million) and $606,000 (CDN$714,286), respectively. The Company initially recorded a liability to be settled by the issuance of common shares of $17.0 million which was reduced by the common share issuances at closing on June 17, 2005 and September 19, 2005 and the issuance on the six month anniversary on December 19, 2005 of the initial closing. The issuance of common shares was recorded based on their fair values with $7.9 million recorded to common shares issued and a corresponding reduction in the liability to be settled by the issuance of common shares resulting in a balance of $9.1 million as of December 31, 2005. This liability will be settled through the issuance of common shares, based on the five-day weighted average trading price immediately prior to the date of issuance. If additional Senior Secured Notes are issued, the purchasers will also be entitled to receive, for no additional consideration, additional common shares on similar terms as those issued with the original Senior Secured Notes in pro rata amount based on the additional principal amount of the Senior Secured Notes.

Under the terms of the Senior Secured Notes, the Company may not at any time issue common shares to note holders to the extent the issuance of the common shares would cause the note holders and/or their affiliates to beneficially own more than 9.9% of our outstanding common shares. In addition, the aggregate common shares issueable to the holders of the Senior Secured Notes are limited to the maximum number that may be issued without breaching the Company's obligations under the rules and regulations of the principal market or exchange where the Company's common shares trade. In the event the issuance of commons shares to the holders of the Senior Secured Note reach that maximum, the issuances would be proportionately reduced, and the Company would be required to pay cash for such unissued common shares on a formula for determining the number of common shares required to be issued. In the event of a change of control or upon a sale of substantially all of the Company's assets or a reorganization or merger where the Company is not the surviving entity, the holders of the Senior Secured Notes may require the Company to accelerate the future issuance of common shares.

Pursuant to the GeoStar Acquisition Properties agreement, 50% of the final purchase price adjustment is to be settled by the issuance of Company common shares valued at CDN$4.50 per share. This results in a liability of $2.1 million (CDN$2.5 million) that is to be settled by the issuance of approximately 548,128 common shares upon completion of the final settlement statement.

12. Equity Compensation Plan

The Company's Stock Option Plan authorizes the issuance by the Company's Board of Directors of options to directors, officers, employees and consultants of the Company and its subsidiaries to purchase a maximum of 25.0 million common shares. Option grant expirations vary between five and ten years. The vesting schedule may vary, but vesting generally occurs over a four-year period at 25% per year. Options issued pursuant to the Company's Stock Option Plan have an exercise price determined by the Board of Directors, but that exercise price cannot be less than the market price on date of grant as required by any stock exchange on which the Company's common shares are listed. If an option granted under the Company's Stock Option Plan expires or terminates for any reason in accordance with the terms of the Company's Stock Option Plan, the unpurchased common shares subject to that option become available for other option grants under the Company's Stock Option Plan.

In April 2004, the Board of Directors amended the provisions of the Company's Stock Option Plan to specifically incorporate a provision to provide for stock options to be exercised on a cashless basis whereby the Company issues the optionee the number of common shares equal to the stock option exercised, less the number of common shares which when multiplied by the market price at the date of exercise equals the aggregate exercise price for all of the common shares exercised.

For the years ended December 31, 2005 and 2004, the Company recorded $2.3 million and $1.4 million, respectively, in stock-based compensation expense for stock options granted using the fair-value method. The 711,000 options granted in 2005 had a weighted average fair value on grant date of $1.01 (CDN$1.33) per option. The 5,470,000 options granted in 2004 had a weighted average fair value on grant date of $0.88 (CDN$1.16) per option. There were no stock options grants in 2003.

The following table summarizes the annual changes and option exercise prices for stock options under the Company's Stock Option Plan for each of the three years in the period ended December 31, 2005:

	Number of Shares Under Option	Weighted Average Exercise Price (1)	
		CDN$	US$
Options outstanding as of December 31, 2002 and 2003	18,898,600	1.92	1.20
Options granted	5,470,000	3.45	2.61
Options outstanding as of December 31, 2004	24,368,600	2.26	1.52
Options granted	711,000	3.64	3.01
Options exercised (2)	(6,391,500)	0.50	0.33
Options cancelled/expired	(1,187,500)	1.49	1.08
Options outstanding as of December 31, 2005	17,500,600	3.02	2.04
Options exercisable:			
December 31, 2003	10,949,050	1.64	1.07
December 31, 2004	15,673,700	1.76	1.09
December 31, 2005	12,783,350	2.83	1.87

(1) Stock option grants are denominated in CDN$. U.S. dollar equivalent was calculated at the exchange rate that existed on the date of grant.
(2) Includes 455,312 options forfeited due to the cashless exercise of stock options.

The following table summarizes the range of exercise prices for stock options outstanding and vested as of December 31, 2005:

Exercise Prices	Number of Shares Under Stock Options Outstanding	Number of Shares Under Stock Options Exercisable	Expiration Date
CDN$2.76 ($1.80)	10,974,600	10,974,600	July 13, 2006
CDN$2.81 ($1.80)	700,000	525,000	April 29, 2007
CDN$3.70 ($2.73)	725,000	181,250	April 20, 2009
CDN$3.41 ($2.47)	4,410,000	1,102,500	August 4, 2009
CDN$3.50 ($2.84)	345,000	—	June 24, 2010
CDN$3.40 ($2.76)	50,000	—	June 28, 2010
CDN$3.25 ($2.74)	150,000	—	September 7, 2010
CDN$4.00 ($3.42)	40,000	—	September 20, 2010
CDN$4.30 ($3.54)	21,000	—	March 1, 2010
CDN$4.80 ($3.86)	10,000	—	April 1, 2010
CDN$4.50 ($3.81)	75,000	—	October 18, 2015
	17,500,600	12,783,350	

Effective January 1, 2003, the Company adopted SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123), which requires the Company to record compensation costs for options granted under the Company's stock option plan in accordance with the fair value method prescribed in SFAS No. 123. See Note 2 – Summary of Significant Accounting Policies.

13. Common Stock

Authorized

The Company's articles of incorporation allow the Company to issue an unlimited number of common shares without par value.

Share Issuances

During 2004, $8.2 million in principal amount of 12% convertible debentures and notes were converted into an aggregate of 6,847,215 common shares of the Company. Of the common shares issued, 6,099,999 common shares were at a conversion price of $1.10 and 747,216 common shares were at a conversion price of $1.97 per share.

On June 17, 2005, the Company issued 1,217,269 common shares valued at $3.6 million (CDN$4.5 million) based upon a five-day weighted average trading price of CDN$3.69 per share pursuant to the private placement of $63.0 million Senior Secured Notes.

On June 17, 2005, concurrent with private placement of $63.0 million Senior Secured Notes, the Company issued 1,650,133 common shares valued at $6.0 million (CDN$7.4 million at CDN$4.50 per share) pursuant to the acquisition of additional leasehold and working interest properties in East Texas and the Powder River Basin from GeoStar.

On June 30, 2005, the Company completed a private placement of 6,617,736 common shares valued at $16.4 million (CDN$20.5 million at CDN$3.31 per share) after deducting placement fees and expenses.

On August 11, 2005, the Company issued to GeoStar 6,373,694 common shares at CDN$3.25 per share in conjunction with partial payment of $17.0 million of the $32.0 million GeoStar Subordinated Notes.

On September 19, 2005, the Company issued 206,354 common shares representing and aggregate value of $606,000 (CDN$714,286) based upon a five-day weighted average trading price of CDN$3.4615 per share pursuant to the private placement of $10.0 million of Senior Secured Notes.

During the month of September 2005, the 2,005,027 Bossier Warrants were exercised and converted into common shares of the Company. Of the Bossier Warrants exercised, 207,814 were exercised for cash proceeds of $413,000 (CDN$485,000) and 1,797,214 were exercised on a cashless basis. The Bossier Warrants exercised on a cashless basis resulted in the issuance of 841,224 net Company common shares.

On November 4, 2005, the Company completed a private placement of 27,151,641 common shares to Chesapeake valued at $73.8 million (CDN$89.9 million at CDN$3.31 per share) after deducting placement fees and expenses.

On December 19, 2005, the Company issued 1,082,105 common shares valued at $3.6 million (CDN$4.5 million) based upon a five-day weighted average trading price of CDN$4.1586 per share upon the six month anniversary of the private placement of $63.0 million Senior Secured Notes.

During 2005, pursuant to the Company's Stock Option Plan, the Company issued 3,721,300 common shares for cash exercises of $707,000 and 2,214,888 common shares on a cashless exercise basis.

Share Repurchases

At various times from 2002 to 2004, the Company conducted normal course issuer bids to repurchase common shares of the Company. Pursuant to this program, the Company repurchased 340,000 common shares for $894,000 and 1,391,500 common shares for $2.1 million in 2004 and 2003, respectively. The bid expired on August 4, 2004. The common shares were cancelled upon repurchase. The amount recorded for stock repurchase represents purchase prices paid and costs of repurchase and cancellation.

Shares Reserved

At December 31, 2005, the Company has reserved 27,342,176 common shares to be issued pursuant to the conversion of convertible debt (up to 6,849,315), exercise of options (17,500,600), and the exercise of warrants (2,992,261).

14. Warrants

The following table summarizes warrant information to purchase common shares:

	Number of Warrants	Fair Value of Warrant (in thousands)	Warrant Price per Share Range in CDN$	Warrant Price per Share Range in US$	WA (1) Remaining Life in Years	WA (1) Exercise Price in CDN$	WA (1) Exercise Price in US$
Warrants outstanding December 31, 2003	2,005,027	$ 425	2.35	1.49	—	2.35	1.49
Issued in connection with:							
Senior Notes	2,500,000	1,828	4.40-4.54	3.23-3.63	2.75	4.51	3.55
Subordinated Unsecured Notes	232,521	235	3.64-4.18	2.76-3.03	4.36	3.76	2.80
Convertible Subordinated Debentures	259,740	359	4.65	3.87	4.92	4.65	3.87
Warrants outstanding December 31, 2004	4,997,288	2,847	2.35-4.65	1.19-3.87	2.14	3.62	2.70
Exercise of Bossier Warrants	(2,005,027)	(425)	2.35	1.49	—	2.35	1.49
Warrants outstanding December 31, 2005	2,992,261	$2,422	3.64-4.65	2.76-3.87	2.06	4.46	3.52

(1) WA – weighted average as of the respective period end dates.

15. Interest Expense

The following table summarizes interest expense components:

	For the Years Ended December 31, 2005	2004	2003
	(in thousands)		
Cash and accrued	$ 9,834	$ 957	$1,204
Paid in-kind	—	1,483	—
Call premium	622	—	—
Amortization of deferred financing costs and debt discount	4,805	808	1,363
Total	$15,261	$3,248	$2,567

16. Related Party Transactions

GeoStar is the beneficial owner of approximately 10.9% of our common shares. The Company's Chairman of the Board of Directors is an officer and director of GeoStar. Except as disclosed elsewhere in these financial statements, the Company had the following related party transactions with GeoStar:

(a) In 2001, the Company entered into a Participation and Operating Agreement ("POA") with GeoStar. For the East Texas properties, the POA was replaced effective January 1, 2005 with a Joint Operating Agreement ("JOA"), as detailed below. Pursuant to the terms of the original POA, which still governs the Company's West Virginia and certain Australian assets, the Company has the option to participate as a working interest partner in properties in which GeoStar and its subsidiaries have interests in on an "at cost" basis, subject to the Company's full due diligence review prior to its participation election. Upon agreeing to participate, the Company is responsible for its proportionate share of actual costs expended by GeoStar and its subsidiaries to third parties on an "at cost" basis. The $601,000 due to related parties at December 31, 2004 represented the amount owed to GeoStar and its subsidiaries for natural gas and oil property development. In 2004, pursuant to the terms of the POA, GeoStar billed the Company $27,000 (2003—$369,000) for administrative overhead.

(b) On June 1, 2000, the Company entered into an agreement with GeoStar to settle accounts payable related to the development of natural gas and oil properties with the issuance of a floating convertible debenture for up to CDN$25.0 million. Under the debenture agreement, GeoStar would continue to provide funds for development and operations by allowing the Company to draw on the debenture. Advances under the debenture were subject to GeoStar's availability of funds and the approval of the requested advances by GeoStar's board of directors. The debenture was payable in cash or convertible into common shares, at prevailing market prices, at the option of the Company.

(c) Effective January 1, 2005, the Company and GeoStar entered into a JOA covering an Area of Mutual Interest ("AMI") in East Texas, with the Company as non-operator and GeoStar as operator. Under the terms of the JOA, GeoStar would receive overhead reimbursement equal to 12.5% of development costs for the first 10 wells drilled after the effective date, 10% of the development costs for the 11th through 20th wells and 8.5% of the developments costs for all subsequent wells. As a result of the JOA, GeoStar ceased charging the Company a proportionate amount of direct salary and shared premises rent expense for GeoStar employees providing administrative and technical support services to the Company. In conjunction with the execution of the JOA, the Company terminated the convertible debenture arrangement with GeoStar and is required to finance its share of future joint venture costs.

During 2005, GeoStar billed the Company $1.4 million, which was equal to 12.5% of development costs for two wells drilled in East Texas. These costs have been capitalized to property and equipment and were paid in 2005.

At December 31, 2005, the Company had a due from related parties receivable of $2.3 million primarily relating to revenues earned on GeoStar operated properties and property cost advances. Pursuant to the GeoStar Acquisition Properties agreement, the final purchase price adjustments are to be settled 50% in cash and 50% in Company common shares valued at CDN$4.50 per share. At December 31, 2005, the Company had a due to related parties payable of $2.1 million ,with a corresponding $2.1 million included in the liability to be settled by issuance of 548,128 common shares related to purchase price adjustments. The GeoStar Acquisitions Properties agreement provides for certain post closing adjustments relating to expenditures incurred on the acquired properties which may include additional agreed upon drilling overhead charges.

(d) In 2004, the Company recorded $1.3 million (2003—$Nil) in general and administrative costs for administrative and technical support provided by GeoStar to the Company. The consolidated financial statements also include approximately $1,000, $115,000 and $33,000 in seismic reprocessing fees paid to GeoStar at December 31, 2005, 2004 and 2003, respectively. The seismic reprocessing fees were capitalized to natural gas and oil properties.

(e) Effective January 1, 2005, the Company agreed to hire and employ directly certain GeoStar employees as members of the management team.

All related party transactions in the normal course of operations have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

17. Income Taxes

Only a minimal amount of the Company's operations is outside of the U.S. The Company's pre-tax loss in the U.S. was $9.0 million, and the foreign pre-tax loss was $16.7 million (primarily interest expense) for the year ended December 31, 2005.

The components of income tax provisions and reconciliation of the effective tax rates from the statutory rate are as follows:

	For the Years Ended December 31,					
	2005		2004		2003	
	(in thousands, except tax rates)					
Expected income tax provision at statutory rates	$(8,992)	35.0%	$(4,472)	35.0%	$(1,689)	35.0%
State tax, tax effected	(437)	1.7%	(217)	1.7%	(82)	1.7%
Net operating loss carryforwards	9,429	(36.7%)	4,689	(36.7%)	1,771	(36.7%)
Actual income tax provision	$ —	—	$ —	—	$ —	—

The Company has the following approximate undeducted Canadian tax pools:

	As of December 31,		
	2005	2004	2003
	(in thousands)		
Cumulative Canadian exploration expense	$ 930	$ 930	$ 930
Cumulative Canadian development expense	$ 171	$ 171	$ 171
Foreign exploration and development expense	$ 610	$ 610	$ 610
Undeducted undepreciated capital costs	$ 3	$ 3	$ 2
Undeducted share issue costs	$ 2,967	$ 386	$ 35
Undeducted non-capital loss carryforwards	$18,253	$8,090	$6,111

If not utilized, the non-capital loss carryforwards for the above expire between 2006 and 2015.

The Company has the following approximate undeducted Australian tax pools:

	As of December 31,		
	2005	2004	2003
	(in thousands)		
Net operating loss carryforwards	$7,771	$6,196	$9,254

The components of the Company's Canadian deferred tax assets are a result of the origination and reversal of temporary differences and are comprised of the following:

	As of December 31,		
	2005	2004	2003
	(in thousands)		
Deferred tax assets:			
Capital assets	$ 629	$ 629	$ 629
Share issue costs	1,089	141	13
Net operating loss carryforwards	6,699	2,970	2,243
Valuation allowance	(8,417)	(3,740)	(2,885)
Net deferred tax asset	$ —	$ —	$ —

The components of the Company's U.S. deferred taxes are a result of the origination and reversal of temporary differences and are comprised of the following:

	As of December 31,		
	2005	2004	2003
		(in thousands)	
Deferred tax asset (liability):			
Capital assets	$(20,744)	$(11,692)	$(1,528)
Net operating loss carryforwards	29,508	16,842	8,542
Valuation allowance	(8,764)	(5,150)	(7,014)
Net deferred tax asset	$ —	$ —	$ —

For U.S. federal income tax purposes, the Company has net operating loss carryforwards of approximately $80.0 million, which if not utilized will begin to expire in 2020.

The components of the Company's Australian deferred taxes are a result of the origination and reversal of temporary differences and are comprised of the following:

	As of December 31,		
	2005	2004	2003
		(in thousands)	
Deferred tax asset:			
Net operating loss carryforwards	$ 2,331	$ 1,859	$ 2,776
Valuation allowance	(2,331)	(1,859)	(2,776)
Net deferred tax asset	$ —	$ —	$ —

All deferred tax assets have been fully reserved, as it is more likely than not that the Company will be unable to realize this benefit.

18. Loss per share

In accordance with the provisions of SFAS No. 128, basic earnings per share is computed on the basis of the weighted average number of common shares outstanding during the periods. Diluted earnings per share is computed based upon the weighted average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities. Diluted amounts are not included in the computation of diluted loss per share, as such would be anti-dilutive.

	For the Years Ended December 31.		
	2005	2004	2003
	(in thousands, except per share and share data)		
Basic loss and shares outstanding:			
Loss before cumulative effect of change in accounting principle	$ (25,692)	$ (12,776)	$ (4,826)
Net loss	$ (25,692)	$ (12,776)	$ (4,947)
Weighted average common shares outstanding	129,398,548	111,374,446	104,958,180
Basic and diluted loss per common share:			
Loss per share before cumulative effect of change in accounting principle	$ (0.20)	$ (0.12)	$ (0.05)
Net loss per share applicable to all common shares	$ (0.20)	$ (0.12)	$ (0.05)
Common shares excluded from denominator as anti-dilutive:			
Stock options	17,500,600	24,368,600	18,898,600
Warrants	2,992,261	4,997,288	2,005,027
Convertible debentures	6,849,315	6,849,315	—
Liability to be settled by issuance of common shares (1)	3,042,484	—	—
Total	30,384,660	36,215,203	20,903,627

(1) Assumes conversion of liability to be settled by issuance of common shares for the Senior Secured Notes of 2,494,356 common shares at a December 31, 2005 closing price of CDN$4.25 per common share and 548,128 common shares for the GeoStar Acquisition Properties settlement statement at CDN$4.50 per common share.

19. Commitments and Contingencies

Operating Leases

The Company leases its office facilities and certain gas treatment facilities under non-cancelable operating lease agreements. Rent expense for 2005 totaled approximately $53,000. The Company had no rent expense prior to August 1, 2005. For the years ended December 31, 2005 and 2004, gas treatment lease payments were approximately $759,000 and $91,000, respectively. The Company had no gas treatment lease payments prior to 2004.

As of December 31, 2005, the Company's operating leases for the indicated periods were as follows:

	For the Years Ended December 31,						
	2006	2007	2008	2009	2010	Thereafter	Total
	(in thousands)						
Office leases	$100	$108	$108	$108	$89	$—	$ 513
Gas treatment plants and other	704	38	2	2	1	—	747
Total	$804	$146	$110	$110	$90	$—	$1,260

Litigation

The Company is party to various litigation matters arising out of the normal course of business. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from an adverse outcome be reasonably estimated at this time. The Company does not expect that the outcome of these proceedings will have a material adverse effect on its financial position or results of operations. The more significant litigation matters are summarized below.

Estate of Virgil Sparks and Oil Wells of Kentucky, Inc. vs. First Sourcenergy Group Inc. and Geostar Corporation Arbitration. In August 2002, FSG, a wholly owned Company subsidiary, was a named party to this arbitration proceeding. The dispute involves historical dealings with the development of an Authority to Prospect ("ATP") Area in Queensland, Australia, as well as an ancillary agreement. The formal arbitration is in discovery stages. FSG and GeoStar have moved to dismiss the arbitration on the grounds of a claimed prior settlement and release agreement. FSG and GeoStar are vigorously defending the arbitration, and firmly believe that its position is sound and intends to continue to defend vigorously against the claim. Further, FSG's interest in ATP 560 were transferred from FSG to a third party in 2001, the result of which means that, although FSG is a named defendant, the third party and GeoStar would bear primary liability from this arbitration action.

Western Gas Resources, Lance oil and Gas Company, Inc. and Williams Production RMT Company vs. First Sourcenergy Wyoming, Inc. and First Sourcenergy Group, Inc. On May 3, 2005, FSW and FSG, both wholly owned Company subsidiaries, were party to a complaint concerning a June 2002 Lease Exchange and Purchase Agreement between certain of the parties. The issue involves a certain gas gathering agreement and its applicability to some of the properties exchanged under the June 2002 Agreement. A formal response to the complaint was filed in June 2005. Discovery on this matter is just beginning, and as such it is premature to assess a probability of success in defense of this action or of the Company's exposure if liability were to be found. The Company believes that it has multiple strong defenses to this action and intends to continue to vigorously defend against the claim.

Navasota Resources L.P. vs. First Source Texas, Inc., First Source Gas L.P. and Gastar Exploration Ltd. (Cause No. 0-05-451) District Court of Leon County, Texas 12th Judicial District. This lawsuit contends that the Company breached Navasota's preferential right to purchase 33.33% of the Company's interest in certain oil and gas leases located in Leon and Robertson Counties sold to Chesapeake Energy Corporation pursuant to a transaction closed November 4, 2005. The preferential right claimed is under an operating agreement dated July 7, 2000. The Company contends, among other things, that Navasota neither properly nor timely exercised any preferential right election it may have had with respect to the inter-dependent Chesapeake transaction. This litigation matter is currently in the discovery stage and the Company intends to vigorously defend against the claim.

East Texas Lease Dispute. Certain members of a family from which leases were obtained claim to own unleased mineral interests in the same tract covering approximately 2,600 gross acres (1,500 net disputed acres) in Leon County, Texas on which the Company's Lone Oak Ranch Well No. 1 is drilled. These family members have demanded an accounting of the revenue and expenses on the drilled well. Based on the accounting, there does not appear to be a basis for any adverse claim against the Company that would give rise to a monetary damage award at this time. However, the existence of unleased mineral interests in this tract could adversely impact future development of the tract. The Company intends to vigorously defend against this claim.

Restoration, Removal and Environmental Liabilities

The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are initially measured at a fair value and are recognized in the consolidated financial statements as the present value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement obligation cost are recognized in the results of operations. Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from the Company's cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any quarter or year.

Indemnifications

Indemnifications in the ordinary course of business have been provided pursuant to provisions of purchase and sale contracts, service agreements, joint venture agreements, operating agreements and leasing agreements. In these agreements, the Company may indemnify counterparties if certain events occur. These indemnification provisions vary on an agreement by agreement basis. In some cases, there are no pre-determined amounts or limits included in the indemnification provisions and the occurrence of contingent events that will trigger payment, if any, is difficult to predict.

Employment Agreements

Under the terms of employment agreements executed in March 2005 and April 2005, the Company has agreed to indemnify two executives, who have acted at the Company's request to be officers of the Company, to the extent permitted by law, against any and all damages, liabilities, costs, charges or expenses suffered by or incurred by the individuals as a result of their service. The nature of the indemnification agreements prevents the Company from making a reasonable estimate of the maximum potential amount it could be required to pay to beneficiary of such indemnification agreement. In addition to defining the terms of employment, the agreements provide for severance benefits of up to two years compensation.

20. Concentration of Risk and Significant Customers

Approximately 66% of the Company's 2005 revenues was from production from the Company's four producing wells in the East Texas Bossier Field in Texas.

During 2005, ETC Texas Pipeline Ltd. and Western Gas Resources, Inc. accounted for 66% and 32%, respectively, of the Company's natural gas and oil revenues. During 2004, ETC Texas Pipeline Ltd. and Western Gas Resources, Inc. accounted for 59% and 35%, respectively, of the Company's natural gas and oil revenues. During 2003, Western Gas Resources, Inc. and Equitable Gas Company a division of Equitable Resources, Inc. accounted for 79% and 17%, respectively, of the Company's natural gas and oil revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

21. Statement of Cash Flows

Non-cash transactions have been disclosed in Notes 3, 5, 6, 8, 9, 10, 11, 12, 13, 15 and 16.

22. Quarterly Consolidated Financial Data – unaudited

	For the Three Months Ended			
	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
	(in thousands, except per share data)			
Revenues	$ 4,731	$ 4,943	$ 7,822	$ 9,946
Loss from operations	$(5,497)	$(3,898)	$(1,031)	$ (537)
Loss before income taxes	$(7,636)	$(8,663)	$(4,622)	$(4,771)
Net loss	$(7,636)	$(8,663)	$(4,622)	$(4,771)
Loss per share, basic and diluted	$ (0.06)	$ (0.07)	$ (0.04)	$ (0.03)

	For the Three Months Ended,			
	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004
	(in thousands, except per share data)			
Revenues	$ 356	$ 517	$ 815	$ 4,371
Loss from operations	$ (242)	$ (610)	$(1,132)	$(7,603)
Loss before income taxes	$ (670)	$ (750)	$(1,971)	$(9,385)
Net loss	$ (670)	$ (750)	$(1,971)	$(9,385)
Loss per share, basic and diluted	$(0.01)	$(0.01)	$ (0.02)	$ (0.08)

23. Differences between Canadian and U.S. Generally Accepted Accounting Principles

The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles in the U.S. U.S. principles differ from Canadian principles as follows:

Reconciliation of Net Loss under US GAAP to Canadian GAAP

Consolidated Statement of Operations – Canadian GAAP

	For the Years Ended December 31,		
	2005	2004	2003
	(in thousands, except per share data)		
Net loss in accordance with U.S. principles	$(25,692)	$(12,776)	$(4,947)
Impact of Canadian principles:			
Depreciation, depletion and amortization (1)(4)	(2,948)	(264)	(48)
Natural gas and oil impairment (4)	8,697	6,306	537
Mineral resource properties (3)	63	32	(32)
Accretion expense on convertible notes (2)	(57)	(9)	—
Amortization expense—deferred charges (5)(6)	(3,233)	(208)	—
Amortization expense—debt discount (5)(6)	—	32	455
Interest—debt discount (5)(6)	3,233	208	—
Cumulative effect of change in accounting principle (8)	—	—	121
Net adjustments	5,755	6,097	1,033
Net loss in accordance with Canadian principles	$(19,937)	$ (6,679)	$(3,914)
Loss per common share in accordance with Canadian principles:			
Basic and diluted	$ (0.15)	$ (0.06)	$ (0.04)

Consolidated Statements of Operations – Canadian GAAP

	For the Years Ended December 31,		
	2005	2004	2003
	(in thousands, except per share and share data)		
REVENUES	$ 27,442	$ 6,059	$ 1,461
EXPENSES:			
Lease operating, transportation and selling expenses	6,910	2,000	712
Depreciation, depletion and amortization (4)	16,864	3,495	619
Impairment of natural gas properties (4)	—	—	15
Accretion on asset retirement obligation	109	52	53
General and administrative expenses	8,710	4,023	1,909
LOSS FROM OPERATIONS	(5,151)	(3,511)	(1,847)
Loss on abandonment of mineral resource properties (4)	—	—	(63)
Interest expense (5)(6)	(15,318)	(3,227)	(2,113)
Investment income	492	56	18
Foreign exchange gain	40	3	91
LOSS BEFORE INCOME TAX	(19,937)	(6,679)	(3,914)
Provision for income taxes (7)	—	—	—
NET LOSS	$ (19,937)	$ (6,679)	$ (3,914)
NET LOSS PER SHARE:			
Basic and diluted	$ (0.15)	$ (0.06)	$ (0.04)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic and diluted	129,398,458	111,374,446	104,958,180

Condensed Consolidated Balance Sheet (U.S. GAAP and Canadian GAAP)

	As of December 31,			
	2005		2004	
	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP
	(in thousands)			
ASSETS				
Current assets	$ 69,468	$ 69,468	$17,880	$17,880
Deferred charges (5)(6)	4,922	20,541	3,680	5,535
Cash call receivable	391	391	6,318	6,318
Property, plant and equipment, net (1) (3) (4)	165,347	179,158	56,564	64,563
Total assets	$240,128	$269,558	$84,442	$94,296
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities	$ 13,942	$ 13,942	$ 1,798	$ 1,798
Senior secured notes (6)	57,546	73,000	—	—
Senior notes (5)	—	—	24,840	26,483
Subordinated, unsecured notes payable (5)	3,085	3,250	3,038	3,250
Convertible senior debentures (2)	30,000	29,782	30,000	29,725
Other accrued long-term liabilities	—	—	1,079	1,079
Asset retirement obligation	3,558	3,558	1,711	1,711
Liability to be settled by issuance of common shares	11,221	11,221	—	—
Shareholders' equity (2)	120,776	134,805	21,976	30,250
Total liabilities and shareholders' equity	$240,128	$269,558	$84,442	$94,296

Reconciliation of Shareholders' Equity under U.S. GAAP to Canadian GAAP:

	As of December 31,		
	2005	2004	2003
	(in thousands)		
Shareholders' equity, in accordance with U.S. principles	$120,776	$21,976	23,669
Convertible notes, beneficial conversion feature (2)	218	275	32
Mineral resource properties (3)	141	78	—
Natural gas and oil properties (1)(4)	13,670	7,921	1,861
Shareholders' equity, in accordance with Canadian principles	$134,805	$30,250	$25,562

(1) In accordance with U.S. principles, the Company recognizes revenue and expenses on the income statement without regard to levels of commercial production and calculated and reported depletion on the income statement. For Canadian principles, since the Company had not reached commercial levels of production, it was considered to be in the pre-production stage. While in the pre-production stage, the Company netted their natural gas and oil revenue and lease operating expenses against oil and gas properties on the balance sheet and did not record depletion on their natural gas and oil properties. The Company was in the pre-production stage until June 30, 2002.

(2) In accordance with U.S. principles, the amount of Convertible Senior Debentures is recognized as debt and is offset by the value attributable to the beneficial conversion feature. The value of the warrants attached to debt as well as the value of the conversion feature of the convertible debt is recognized as paid-in capital in Shareholders' Equity. The amortization of the beneficial conversion feature is amortized over the term of the related convertible notes. For Canadian principles, these convertible notes are considered to be compound financial instruments and the liability component and the equity component must be presented separately as determined at initial recognition.

(3) In accordance with U.S. principles, expenditures on mineral resource properties are expensed. For Canadian principles, the Company capitalizes expenditures on mineral resource properties.

(4) In accordance with U.S. principles, a ceiling test is applied to ensure the unamortized capitalized costs in each cost center do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs, abandonment and reclamation costs and applicable taxes, as determined by independent engineers. For Canadian principles, the Company adopted the new Canadian guideline AcG-16 in 2003, in which a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing, based on sales prices achievable under existing contracts and posted average reference prices in effect between the end of the year and the finalization of the year end audit and current costs to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves. Unproved properties are tested separately for impairment.

In computing its consolidated net loss for U.S. GAAP purposes, the Company recorded a write down of properties in 2000, 2001, 2002, 2003, 2004 and the first and second quarters of 2005 as a result of the application of the U.S. GAAP ceiling test. For Canadian principles, the Company recorded a write down in 2002 and 2003 only. Therefore, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

Effective January 1, 2004, the Canadian Accounting Standard's Board amended the Full Cost Accounting Guideline. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using estimated future prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices.

(5) For U.S. principles, the value of the warrants is allocated based on relative fair values and is netted against the debt and is amortized as interest expense. For Canadian principles, the fair value of the warrants are recorded as a deferred charge and amortized over the life of the note.
(6) In accordance with U.S. principles, debt discount is netted against the debt and not deferred as a financing cost. The debt discount is amortized as interest expense using the interest method. For Canadian principles, the fair value of the debt discount is recorded as a deferred charge and amortized over the life of the note.
(7) There are no tax effects as the Company currently is not taxable and a valuation allowance has been recorded for the balance of the deferred tax assets.
(8) In accordance with U.S. principles, a change in accounting principle is reflected in the year of adoption under cumulative effect of a change in accounting principle. For Canadian principles, the effect of the change is recognized through accumulated deficit.

24. Supplemental Oil and Gas Disclosures – Unaudited

The following disclosures for the Company are made in accordance with SFAS No. 69, “Disclosures About Oil and Gas Producing Activities”.

Capitalized Costs Relating Oil and Producing Activities

The following table presents the Company’s aggregate capitalized costs relating to oil producing activities and the related depreciation, depletion and amortization:

	United States	Australia	Total
	(in thousands)		
At December 31, 2005:			
Unproved properties	$ 70,519	$3,061	$ 73,580
Proved properties	128,549	1,043	129,592
	199,068	4,104	203,172
LESS:			
Impairment allowance	(19,414)	(604)	(20,018)
Accumulated depreciation, depletion and amortization	(18,123)	—	(18,123)
Total	$161,531	$3,500	$165,031
At December 31, 2004:			
Unproved properties	$ 27,666	$2,093	$ 29,759
Proved properties	41,748	615	42,363
	69,414	2,708	72,122
LESS:			
Impairment allowance	(10,716)	(604)	(11,320)
Accumulated depreciation, depletion and amortization	(4,246)	—	(4,246)
Total	$ 54,452	$2,104	$ 56,556

Pursuant to SFAS No. 143, net capitalized cost includes related asset retirement cost of approximately $3.6 million and $1.5 million at December 31, 2005 and 2004, respectively.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's natural gas and oil activities for the years ended December 31, 2005, 2004, and 2003:

	United States	Australia	Total
		(in thousands)	
For the year ended December 31, 2005:			
Unproved property acquisition	$ 42,853	$ 968	$ 43,821
Proved property acquisition	23,208	—	23,208
Exploration	28,239	428	28,667
Development	35,354	—	35,354
Total	$129,654	$1,396	$131,050
For the year ended December 31, 2004:			
Unproved property acquisition	$ 3,163	$ (288)	$ 2,875
Proved property acquisition	1,460	2	1,462
Exploration	27,662	195	27,857
Development	2,437	—	2,437
Total	$ 34,722	$ (91)	$ 34,631
For the year ended December 31, 2003:			
Unproved property acquisition	$ 3,600	$ 100	$ 3,700
Proved property acquisition	826	3	829
Exploration	6,012	346	6,358
Development	458	—	458
Total	$ 10,896	$ 449	$ 11,345

The United States proved properties are expected to be developed over the next two to five years while the Australian properties are anticipated to be developed over the next three to seven years.

Results of Operations for Oil and Gas Producing Activities

The following table sets forth results of operations for oil and gas producing activities for the years ended December 31, 2005, 2004 and 2003:

	United States (in thousands)
For the year ended December 2005:	
Natural gas and oil sales	$ 27,442
Production expenses	(6,910)
Impairment of natural gas and oil properties	(8,697)
Depreciation, depletion, and amortization	(13,877)
Results of producing activities	$ (2,042)
Depreciation, depletion, and amortization rate per Mcfe	$ 3.63
For the year ended December 2004:	
Natural gas and oil sales	$ 6,059
Production expenses	(2,000)
Impairment of natural gas and oil properties	(6,306)
Depreciation, depletion, and amortization	(3,231)
Results of producing activities	$ (5,478)
Depreciation, depletion, and amortization rate per Mcfe	$ 2.89
For the year ended December 2003:	
Natural gas and oil sales	$ 1,461
Production expenses	(712)
Impairment of natural gas and oil properties	(552)
Depreciation, depletion and amortization	(570)
Results of producing activities	$ (373)
Depreciation, depletion, and amortization rate per Mcfe	$ 1.46

The results of producing activities exclude interest charges and general corporate expenses and represent United States activities only due to no producing operations activities in Australia to date.

Net Proved and Proved Developed Reserve Summary

The Company's proved net developed and proved undeveloped reserves are located only in the United States. The Company cautions that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. In addition, estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are expected to change as future information becomes available. Material revisions of reserve estimates may occur in the future; development and production of the oil and gas reserves may not occur in the periods assumed and actual prices realized and actual costs incurred may vary significantly from those used. Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

The following table sets forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2003, 2004 and 2005:

	Gas (MMcf)	Oil (MBbl)
Change in proved reserves		
Proved reserves as of December 31, 2002	15,176	26
Extensions and discoveries	5,067	—
Purchase of minerals in place	(9,082)	—
Revisions of previous estimates	(2,912)	(21)
Production	(385)	(1)
Proved reserves as of December 31, 2003	7,864	4
Extensions and discoveries	14,931	4
Purchase of minerals in place	2,528	—
Sale of minerals in place	(2,408)	—
Revisions of previous estimates	(407)	—
Production	(1,108)	(2)
Proved reserves as of December 31, 2004	21,400	6
Extensions and discoveries	12,936	—
Purchase of minerals in place	13,048	—
Revisions of previous estimates	(10,551)	(3)
Production	(3,810)	(2)
Proved reserves as of December 31, 2005	33,023	1
Proved Developed and Undeveloped Reserves as of:		
December 31, 2003		
Proved developed reserves	1,865	4
Proved undeveloped reserves	5,999	—
Total	7,864	4
December 31, 2004		
Proved developed reserves	6,179	6
Proved undeveloped reserves	15,221	—
Total	21,400	6
December 31, 2005		
Proved developed reserves	7,095	1
Proved undeveloped reserves	25,928	—
Total	33,023	1

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence at year end. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and gas producing activities. Operating loss carryforwards to the extent estimated to be available in the future were also considered, thereby reducing expected tax expense.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves is presented below:

	United States (in thousands)
December 31, 2003:	
Future cash inflows	$ 41,450
Future production costs	(21,535)
Future development costs	(8,475)
Future income taxes	—
Future net cash flows	11,440
10% annual discount for estimated timing of cash flows	(3,303)
Standardized measure of discounted future cash flows	$ 8,137
December 31, 2004:	
Future cash inflows	$112,273
Future production costs	(38,097)
Future development costs	(39,680)
Future income taxes	—
Future net cash flows	34,496
10% annual discount for estimated timing of cash flows	(8,887)
Standardized measure of discounted future cash flows	$ 25,609
December 31, 2005:	
Future cash inflows	$244,104
Future production costs	(82,908)
Future development costs	(43,493)
Future income taxes	—
Future net cash flows	117,703
10% annual discount for estimated timing of cash flows	(26,408)
Standardized measure of discounted future cash flows	$ 91,295

Changes in Standardized Measure of Discounted Future Net Cash Flows

The principal sources of changes in the Standardized Measure of Future Net Cash Flows are as follows:

	United States (in thousands)
December 31, 2002	$ 10,495
Extensions and discoveries, less related costs	5,378
Sale of natural gas and oil, net of production costs	(749)
Sales of minerals in place	(10,054)
Revisions of previous quantity estimates	(4,675)
Net change in income tax	111
Net change in prices and production costs	2,129
Accretion of discount	1,273
Development costs incurred	1,713
Net change in estimated future development costs	3,689
Change in production rates (timing)—other	(1,173)
December 31, 2003	8,137
Extensions and discoveries, less related costs	21,371
Sale of natural gas and oil, net of production costs	(4,059)
Purchase of minerals in place	2,853
Sales of minerals in place	(2,718)
Revisions of previous quantity estimates	(1,458)
Net change in income tax	—
Net change in prices and production costs	291
Accretion of discount	864
Development costs incurred	337
Net change in estimated future development costs	1,684
Change in production rates (timing)—other	(1,693)
December 31, 2004	25,609
Extensions and discoveries, less related costs	43,029
Sale of natural gas and oil, net of production costs	(20,532)
Purchase of minerals in place	31,746
Revisions of previous quantity estimates	(38,448)
Net change in income tax	—
Net change in prices and production costs	40,506
Accretion of discount	2,561
Development costs incurred	20,340
Net change in estimated future development costs	(7,238)
Change in production rates (timing) other	(6,278)
December 31, 2005	$ 91,295

Exhibit 10.10

[FORM OF EXECUTIVE STOCK OPTION AGREEMENT]

THIS AGREEMENT made as of the 16th day of January 2006

BETWEEN:

•, an individual resident in •, •, (the "Executive")

\- and -

GASTAR EXPLORATION LTD., a body corporate, having its registered office in the City of Calgary, in the Province of Alberta (the "Corporation")

STOCK OPTION AGREEMENT

WHEREAS:

A. the Corporation is governed by the laws of the Province of Alberta, having an authorized capital consisting of an unlimited number of Common Shares and an unlimited number of Preferred Shares, all without nominal or par value; and

B. the Board of Directors have agreed to grant unto the Executive an option to purchase an aggregate of • **(•) Common Shares** without par value of its authorized unissued share capital in consideration of the Executive's ongoing services and contributions to the Corporation; and

C. the granting of such option to the Executive was authorized by the Board of Directors of the Corporation effective January 16, 2006;

NOW, THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter set forth, and for other valuable consideration, the Parties have agreed as follows:

ARTICLE I
DEFINITIONS

1.1 In this Agreement the following terms shall have the following meanings:

(a) "Board" means the Board of Directors of the Corporation.

(b) "Corporation" means Gastar Exploration Ltd. and any successor or continuing corporation resulting from any form of corporate reorganization.

(c) "Option Shares" means the Shares the Executive is entitled to purchase under a Share Option.

(d) "Parties" means the Executive and the Corporation, collectively.

(e) "Share Option" means an option to purchase treasury shares granted to the Executive pursuant to this Agreement, and includes any portion of that option.

(f) "Share Option Agreement" means this Agreement and any novations thereof.

(g) "Expiration Date" means January 16, 2016.

(h) "Option Date" in respect of the Share Option means the date of this Agreement.

(i) "Option Price" means the price per share for each portion of the Share Option set forth in Clause 2.1 hereof.

(j) "Share" means a Common Share of the Corporation as constituted at the date hereof.

(k) "Treasury Share" means a theretofore-unissued Share which is purchased directly from the Corporation by or for the account of the Executive.

(l) "Market Price" means the price at which the Shares are being offered for upon the Exchange.

(m) "Option Period" means the period commencing upon the Option Date and expiring upon the Expiration Date.

(n) "Exchange" means the stock exchanges upon which the Corporation may be listed upon during the Option Period.

1.2 In this Agreement, the masculine gender shall include the feminine gender and the singular shall include the plural and vice versa wherever the context requires.

ARTICLE II

SHARE OPTION

2.1 Subject to the terms and conditions hereinafter set out, the Corporation hereby grants to the Executive, an irrevocable option to purchase • **(•)** Shares of the Corporation at an exercise price of **• Dollars • Cent (CDN $•)** per Share, which may be exercised on the following basis:

a. **• (•) Shares** at any time or from time to time during the period commencing January 16, 2007 and expiring on the Expiration Date;

b. **• (•) Shares** at any time or from time to time during the period commencing January 16, 2008 and expiring on the Expiration Date;

c. **• (•) Shares** at any time or from time to time during the period commencing January 16, 2009 and expiring on the Expiration Date; and

d. the remaining **• (•) Shares** at any time or from time to time during the period commencing January 16, 2010 and expiring on the Expiration Date.

2.2 Notwithstanding Clause 2.1 hereof, in the event of:

a. any disposition of substantially all of the assets of the Corporation, or the dissolution, merger, amalgamation or consolidation of the Corporation, with or into any other corporation, or the merger, amalgamation or consolidation of any other corporation into the Corporation; or

b. any Change in Control of the Corporation;

the Executive may exercise of any or all of the remaining Optioned Shares prior to the completion of any such transaction. Upon the Corporation entering into an agreement to effect any of the transactions set forth in Clause 2.2(a) or a change in control being effected as contemplated in Clause 2.2(b), the Option shall be deemed to have been amended to permit the exercise thereof in whole or in part by the Executive at any time or from time to time prior to the completion of such transaction.

For the purposes of this Agreement, a "Change in Control" shall be deemed to have occurred if any person, or any two or more persons acting as a group, and all affiliates of such person or persons, who prior to such time beneficially owned less than 20% of the then outstanding Shares, shall acquire such additional Shares in one or more transactions, or series of transactions, such that following such transaction or transactions, such person or group and affiliates beneficially own 20% or more of the Shares outstanding.

2.3 At 4:30 p.m., Calgary time, on the Expiration Date, the Share Option shall forthwith expire and terminate and be of no further force or effect whatsoever as to such of the Option Shares in respect of which the Share Option hereby granted has not then been exercised.

ARTICLE III

CURRENCY DURING TERM OF EMPLOYMENT

3.1 If subsequent to the Option Date and prior to the Expiration Date, the Executive's position as a director, an officer, a consultant to the Corporation and/or the Corporation's subsidiary, or as an employee of the Corporation and/or the Corporation's subsidiary, as the case may be, is terminated by reason of the death or disability of the Executive, the Share Option may be exercised during the period expiring the earlier of the Expiration Date or one year after such date of death or the date of termination of his employment by reason of disability. In the event of the Executive's death or disability, the rights of the Executive under the Share Option may be exercised by the person or persons to whom the Executive's rights under the Share Option shall pass by will or applicable law or, if no such person has such right, by the Executive's executors or administrators, subject to the time limitations as aforesaid.

3.2 If subsequent to the Option Date and prior to the Expiration Date, the Executive's position as a director, an officer, a consultant to the Corporation and/or the Corporation's subsidiary, or an employee of the Corporation and/or the Corporation's subsidiary, as the case may be, is terminated for any reason other than the death or disability of the Executive, the Share Option may be exercised in respect of any outstanding Option Shares for which the Share Option was capable of exercise prior to the termination (but this shall not include any Option Shares for which the defined period for exercise of the Option has not yet started at the effective date of the termination) during the ninety (90) day period following the date on which the Executive's position with the Corporation is terminated, and upon the expiry of such ninety (90) day period, the Share Option shall expire.

ARTICLE IV

MATERIAL CHANGE

4.1 In the event that, prior to the Expiration Date or exercise in full of the Share Option, the outstanding share capital of the Corporation shall be subdivided or consolidated into a greater or lesser number of Shares, or, in the event of the payment of a stock dividend by the Corporation, or in the event that all of the shareholders of the Corporation are granted the right to purchase additional Shares of the Corporation, the number and price of Option Shares remaining subject to the Share Option hereunder shall be increased or reduced accordingly, as the case may be.

4.2 If, prior to the Expiration Date or exercise in full of the Share Option granted hereby, the Corporation shall, at any time arrange with or merge into another corporation, the Executive will thereafter receive, upon the exercise of the Share Option, the securities or properties to which a holder of the number of shares then deliverable upon the exercise of the Share Option would have been entitled upon such arrangement or merger, and the Corporation will take steps in connection with such arrangement or merger as may be necessary to assure that the provisions hereof shall thereafter be applicable, in relation to any securities or property thereafter deliverable upon the exercise of the Share Option granted hereby. A sale of all or substantially all of the assets of the Corporation for consideration, (apart from the assumption of obligations), consisting primarily of securities shall be deemed to be an arrangement or merger for the foregoing purposes.

ARTICLE V

RESERVATION OF TREASURY SHARES

5.1 The Corporation shall at all times during the term of this Agreement, reserve and keep available a sufficient number of Treasury Shares to satisfy the requirements hereof.

ARTICLE VI

RESTRICTION ON ASSIGNMENT

6.1 The Share Option granted hereby is, insofar as the Executive is concerned, personal and non-assignable and neither this Agreement nor any rights in regard thereto shall be transferable or assignable except upon the death of the Executive pursuant to Clause 3.1 hereof.

ARTICLE VII

EXERCISE OF THE SHARE OPTION

7.1 The Share Option may be exercised by the Executive in accordance with the provisions hereof in whole or in part, from time to time, by delivery of written notice of such exercise and by tendering the payment therefor in cash or by certified cheque to the Corporation at its principal office in the City of Houston, in the State of Texas. Such notice shall state the number of the Option Shares with respect to which the Share Option is then being exercised. The Share Option shall be deemed for all purposes to have been exercised to the extent stated in such notice upon delivery of the notice and a tender of payment in full, notwithstanding any delay in the issuance and delivery of the certificates for the Shares so purchased.

ARTICLE VIII

RIGHTS OF THE EXECUTIVE PRIOR TO EXERCISE DATE

8.1 The Share Option herein granted shall not entitle the Executive to any rights whatsoever as a shareholder of the Corporation with respect to any Shares subject to the Share Option until it has been exercised in accordance with Clause 7.1 and Option Shares have been issued as fully paid and non-assessable.

ARTICLE IX

FURTHER ASSURANCES

9.1 The Parties covenant that they shall and will from time to time and at all times hereafter do and perform all such acts and things and execute all such additional documents as may be required to give effect to the terms and intention of this Agreement.

ARTICLE X

INTERPRETATION

10.1 It is understood and agreed by the Parties that questions may arise as to the interpretation, construction or enforcement of this Agreement and the parties are desirous of having the Board determine any such question of interpretation, construction or enforcement. It is therefore understood and agreed by and between the Parties that any question arising under the terms of this Agreement as to interpretation, construction or enforcement shall be referred to the Board and their majority decision shall be final and binding on both of the Parties.

ARTICLE XI

ENTIRE AGREEMENT

11.1 This Agreement supersedes all other agreements, documents, writings and verbal understandings among the parties relating to the subject matter hereof and represents the entire agreement between the parties relating to the subject matter hereof.

ARTICLE XII

ENUREMENT

12.1 Subject to the other provisions hereof, this Agreement shall enure to the benefit of and be binding upon the Parties and their respective heirs, executors, administrators, successors and permitted assigns.

12.2 This Agreement shall continue to constitute a binding obligation of the Corporation notwithstanding any change of control of its voting securities during the term hereof.

IN WITNESS WHEREOF the Parties have executed this Agreement as of the day and year first above written.

SIGNED, SEALED AND DELIVERED	)	
in the presence of:	)	
	)	
	)	
	)	
______________________________ Witness	)	______________________________ •

GASTAR EXPLORATION LTD.

Per: ______________________________

Per: ______________________________

EXHIBIT 21.1

GASTAR EXPLORATION LTD.

Subsidiary List — January 5, 2006

100% Subsidiaries owned of Gastar Exploration Ltd. (Alberta, Canada)

Gastar Exploration USA, Inc. (Michigan)
Gastar Exploration New South Wales, Inc. (Michigan)
Gastar Exploration Victoria, Inc. (Michigan)
Gastar Exploration Texas LP (Delaware) (1)(2)

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(1) Gastar Exploration Texas LLC (Delaware), General Partner (1%)
(2) Gastar Exploration Texas, Inc. (Michigan), Limited Partner (99%)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (File No. 333-130867) of Gastar Exploration Ltd. of our report dated March 21, 2006, relating to the consolidated financial statements as of and for the year ended December 31, 2005, which appear in this Form 10-K.

/s/ BDO SEIDMAN, LLP

Dallas, Texas
March 30, 2006

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-130867) of Gastar Exploration Ltd. of our report dated March 18, 2005 (December 21, 2005 as to Notes 5, 13, 14, 22 and Note 25) relating to the consolidated financial statements of Gastar Exploration Ltd. and subsidiaries, which appears in this Annual Report on Form 10-K.

/s/ BDO DUNWOODY LLP

Calgary, Alberta
March 31, 2006

Exhibit 23.3

NETHERLAND, SEWELL & ASSOCIATES, INC.

Gastar Exploration Ltd.
1331 Lamar Street, Suite 1080
Houston, Texas 77010

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Gentlemen:

As independent oil and gas consultants, Netherland, Sewell & Associates, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-130867) of Gastar Exploration Ltd. of information from our reserve report dated March 10, 2006 entitled "Estimate of Reserves and Future net Revenues to Gastar Exploration Ltd. Interest in Certain Oil and Gas Properties located in the United States as of December 31, 2005, Based on Constant Prices and Costs in accordance with Securities and Exchange Commission Guidelines" and all references to our firm included in or made a part of the Gastar Exploration Ltd. Annual Report on Form 10-K for the year ended December 31, 2005.

Yours very truly,

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ FREDERIC D. SEWELL
Frederic D. Sewell
Chairman and Chief Executive Officer

March 28, 2006
Dallas, Texas

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

PURSUANT TO 15 U.S.C. SECTION 7241, AS ADOPTED
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, J. Russell Porter, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gastar Exploration, Ltd. (the “Registrant”);

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

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

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Registrant and we have:

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

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

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

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

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

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

Date: March 31, 2006

/s/ J. RUSSELL PORTER
J. Russell Porter
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO 15 U.S.C. SECTION 7241, AS ADOPTED
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael A. Gerlich, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gastar Exploration, Ltd. (the "Registrant");

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

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

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Registrant and we have:

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

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

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

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

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

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

Date: March 31, 2006

/s/ MICHAEL A. GERLICH
Michael A. Gerlich
Chief Financial Officer

Exhibit 32.1

Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, J. Russell Porter, Chief Executive Officer of Gastar Exploration, Ltd. (the "Company"), hereby certify that the accompanying Annual Report on Form 10-K for the year ended December 31, 2005 (the "Report"), filed by the Company with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 fully complies with the requirements of that section.

I further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 31, 2006

/s/ J. RUSSELL PORTER
J. Russell Porter
Chief Executive Officer

Exhibit 32.2

Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, Michael A. Gerlich, Chief Financial Officer of Gastar Exploration, Ltd. (the “Company”), hereby certify that the accompanying Annual Report on Form 10-K for the year ended December 31, 2005 (the “Report”), filed by the Company with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 fully complies with the requirements of that section.

I further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 31, 2006

/s/ MICHAEL A. GERLICH

Michael A. Gerlich
Chief Financial Officer