GASTAR EXPLORATION LTD
Form 10-Q
May 05, 2011
**Table of Contents**

**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

# FORM 10-Q

**[ X ] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED March 31, 2011 OR**

**[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ___________ TO ___________.**

**Commission File Number: 001-32714**

# GASTAR EXPLORATION LTD.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Alberta, Canada**<br>(State or other jurisdiction of<br>incorporation or organization) | **98-0570897**<br>(I.R.S. Employer Identification No.) |
| **1331 Lamar Street, Suite 650**<br>**Houston, Texas 77010**<br>(Address of principal executive offices) | **77010**<br>(ZIP Code) |

**(713) 739-1800**

(Registrant s telephone number, including area code)

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

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

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

Large accelerated filer [ ] Accelerated filer [X]

Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

Total number of outstanding common shares, no par value per share, as of May 4, 2011 was 64,862,341.

**GASTAR EXPLORATION LTD.**

**QUARTERLY REPORT ON FORM 10-Q**

**FOR THE THREE MONTHS ENDED MARCH 31, 2011**

**TABLE OF CONTENTS**



*Unless otherwise indicated or required by the context, (i) Gastar, the Company, we, us, our and similar terms refer collectively to Gastar Exploration Ltd. and its subsidiaries, including Gastar Exploration USA, Inc., and predecessors, (ii) Gastar USA refers to Gastar Exploration USA, Inc., our first-tier subsidiary and primary operating company, (iii) Parent refers solely to Gastar Exploration Ltd., (iv) all dollar amounts appearing in this report on Form 10-Q are stated in United States dollars ( U.S. dollars ) and (v) all financial data included in this report have been prepared in accordance with generally accepted accounting principles in the United States of America ( U.S. GAAP ).*

*General information about us can be found on our website at www.gastar.com. The information available on or through our website, or about us on any other website, is neither incorporated into, nor part of, this report. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings that we make with the U.S. Securities and Exchange Commission ( SEC ),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 SEC. Information is also available on the SEC website at www.sec.gov for our United States filings.*

Table of Contents

**PART I. FINANCIAL INFORMATION**

**Item 1. Financial Statements**

**GASTAR EXPLORATION LTD. AND SUBSIDIARIES**

**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | March 31, 2011 (Unaudited) | December 31, 2010 |
|---|---|---|
| | (in thousands) | |
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 12,524 | $ 7,439 |
| Accounts receivable, net of allowance for doubtful accounts of $566 and $571, respectively | 5,711 | 4,034 |
| Commodity derivative contracts | 9,060 | 10,229 |
| Prepaid expenses | 861 | 1,191 |
| Total current assets | 28,156 | 22,893 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| Natural gas and oil properties, full cost method of accounting: | | |
| Unproved properties, excluded from amortization | 147,186 | 162,230 |
| Proved properties | 384,253 | 345,042 |
| Total natural gas and oil properties | 531,439 | 507,272 |
| Furniture and equipment | 1,305 | 1,175 |
| Total property, plant and equipment | 532,744 | 508,447 |
| Accumulated depreciation, depletion and amortization | (297,444) | (293,332) |
| Total property, plant and equipment, net | 235,300 | 215,115 |
| OTHER ASSETS: | | |
| Restricted cash | 50 | 50 |
| Commodity derivative contracts | 6,334 | 8,482 |
| Deferred charges, net | 444 | 508 |
| Drilling advances and other assets | - | 304 |
| Total other assets | 6,828 | 9,344 |
| TOTAL ASSETS | $ 270,284 | $ 247,352 |
| **LIABILITIES AND SHAREHOLDERS EQUITY** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 7,313 | $ 8,294 |
| Revenue payable | 4,239 | 4,331 |
| Accrued interest | 191 | 138 |
| Accrued drilling and operating costs | 3,183 | 1,490 |
| Operated prepayment liability | 7,529 | 783 |
| Commodity derivative contracts | 1,370 | 1,991 |

| | | |
|---|---|---|
| Commodity derivative premium payable | 3,836 | 3,451 |
| Accrued litigation settlement liability | 2,592 | 3,164 |
| Other accrued liabilities | 1,692 | 2,024 |
| Total current liabilities | 31,945 | 25,666 |
| LONG-TERM LIABILITIES: | | |
| Long-term debt | 20,000 | - |
| Commodity derivative contracts | 955 | 1,521 |
| Commodity derivative premium payable | 3,612 | 4,725 |
| Accrued litigation settlement liability | 200 | 800 |
| Asset retirement obligation | 7,552 | 7,249 |
| Total long-term liabilities | 32,319 | 14,295 |
| Commitments and contingencies (Note 12) | | |
| SHAREHOLDERS EQUITY: | | |
| Preferred stock, no par value; unlimited shares authorized; no shares issued | - | - |
| Common stock, no par value; unlimited shares authorized; 64,862,341 and 64,179,115 shares issued and outstanding at March 31, 2011 and December 31, 2010, respectively | 316,346 | 316,346 |
| Additional paid-in capital | 23,764 | 23,200 |
| Accumulated deficit | (134,090) | (132,155) |
| Total shareholders equity | 206,020 | 207,391 |
| TOTAL LIABILITIES AND SHAREHOLDERS EQUITY | $ 270,284 | $ 247,352 |

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

Table of Contents

**GASTAR EXPLORATION LTD. AND SUBSIDIARIES**

**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**

**(Unaudited)**

| | For the Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| | (in thousands, except share and per share data) | |
| REVENUES: | | |
| Natural gas and oil revenues | $ 10,028 | $ 6,758 |
| Unrealized natural gas hedge gain (loss) | (1,899) | 9,378 |
| Total revenues | 8,129 | 16,136 |
| EXPENSES: | | |
| Production taxes | 109 | 123 |
| Lease operating expenses | 1,707 | 1,743 |
| Transportation, treating and gathering | 1,103 | 1,249 |
| Depreciation, depletion and amortization | 4,112 | 1,731 |
| Accretion of asset retirement obligation | 125 | 95 |
| General and administrative expense | 2,880 | 3,832 |
| Total expenses | 10,036 | 8,773 |
| INCOME (LOSS) FROM OPERATIONS | (1,907) | 7,363 |
| OTHER INCOME (EXPENSE): | | |
| Interest expense | (32) | (78) |
| Investment income and other | 2 | 792 |
| Unrealized warrant derivative gain | - | 148 |
| Foreign transaction gain | 2 | 319 |
| INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES | (1,935) | 8,544 |
| Provision for income tax expense (benefit) | - | (849) |
| NET INCOME (LOSS) | $ (1,935) | $ 9,393 |
| NET INCOME (LOSS) PER SHARE: | | |
| Basic | $ (0.03) | $ 0.19 |
| Diluted | $ (0.03) | $ 0.19 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING: | | |
| Basic | 63,024,481 | 48,997,016 |
| Diluted | 63,024,481 | 49,486,656 |

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

2

Table of Contents

**GASTAR EXPLORATION LTD. AND SUBSIDIARIES**

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(Unaudited)**

| | For the Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| | (in thousands) | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income (loss) | $ (1,935) | $ 9,393 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 4,112 | 1,731 |
| Stock-based compensation | 705 | 759 |
| Unrealized natural gas hedge (gain) loss | 1,899 | (9,378) |
| Realized loss (gain) on derivative contracts | (442) | 1,039 |
| Amortization of deferred financing costs and debt discount | 64 | 96 |
| Accretion of asset retirement obligation | 125 | 95 |
| Warrant derivative gain | - | (148) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (1,677) | 1,451 |
| Commodity derivative contracts | (54) | 1,114 |
| Prepaid expenses | 330 | 71 |
| Accrued taxes payable | - | 1,259 |
| Accounts payable and accrued liabilities | (1,524) | 310 |
| Net cash provided by operating activities | 1,603 | 7,792 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Development and purchase of natural gas and oil properties | (23,196) | (10,830) |
| Proceeds from sale of natural gas and oil properties | - | 17,350 |
| Proceeds from (application of) operated property prepayments | 6,746 | (422) |
| Purchase of furniture and equipment | (130) | (66) |
| Purchase of term deposit | - | (6,914) |
| Net cash used in investing activities | (16,580) | (882) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Repayment of short-term loan | - | (17,000) |
| Proceeds from revolving credit facility | 20,000 | - |
| Other | 62 | (39) |
| Net cash provided by (used in) financing activities | 20,062 | (17,039) |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | 5,085 | (10,129) |
| CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD | 7,439 | 21,866 |
| CASH AND CASH EQUIVALENTS, END OF PERIOD | $ 12,524 | $ 11,737 |

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

3

## GASTAR EXPLORATION LTD. AND SUBSIDIARIES

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

### 1. Description of Business

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

Gastar Exploration Ltd. (the Parent ) is a holding company; substantially all of its operations are conducted through, and substantially all of its assets are held by, its primary operating subsidiary, Gastar Exploration USA, Inc. ( Gastar USA ), and its subsidiaries. References in these notes to Gastar, the Company and similar terms refer collectively to Gastar Exploration Ltd. and its wholly owned subsidiaries, including Gastar USA, and predecessors.

### 2. Summary of Significant Accounting Policies

The accounting policies followed by the Company and its subsidiaries are set forth in the notes to the Company s audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2010 ( 2010 Form 10-K ) filed with the SEC. Please refer to the notes to the financial statements included in the Company s 2010 Form 10-K for additional details of the Company s financial condition, results of operations and cash flows. All material items included in those notes have not changed except as a result of normal transactions in the interim or as disclosed within this report.

The unaudited interim condensed consolidated financial statements of the Company included herein are stated in U.S. dollars unless otherwise noted and were prepared from the records of the Company by management in accordance with U.S. GAAP applicable to interim financial statements and reflect all normal and recurring adjustments, which are, in the opinion of management, necessary to provide a fair presentation of the results of operations and financial position for the interim periods. Such financial statements conform to the presentation reflected in the Company s 2010 Form 10-K. The current interim period reported herein should be read in conjunction with the financial statements and accompanying notes, including Item 8. Financial Statements and Supplementary Data, Note 2 - Summary of Significant Accounting Policies included in the Company s 2010 Form 10-K.

The preparation of financial statements in conformity with U.S. 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.

The condensed consolidated financial statements include the accounts of the Company and the consolidated accounts of all of its subsidiaries. The entities included in these consolidated accounts are wholly owned by the Company. All significant intercompany accounts and transactions have been eliminated in consolidation.

Certain reclassifications of prior year balances have been made to conform to the current year presentation; these reclassifications have no impact on net income (loss).

The results of operations for the three months ended March 31, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. In preparing these financial statements, the

Table of Contents

Company has evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued and has disclosed certain subsequent events in these condensed consolidated financial statements, as appropriate.

***Recent Accounting Developments***

The following recently issued accounting pronouncements have been adopted or may impact the Company in future periods:

*Business Combinations.* In December 2010, the Financial Accounting Standards Board s ( FASB ) Emerging Issues Task Force ( EITF ) issued an amendment to previously issued guidance regarding the pro forma revenue and earnings disclosure requirements for business combinations. The amendments specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures under current guidance to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Earlier application is permitted. The adoption of this guidance did not impact our operating results, financial position or cash flows.

**3. 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 United States, specifically the states of Texas, Pennsylvania, West Virginia, Wyoming and Montana.

The following table summarizes the components of unproved properties excluded from amortization for the periods indicated:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| | (in thousands) | |
| Unproved properties, excluded from amortization: | | |
| Drilling in progress costs | $ 2,733 | $ 17,603 |
| Acreage acquisition costs | 127,156 | 126,388 |
| Capitalized interest | 17,297 | 18,239 |
| Total unproved properties excluded from amortization | $ 147,186 | $ 162,230 |

Management s ceiling test evaluations for the three months ended March 31, 2011 and 2010 did not result in an impairment of proved properties. The ceiling test evaluations utilized a historical 12-month un-weighted average of the first-day-of-the-month Henry Hub natural gas price of $4.10 per MMBtu and $3.99 per MMBtu for the three months ended March 31, 2011 and 2010, respectively.

***Atinum Joint Venture***

In September 2010, the Company entered into a joint venture (the Atinum Joint Venture ) pursuant to a purchase and sale agreement with an affiliate of Atinum Partners Co., Ltd. ( Atinum ), a Korean investment firm. Pursuant to the agreement, at the closing of the transactions on November 1, 2010, the Company assigned to Atinum an initial 21.43% interest in all of its existing Marcellus Shale assets in West Virginia and Pennsylvania, which consisted of approximately 37,600 gross (34,200 net) acres and a 50% working interest in 16 producing shallow conventional wells and one non-producing vertical Marcellus Shale well, in a transaction valued at $70.0 million. Atinum paid the Company approximately $30.0 million in cash at the closing and will pay an additional $40.0 million of future drilling obligations over time in the form of a drilling carry. Upon completion of the funding of the drilling carry, the Company will make additional assignments to Atinum, as necessary, so Atinum will own a 50% interest in the 34,200 net acres of Marcellus Shale rights initially owned by the Company. The terms of the drilling carry require Atinum to fund its ultimate 50% share of drilling, completion and infrastructure costs along with 75% of the Company s ultimate 50% share of those same costs until the $40.0 million drilling carry has been satisfied. As of March 31, 2011, approximately $37.0 million of drilling carry obligation remained outstanding.

The Atinum Joint Venture is pursuing an initial three-year development program that calls for the partners to drill a minimum of 12 horizontal wells in 2011 and 24 horizontal wells in each of 2012 and 2013. An initial Area of Mutual Interest ( AMI ) was established for potential additional acreage acquisitions in Ohio and New York along with the counties in West Virginia and Pennsylvania in which the existing Atinum Joint Venture interests are located. Within this initial AMI, the Company will act as operator and is obligated to offer any future lease acquisitions within the AMI to Atinum on a 50/50 basis, and Atinum will pay the Company on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs up to $20.0 million and 5% of such costs on activities above $20.0 million. Until June 30, 2011, Atinum will have the right to participate in any future leasehold acquisitions made by the Company outside of the initial AMI and within West Virginia or Pennsylvania on terms identical to those governing the existing Atinum Joint Venture.

As of March 31, 2011, total cash consideration received by the Company pursuant to the Atinum Joint Venture was approximately $33.0 million, $30.0 million of which was received upon closing and $3.0 million of drilling carry. The $30.0 million received upon closing reduced proved property and unproved property costs by approximately $5.0 million and $25.0 million, respectively.

***Marcellus Shale Leasehold Acquisition***

In December 2010, the Company completed an acquisition of undeveloped leasehold in the Marcellus Shale concentrated in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia, including a gathering system comprised of 41 miles of four and six inch steel pipe, a salt water disposal well and five conventional producing wells. This acreage is not included in the Atinum Joint Venture and the counties in which the acquired assets are located are not part of the initial AMI.

Total cash consideration paid by the Company was $28.9 million. The Company allocated $19.9 million to unproved properties and $9.0 million to proved properties based on the fair value of the assets acquired on the acquisition date.

**4. Long-Term Debt**

***Amended and Restated Revolving Credit Facility***

On October 28, 2009, Gastar USA, together with the Parent and Subsidiary Guarantors (as defined in the Revolving Credit Facility), and the lenders, administrative agent and letter of credit issuer party thereto, entered into an amended and restated credit facility, amending and restating in its entirety the original revolving credit facility (as amended and restated, the Revolving Credit Facility ). The Revolving Credit Facility provided an initial borrowing base of $47.5 million, with borrowings bearing interest, at the Company s election, at the prime rate or LIBO rate plus an applicable margin. Pursuant to the Revolving Credit Facility, the applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the prime rate and from 2.5% to 3.5% in the case of borrowings based on LIBO rate, depending on the utilization percentage in relation to the borrowing base. An annual commitment fee of 0.50% is payable quarterly based on the unutilized balance of the borrowing base. The Revolving Credit Facility has a scheduled maturity date of January 2, 2013.

The Revolving Credit Facility is guaranteed by the Parent and all of Gastar USA s current domestic subsidiaries and all future domestic subsidiaries formed during the term of the Revolving Credit Facility. Borrowings and related guarantees under the Revolving Credit Facility are secured by a first priority lien on all domestic natural gas and oil properties currently owned by or later acquired by Gastar USA and its subsidiaries, excluding *de minimus* value properties as determined by the lender. The facility is secured by a first priority pledge of the stock of each domestic subsidiary, a first priority interest on all accounts receivable, notes receivable, inventory, contract rights, general intangibles and material property of the issuer and 65% of the stock of each foreign subsidiary of Gastar USA.

The Revolving Credit Facility contains various covenants, including among others:

- Restrictions on liens;
- Restrictions on incurring other indebtedness without the lenders consent;
- Restrictions on dividends and other restricted payments;
- Maintenance of a minimum consolidated current ratio as of the end of each quarter of not less than 1.0 to 1.0, as adjusted;
- Maintenance of a maximum ratio of indebtedness to EBITDA on a rolling four quarter basis, as adjusted, of not greater than 4.0 to 1.0; and
- Maintenance of an interest coverage ratio on a rolling four quarters basis, as adjusted, of EBITDA to interest expense, as of the end of each quarter, to be less than 2.5 to 1.0.

All outstanding amounts owed under the Revolving Credit Facility become due and payable upon the occurrence of certain usual and customary events of default, including among others:

- Failure to make payments under the Revolving Credit Facility;
- Non-performance of covenants and obligations continuing beyond any applicable grace period; and
- The occurrence of a Change in Control (as defined in the Revolving Credit Facility) of the Parent.

Should there occur a Change in Control of the Parent, then, five days after such occurrence, immediately and without notice, (i) all amounts outstanding under the Revolving Credit Facility shall automatically become immediately due and payable and (ii) the commitments shall immediately cease and terminate unless and until reinstated by the lender in writing. If amounts outstanding under the Revolving Credit Facility become immediately due and payable, the obligation of Gastar USA with respect to any commodity hedge exposure shall be to provide cash as collateral to be held and administered by the lender as collateral agent.

Following our scheduled semi-annual borrowing base redetermination in May 2010, on June 24, 2010, Gastar USA, together with the other parties thereto, entered into the Second Amendment to the Amended and Restated Credit Agreement (the Second Amendment ). The Second Amendment amended the Revolving Credit Facility, by, among other things, (i) allowing the Company to hedge up to 80% of the proved developed producing ( PDP ) reserves reflected in its reserve report using hedging other than floors and protective spreads, (ii) relatedly, allowing the Company to present to the administrative agent a report showing any PDP additions resulting from new wells or the conversion of proved developed non-producing reserves to PDP reserves since the last reserve report in order to hedge the revised PDP reserves, and (iii) removing the limitations on hedging using floors and protective spreads.

As of March 31, 2011, the Revolving Credit Facility had a borrowing base of $47.5 million, with $20.0 million of borrowings outstanding and availability of $27.5 million. Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year, with the next redetermination scheduled for May 2011. The Company and the lenders may each request one additional unscheduled redetermination annually.

At June 30, 2010, the Company was not in compliance with the 80% hedge limitation for 2011 under the Revolving Credit Facility; the Company was in compliance with all other financial covenants under the Revolving Credit Facility at such time. The Company was granted a waiver in regards to the hedge limitation through March 31, 2011 and in conjunction with such waiver, at March 31, 2011, the Company was in compliance with all financial covenants under the Revolving Credit Facility.

***Other Debt***

Credit support for the Company s open derivatives at March 31, 2011 is provided through inter-creditor agreements or open accounts.

Table of Contents

**5. Fair Value Measurements**

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company discloses its recognized non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. Since none of the Company s non-financial assets and liabilities were impaired during the period-ended March 31, 2011, and no other fair value measurements are required to be recognized on a non-recurring basis, no additional disclosures are provided at March 31, 2011.

As defined in the guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ( Level 1 ) and the lowest priority to unobservable inputs ( Level 3 ). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. The Company s cash equivalents consist of short-term, highly liquid investments, which have maturities of 90 days or less, including sweep investments and money market funds.

Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources. These inputs may be used with internally developed methodologies or third party broker quotes that result in management s best estimate of fair value. The Company s valuation models consider various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments. Level 3 instruments are natural gas costless collars, index, basis and fixed price swaps, put and call options and warrants. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values below incorporates various factors, including the impact of the counterparty s non-performance risk with respect to the Company s financial assets and the Company s non-performance risk with respect to the Company s financial liabilities. The Company has not elected to offset the fair value amounts recognized for multiple derivative instruments executed with the same counterparty, but reports them gross on its condensed consolidated balance sheets.

Table of Contents

The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011 and December 31, 2010:

| | Fair value as of March 31, 2011 | | | |
|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** |
| | (in thousands) | | | |
| Assets: | | | | |
| Cash and cash equivalents | $ 12,524 | $ - | $ - | $ 12,524 |
| Restricted cash | 50 | - | - | 50 |
| Commodity derivative contracts | - | - | 15,394 | 15,394 |
| Liabilities: | | | | |
| Commodity derivative contracts | - | - | (2,325) | (2,325) |
| Total | $ 12,574 | $ - | $ 13,069 | $ 25,643 |

| | Fair value as of December 31, 2010 | | | |
|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** |
| | (in thousands) | | | |
| Assets: | | | | |
| Cash and cash equivalents | $ 7,439 | $ - | $ - | $ 7,439 |
| Restricted cash | 50 | - | - | 50 |
| Commodity derivative contracts | - | - | 18,711 | 18,711 |
| Liabilities: | | | | |
| Commodity derivative contracts | - | - | (3,512) | (3,512) |
| Total | $ 7,489 | $ - | $ 15,199 | $ 22,688 |

**Table of Contents**

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy for the three months ended March 31, 2011 and 2010. Level 3 instruments presented in the table consist of net derivatives that, in management s opinion, reflect the assumptions a marketplace participant would have used at March 31, 2011 and 2010.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Balance at beginning of period | $ 15,199 | $ 7,638 |
| Total gains (losses) (realized or unrealized): | | |
| included in earnings | 562 | 8,528 |
| included in other comprehensive income | - | - |
| Purchases | - | - |
| Issuances | - | - |
| Settlements (1) | (2,692) | (1,155) |
| Transfers in and (out) of Level 3 | - | - |
| Balance at end of period | $ 13,069 | $ 15,011 |
| The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at March 31, 2011 and 2010 | $ (1,899) | $ 9,526 |

(1) Included in natural gas and oil revenues and other income (expense) on the statement of operations.

At March 31, 2011, the estimated fair value of accounts receivable, prepaid expenses, accounts and revenue payables and accrued liabilities approximates their carrying value due to their short-term nature. The estimated fair value of the Company s long-term debt at March 31, 2011 approximates the respective carrying value because the interest rate approximates the current market rate.

The fair value guidance, as amended, establishes that every derivative instrument is to be recorded on the balance sheet as either an asset or liability measured at fair value. See Part I, Item 1. Financial Statements, Note 6 - Derivative Instruments and Hedging Activity of this report.

**6. Derivative Instruments and Hedging Activity**

The Company maintains a commodity price risk management strategy that uses derivative instruments to minimize significant, unanticipated earnings fluctuations that may arise from volatility in commodity prices. The Company uses costless collars, index, basis and fixed price swaps and put and call options to hedge natural gas price risk.

All derivative contracts are carried at their fair value on the balance sheet and all unrealized gains and losses are recorded in the statement of operations in unrealized natural gas hedge gain (loss), while realized gains and losses related to contract settlements are recognized in natural gas and oil revenues. For the three months ended March 31, 2011 and 2010, the Company reported an unrealized loss of $1.9 million and an unrealized gain of $9.4 million, respectively, in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments.

**Table of Contents**

As of March 31, 2011, the following derivative transactions were outstanding with the associated notational volumes and weighted average underlying hedge prices:

| Settlement Period | Derivative Instrument | Average Daily Volume | Total of Notional Volume | Base Fixed Price | Floor (Long) | Short Put | Ceiling (Short) |
|---|---|---|---|---|---|---|---|
| | | (in MMBtu s) | | | | | |
| 2011 | Put spread | 11,343 | 2,658,670 | - | 6.07 | 4.14 | - |
| 2011 | Costless three-way collar | 7,762 | 782,000 | - | 6.12 | 4.23 | 7.12 |
| 2011 | Fixed price swap | 2,000 | 550,000 | 6.11 | - | - | - |
| 2011 | Basis - HSC (1) | 9,667 | 880,000 | (0.23) | - | - | - |
| 2011 | Basis - CIG (2) | 800 | 220,000 | (1.21) | - | - | - |
| 2012 | Put spread | 13,028 | 4,770,420 | - | 6.00 | 4.00 | - |
| 2012 | Costless three-way collar | 5,410 | 1,979,580 | - | 6.00 | 4.00 | 7.39 |
| 2012 | Fixed price swap | 2,000 | 732,000 | 5.00 | - | - | - |

(1) East Houston-Katy Houston Ship Channel

(2) Inside FERC Colorado Interstate Gas, Rocky Mountains

As of March 31, 2011, all of the Company s economic derivative hedge positions were with a multinational energy company or large financial institutions, which are not known to the Company to be in default on their derivative positions. Credit support for the Company s open derivatives at March 31, 2011 is provided under the Revolving Credit Facility through inter-creditor agreements or open credit accounts of up to $5.0 million. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate non-performance by such counterparties. None of the Company s derivative instruments contains credit-risk related contingent features.

In conjunction with certain derivative hedging activity, the Company deferred the payment of certain put premiums for the production month period July 2010 through December 2012. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company began amortizing the deferred put premium liabilities during July 2010.

The following table provides information regarding the deferred put premium liabilities for the periods indicated:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| | (in thousands) | |
| Current commodity derivative premium payable | $ 3,836 | $ 3,451 |
| Long-term commodity derivative premium payable | 3,612 | 4,725 |
| Total unamortized put premium liabilities | $ 7,448 | $ 8,176 |

Table of Contents

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of the period indicated:

| | March 31, 2011 (in thousands) |
|---|---|
| April - December 2011 | $ 2,723 |
| January - December 2012 | 4,725 |
| Total unamortized put premium liabilities | $ 7,448 |

***Warrants***

The Company reclassified the fair value of its warrants to purchase common stock, which had exercise price reset features, from equity to liability status as if these warrants were treated as a derivative liability since their date of issue in June 2008. On January 1, 2009, the Company reclassified from additional paid-in capital, as a cumulative effect adjustment, $5.4 million to beginning retained earnings and did not recognize any value to common stock warrant liability for representing the fair value of such warrants on such date. The fair value of these warrants to purchase common stock was zero as of March 31, 2011. The Company recognized $148,000 in unrealized gains in other income for the change in fair value of these warrants for the three months ended March 31, 2010.

The following warrants to purchase common shares were outstanding as of March 31, 2011:

| Warrants Outstanding | Fair Value (in thousands) | Weighted Price per Share Range | Average Remaining Life in Years | Average Exercise Price |
|---|---|---|---|---|
| 2,000,000 | $ - | (1) | 0.7 | (1) |

(1) The warrants are exercisable for $13.75 per share in the event that, on or before June 11, 2011, the Company sells all or substantially all of its present natural gas and oil interests located in Leon and Robertson Counties in East Texas for net proceeds exceeding $500.0 million. A sale or a series of sales of all or substantially all of the Company s present East Texas properties prior to June 11, 2011 for $500.0 million or less will terminate the warrants. If the Company does not sell all or substantially all of these properties by June 11, 2011, the warrants will be exercisable for a six-month period commencing on that date at $15.00 per share. The Company is not obligated to sell any of its East Texas properties. Fair value is based on the Black-Scholes-Merton model for option pricing.

**Table of Contents**

***Additional Disclosures about Derivative Instruments and Hedging Activities***

The tables below provide information on the location and amounts of derivative fair values in the statement of financial position and derivative gains and losses in the statement of operations for derivative instruments that are not designated as hedging instruments:

**Fair Values of Derivative Instruments**

**Derivative Assets (Liabilities)**

| | **Balance Sheet Location** | **Fair Value March 31, 2011** | **Fair Value December 31, 2010** |
|---|---|---|---|
| | | **(in thousands)** | |
| **Derivatives not designated as hedging instruments** | | | |
| Commodity derivative contracts | Current assets | $ 9,060 | $ 10,229 |
| Commodity derivative contracts | Other assets | 6,334 | 8,482 |
| Commodity derivative contracts | Current liabilities | (1,370) | (1,991) |
| Commodity derivative contracts | Long-term liabilities | (955) | (1,521) |
| **Total derivatives not designated as hedging instruments** | | $ 13,069 | $ 15,199 |

**Amount of Gain (Loss) Recognized in Income on Derivatives**

| | **Location of Gain (Loss) Recognized in Income on Derivatives** | **Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended March 31, 2011** | **March 31, 2010** |
|---|---|---|---|
| | | **(in thousands)** | |
| **Derivatives not designated as hedging instruments** | | | |
| Commodity derivative contracts | Unrealized natural gas hedge gain (loss) | $ (1,899) | $ 9,378 |
| Warrant derivative | Unrealized warrant derivative gain (loss) | - | 148 |
| **Total** | | $ (1,899) | $ 9,526 |

**7. Capital Stock**

***Other Share Issuances***

The following table provides information regarding the issuances and forfeitures of common shares pursuant to the Company s 2006 Long-Term Incentive Plan for the periods indicated:

| | **For the Three Months Ended March 31, 2011** |
|---|---|
| Other share issuances: | |
| Restricted common shares granted | 753,199 |
| Restricted common shares vested | 117,176 |
| Common shares forfeited (1) | 32,473 |
| Common shares canceled | 37,500 |

(1) Represents common shares forfeited in connection with the payment of estimated withholding taxes on restricted common shares that vested during the period.

Table of Contents

***Shares Reserved***

The following table summarizes the components of common shares reserved at March 31, 2011:

| | |
|---|---|
| Common shares reserved for the: | |
| Exercise of stock options | 1,077,100 |
| Exercise of warrants | 2,000,000 |
| Total common shares reserved | 3,077,100 |

**8. Interest Expense**

The following table summarizes the components of interest expense for the periods indicated:

| | For the Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Interest expense: | | |
| Cash and accrued | $ 142 | $ 105 |
| Amortization of deferred financing costs and debt discount | 63 | 96 |
| Capitalized interest | (173) | (123) |
| Total interest expense | $ 32 | $ 78 |

**9. Related Party Transactions**

***Chesapeake Energy Corporation***

Chesapeake Energy Corporation ( Chesapeake ) acquired 6,781,767 common shares during 2005 to 2007 in a series of private placement transactions. As a result of its share ownership, Chesapeake has the right to have an observer present at meetings of the board of directors of the Company.

As of March 31, 2011, Chesapeake owned 6,781,767 common shares, or 10.5% of the Company s outstanding common shares.

**10. Income Taxes**

For the three months ended March 31, 2011, the Company did not recognize a current income tax benefit or provision. For the three months ended March 31, 2010, the Company recognized a current tax benefit of $849,000 primarily as a result of the Australian Taxation Office s ( ATO ) issuance of an amended assessment of the income tax with respect to the gain on sale of the Company s Australian assets in July 2009. The issuance of the amended assessment by the ATO represented final resolution in favor of the Company of certain tax issues that could not be resolved until the ATO completed its review of the Australian assets sale in April 2010. The ATO resolution resulted in the recognition of an Australian tax expense benefit of AU$1.3 million ($1.0 million), which was reduced by AU$213,000 ($196,000) of Australian withholding tax on interest income earned on term deposits in Australia from the date of the sale through March 31, 2010.

**11. Earnings per Share**

In accordance with the provisions of current authoritative guidance, basic earnings or loss per share is computed on the basis of the weighted average number of common shares outstanding during the periods. Diluted earnings or loss per share is computed based upon the weighted average number of common shares outstanding 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.

Table of Contents

| | For the Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands, except per share and share data) | |
| Net income (loss) | $ (1,935) | $ 9,393 |
| Weighted average common shares outstanding - basic | 63,024,481 | 48,997,016 |
| Incremental shares from unvested restricted shares | - | 414,182 |
| Incremental shares from outstanding stock options | - | 75,458 |
| Weighted average common shares outstanding - diluted | 63,024,481 | 49,486,656 |
| Income (loss) per common share: | | |
| Basic | $ (0.03) | $ 0.19 |
| Diluted | $ (0.03) | $ 0.19 |
| Common shares excluded from denominator as anti-dilutive: | | |
| Unvested restricted shares | 402,632 | - |
| Stock options | 867,800 | 1,075,000 |
| Warrants | 2,000,000 | 2,000,000 |
| Total | 3,270,432 | 3,075,000 |

**12. Commitments and Contingencies**

***Litigation***

*Navasota Resources L.P. ( Navasota ) vs. First Source Texas, Inc., First Source Gas L.P. (now Gastar Exploration Texas LP) and Gastar Exploration Ltd. (Cause No. 0-05-451) District Court of Leon County, Texas12th Judicial District.* This lawsuit, dated October 31, 2005, contends that the Company breached Navasota s preferential right to purchase 33.33% of the Company s interest in certain natural gas and oil leases located in Leon and Robertson Counties, which were sold to Chesapeake on November 4, 2005 (the 2005 Transaction ). 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 2005 Transaction. In July 2006, the District Court of Leon County, Texas issued a summary judgment in favor of the Company and Chesapeake. Navasota filed a Notice of Appeal to the Tenth Court of Appeals in Waco. Oral argument was heard on September 26, 2007 and the Court of Appeals issued its opinion on January 9, 2008 reversing the trial court s rulings, rendering judgment in favor of Navasota on its claims for breach of contract and specific performance, and remanding the case for further proceedings on Navasota s other counts, which include claims for suit to quiet title, trespass to try title, tortuous interference with contract, conversion, money had and received, and declaratory relief. The Company and Chesapeake filed a motion for rehearing on February 6, 2008, which was denied on March 18, 2008. The Company and Chesapeake filed a joint Petition for Review in the Texas Supreme Court on May 13, 2008. On August 28, 2008, the Texas Supreme Court requested briefing on the merits. On January 9, 2009, the Texas Supreme Court denied the Petition for Review. On January 26, 2009, the Company and Chesapeake jointly filed a motion for rehearing in the Texas Supreme Court on its denial of the Petition for Review. On April 24, 2009, the Texas Supreme Court denied the Petition for Review.

Pursuant to a provision in the Purchase and Sale and Exploration Development Agreement, dated November 4, 2005 (the Purchase and Sale Agreement ), between the Company and Chesapeake, Chesapeake acknowledged the existence of the Navasota lawsuit and claims and further agreed that if Navasota were to prevail on its claims, that Chesapeake would convey the affected interests it purchased from the Company to Navasota upon receipt of the purchase price and/or other consideration paid by Navasota. Therefore, the Company believes that Navasota s exercise of its rights of specific performance should impact only Chesapeake s assigned leasehold interests. However, in December 2008, Chesapeake stated to the Company that if the Texas Supreme Court were not to reverse the decision of the Tenth Court of Appeals, Chesapeake would seek rescission of the 2005 Transaction and restitution of consideration paid, indicating that Chesapeake might assert such rescission and restitution as to the Purchase and Sale Agreement and the Exploration and Development Agreement and the Common Share Purchase Agreement, both dated November 4, 2005. Chesapeake did not identify particular sums as to which it might seek restitution, but amounts paid to the Company in connection with the 2005 Transaction could be asserted to include the $76.0 million paid by Chesapeake for the purchase of 5.5 million common shares as part of the 2005 Transaction and/or other amounts. Chesapeake amended its answer to include cross-claims and counterclaims, including a claim for rescission.

On or about June 9, 2009, Navasota filed and served its Fourth Amended Petition, essentially re-pleading its previously-asserted claims against the Company and Chesapeake. Navasota has exercised its rights of specific performance, and Chesapeake assigned leases to Navasota in July 2009. In March 2011, Chesapeake dismissed the cross-claims against the Company, including the claim for rescission, without prejudice to the subsequent refiling of those claims. On April 12, 2011, Navasota filed its Fifth Amended Petition. The Fifth Amended Petition adds a new claim that the Company allegedly has refused to offer Navasota interests in oil and gas leases located within an area of mutual interest, failed to assign Navasota overriding royalty interests, and failed to recognize back-in-after-payout interests.

The case has been set for trial on July 26, 2011. The Company intends to vigorously defend all claims asserted in the suit.

*Craig S. Tillotson v. S. David Plummer 2nd, Spencer Plummer 3rd, Tony Ferguson, John Parrott, Thomas Robinson, GeoStar Corporation, First Source Wyoming, Inc. GeoStar Financial Services Corporation, Gastar Exploration Ltd., Zeus Investments, LLC and John Does 1-10 (Civil No. 080412334).* This lawsuit was filed on July 7, 2008 in Utah state court by Craig S. Tillotson ( Tillotson ), in which he alleges that he was fraudulently induced to invest in a mare leasing program operated by Classic Star LLC, ( ClassicStar ) a subsidiary of GeoStar Corporation ( GeoStar ), on the basis of certain verbal representations, and to convert interests in that program into shares of a working interest in the Powder River Basin. Tillotson asserts causes of action against all defendants including common law fraud, fraudulent inducement, statutory securities fraud under Utah state law, civil conspiracy and negligent misrepresentation, and asserts certain additional causes of action only against GeoStar, a GeoStar affiliate, and David and Spencer Plummer. The Company has not been served and has not yet answered or otherwise responded. The Company intends to vigorously defend the suit.

*Gastar Exploration Texas L.P. vs. J. Ken Welch d/b/a W-S-M Oil Company, et al; Cause No. 0-09-117 in the 87th Judicial District Court of Leon County, Texas.* This lawsuit, filed on March 12, 2009, is a suit for trespass to try title and, in the alternative, to quiet title to an undivided mineral interest under several Company oil and gas leases covering approximately 4,273.7 gross acres (the Leases ). The Company contends that certain oil and gas leases claimed by the defendants have expired according to their terms and that the defendants failure to release those leases constitutes a trespass upon and cloud on the Leases. The defendants have responded with a general denial and produced a portion of the documents the Company sought in its request for production of documents. They have also served their own requests for admissions and production of documents, to which the Company has responded. After repeated demands, the defendants produced certain documents they obtained from third parties through depositions on written questions. The defendants have filed their own counterclaim asserting various theories of recovery. The defendants claim that their leases are still valid and that they own a working interest and/or an overriding royalty in the Company s Belin No. 1 well located in Leon County. The parties attended mediation but no settlement was reached. The defendants were deposed in March 2011. The case is set for trial starting October 3, 2011. The Company believes it has gathered evidence to diminish the defendant s interest ownership claims and will continue to vigorously pursue this claim.

The Company has been expensing legal defense costs on these proceedings as they are incurred. With respect to the *Navasota Resources, Tillotson and J. Ken Welch* matters, the Company has not accrued a liability for settlement or other resolution of these proceedings because, in the Company s judgment, the incurrence or amount of such liabilities is either not probable or not reasonably estimable.

The Company is party to various legal proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Net of available insurance and performance of contractual

Table of Contents

defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the Company s financial position, results of operations or cash flows.

**13. Statement of Cash Flows Supplemental Information**

The following is a summary of supplemental cash paid and non-cash transactions for the periods indicated:

| | For the Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| | (in thousands) | |
| Cash paid for interest | $ 89 | $ 146 |
| Non-cash transactions: | | |
| Non-cash capital expenditures excluded from accounts payable and accrued drilling costs | $ 809 | $ 3,534 |
| Non-cash capital expenditures excluded from accounts receivable | - | (1,400) |
| Asset retirement obligation included in natural gas and oil properties | 178 | 10 |
| Drilling advances application | 204 | 150 |

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking information regarding Gastar that is intended to be covered by the forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate, pre target or continue, the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations and beliefs concerning future developments and their potential effect on us, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. 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, including the anticipated scheduling and results of such operations;
- natural gas and oil reserves;
- timing and amount of future production of natural gas, natural gas liquids, oil and condensate;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development; and
- property acquisitions and sales.

Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management s assumptions about future events may prove to be inaccurate. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for natural gas and oil;
- low and/or declining prices for natural gas and oil;
- natural gas and oil price volatility;
- worldwide political and economic conditions and conditions in the energy market;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or fulfill their obligation to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- uncertainties about the estimated quantities of natural gas and oil reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;
- strength and financial resources of competitors;
- availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- availability and cost of processing and transportation;
- changes or advances in technology;

Table of Contents

the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells, operating hazards inherent to the natural gas and oil business and 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;
environmental risks;
possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
potential losses from pending or possible future claims, litigation or enforcement actions;
potential defects in title to our properties or lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;
the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;
ability to find and retain skilled personnel; and
any other factors that impact or could impact the exploration of natural gas or oil resources, including, but not limited to, the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of natural gas and oil.

For a more detailed description of the risks and uncertainties that we face and other factors that could affect our financial performance or cause our actual results to differ materially from our projected results please see (i) Part II, Item 1A. Risk Factors and elsewhere in this report, (ii) Part I, Item 1A. Risk Factors and elsewhere in our 2010 Form 10-K, (iii) our subsequent reports and registration statements filed from time to time with the SEC and (iv) other announcements we make from time to time.

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

**Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations**

**Overview**

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

The Parent is a Canadian corporation, incorporated in Alberta in 1987 and subsisting under the Business Corporations Act (Alberta), with its common shares listed on the NYSE Amex under the symbol GST. The Parent is a holding company. Substantially all of the Company s operations are conducted through, and substantially all of its assets are held by, the Parent s primary operating subsidiary, Gastar USA, and its subsidiaries.

Our current operational activities are conducted primarily in the United States. As of March 31, 2011, our major assets consist of approximately 35,300 gross (19,400 net) acres in the Bossier play in the Hilltop area of East Texas, approximately 103,500 gross (73,600 net) acres in the Marcellus Shale in West Virginia and southwestern

**Table of Contents**

Pennsylvania and approximately 43,400 gross (19,600 net) acres in the Powder River Basin of Wyoming and Montana.

The following discussion addresses material changes in our results of operations for the three months ended March 31, 2011 compared to the three months ended March 31, 2010 and material changes in our financial condition since December 31, 2010. This discussion should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in Part I. Item 1. of this report, as well as our 2010 Form 10-K, which includes important disclosures regarding our critical accounting policies as part of Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

***Natural Gas and Oil Activities***

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

*Hilltop Area, East Texas.* The majority of our activities in the first quarter of 2011 have been in the Bossier play in the Hilltop area of East Texas, approximately midway between Dallas and Houston in Leon and Robertson Counties. As of March 31, 2011, our acreage position in the play was approximately 35,300 gross (19,400 net) acres. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production and attractive long-lived per well reserves.

In May 2010, we drilled the Wildman 6H, a horizontal well, in the Glen Rose formation and completed it with a single stage fracture stimulation. The Wildman 6H well was completed using a slotted liner which did not allow for the multi-stage fracture stimulation of the horizontal wellbore where several natural fractures were observed. Currently, the well is producing approximately 12 barrels of oil per day ( BOPD ). Recognizing that our original completion approach was not optimal, we decided to further test the Glen Rose formation. Subsequently, we drilled two other wells to test the Glen Rose formation - another horizontal well, the Wildman 8H, and a vertical well, the Williams #2. The Wildman 8H and Williams #2 were fracture stimulated and completed in late February 2011. The Wildman 8H production currently averages approximately 160 BOPD and approximately 200 barrels of fracture stimulation fluids per day on artificial gas lift. While these initial production results are encouraging, we plan on monitoring production for a period of time before continuing with horizontal development of the Glen Rose formation. The Williams #2 was initially flowing naturally after stimulation and was placed on artificial lift at a current rate of approximately 6 BOPD. We plan on adding additional Glen Rose perforations and, ultimately, commingling the Glen Rose and Eagle Ford Shale/Woodbine in the Williams #2 well later in 2011.

In January 2011, we also began testing the Eagle Ford Shale/Woodbine formation with one recent well in East Texas, the Wildman 7H. The Wildman 7H horizontal well was intended to test the Eagle Ford Shale/Woodbine formation, but due to drilling issues, the well was re-targeted and the horizontal lateral drilled in a slightly deeper transitional limestone zone known as the False Buda. The well was fracture stimulated with a 16-stage completion. Micro-seismic information was gathered during the completion process and processing and interpretation of that data revealed that our fracture stimulation did not extend upward as anticipated in order to allow communication with the Eagle Ford Shale/Woodbine formation. The Wildman 7H initially flowed at 145 BOPD and was placed on artificial lift in mid-February 2011 and production is currently averaging approximately 40 BOPD and approximately 400 barrels of water per day. We plan to drill a subsequent well based on the production results observed to date from the Wildman 7H well. We expect the horizontal lateral in the next Eagle Ford Shale/Woodbine well will be targeted within the portion of the Eagle Ford Shale/Woodbine formation that was originally the target of the Wildman 7H well. We are currently awaiting the evaluation results of a core taken in the Eagle Ford Shale/Woodbine section while drilling the Belin #3 well before commencing drilling of the next test well.

In December 2010, we began drilling the Belin #2 well, an exploration well testing the deep Bossier in a separate fault block near the Belin #1 well. The well reached total depth of 19,650 feet and encountered approximately 130 net feet of pay in the lower Bossier formation within five separate sand intervals. The initial formation zone was fracture stimulated in April 2011 with marginal results and a bridge plug has been set. In early May 2011, we anticipate fracture stimulating the next zone which, based on log interpretation, should be a more

**Table of Contents**

prolific producing lower Bossier zone. We have a 67% before payout working interest and an approximate 50% before payout net revenue interest in the well.

We are currently drilling the Belin #3 well to a true vertical depth of approximately 19,600 feet to test the lower Bossier. The well is anticipated to reach total depth by in early July 2011. We have a 67% before payout working interest and an approximate 50% before payout net revenue interest in the well.

For the three months ended March 31, 2011, net production from the Hilltop area averaged approximately 20.4 MMcfe per day compared to 17.0 MMcfe per day for the first quarter of 2010.

*Appalachia West Virginia and Central and Southwestern Pennsylvania.* The Marcellus Shale is a Devonian aged shale that underlies much of the Appalachian region of Pennsylvania, New York, Ohio, West Virginia and adjacent states. The depth of the Marcellus Shale and its low permeability make the Marcellus Shale an unconventional exploration target. Advancements in stimulation and horizontal drilling have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of March 31, 2011, our acreage position in the play was approximately 103,500 gross (73,600 net) acres, of which 41,500 gross (19,000 net) acres are referred to as Marcellus West acreage and is included in the Atinum Joint Venture and 62,000 gross (54,600 net) acres are referred to as Marcellus East acreage. The entirety of our acreage is believed to be in the core, over-pressured area of the Marcellus play and is in close proximity to wells being drilled by other operators.

In early 2010, we completed the drilling of our first vertical Marcellus Shale well, the Yoho #1. We drilled the well to a depth of 6,600 feet, and it was completed and tested in January 2010. It tested at a stabilized gross rate of 1.5 MMcf and 120 barrels of condensate per day, with no water production at approximately 1,000 psi of flowing tubing pressure. We are currently waiting for a connection to a pipeline and do not expect natural gas sales until the fourth quarter of 2011.

On September 21, 2010, we entered into the Atinum Joint Venture pursuant to a purchase and sale agreement with Atinum. Pursuant to the agreement, at the closing of the transaction on November 1, 2010, we assigned to Atinum, for $70.0 million in total consideration, an initial 21.43% interest in all of our existing Marcellus Shale assets in West Virginia and Pennsylvania, consisting of approximately 37,600 gross (34,200 net) acres and a 50% working interest in 16 producing shallow conventional wells and one non-producing vertical Marcellus Shale well (the Atinum Joint Venture Assets ). Atinum paid us approximately $30.0 million in cash upon closing. Additionally, Atinum is obligated to fund its 50% share of drilling, completion and infrastructure costs, and will pay an additional $40.0 million of future drilling costs in the form of a drilling carry obligation by funding 75% of our 50% share of those same costs. Upon completion of the funding of the drilling carry, we will make additional assignments, as necessary, to Atinum as a result of which Atinum will own a 50% interest in the Atinum Joint Venture Assets. As of March 31, 2011, approximately $37.0 million of drilling carry obligation remained outstanding.

The Atinum Joint Venture is pursuing an initial three-year development program that calls for the partners to drill a minimum of 12 horizontal wells in 2011 and 24 horizontal wells in each of 2012 and 2013. An initial AMI has been established for potential additional acreage acquisitions in Ohio and New York along with the counties in West Virginia and Pennsylvania in which the existing Atinum Joint Venture Assets are located. Within the initial AMI, we will act as operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis, and Atinum will pay us on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs up to $20.0 million and 5% of such costs on activities above $20.0 million. Until June 30, 2011, Atinum will have the right to participate in any future leasehold acquisitions made by us outside of the initial AMI and within West Virginia or Pennsylvania on terms identical to those governing the existing Atinum Joint Venture.

During 2010, we commenced the drilling of our first Atinum Joint Venture operated horizontal well, the Wengerd 1H, in Marshall County, West Virginia. The Wengerd 1H has been drilled to total depth and cased and is awaiting the availability of fracture stimulation services in order to be completed.

In December 2010, we completed a Marcellus Shale leasehold acquisition (the Marcellus East Acquisition ) for an aggregate purchase price of $28.9 million. The acquisition consisted of undeveloped leasehold in the Marcellus Shale concentrated in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia, including a gathering system comprised of 41 miles of four and six inch steel pipeline, a salt water disposal well, and five conventional producing wells. The Marcellus East Acquisition acreage is outside the initial AMI with Atinum, and Atinum elected not to acquire a 50% interest as provided under the terms of the Atinum Joint Venture. We believe their decision was due to the timing of the transaction and limited prior operational results within the initial Atinum Joint Venture AMI. We plan to drill one horizontal Marcellus well on the Marcellus East Acquisition acreage during 2011 in order to further evaluate the acreage and to provide data that could allow for the possible marketing of a second joint venture on our Marcellus East Acquisition acreage.

During 2010, we began participating in the drilling of seven horizontal Marcellus Shale wells in Butler County, Pennsylvania with Rex Energy as operator. The vertical portion of those wells was drilled in 2010. The operator commenced horizontal drilling operations on the seven wells in March 2011, which is anticipated to be followed by completion of the wells in succession with expected initial sales in the fourth quarter of 2011.

In April 2011, we commenced drilling the Corley #1 and Wengerd 7H, both Atinum Joint Venture horizontal Marcellus wells in Marshall County, West Virginia. Fracture stimulations of the Wengerd 1H and 7H are anticipated to commence in June 2011 with first production in August 2011. We plan on immediately drilling five additional Corley wells on the Corley #1 location with fracture stimulation services to commence on all six wells in September 2011 with first production from the Corley pad anticipated in October 2011. Currently, we plan on commencing drilling operations on 27 Atinum Joint Venture wells in 2011 of which 12 are anticipated to be fracture stimulated and 10 placed on sales. In addition, we are planning to drill the Hickory Ridge 2H horizontal Marcellus well in Preston County, West Virginia with drilling operations anticipated to commence in June 2011.

For the three months ended March 31, 2011, net production from the Appalachia area averaged approximately 0.7 MMcfe per day compared to 0.4 MMcfe per day for the first quarter of 2010.

*Coalbed Methane Powder River Basin, Wyoming and Montana.* As of March 31, 2011, we own an approximate 40% average working interest in approximately 43,400 gross (19,600 net) acres in the Powder River Basin of Wyoming and Montana. As a result of decreased drilling activity, Powder River Basin production averaged 1.4 MMcfe per day and 2.2 MMcfe per day for the three months ended March 31, 2011 and 2010, respectively.

***Results of Operations***

The following is a comparative discussion of the results of operations for the periods indicated. It should be read in conjunction with the condensed consolidated financial statements and the related notes to the condensed consolidated financial statements found elsewhere in this report.

The following table provides information about production volumes, average prices of natural gas and oil and operating expenses for the periods indicated:

| | For the Three Months Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Production: | | |
| Natural gas (MMcf) | 1,966 | 1,753 |
| Oil (MBbl) | 11 | 2 |
| Total production (MMcfe) | 2,031 | 1,764 |
| Total (MMcfed) | 22.6 | 19.6 |
| Average sales price per unit: | | |
| Natural gas per Mcf, excluding impact of realized hedging activities | $ 3.35 | $ 4.35 |
| Natural gas per Mcf, including impact of realized hedging activities | 4.62 | 3.78 |
| Oil per Bbl | 88.05 | 72.01 |
| Selected operating expenses (in thousands): | | |
| Production taxes | $109 | $123 |
| Lease operating expenses | 1,707 | 1,743 |
| Transportation, treating and gathering | 1,103 | 1,249 |
| Depreciation, depletion and amortization | 4,112 | 1,731 |
| General and administrative expense | 2,880 | 3,832 |
| Selected operating expenses per Mcfe: | | |
| Production taxes | $ 0.05 | $ 0.07 |
| Lease operating expenses | 0.84 | 0.99 |
| Transportation, treating and gathering | 0.54 | 0.71 |
| Depreciation, depletion and amortization | 2.02 | 0.98 |
| General and administrative expense | 1.42 | 2.17 |

***Three Months Ended March 31, 2011 compared to the Three Months Ended March 31, 2010***

*Revenues.* Substantially all of our revenues are derived from the production of natural gas in the United States. Natural gas and oil revenues were $10.0 million for the three months ended March 31, 2011, up from $6.8 million for the three months ended March 31, 2010. The increase in revenues was the result of a 29% increase in prices and a 15% increase in volumes. Average daily production on an equivalent basis was 22.6 MMcfe per day for the three months ended March 31, 2011 compared to 19.6 MMcfe per day for the same period in 2010.

During the three months ended March 31, 2011, approximately 89% of our natural gas production was hedged. The realized effect of hedging on natural gas sales was an increase of $2.5 million in natural gas and oil revenues resulting in an increase in total price realized from $3.35 per Mcf to $4.62 per Mcf. The realized hedge impact includes a benefit of $442,000 for amortization of prepaid call sale premiums. Excluding the non-cash amortization, the realized effect of hedging was an increase in revenues of $2.0 million, which was comprised of $3.0 million of NYMEX hedge gains offset by $236,000 of regional basis losses and payment of deferred put premiums of $699,000. For the remainder of 2011, we have costless three way collar hedges for approximately 7,800 MMBtu per day with a weighted average floor of $6.12, short put of $4.23 and a ceiling of $7.12. In addition, we have put spread hedges for approximately 11,300 MMBtu per day with a weighted average floor of $6.07 and a short put of $4.14. Currently, these hedge positions represent approximately 73% of our estimated future 2011 natural gas production. During the three months ended March 31, 2010, the realized effect of hedging on natural gas sales was a decrease of $1.0 million in natural gas and oil revenues resulting in a decrease in total price realized from $4.35 per Mcf to $3.78 per Mcf. The 2010 realized hedge impact included $1.0 million of amortization of prepaid put purchase premiums.

**Table of Contents**

Unrealized natural gas hedge loss was $1.9 million for the three months ended March 31, 2011 compared to an unrealized natural gas hedge gain of $9.4 million for the three months ended March 31, 2010. The increase in unrealized natural gas hedge loss is the result of lower future NYMEX gas prices partially offset by losses related to projected basis differentials.

*Production taxes* We reported production taxes of $109,000 for the three months ended March 31, 2011 compared to $123,000 for the three months ended March 31, 2010. The decrease in production taxes was primarily the result of lower revenues in Wyoming due to lower production volumes and gas prices partially offset by higher oil taxes due to increased oil production in Texas.

*Lease operating expenses.* We reported lease operating expenses of $1.7 million for the three months ended March 31, 2011 and for the three months ended March 31, 2010. Our lease operating expenses were $0.84 per Mcfe for the three months ended March 31, 2011 compared to $0.99 per Mcfe for the same period in 2010. The decrease in the rate per Mcfe was primarily due to lower ad valorem taxes of $0.09 per Mcfe and lower workover costs of $0.07 per Mcfe and higher production volumes.

*Transportation, treating and gathering.* We reported transportation expenses of $1.1 million for the three months ended March 31, 2011, down slightly from $1.2 million for the three months ended March 31, 2010. This decrease was primarily due to lower fees in Wyoming due to lower production volumes and slightly lower gathering charges in Texas due to owner reimbursement adjustments. The current quarter included $267,000 of charges under our Hilltop gas gathering agreement with Hilltop Resort GS, LLC resulting from actual production volumes being less than minimum contractual volume requirements compared to $391,000 of charges in the same quarter 2010.

*Depreciation, depletion and amortization.* We reported depreciation, depletion and amortization ( DD&A ) expense of $4.1 million for the three months ended March 31, 2011 up from $1.7 million for the three months ended March 31, 2010. The increase in DD&A expense was the result of a 106% increase in the DD&A rate per Mcfe and a 15% increase in production. The DD&A rate for the three months ended March 31, 2011 was $2.02 per Mcfe compared to $0.98 per Mcfe for the same period in 2010. The increase in the rate is primarily due to higher proved costs associated with recent wells drilled to test oil prospects with limited initial reserve increases from these activities. The proved cost increase in the first quarter of 2011 also included re-classes of undeveloped costs including capitalized interest primarily related to wells in Texas. The March 31, 2010 DD&A rate was partially benefitted by the gathering system sales proceeds credited to proved property costs in the fourth quarter of 2009.

*General and administrative.* We reported general and administrative expenses of $2.9 million for the three months ended March 31, 2011, down from $3.8 million for the three months ended March 31, 2010. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $705,000 and $759,000 for the three months ended March 31, 2011 and 2010, respectively. The decrease in stock-based compensation expense is primarily due to prior year awards being fully amortized and recently issued shares having a lower fair value. Excluding stock-based compensation expense, general and administrative expense decreased $898,000 to $2.2 million for the three months ended March 31, 2011 compared to March 31, 2010. This decrease is primarily due to lower legal fees as a result of the Classic Star litigation settlement in November 2010.

*Interest expense.* We reported interest expense of $32,000 for the three months ended March 31, 2011 compared to $78,000 for the three months ended March 31, 2010. The decrease in interest expense was primarily the result of the payoff of the short-term loan in January 2010.

*Investment income and other.* We reported investment income of $2,000 for the three months ended March31, 2011 compared to $792,000 for the three months ended March 31, 2010. The decrease in investment income is primarily due to the three months ended March 31, 2010 including interest earned on the Australian term deposit established in conjunction with the sale of the Australian properties in July 2009 for the future tax payment on the sale. At maturity on June 1, 2010, the term deposit was used to settle the Australian tax liability resulting from the Australian property sale in 2009 and thus resulting in no comparable investment income for the three months ended March 31, 2011.

Table of Contents

*Warrant derivative gain (loss).* For the three months ended March 31, 2010, we reported a $148,000 unrealized gain related to the fair value measurement of our warrants outstanding. At March 31, 2011 the outstanding warrants had a zero fair market value.

*Foreign transaction gain.* We reported a foreign transaction gain of $2,000 for the three months ended March 31, 2011 compared to a gain of $319,000 for the three months ended March 31, 2010. The decrease in the foreign transaction gain is primarily due to the decrease in Australian denominated cash and accounts receivable balances arising from the sale of the Australian properties.

*Provision for income tax expense (benefit).* We did not report an income tax benefit or expense for the three months ended March 31, 2011. For the three months ended March 31, 2010, we reported an income tax benefit of $849,000. The 2010 tax benefit was primarily due to a $1.0 million downward adjustment to the tax expense related to the sale of the Australian assets after final review from the Australian Tax Office partially offset by withholding tax on Australian interest income earned.

**Liquidity and Capital Resources**

*Overview.* Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities or asset sales, availability under our Revolving Credit Facility, and access to capital markets, to the extent available. In addition, our Atinum Joint Venture will provide a cash source for our Marcellus Shale development program by providing carried interest funding of up to $40.0 million, $37.0 million of which remains to fund our share of future drilling and completion costs on joint venture wells. We continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets. We adjust capital expenditures in response to changes in natural gas and oil prices, drilling results and cash flow.

For the three months ended March 31, 2011, we reported cash flows provided by operating activities of $1.6 million, net cash used in investing activities of $16.6 million and net cash provided by financing activities of $20.1 million. As a result of these activities, our cash and cash equivalents balance increased by $5.1 million, resulting in a cash and cash equivalents balance of $12.5 million at March 31, 2011.

At March 31, 2011, we had a net working capital deficit of approximately $3.8 million, including $7.5 million of operated prepayment liability. Currently, the availability under our Revolving Credit Facility is $27.5 million.

*Future capital and other expenditure requirements.* Capital expenditures for the remainder of 2011 are projected to be approximately $59.4 million, consisting of drilling, completion and infrastructure costs of $15.4 million in East Texas and $22.4 million in Appalachia and an additional $15.7 million in lease acquisition costs, $3.1 million for seismic and $2.8 million for capitalized interest and other costs. We plan on funding this capital activity through existing cash balances, internally generated cash flow from operating activities, borrowings under our Revolving Credit Facility, a possible joint venture for the development of our Marcellus Acquisition acreage and possibly accessing the capital markets with either debt or preferred equity securities. The majority of projected capital expenditures are operated by us and thus, we can adjust capital expenditures for changes in commodity prices, cash flows from operating activities or availability under our Revolving Credit Facility. Our capital expenditures and the scope of our drilling activities may change as a result of several factors, including, but not limited to, changes in natural gas and oil prices, costs of drilling and completion and leasehold acquisitions and drilling results.

*Commodity Hedging Activities.* Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas. Prices for these commodities are determined primarily by prevailing market conditions including national and worldwide economic activity, weather, infrastructure capacity to reach markets, supply levels and other variable factors. These factors are beyond our control and are difficult to predict.

To mitigate some of the potential negative impact on cash flows caused by changes in natural gas prices, we have entered into financial commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge natural gas price risk. In addition to NYMEX swaps and collars and fixed price swaps, we also have entered into basis only swaps. With a basis only swap, we have hedged the difference between the NYMEX

Table of Contents

price and the price received for our natural gas production at the specific delivery location. See Part I, Item 1. Financial Statements, Note 6 Derivative Instruments and Hedging Activity of this report.

At March 31, 2011, the estimated fair value of all of our commodity derivative instruments was a net asset of $13.1 million, comprised of current and noncurrent assets and liabilities. In conjunction with certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period July 2010 through December 2012. At March 31, 2011, we had a current commodity derivative premium payable of $3.8 million and a long-term commodity derivative premium payable of $3.6 million. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

By removing the price volatility from a portion of our natural gas for 2011 and 2012, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows for those periods. While mitigating negative effects of falling commodity prices, certain derivative contracts also limit the benefits we could receive from increases in commodity prices.

As of March 31, 2011, all of our economic derivative hedge positions were with a multinational energy company or large financial institutions, which are not known to us to be in default on their derivative positions. Credit support for our open derivatives at March 31, 2011 is provided under the Revolving Credit Facility through inter-creditor agreements or open credit accounts of up to $5.0 million. We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.

*Revolving Credit Facility*. At March 31, 2011, we had $20.0 million outstanding under our Revolving Credit Facility compared to our December 31, 2010 outstanding balance of zero. The increase in our long-term debt balance is associated with expenditures for the development of natural gas and oil properties during the three months ended March 31, 2011 of $23.2 million. Our borrowing base was $47.5 million at March 31, 2011 based on the results of the September 2010 redetermination, which became effective on October 1, 2010. Borrowing base redeterminations are scheduled semi-annually with the next redetermination scheduled for May 2011. Borrowings under the Revolving Credit Facility bear interest, at our election, at the prime rate or LIBO rate plus an applicable margin. Pursuant to the Revolving Credit Facility, the applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the prime rate and from 2.5% to 3.5% in the case of borrowings based on the LIBO rate, depending on the utilization percentage in relation to the borrowing base. Under the Revolving Credit Facility, we are subject to certain financial covenants, including interest coverage ratio, a total net indebtedness to EBITDA ratio and current ratio requirement. Currently, our availability under our borrowing base is $27.5 million.

At June 30, 2010, we were not in compliance with the 80% hedge limitation for 2011 under the revolving credit facility. We continued to be out of compliance with the 80% hedge limitation for 2011 under the revolving credit facility through March 31, 2011. We have been granted a waiver in regards to the hedge limitation through March 31, 2011 and in conjunction with such waiver, at March 31, 2011, we were in compliance with all financial covenants under the revolving credit facility. See Part I, Item 1. Financial Statements, Note 4 Long-Term Debt of this report.

**Off-Balance Sheet Arrangements**

As of March 31, 2011, we had no off-balance sheet arrangements. We have no plans to enter into any off- balance sheet arrangements in the foreseeable future.

**Commitments and Contingencies**

As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved natural gas properties. It is management s belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

We are party to various litigation matters and administrative claims arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such

**Table of Contents**

matters will have a material adverse effect on our financial position, results of operations or cash flows. A discussion of current legal proceedings is set forth in Part. I Item 1. Financial Statements, Note 12 Commitments and Contingencies of this report.

**Critical Accounting Policies and Estimates**

The preparation of financial statements in conformity with US GAAP 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 condensed 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.

Significant accounting policies that we employ and 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 are presented in Part I, Item I. Financial Statements, Note 2 -Summary of Significant Accounting Policies of this report and in Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates included in our 2010 Form 10-K.

***Recent Accounting Developments***

For a discussion of recent accounting developments, see Part I, Item 1. Financial Statements, Note 2 Summary of Significant Policies of this report.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

***Commodity Price Risk***

Our major commodity price risk exposure is to the prices received for our natural gas production and our results of operations and operating cash flows are affected by changes in market prices. 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. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. For the three months ended March 31, 2011, a 10% change in the prices received for natural gas production would have had an approximate $754,000 impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. See Part I, Item 1. Financial Statements, Note 6 - Derivative Instruments and Hedging Activity of this report for additional information regarding our hedging activities.

***Interest Rate Risk***

At March 31, 2011, we had $20.0 million outstanding under our Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at March 31, 2011, a one percentage point change in the interest rate would have had a $49,000 impact on our interest expense, all of which would have been capitalized. We currently do not use interest rate derivatives to mitigate our exposure to the volatility in interest rates, including under our Revolving Credit Facility, as this risk is minimal.

***Foreign Currency Exchange Risk***

During 2009, we sold all of our Australian assets. As a result, all of our current and future revenues and capital expenditures and substantially all of our expenses are in U.S. dollars, thus limiting our exposure to foreign currency exchange risk.

Table of Contents

**Item 4. Controls and Procedures**

***Management s Evaluation on the Effectiveness of Disclosure Controls and Procedures***

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended ( Exchange Act ), as of March 31, 2011. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of March 31, 2011, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended March 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

**PART II. OTHER INFORMATION**

**Item 1. Legal Proceedings**

A discussion of current legal proceedings is set forth in Part I, Item 1. Financial Statements, Note 12 - Commitments and Contingencies of this report.

**Item 1A. Risk Factors**

Except as set forth below, information about material risks related to our business, financial condition and results of operations for the three months ended March 31, 2011 does not materially differ from that set out under Part I, Item 1A. Risk Factors in our 2010 Form 10-K. You should carefully consider the risk factors and other information discussed in our 2010 Form 10-K, as well as the information provided in this report. These risks are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, operating results and cash flows.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency (the EPA ) recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injection Control Program. While the EPA has yet to take action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study expected to be available in late 2012 and final result in 2014. In addition, for the second consecutive session, Congress is considering two companion bills, known as the Fracturing Responsibility and Awareness of Chemicals Act, or FRAC Act, that would repeal an exemption in the Safe Drinking Water Act for the underground injection of hydraulic fracturing fluids other than diesel near drinking water sources. This legislation, if adopted, would require federal regulation of hydraulic fracturing as well as disclosure of the chemicals used in the fracturing process.

Also, some states, including New York, Pennsylvania and Wyoming, have adopted, and other states, including Texas, are considering adopting, regulations imposing disclosure obligations or restrictions on hydraulic fracturing activities in certain circumstances. New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized, a draft of which must be published by June 1, 2011 followed by a 30-day comment period. Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed and Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. More recently, on March 1, 2011, a bill was introduced in the Texas Senate that, if adopted, would require written disclosure to the Railroad Commission of Texas, or RCT, of specific information about the fluids, proppants and additives used in hydraulic fracturing treatment operations and, on March 11, 2011, a bill was introduced in the Texas House of Representatives that would require service companies to submit master lists of base fluids, additives and chemical constituents to be used in hydraulic fracturing activities in Texas, subject to certain trade secret protections, to the RCT. Hydraulic fracturing is a primary production method used to produce reserves located in the Marcellus Shale formations and East Texas area. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing or otherwise reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. In addition, if hydraulic fracturing is regulated at the federal level, exploration and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements and attendant permitting delays and potential increases in costs. Some or all of these developments could have a material adverse effect on our business, financial condition and results of operations.

Table of Contents

**Item 2. Unregistered Sales of Equity Securities and Use of Proceeds**

None.

**Item 3. Defaults Upon Senior Securities**

None.

**Item 4. (Removed and Reserved)**

**Item 5. Other Information**

None.

**Item 6. Exhibits**

The following is a list of exhibits filed or furnished (as indicated) as part of this Form 10-Q. Where so indicated by a note, 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. (incorporated herein by reference to Exhibit 3.1 the Company s Amendment No. 1 to Registration Statement on Form S-1/A filed October 13, 2005, Registration No. 333-127498). |
| 3.2 | Amended Bylaws of Gastar Exploration Ltd. dated as of June 3, 2010 (incorporated herein by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated June 4, 2010. File No. 001-32714). |
| 3.3 | Articles of Amendment and Share Structure attached to and forming part of the Amended and Restated Articles of Incorporation of Gastar Exploration Ltd, dated as of June 30, 2009. (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated July 1, 2009. File No. 001-32714). |
| 3.4 | Articles of Amendment attached to and forming part of the Amended and Restated Articles of Incorporation of Gastar Exploration Ltd, dated as of July 23, 2009 (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated July 24, 2009. File No. 001-32714). |
| 4.1 | Indenture related to the 12 3/4% Senior Secured Notes due November 29, 2012, dated as of November 29, 2007, between Gastar Exploration USA, Inc., Gastar Exploration Ltd., Wells Fargo Bank, National Association, as Trustee and Collateral Agent and each of the other Guarantors party thereto (including the form of 12 3/4% Senior Secured Note due 2012) 2007 (incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated December 4, 2007. File No. 333-32714). |
| 4.2 | Supplemental Indenture dated as of February 16, 2009, related to the 12 3/4% Senior Secured Notes due 2012, between Gastar Exploration USA, Inc., Gastar Exploration Ltd., Wells Fargo Bank, National Association, as Trustee and Collateral Agent, and each of the other Guarantors party thereto. 2007 (incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated February 20, 2009. File No. 001-32714). |
| 4.3 | Agreement between Gastar Exploration Ltd. and GeoStar Corporation dated August 11, 2005 (incorporated by reference to Exhibit 4.17 of the Company s Amendment No. 1 to Registration Statement on Form S-1/A, filed on October 30, 2005. Registration No. 333-127498). |
| 4.4 | Facsimile of common share certificate of Gastar Exploration Ltd. (incorporated by reference to Exhibit 4.21 of the Company s Amendment No. 3 to Registration Statement on Form S-1/A, dated December 15, 2005. Registration No. 333-127498). |

**Table of Contents**

| Exhibit Number | Description |
|---|---|
| 4.5 | Warrant dated June 11, 2008, entitling GeoStar Corporation to acquire, subject to adjustments, 10,000,000 Gastar Exploration Ltd. common shares (incorporated by reference to Exhibit 4.1 of the Company s Current Report of Form 8-K dated June 13, 2008. File No. 001-32714). |
| 10.1* | Second Amendment to Employment Agreement entered into by and between Gastar Exploration Ltd., Gastar Exploration USA, Inc. and J. Russell Porter as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K dated February 7, 2011. File No. 001-32714). |
| 14.1 | Gastar Exploration Ltd. Code of Conduct and Ethics, amended and restated as of March 22, 2011 (incorporated herein by reference to Exhibit 14.1 of the Company s Current Report on Form 8-K dated March 23, 2011. File No. 001-32714). |
| 31.1 | Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |

* Management contract or compensatory plan or arrangement.
Filed herewith.
Furnished herewith.

Table of Contents

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**GASTAR EXPLORATION LTD.**

| | | |
|---|---|---|
| Date: May 5, 2011 | By: | /s/ J. RUSSELL PORTER<br>**J. Russell Porter**<br>**President and Chief Executive Officer**<br>**(Duly authorized officer and principal executive officer)** |
| Date: May 5, 2011 | By: | /s/ MICHAEL A. GERLICH<br>**Michael A. Gerlich**<br>**Vice President and Chief Financial Officer**<br>**(Duly authorized officer and principal financial and accounting officer)** |

Table of Contents

**EXHIBIT INDEX**

| Exhibit Number | Description |
|---|---|
| 3.1 | Amended and Restated Articles of Incorporation of Gastar Exploration Ltd. (incorporated herein by reference to Exhibit 3.1 the Company s Amendment No. 1 to Registration Statement on Form S-1/A filed October 13, 2005, Registration No. 333-127498). |
| 3.2 | Amended Bylaws of Gastar Exploration Ltd. dated as of June 3, 2010 (incorporated herein by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated June 4, 2010. File No. 001-32714). |
| 3.3 | Articles of Amendment and Share Structure attached to and forming part of the Amended and Restated Articles of Incorporation of Gastar Exploration Ltd, dated as of June 30, 2009. (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated July 1, 2009. File No. 001-32714). |
| 3.4 | Articles of Amendment attached to and forming part of the Amended and Restated Articles of Incorporation of Gastar Exploration Ltd, dated as of July 23, 2009 (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K dated July 24, 2009. File No. 001-32714). |
| 4.1 | Indenture related to the 12 3/4% Senior Secured Notes due November 29, 2012, dated as of November 29, 2007, between Gastar Exploration USA, Inc., Gastar Exploration Ltd., Wells Fargo Bank, National Association, as Trustee and Collateral Agent and each of the other Guarantors party thereto (including the form of 12 3/4% Senior Secured Note due 2012) 2007 (incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated December 4, 2007. File No. 333-32714). |
| 4.2 | Supplemental Indenture dated as of February 16, 2009, related to the 12 3/4% Senior Secured Notes due 2012, between Gastar Exploration USA, Inc., Gastar Exploration Ltd., Wells Fargo Bank, National Association, as Trustee and Collateral Agent, and each of the other Guarantors party thereto. 2007 (incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated February 20, 2009. File No. 001-32714). |
| 4.3 | Agreement between Gastar Exploration Ltd. and GeoStar Corporation dated August 11, 2005 (incorporated by reference to Exhibit 4.17 of the Company s Amendment No. 1 to Registration Statement on Form S-1/A, filed on October 30, 2005. Registration No. 333-127498). |
| 4.4 | Facsimile of common share certificate of Gastar Exploration Ltd. (incorporated by reference to Exhibit 4.21 of the Company s Amendment No. 3 to Registration Statement on Form S-1/A, dated December 15, 2005. Registration No. 333-127498). |
| 4.5 | Warrant dated June 11, 2008, entitling GeoStar Corporation to acquire, subject to adjustments, 10,000,000 Gastar Exploration Ltd. common shares (incorporated by reference to Exhibit 4.1 of the Company s Current Report of Form 8-K dated June 13, 2008. File No. 001-32714). |
| 10.1* | Second Amendment to Employment Agreement entered into by and between Gastar Exploration Ltd., Gastar Exploration USA, Inc. and J. Russell Porter as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K dated February 7, 2011. File No. 001-32714). |
| 14.1 | Gastar Exploration Ltd. Code of Conduct and Ethics, amended and restated as of March 22, 2011 (incorporated herein by reference to Exhibit 14.1 of the Company s Current Report on Form 8-K dated March 23, 2011. File No. 001-32714). |
| 31.1 | Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |

* Management contract or compensatory plan or arrangement.

**Table of Contents**

Filed herewith.
Furnished herewith.