GASTAR EXPLORATION LTD
Form 10-Q
August 07, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2012
OR
o 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
Commission File Number: 001-35211

GASTAR EXPLORATION LTD.
GASTAR EXPLORATION USA, INC.
(Exact name of registrant as specified in its charter)

Alberta, Canada	98-0570897
Delaware	38-3531640
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1331 Lamar Street, Suite 650	
Houston, Texas	77010
(Address of principal executive offices)	(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.

Gastar Exploration Ltd.	Yes	ý	No	o
Gastar Exploration USA, Inc.	Yes	ý	No	o

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).

Gastar Exploration Ltd.	Yes	ý	No	o
Gastar Exploration USA, Inc.	Yes	ý	No	o

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.

Gastar Exploration Ltd.

Large accelerated filer	o	Accelerated filer	ý
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o

Gastar Exploration USA, Inc.

Large accelerated filer	o	Accelerated filer	o
Non-accelerated filer	ý (Do not check if a smaller reporting company)	Smaller reporting company	o

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

Gastar Exploration Ltd.	Yes	o	No	ý
Gastar Exploration USA, Inc.	Yes	o	No	ý

The total number of outstanding common shares, no par value per share, as of August 1, 2012 was

Gastar Exploration Ltd.	65,714,897	shares of common stock
Gastar Exploration USA, Inc.	750	shares of common stock

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GASTAR EXPLORATION LTD.
QUARTERLY REPORT ON FORM 10-Q
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2012
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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 U.S. dollars unless otherwise noted and (v) all financial data included in this report on Form 10-Q 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 U.S. filings.

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Glossary of Terms

AMI	Area of Mutual Interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bbl/d	Barrels of oil, condensate or NGLs per day
Btu	British thermal unit, typically used in measuring natural gas energy content
CRP	Central receipt point
FASB	Financial Accounting Standards Board
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condendate or NGLs per day
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
MMBtu/d	One million British thermal units per day
MMcf	One million cubic feet of natural gas
MMcf/d	One million cubic feet of natural gas per day
Mcfe	One thousand cubic feet of natural gas equivalent
MMcfe	One million cubic feet of natural gas equivalent
MMcfe/d	One million cubic feet of natural gas equivalent per day
NGLs	Natural gas liquid
psi	Pounds per square inch

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements
GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2012 (Unaudited)	December 31, 2011
	(in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$8,039	$10,647
Accounts receivable, net of allowance for doubtful accounts of $546 and $551, respectively	12,362	10,706
Commodity derivative contracts	18,610	19,385
Prepaid expenses	951	1,243
Total current assets	39,962	41,981
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, full cost method of accounting:		
Unproved properties, excluded from amortization	85,807	78,302
Proved properties	576,110	514,357
Total natural gas and oil properties	661,917	592,659
Furniture and equipment	1,854	1,629
Total property, plant and equipment	663,771	594,288
Accumulated depreciation, depletion and amortization	(393,890)	(308,548)
Total property, plant and equipment, net	269,881	285,740
OTHER ASSETS:		
Restricted cash	50	50
Commodity derivative contracts	5,515	4,130
Deferred charges, net	768	535
Advances to operators and other assets	825	2,067
Total other assets	7,158	6,782
TOTAL ASSETS	$317,001	$334,503
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$15,009	$17,693
Revenue payable	6,795	4,137
Accrued interest	142	144
Accrued drilling and operating costs	8,208	4,647
Advances from non-operators	25,370	19,523
Commodity derivative contracts	5,616	6,479
Commodity derivative premium payable	2,590	4,725
Accrued litigation settlement liability	—	800
Other accrued liabilities	1,901	1,723
Total current liabilities	65,631	59,871
LONG-TERM LIABILITIES:		
Long-term debt	47,000	30,000
Commodity derivative contracts	3,049	1,163
Asset retirement obligation	6,454	8,275

Total long-term liabilities	56,503	39,438
Commitments and contingencies (Note 12)		
SHAREHOLDERS' EQUITY:		
Common stock, no par value; unlimited shares authorized; 65,721,018 and 64,706,750 shares issued and outstanding at June 30, 2012 and December 31, 2011, respectively	316,346	316,346
Additional paid-in capital	26,945	25,376
Accumulated deficit	(214,264)	(133,919)
Total shareholders' equity	129,027	207,803
Non-controlling interest:		
Preferred stock of subsidiary, aggregate liquidation preference $84,683 and $34,114 at June 30, 2012 and December 31, 2011, respectively	65,840	27,391
Total equity	194,867	235,194
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$317,001	$334,503

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except share and per share data)			
REVENUES:				
Natural gas	$6,682	$7,494	$13,593	$16,571
Oil	2,408	1,020	4,291	1,971
NGLs	2,027	—	3,911	—
Total natural gas, oil and NGLs revenues	11,117	8,514	21,795	18,542
Unrealized hedge gain (loss)	2,804	502	1,280	(1,397)
Total revenues	13,921	9,016	23,075	17,145
EXPENSES:				
Production taxes	481	118	934	227
Lease operating expenses	1,558	1,875	3,974	3,582
Transportation, treating and gathering	1,231	1,123	2,410	2,226
Depreciation, depletion and amortization	6,956	2,991	12,609	7,103
Impairment of natural gas and oil properties	72,733	—	72,733	—
Accretion of asset retirement obligation	89	129	183	254
General and administrative expense	3,151	2,596	6,312	5,476
Litigation settlement expense	—	—	1,250	—
Total expenses	86,199	8,832	100,405	18,868
INCOME (LOSS) FROM OPERATIONS	(72,278)	184	(77,330)	(1,723)
OTHER INCOME (EXPENSE):				
Interest expense	(29)	(31)	(56)	(63)
Investment income and other	2	3	4	5
Foreign transaction gain (loss)	(3)	1	—	3
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	(72,308)	157	(77,382)	(1,778)
Provision for income taxes	—	—	—	—
NET INCOME (LOSS)	(72,308)	157	(77,382)	(1,778)
Dividend on preferred stock attributable to non-controlling interest	1,727	31	2,963	31
NET INCOME (LOSS) ATTRIBUTABLE TO GASTAR EXPLORATION LTD.	$(74,035)	$126	$(80,345)	$(1,809)
NET INCOME (LOSS) PER COMMON SHARE ATTRIBUTABLE TO GASTAR EXPLORATION LTD. COMMON SHAREHOLDERS:				
Basic	$(1.17)	$0.00	$(1.27)	$(0.03)
Diluted	$(1.17)	$0.00	$(1.27)	$(0.03)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	63,541,739	63,134,109	63,439,412	63,079,475
Diluted	63,541,739	63,723,093	63,439,412	63,079,475

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended June 30,	
	2012	2011
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(77,382)	$(1,778)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	12,609	7,103
Impairment of natural gas and oil properties	72,733	—
Stock-based compensation	1,846	1,243
Unrealized hedge (gain) loss	(1,280)	1,397
Realized gain on derivative contracts	(440)	(871)
Amortization of deferred financing costs	98	128
Accretion of asset retirement obligation	183	254
Changes in operating assets and liabilities:		
Accounts receivable	(2,996)	(625)
Commodity derivative contracts	—	(54)
Prepaid expenses	222	388
Accounts payable and accrued liabilities	(932)	555
Net cash provided by operating activities	4,661	7,740
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of natural gas and oil properties	(62,856)	(39,074)
Advances to operators	(1,911)	(3,155)
Proceeds from non-operators	5,847	11,001
Purchase of furniture and equipment	(225)	(274)
Net cash used in investing activities	(59,145)	(31,502)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	43,000	20,000
Repayment of revolving credit facility	(26,000)	(12,000)
Proceeds from issuance of preferred stock, net of issuance costs	38,449	14,000
Dividend on preferred stock attributable to non-controlling interest	(2,963)	(31)
Deferred financing charges	(332)	(13)
Other	(278)	(138)
Net cash provided by financing activities	51,876	21,818
NET DECREASE IN CASH AND CASH EQUIVALENTS	(2,608)	(1,944)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	10,647	7,439
CASH AND CASH EQUIVALENTS, END OF PERIOD	$8,039	$5,495

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2012 (Unaudited) (in thousands)	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$7,961	$10,595
Accounts receivable, net of allowance for doubtful accounts of $546 and $551, respectively	12,361	10,703
Commodity derivative contracts	18,610	19,385
Prepaid expenses	871	1,088
Total current assets	39,803	41,771
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, full cost method of accounting:		
Unproved properties, excluded from amortization	85,807	78,302
Proved properties	576,102	514,349
Total natural gas and oil properties	661,909	592,651
Furniture and equipment	1,854	1,629
Total property, plant and equipment	663,763	594,280
Accumulated depreciation, depletion and amortization	(393,883)	(308,541)
Total property, plant and equipment, net	269,880	285,739
OTHER ASSETS:		
Restricted cash	25	25
Commodity derivative contracts	5,515	4,130
Deferred charges, net	768	535
Advances to operators and other assets	825	2,067
Total other assets	7,133	6,757
TOTAL ASSETS	$316,816	$334,267
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$15,001	$17,682
Revenue payable	6,795	4,137
Accrued interest	142	144
Accrued drilling and operating costs	8,208	4,647
Advances from non-operators	25,370	19,523
Commodity derivative contracts	5,616	6,479
Commodity derivative premium payable	2,590	4,725
Accrued litigation settlement liability	—	800
Other accrued liabilities	1,683	1,654
Total current liabilities	65,405	59,791
LONG-TERM LIABILITIES:		
Long-term debt	47,000	30,000
Commodity derivative contracts	3,049	1,163
Asset retirement obligation	6,447	8,268
Due to parent	30,513	27,432
Total long-term liabilities	87,009	66,863

Commitments and contingencies (Note 12)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; 3,387,305 and 1,364,543 shares issued and outstanding at June 30, 2012 and December 31, 2011, respectively, with liquidation preference of $25.00 per share	34	14
Common stock, no par value; 1,000 shares authorized; 750 shares issued and outstanding	237,431	239,431
Additional paid-in capital	65,806	27,377
Accumulated deficit	(138,869)	(59,209)
Total stockholders' equity	164,402	207,613
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$316,816	$334,267

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except share and per share data)			
REVENUES:				
Natural gas	$6,682	$7,494	$13,593	$16,571
Oil	2,408	1,020	4,291	1,971
NGLs	2,027	—	3,911	—
Total natural gas, oil and NGLs revenues	11,117	8,514	21,795	18,542
Unrealized hedge gain (loss)	2,804	502	1,280	(1,397)
Total revenues	13,921	9,016	23,075	17,145
EXPENSES:				
Production taxes	481	118	934	227
Lease operating expenses	1,558	1,874	3,974	3,581
Transportation, treating and gathering	1,231	1,123	2,410	2,226
Depreciation, depletion and amortization	6,956	2,991	12,609	7,103
Impairment of natural gas and oil properties	72,733	—	72,733	—
Accretion of asset retirement obligation	89	129	183	254
General and administrative expense	2,853	2,414	5,624	5,113
Litigation settlement expense	—	—	1,250	—
Total expenses	85,901	8,649	99,717	18,504
INOME (LOSS) FROM OPERATIONS	(71,980)	367	(76,642)	(1,359)
OTHER INCOME (EXPENSE):				
Interest expense	(29)	(30)	(57)	(62)
Investment income and other	(1)	3	1	97
Foreign transaction gain (loss)	(1)	1	1	3
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	(72,011)	341	(76,697)	(1,321)
Provision for income taxes	—	—	—	—
NET INCOME (LOSS)	(72,011)	341	(76,697)	(1,321)
Dividend on preferred stock	1,727	31	2,963	31
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDER	$(73,738)	$310	$(79,660)	$(1,352)

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended June 30,	
	2012	2011
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(76,697)	$(1,321)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	12,609	7,103
Impairment of natural gas and oil properties	72,733	—
Stock-based compensation	1,846	1,243
Unrealized hedge (gain) loss	(1,280)	1,397
Realized gain on derivative contracts	(440)	(871)
Amortization of deferred financing costs	98	128
Accretion of asset retirement obligation	183	254
Changes in operating assets and liabilities:		
Accounts receivable	(2,998)	(625)
Commodity derivative contracts	—	(54)
Prepaid expenses	147	291
Accounts payable and accrued liabilities	(1,078)	515
Net cash provided by operating activities	5,123	8,060
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of natural gas and oil properties	(62,856)	(39,074)
Advances to operators	(1,911)	(3,155)
Proceeds from non-operators	5,847	11,001
Purchase of furniture and equipment	(225)	(274)
Net cash used in investing activities	(59,145)	(31,502)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	43,000	20,000
Repayment of revolving credit facility	(26,000)	(12,000)
Proceeds from issuance of preferred stock, net of issuance costs	38,449	14,000
Dividend on preferred stock	(2,963)	(31)
Deferred financing charges	(332)	(13)
Dividend to parent, net	(766)	(571)
Other	—	100
Net cash provided by financing activities	51,388	21,485
NET DECREASE IN CASH AND CASH EQUIVALENTS	(2,634)	(1,957)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	10,595	7,401
CASH AND CASH EQUIVALENTS, END OF PERIOD	$7,961	$5,444

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

GASTAR EXPLORATION LTD. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Description of Business

Gastar Exploration Ltd. is an independent energy company engaged in the exploration, development and production of natural gas and oil in the United States ("U.S."). Gastar Exploration Ltd.'s principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties with an emphasis on unconventional reserves, such as shale resource plays. Gastar Exploration Ltd. is currently pursuing the development of liquids-rich natural gas in the Marcellus Shale play in the Appalachia area of West Virginia and central and southwestern Pennsylvania. Gastar Exploration Ltd. also holds prospective acreage in the deep Bossier play in East Texas and in the Mid-Continent area of the U.S.

Gastar Exploration Ltd. is a holding company and 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. and its wholly-owned subsidiaries. Unless otherwise stated or the context requires otherwise, all references in these notes to "Gastar USA" refer collectively to Gastar Exploration USA, Inc. and its wholly-owned subsidiaries, all references to "Parent" refer solely to Gastar Exploration Ltd., and all references to "Gastar," the "Company" and similar terms refer collectively to Gastar Exploration Ltd. and its wholly-owned subsidiaries, including Gastar Exploration USA, Inc.

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company 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, 2011 ("2011 Form 10-K") filed with the SEC. Please refer to the notes to the financial statements included in the 2011 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.

These financial statements are a combined presentation of the condensed consolidated financial statements of the Company and Gastar USA. Separate information is provided for the Company and Gastar USA as required. Except as otherwise noted, there are no material differences between the unaudited condensed consolidated information for the Company presented herein and the unaudited condensed consolidated information of Gastar USA.

The unaudited interim condensed consolidated financial statements of the Company and Gastar USA included herein are stated in U.S. dollars unless otherwise noted and were prepared from the records of the Company and Gastar USA 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 2011 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 2011 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 unaudited condensed consolidated financial statements of the Company include the accounts of Parent and the consolidated accounts of all of its subsidiaries, including Gastar USA. All significant intercompany accounts and transactions have been eliminated in consolidation.

The unaudited condensed consolidated financial statements of Gastar USA include the accounts of Gastar USA and the consolidated accounts of all of its subsidiaries. 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 and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. In preparing these financial statements, the 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.

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Recent Accounting Developments

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

Comprehensive Income. In June 2011, the FASB issued an amendment to previously issued guidance regarding the reporting and presentation of other comprehensive income. The amendments require that all non-owner changes in stockholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income and the total of comprehensive income. Regardless of whether an entity chooses to present comprehensive income in a single continuous statement or in two separate but consecutive statements, the entity is required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement(s) where the components of net income and the components of other comprehensive income are presented. The amendments do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and should be applied retrospectively. Earlier application is permitted. The adoption of this guidance did not impact our operating results, financial position or cash flows.

Fair Value Measurement. In May 2011, the FASB issued an amendment to previously issued guidance regarding fair value measurement and disclosure requirements. The amendments explain how to measure fair value and do not require additional fair value measurements and are not intended to establish valuation standards or affect valuation practices outside of financial reporting. The amendments result in common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards. This guidance is effective prospectively for interim and annual periods beginning after December 15, 2011. 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 U.S., specifically the states of Texas, Pennsylvania, West Virginia, Wyoming and Montana and the Mid-Continent area. The Company's working interest in its Wyoming and Montana properties in the Powder River Basin were assigned to the operator on May 3, 2012, effective January 1, 2012.

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

	June 30, 2012	December 31, 2011
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$133	$3,958
Acreage acquisition costs	79,198	68,217
Capitalized interest	6,476	6,127
Total unproved properties excluded from amortization	$85,807	$78,302

The full cost method of accounting for natural gas and oil properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full cost ceiling calculation. The ceiling is the present value of estimated future cash flow from proved natural gas and oil reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage) to the extent not included in natural gas and oil properties pursuant to authoritative guidance and estimated future income taxes thereon. To the extent that our capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of natural gas and oil properties is not reversible at a later date even if natural gas and oil prices increase.

The ceiling calculation dictates that the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect are held constant indefinitely.

Management’s ceiling test evaluation for the six months ended June 30, 2012 resulted in an impairment of proved natural gas and oil properties of $72.7 million recorded at June 30, 2012. Management's ceiling test evaluation for the six months ended June 30, 2011 did not result in an impairment of proved natural gas and oil properties. The following table provides the 12-month unweighted arithmetic average of the equivalent realized price utilized in the ceiling test evaluations for the periods indicated:

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	For the Six Months Ended June 30,	
	2012	2011
Average price per Mcfe	$4.03	$4.73

Given the current price environment, the Company expects that future declines in the 12-month average natural gas, oil and NGLs prices will likely result in the recognition of future ceiling impairments.

Atinum Joint Venture

In September 2010, Gastar USA 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, Gastar USA 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 (the "Atinum Joint Venture Assets"). Atinum paid Gastar USA approximately $30.0 million in cash at the closing and paid additional $40.0 million of Gastar USA's share of drilling costs over time in the form of a "drilling carry." Upon completion of the funding of the drilling carry, Gastar USA made additional assignments to Atinum in early 2012 as a result of which Atinum owns a 50% interest in the Atinum Joint Venture Assets. The terms of the drilling carry required Atinum to fund its ultimate 50% share of drilling, completion and infrastructure costs along with 75% of Gastar USA's ultimate 50% share of those same costs until the $40.0 million drilling carry had been satisfied. As of December 31, 2011, Atinum had completed the funding of the $40.0 million drilling carry. Subsequent to December 31, 2011, Atinum only funds its 50% share of costs.

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 operated horizontal wells in each of 2012 and 2013, respectively. Due to recent natural gas price declines, Atinum and Gastar USA agreed to reduce the 2012 minimum wells to be drilled requirement from 24 wells to 20 wells. As of June 30, 2012, 26 operated wells were drilled and cased under the Atinum Joint Venture. Subsequent to June 30, 2011, an AMI was established for additional acreage acquisitions in Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia. Within this AMI, Gastar USA acts 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 Gastar USA 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.

4. Long-Term Debt

Amended and Restated Revolving Credit Facility

On October 28, 2009, Gastar USA, together with the other parties thereto, entered into an amended and restated 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 Gastar USA's election, at the prime rate or LIBO rate plus an applicable margin. 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 0.5% is payable quarterly based on the unutilized balance of the borrowing base. The Revolving Credit Facility had a scheduled maturity date of January 2, 2013.

The Revolving Credit Facility is guaranteed by Parent (as defined in the Revolving Credit Facility) 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 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, incurrence of other indebtedness without lenders' consent and 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;

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- 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 become due and payable upon the occurrence of certain usual and customary events of default, including among others:

- Failure to make payments;
- 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 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 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.

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”) amending that certain Amended and Restated Credit Agreement dated October 28, 2009 (as amended by that certain Consent and First Amendment to Amended and Restated Credit Agreement dated November 20, 2009, the Second Amendment, the Third Amendment (as defined below) and the Fourth Amendment (as defined below), the “Credit Agreement”) . The Second Amendment amended the Revolving Credit Facility, by, among other things, (i) allowing Gastar USA 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) allowing Gastar USA 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.

On June 14, 2011, Gastar USA, together with the parties thereto, entered into the Third Amendment to the Credit Agreement (the “Third Amendment”). The Third Amendment amended the Revolving Credit Facility by, among other things, allowing Gastar USA to issue Series A Preferred Stock (as defined below) described in Part I, Item 1. “Financial Statements, Note 7 – Capital Stock” of this report and pay cash dividends on the Series A Preferred Stock of no more than $10.0 million in the aggregate in each calendar year and as long as payment of such dividends does not exceed 10% of the current availability under the then existing borrowing base.

On December 2, 2011, Gastar USA, together with the parties thereto, entered into the Fourth Amendment to the Credit Agreement, effective as of November 10, 2011 (the “Fourth Amendment”). The Fourth Amendment amended the Revolving Credit Facility, by, among other things, (i) extending the maturity date on borrowings under the Revolving Credit Facility to September 30, 2015; (ii) allowing Gastar USA to hedge up to 100% of the PDP reserves reflected in its reserve report using hedging other than floors and protective spreads; and (iii) allowing no more than ten separate LIBO Rate Loans to be outstanding at one time.

As of December 31, 2011, the Revolving Credit Facility had a borrowing base of $50.0 million, with $30.0 million of borrowings outstanding and availability of $20.0 million. Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. Gastar USA requested that the May 2012 redetermination be accelerated to March 2012. The next regularly scheduled redetermination is set for November 2012. Gastar USA and the lenders may request one additional unscheduled redetermination annually. On March 5, 2012, Gastar USA was notified by its lenders that, effective immediately, the borrowing base was increased from $50.0 million to $100.0 million. At June 30, 2012, the Revolving Credit Facility had a borrowing base of $100.0 million, with $47.0 million of borrowings outstanding and availability of $53.0 million.

At June 30, 2012, Gastar USA was in compliance with all financial covenants under the Revolving Credit Facility.

Other Debt

Credit support for the Company’s open derivatives at June 30, 2012 is provided under the Revolving Credit Facility through inter-creditor agreements or open accounts of up to $5.0 million.

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, unproved properties and other property and

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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. The Company assesses its unproved properties for impairment whenever events or circumstances indicate the carrying value of those properties may not be recoverable. The fair value of the unproved properties is measured using an income approach based upon internal estimates of future production levels, current and future prices, drilling and operating costs, discount rates, current drilling plans and favorable and unfavorable drilling activity on the properties being evaluated and/or adjacent properties, which are Level 3 inputs. During the six months ended June 30, 2012 and 2011, respectively, the Company did not recognize an impairment of unproved properties. As no other fair value measurements are required to be recognized on a non-recurring basis at June 30, 2012, no additional disclosures are provided at June 30, 2012.

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. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. The Company does not have access to the specific assumptions used in its' counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided. Level 3 instruments are commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge natural gas, oil and NGLs price risk. 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.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the 2012 and 2011 periods.

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 June 30, 2012 and December 31, 2011:

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	Fair value as of June 30, 2012			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$8,039	$—	$—	$8,039
Restricted cash	50	—	—	50
Commodity derivative contracts	—	—	24,125	24,125
Liabilities:				
Commodity derivative contracts	—	—	(8,665)	(8,665)
Total	$8,089	$—	$15,460	$23,549

	Fair value as of December 30, 2011			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$10,647	$—	$—	$10,647
Restricted cash	50	—	—	50
Commodity derivative contracts	—	—	23,515	23,515
Liabilities:				
Commodity derivative contracts	—	—	(7,642)	(7,642)
Total	$10,697	$—	$15,873	$26,570

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy for the three and six months ended June 30, 2012 and 2011. 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 June 30, 2012 and 2011.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Balance at beginning of period	$13,456	$13,069	$15,873	$15,199
Total gains (losses) (realized or unrealized):				
included in earnings	5,768	2,221	6,641	2,782
included in other comprehensive income	—	—	—	—
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements (1)	(3,764)	(2,004)	(7,054)	(4,695)
Transfers in and (out) of Level 3	—	—	—	—
Balance at end of period	$15,460	$13,286	$15,460	$13,286
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets still held at June 30, 2012 and 2011	$2,804	$502	$1,280	$(1,397)

(1) Included in total revenues on the statement of operations.

At June 30, 2012, 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 June 30, 2012 approximates the respective carrying value because the interest rate

approximates the current market rate (Level 2).
The Company has consistently applied the valuation techniques discussed above in all periods presented.

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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 Note 6, "Derivative Instruments and Hedging Activity."

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, oil and NGLs 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, oil and NGLs revenues. For the three and six months ended June 30, 2012, the Company reported unrealized gains of $2.8 million and $1.3 million, respectively, in the condensed consolidated statement of operations related to the change in the fair value of its commodity derivative instruments. For the three and six months ended June 30, 2011, the Company reported an unrealized gain of $502,000 and an unrealized loss of $1.4 million, respectively, in the condensed consolidated statement of operations related to the change in the fair value of its commodity derivative instruments.

As of June 30, 2012, the following natural gas derivative transactions were outstanding with the associated notional 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	Call (Long)	Ceiling (Short)
		(in MMBtu's)						
2012	Put spread	15,256	2,334,110	$—	$6.00	$4.00	$—	$—
2012	Costless three-way collar	7,398	1,131,890	—	5.73	4.00	—	6.88
2012	Call spread	2,000	306,000	—	—	—	4.00	4.50
2012	Basis - HSC (1)	5,000	765,000	(0.08)	—	—	—	—
2013	Call spread	2,500	912,500	—	—	—	4.75	5.25
2013	Costless three-way collar	2,500	912,500	—	5.00	4.00	—	6.45
2013	Protective spread	8,000	2,920,000	4.91	—	3.23	—	—
2013	Protective spread	4,025	853,200	3.70	—	3.00	—	—
2013	Basis - HSC (1)	4,000	1,460,000	(0.11)	—	—	—	—
2014	Short calls	2,500	912,500	—	—	—	—	6.00
2014	Costless three-way collar	3,000	1,095,000	—	4.00	3.00	—	4.36
2014	Costless three-way collar	5,000	1,825,000	—	3.75	3.00	—	4.55

(1) East Houston-Katy - Houston Ship Channel

As of June 30, 2012, the following crude derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (1)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
		(in Bbls)						
2012	Fixed price swap	600	110,400	$102.01	$—	$—	$—	$—
2013	Put spread	400	146,000	—	100.75	70.00	—	—

(1) Crude volumes hedged include oil, condensate and certain components of our NGLs production.

As of June 30, 2012, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

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Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2012	Fixed price swap	200	36,800	$52.50	$—	$—	$—	$—
2013 (1)	Fixed price swap	200	18,000	52.50	—	—	—	—

(1) For the period January to March 2013

As of June 30, 2012, 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 June 30, 2012 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. At June 30, 2012 and December 31, 2011, the Company had current commodity derivative premium payable liabilities of $2.6 million and $4.7 million, respectively.

Additional Disclosures about Derivative Instruments and Hedging Activities

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

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Fair Values of Derivative Instruments

	Derivative Assets (Liabilities)		
		Fair Value	
	Balance Sheet Location	June 30, 2012	December 31, 2011
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$ 18,610	$ 19,385
Commodity derivative contracts	Other assets	5,515	4,130
Commodity derivative contracts	Current liabilities	(5,616)	(6,479)
Commodity derivative contracts	Long-term liabilities	(3,049)	(1,163)
Total derivatives not designated as hedging instruments		$ 15,460	$ 15,873

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 June 30, 2012	June 30, 2011
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Natural gas, oil and NGLs revenues	$ 2,964	$ 1,719
Commodity derivative contracts	Unrealized hedge gain	2,804	502
Total		$ 5,768	$ 2,221

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 Six Months Ended June 30, 2012	June 30, 2011
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Natural gas, oil and NGLs revenues	$ 5,361	$ 4,179
Commodity derivative contracts	Unrealized hedge gain (loss)	1,280	(1,397)

Total	$6,641	$ 2,782

7. Capital Stock

Other Share Issuances

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

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	For the Three Months Ended June 30, 2012	For the Six Months Ended June 30, 2012
Other share issuances:		
Restricted common shares granted	—	1,116,935
Restricted common shares vested	80,817	369,049
Stock options exercised	—	3,000
Common shares forfeited (1)	21,849	104,990
Common shares canceled	676	676

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

On June 7, 2012, Parent's shareholders voted to approve the Second Amendment to Parent's 2006 Long-Term Stock Incentive Plan. This amendment, effective June 3, 2012, increased the total number of shares available for issuance under the plan from 6,000,000 shares to 11,000,000 shares.

Shares Reserved

At June 30, 2012, Parent had 980,900 common shares reserved for the exercise of stock options.

Gastar USA Common Stock

Prior to its conversion, as described below, Gastar USA's articles of incorporation allowed Gastar USA to issue 1,000 shares of common stock, without par value. There were 750 shares issued and outstanding at June 30, 2012 and December 31, 2011, all of which were held by Parent.

On May 24, 2011, Gastar USA converted from a Michigan corporation to a Delaware corporation (the "Conversion"). Following the Conversion, Gastar USA's new Delaware certificate of incorporation allows Gastar USA to issue 1,000 shares of common stock, without par value. In connection with the Conversion, the Parent's 750 shares of common stock in the Michigan corporation were converted to 750 shares of common stock in the new Gastar USA Delaware corporation.

Gastar USA Preferred Stock

Prior to the Conversion, Gastar USA's articles of incorporation did not authorize issuance of preferred stock. Following the Conversion, Gastar USA's new Delaware certificate of incorporation allows Gastar USA to issue 10,000,000 shares of preferred stock, with $0.01 par value. The preferred stock may be issued from time to time in one or more series. Gastar USA's Board of Directors (the "Gastar USA Board") is authorized to fix the number of shares of any series of preferred stock and to determine the designation of any such series. The Gastar USA Board is also authorized to determine or alter the rights, preferences, privileges and restrictions granted to or imposed upon any wholly unissued series of preferred stock and, within the limits and restrictions stated in any resolution or resolutions of the Gastar USA Board originally fixing the number of shares constituting any series, to increase or decrease (but not below the number of shares of any such series outstanding) the number of shares of any series subsequent to the issues shares of that series).

On June 23, 2011, Gastar USA sold an aggregate of 646,295 shares of its 8.625% Series A Cumulative Preferred Stock, par value $0.01 per share and liquidation preference $25.00 per share (the "Series A Preferred Stock") through a best efforts underwritten public offering. The net proceeds to Gastar USA were approximately $13.6 million after deducting underwriting discounts, commissions and estimated offering expenses.

On June 29, 2011, Gastar USA entered into an at-the-market sales agreement ("ATM Agreement") with McNicoll, Lewis & Vlak LLC ("MLV"). According to the provisions of the ATM agreement, Gastar USA may offer and sell from time to time up to 3,400,000 shares of Series A Preferred Stock through MLV, as its sales agent. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between Gastar USA and MLV.

For the six months ended June 30, 2012, Gastar USA sold 2,022,762 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $38.4 million, resulting in 3,387,305 total shares of Series A Preferred Stock issued for net proceeds of $65.8 million at June 30, 2012. From July 1, 2012 to August 3, 2012, Gastar USA sold an additional 253,842 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $4.7 million. The Series A Preferred Stock is subordinated to all of Gastar USA's existing and future debt and all future capital stock

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designated as senior to the Series A Preferred Stock. Parent has entered into a guarantee agreement, whereby it will fully and unconditionally guarantee the payment of dividends that have been declared by the board of directors of Gastar USA, amounts payable upon redemption or liquidation, dissolution or winding up, and any other amounts due with respect to the Series A Preferred Stock, to the extent described in the guarantee agreement. Parent's obligations with respect to the guarantee will be effectively subordinated to all of its existing and future debt.

The Series A Preferred Stock cannot be converted into common stock of Gastar USA or the Company, but may be redeemed by Gastar USA, at Gastar USA's option, on or after June 23, 2014 for $25.00 per share plus any accrued and unpaid dividends or in certain circumstances prior to such date as a result of a change in control. Following a change in control, Gastar USA will have the option to redeem the Series A Preferred Stock, in whole but not in part, within 90 days after the date on which the change in control occurs, for cash at the following prices per share, plus accrued and unpaid dividends (whether or not declared), up to the redemption date:

Redemption Date	Redemption Price
On or after June 23, 2012 and prior to June 23, 2013	$25.50
On or after June 23, 2013 and prior to June 23, 2014	$25.25
On or after June 23, 2014	$25.00

Gastar USA will pay cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference. For the three and six months ended June 30, 2012, Gastar USA paid dividends of $1.7 million and $3.0 million, respectively.

8. Interest Expense

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Interest expense:				
Cash and accrued	$434	$237	$723	$379
Amortization of deferred financing costs	56	65	98	128
Capitalized interest	(461)	(271)	(765)	(444)
Total interest expense	$29	$31	$56	$63

9. Related Party Transactions

Chesapeake Energy Corporation

Chesapeake Energy Corporation ("Chesapeake") acquired 6,781,768 of Parent's 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 Parent's board of directors.

As of June 30, 2012, Chesapeake owned 6,781,768 of Parent's common shares, or 10.3% of the Parent's outstanding common shares.

10. Income Taxes

For the three and six months ended June 30, 2012 and 2011, respectively, the Company did not recognize a current income tax benefit or provision.

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

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such would be anti-dilutive.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except per share and share data)			
Net income (loss) attributable to Gastar Exploration Ltd.	$(74,035)	$126	$(80,345)	$(1,809)
Weighted average common shares outstanding - basic	63,541,739	63,134,109	63,439,412	63,079,475
Incremental shares from unvested restricted shares	—	538,315	—	—
Incremental shares from outstanding stock options	—	50,669	—	—
Weighted average common shares outstanding - diluted	63,541,739	63,723,093	63,439,412	63,079,475
Net income (loss) per common share attributable to Gastar Exploration Ltd. Common Shareholders:				
Basic	$(1.17)	$—	$(1.27)	$(0.03)
Diluted	$(1.17)	$—	$(1.27)	$(0.03)
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	1,865,967	—	1,541,251	205,693
Stock options	980,900	867,800	899,250	867,800
Warrants	—	2,000,000	—	2,000,000
Total	2,846,867	2,867,800	2,440,501	3,073,493

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, contended 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 that was the subject of the lawsuit is under an operating agreement dated July 7, 2000. The Company contended, 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 included claims for suit to quiet title, trespass to try title, tortuous interference with contract, conversion, money had and received, breach of contract and declaratory relief. The Company and Chesapeake filed a motion for rehearing on February 6, 2008, which was denied on March18, 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

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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 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 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 added a new claim that the Company allegedly 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. On September 2, 2011, Navasota filed its Sixth Amended Petition. The Sixth Amended Petition added a new claim that the Company allegedly further violated Navasota's preferential right under the July 7, 2000 operating agreement to the extent the Company sold any other interests in oil and gas leases located in an area of mutual interest without offering them to Navasota. The Sixth Amended Petition also added a claim that the Company violated the Texas Natural Resource Code sections 402 and 403 by failing to pay production proceeds to Navasota.

The claims for monetary damages that Navasota asserted against the Company are as follows:

1. A claim for recovery of the gross proceeds of production for the period that Chesapeake owned record title to the properties, in the approximate amount of $52.0 million.
2. A claim for alleged lost hedging profits that Navasota claims that would have been realized if it had title to the properties during the period that Chesapeake owned record title to the properties, in the approximate amount of $32.0 million.

The Company believed that these claims against the Company were invalid and that Navasota was not entitled to any recovery on its claims for monetary damages. In particular, the Company believed that by virtue of the costs incurred in connection with the properties during the time period that Chesapeake owned record title to the properties compared to amount reimbursed by Navasota to Chesapeake to date, Navasota was in a better position economically than it would have been in had the assignments to Navasota been made in November 2005. The Company also believed that the claim that Navasota would have earned hedging profits if it had received the assignments in November 2005 was both legally invalid and factually wrong based on the undisputed evidence.

The case was set for trial in Leon County, Texas on April 24, 2012. The Company attended court-mandated mediation on April 5, 2012, and at the mediation, the Company entered into a settlement agreement with Navasota. Under the terms of the settlement, Gastar Exploration Texas, LP agreed to pay the sum of $1.3 million to Navasota, Navasota gave a full release of claims to the Company, and Gastar Exploration Texas, LP agreed to offer Navasota the opportunity to acquire one-third (1/3) of Gastar Exploration Texas, LP's current working interest in each oil and gas lease that meets both of the following criteria: (a) Gastar Exploration Texas, LP acquired the lease or an interest in the lease after October 30, 2005 in the AMI that is the subject of the Joint Operating Agreement dated July 7, 2000 covering the Hilltop Prospect to which Navasota and Gastar Exploration Texas, LP are currently parties, and (b) none of the Gastar Defendants (or any of their affiliates) and none of the Chesapeake Defendants (or any of their affiliates) have conveyed a working interest therein to Navasota as of the date of this settlement agreement. The settlement agreement provides for the payment by Navasota of its share of lease acquisition costs for any leases in which it elects to acquire an interest and for an accounting of revenues and costs for any wells drilled on leases in which Navasota elects to acquire an interest. Pursuant to the settlement, Gastar Exploration Texas, LP made the offer for acquisition of certain leasehold interests to Navasota in early May 2012, and in early June 2012, Navasota exercised its election to acquire interests in all of the leases offered pursuant to the settlement agreement. Navasota has paid Gastar Exploration Texas, LP approximately $1.5 million in leasehold reimbursement and received an assignment of approximately 3,200 net acres. Gastar Exploration Texas, LP has paid the $1.3 million of settlement funds to Navasota, and Navasota has dismissed its claims against the Company with prejudice.

Gastar Exploration Texas, LP 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 Company also contends that the defendants’ continued production of oil from wells located on the land in question is a trespass to real property for which the Company is entitled to receive damages. The defendants answered the lawsuit and asserted certain affirmative defenses. The parties exchanged written discovery requests and responses. The parties exchanged documents responsive to requests for production. The defendants filed a counterclaim. 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 Nos. 1, 2

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and 3 wells located in Leon County. The Company and the defendants attended mediation but no settlement was reached. On June 30, 2011, five individuals intervened in the lawsuit and claimed that they are owed overriding royalties under the same leases claimed by the defendants. The Company contends that the intervenors are not entitled to any overriding royalties because the leases claimed by the defendants and the intervenors have expired. The defendants, the intervenors and several third-party witnesses were deposed. On February 24, 2012, the Company and the intervenors reached a confidential settlement. A non-confidential term of the settlement with the intervenors was the intervenors' release of their claim to any overriding royalties. On March 31, 2012, the Company and the defendants entered into a settlement with an effective date of April 1, 2012. Some of the terms of the settlement are confidential. As part of the settlement, the defendants released their leases. By releasing their leases, the defendants gave up any claim to any interest in the Company's Belin Nos. 1, 2 and 3 wells. The defendants also assigned the wells they operated on the leases to the Company. Pursuant to the settlement, the lawsuit was dismissed with prejudice on April 20, 2012.

The settlements of the J. Ken Welch and Navasota lawsuits did not materially impact the Company's operating results, financial position or cash flows.

The Company has been expensing legal defense costs on these proceedings as they are incurred.

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 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 the supplemental cash paid and non-cash transactions for the periods indicated:

	For the Six Months Ended June 30,	
	2012	2011
	(in thousands)	
Cash paid for interest	$725	$387
Non-cash transactions:		
Capital expenditures excluded from accounts payable and accrued drilling costs	3,843	1,359
Capital expenditures excluded from prepaid expenses	70	—
Asset retirement obligation included in natural gas and oil properties	95	178
Asset retirement obligation assigned to operator	(2,099)	—
Application of advances to operators	3,153	204

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking information 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,” “int “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or variat 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, NGLs, 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, oil and NGLs;
- low and/or declining prices for natural gas, oil and NGLs;
- price volatility of natural gas, oil and NGLs;
- 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;

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- 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, 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 2011 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 U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties with an emphasis on unconventional natural gas reserves, such as shale resource plays. We are currently pursuing the development of liquids-rich natural gas in the Marcellus Shale play in the Appalachia area of West Virginia and central and southwestern Pennsylvania. We also hold prospective acreage in the deep Bossier gas play in the Hilltop area of East Texas and in the Mid-Continent area of the U.S.

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 MKT under the symbol “GST.” Parent is a holding company. Substantially all of the Company’s operations are conducted through, and substantially all of its assets are held by, Parent’s primary operating subsidiary, Gastar USA, and its subsidiaries. Gastar USA’s Series A Preferred Stock is listed on the NYSE MKT under the symbol “GST.PRA.”

Our current operational activities are conducted primarily in the U.S. As of June 30, 2012, our major assets consist of approximately 108,100 gross (75,700 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, approximately 38,500 gross (20,300 net) acres in the Bossier play in the Hilltop area of East Texas and approximately 20,300 gross (9,900 net) acres in the Mid-Continent area of the U.S.

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2012 compared to the three and six months ended June 30, 2011 and material changes in our financial condition since December 31, 2011. This discussion should be read in conjunction with our condensed consolidated financial statements and

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the notes thereto included in Part I. Item 1. “Financial Statements” of this report, as well as our 2011 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.” Except as otherwise noted, there are no material differences between the consolidated information for the Company presented herein and the consolidated information of Gastar USA.

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.

Marcellus Shale and Other Appalachia. The Marcellus Shale is 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 in the Appalachian Basin. Advancements in horizontal drilling and stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of June 30, 2012, our acreage position in the play was approximately 108,100 gross (75,700 net) acres. We refer to the approximately 46,400 gross (20,800 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to the Atinum Joint Venture described below as our Marcellus West acreage. We refer to the approximately 61,700 gross (54,900 net) acres in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia as our Marcellus East acreage. The entirety of our acreage is believed to be in the core, over-pressured area of the Marcellus play.

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 certain undeveloped acreage 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 was obligated to fund its 50% share of drilling, completion and infrastructure costs, and paid an additional $40.0 million of 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 made additional assignments in early 2012, as necessary, to Atinum as a result of which Atinum now owns a 50% interest in the Atinum Joint Venture Assets.

The Atinum Joint Venture's initial three-year development program called for the partners to drill a minimum of 12 horizontal wells in 2011 and 24 horizontal wells in each of 2012 and 2013. Due to recent natural gas price declines, Atinum and Gastar USA initially agreed to reduce the 2012 minimum wells to be drilled requirement from 24 wells to 20 wells. Atinum and Gastar USA subsequently agreed to extend the rig contract to May 2013 in the Marcellus Shale resulting in a plan to drill and complete approximately 23 gross (11.2 net) wells during 2012. During the six months ended June 30, 2012, we drilled and cased 12 gross (5.9 net) operated wells, completed fracture stimulation operations on 12 gross (5.5 net) operated wells and were in the process of fracture stimulating five gross (2.5 net) operated wells in Marshall County, West Virginia. We were also in various stages of drilling on nine gross (4.4 net) operated wells in Marshall County, West Virginia. All of our 2012 Marcellus Shale well operations were under the Atinum Joint Venture. As of June 30, 2011, Atinum has the right to participate in any future leasehold acquisitions made by us within Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia, on terms identical to those governing the existing Atinum Joint Venture. We will act as operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis. 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.

In December 2010, we completed a Marcellus Shale leasehold acquisition for the Marcellus East acreage 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 acreage was 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 have completed the drilling of the Hickory Ridge 2H horizontal Marcellus well in Marcellus East in Preston County, West Virginia. We completed the 2,500 foot lateral with a ten-stage fracture stimulation in August 2011 and to date, the well has recovered approximately 58% of the fluids used in its completion. Nearby vertical wells experienced low gas rates prior to recovering at least 75% of completion fluids. We have installed a compressor to assist with accelerating the recovery of the completion fluids from the well. Due to the current natural gas price environment, we are currently not planning to drill any additional wells on the Marcellus East acreage during 2012.

As of June 30, 2012, our operated wells capable of production in Marshall County, West Virginia were comprised of 18 gross (7.8 net) producing wells and two gross (0.9 net) shut-in wells. The 18 gross operated wells on production were comprised of three Accettolo wells, four Corley wells, five Hendrickson wells, three Simms wells and three Hall wells. Our average working interest in these 18 producing wells is 43.5% (net revenue interest 37.2%) and the average well lateral length is approximately 4,700 feet. The Accettolo 1H, 2H and 3H wells were placed on production in late June 2012 and our average working interest in these wells is 50.0% (net revenue interest 40.2%) and the average well lateral length is approximately 4,600 feet. The Wengerd 1H and 7H wells were shut-in to accommodate the current drilling of five additional Wengerd horizontal wells on the pad, discussed in further detail below.

As of June 30, 2012, we were commencing fracture stimulation operations on four gross (2.0 net) operated Wayne wells and one gross (0.5 net) operated Burch Ridge wells. Our average working interest in the Wayne wells is 50.0% (net revenue interest 40.6%) and the average well lateral length is approximately 5,500 feet. Our average working interest in the Burch Ridge wells is 50.0% (net revenue interest 41.5%) and the average well lateral length is approximately 5,400 feet.

As of June 30, 2012, we had drilling operations at various stages on ten gross (4.9 net) operated wells on the Wengerd and Shields leases. Top-hole drilling was commenced on two gross Wengerd wells, the 3H and 5H. We expect that drilling and completion operations on these two wells, as well as three additional Wengerd wells, will be completed by December 2012 and that all Wengerd wells will be turned to production at that time, including the two Wengerd wells shut-in during the second quarter. Our average working interest in the Wengerd wells is 44.5% (net revenue interest 37.7%) and the average well lateral length is targeted to be approximately 5,000 feet. Top-hole drilling was commenced on eight gross Shields wells on a ten horizontal well pad in Marshall County, West Virginia. We will resume horizontal drilling operations on the Shields wells later this year, and all ten Shields wells are scheduled for production in August 2013. Our average working interest in the Shields wells is approximately 50.0% (net revenue interest 42.0%) and the average well lateral length for the Shields wells is targeted to be approximately 2,800 feet.

Currently, we have commenced top-hole drilling operations on four gross (2.0 net) operated wells on the Lily lease in Marshall County, West Virginia. The Lily wells are scheduled to begin production by first quarter 2013. Our average working interest in the Lily wells is 50.0% (net revenue interest 40.6%) and the average well lateral length is approximately 5,200 feet.

As of June 30, 2012, we had participated on a non-operated basis in the drilling of seven horizontal Marcellus Shale wells in Butler County, Pennsylvania and an additional four non-operated horizontal Marcellus Shale wells in Marshall County, West Virginia. Three of the seven Butler County wells were turned to production on December 1, 2011 with the remaining four wells completed and turned to sales in March 2012. Our average working interest in the Butler County non-operated wells is 19.2% (net revenue interest 15.9%) and the average lateral length of the wells is 3,900 feet. Of the four Marshall County non-operated wells, two of the wells were on production prior to December 31, 2011 and the remaining wells were placed on production by mid-April 2012. Our current average working interest in the Marshall County non-operated wells is 21.4% (net revenue interest 18.6%) and the average well lateral length is approximately 4,200 feet.

For the three and six months ended June 30, 2012, net production from the Marcellus Shale averaged approximately 20.7 MMcfe/d and 17.3 MMcfe/d, respectively, compared to 0.6 MMcfe/d for the three and six months ended June 30, 2011, respectively. During the last several quarters, our operated production and sales in West Virginia have been curtailed by issues with condensate handling, dehydration limitations and high line pressures on a third-party-operated gathering system. The gathering system operator has been gradually resolving these issues and the majority of the issues were resolved by the end of May 2012 by increasing dehydration capacity to 70 MMcf/d from 40 MMcf/d and adding compression to reduce line pressure to approximately 550 psi at the Corley CRP. An additional CRP is to be constructed at the Burch Ridge pad and will have 75 MMcf/d dehydration capacity and compression to ensure line pressures are maintained at approximately 550 psi. The Burch Ridge CRP is currently scheduled to be operational by before year-end 2012. If the Burch Ridge CRP is delayed, we may have to restrict our production in the fourth quarter of 2012 until the Burch Ridge CRP is operational.

Hilltop Area, East Texas. At June 30, 2012, we held leases covering approximately 38,500 gross (20,300 net) acres in the Bossier play in the Hilltop area of East Texas in Leon and Robertson Counties. 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. Due to current low natural gas prices, we have suspended all Bossier drilling activities in the Hilltop area for 2012. We are monitoring offset horizontal drilling activity in the Eagle Ford and Woodbine formations by Encana Corporation, EOG Resources, Inc. and other companies. Should the drilling results of the offset operators warrant such, we may consider drilling an Eagle Ford or Woodbine test well in 2013.

For the three and six months ended June 30, 2012, net production from the Hilltop area averaged approximately 13.7 MMcfe/d and 13.9 MMcfe/d, respectively, compared to 16.6 MMcfe/d and 18.5 MMcfe/d for the three and six months ended June 30, 2011, respectively. The decline in production is the result of natural field decline and the suspension of our East Texas drilling plans as a result of low natural gas prices.

Mid-Continent Horizontal Oil Play. At June 30, 2012, we held leases covering approximately 20,300 gross (9,900 net) acres in the previously announced non-operated Mid-Continent horizontal oil play. Our leasing activities are continuing with a goal of leasing at least 25,000 gross acres in an initial AMI. In late July 2012, drilling operations commenced on the first of

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three wells in this play to be drilled during 2012. The first well is targeted to have a horizontal lateral of approximately 4,200 feet and, if successful, should be completed by September 2012. Gross costs to drill and complete the first well are $4.3 million of which we are paying 62.5% ($2.7 million net) to earn a 50% working interest. Drilling operations on the second well are anticipated to commence in early fourth quarter 2012. The third well on the initial prospect should be spudded by December 2012. We will be paying 62.5% of the first four wells' gross drill and complete costs to earn a 50% working interest. For all future wells in the initial prospect area, we will be responsible for paying only our 50% working interest (approximate net revenue interest 39.0%).

Coalbed Methane – Powder River Basin, Wyoming and Montana. On May 3, 2012, we assigned our working interest in the Powder River Basin to the operator effective January 1, 2012.

Gastar USA Series A Preferred Stock

During the six months ended June 30, 2012, Gastar USA sold 2,022,762 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $38.5 million, resulting in 3,387,305 total shares issued for net proceeds of $65.8 million at June 30, 2012. From July 1, 2012 to August 3, 2012, we sold an additional 253,842 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $4.7 million. We plan to continue issuing Series A Preferred Stock under the ATM Agreement in the future depending on market conditions and our capital expenditures program. See “Liquidity and Capital Resources” of this report.

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:

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	For the Three Months Ended June 30, 2012	2011	For the Six Months Ended June 30, 2012	2011
Production:				
Natural gas (MMcf)	2,564	1,634	4,801	3,600
Oil (MBbl)	38	11	65	21
NGLs (MBbl)	62	—	110	—
Total production (MMcfe)	3,169	1,697	5,847	3,728
Total (Mmcfe/d)	34.8	18.6	32.1	20.6
Average sales price per unit:				
Natural gas per Mcf, excluding impact of realized hedging activities	$1.70	$3.52	$1.82	$3.43
Natural gas per Mcf, including impact of realized hedging activities	2.61	4.59	2.83	4.60
Oil per Bbl, excluding impact of realized hedging activities	56.72	96.66	64.03	92.30
Oil per Bbl, including impact of realized hedging activities	62.76	96.66	66.42	92.30
NGLs per Bbl, excluding impact of realized hedging activities	25.44	—	31.64	—
NGLs per Bbl, including impact of realized hedging activities	32.53	—	35.66	—
Average sales price per Mcfe, excluding impact of realized hedging activities	$2.56	$3.99	$2.80	$3.84
Average sales price per Mcfe, including impact of realized hedging activities	3.51	5.02	3.73	4.97
Selected operating expenses (in thousands):				
Production taxes	$481	$118	$934	$227
Lease operating expenses	1,558	1,875	3,974	3,582
Transportation, treating and gathering	1,231	1,123	2,410	2,226
Depreciation, depletion and amortization	6,956	2,991	12,609	7,103
Impairment of natural gas and oil properties	72,733	—	72,733	—
General and administrative expense	3,151	2,596	6,312	5,476
Selected operating expenses per Mcfe:				
Production taxes	$0.15	$0.07	$0.16	$0.06
Lease operating expenses	0.49	1.10	0.68	0.96
Transportation, treating and gathering	0.39	0.66	0.41	0.60
Depreciation, depletion and amortization	2.20	1.76	2.16	1.91
General and administrative expense	0.99	1.53	1.08	1.47

Three Months Ended June 30, 2012 compared to the Three Months Ended June 30, 2011

Revenues. Total natural gas, oil and NGLs revenues were $11.1 million for the three months ended June 30, 2012, up from $8.5 million for the three months ended June 30, 2011. The increase in revenues was the result of an 87% increase in production offset by a 30% decrease in weighted average realized prices. Average daily production on an equivalent basis was 34.8 MMcfe/d for the three months ended June 30, 2012 compared to 18.6 MMcfe/d for the same period in 2011. Oil and NGLs daily production represented approximately 19% of total production for the three months ended June 30, 2012 compared to 16% of daily production for the three months ended March 31, 2012 and 4% of daily production for the prior year three month period, primarily as a result of our increased focus on drilling liquids-rich acreage in 2012.

Liquids revenues (oil, condensate and NGLs) represented approximately 40% of our total natural gas, oil and NGLs revenues for the three month period ended June 30, 2012 compared to 12% for the three month period ended June 30, 2011. Due to continued lower natural gas prices, we are focusing the majority of our 2012 drilling activity on the liquids-rich portions of the Marcellus Shale. If current trends of natural gas prices relative to oil and NGLs prices continue, and assuming that we successfully and timely complete our 2012 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total revenues before hedging gains or losses for the remainder of 2012. NGLs prices also declined during the second quarter of 2012, largely attributable to a record-warm winter, a slowing global economy and growing NGLs supplies. We expect NGLs prices to remain depressed in the near-term, with some anticipated recovery by the end of the year.

During the three months ended June 30, 2012, we had commodity derivative contracts covering approximately 87% of our natural gas production, which resulted in realized gains of $2.3 million and an increase in total price realized from $1.70 per Mcf to $2.61 per Mcf. The realized hedge impact includes a benefit of $220,000 for amortization of prepaid call sale premiums. Excluding the non-cash amortization, the realized effect of hedging was an increase in revenues of $2.1 million, which was comprised of $3.1 million of NYMEX hedge gains offset by $12,000 of regional basis losses and payment of deferred put premiums of $1.0 million. During the three months ended June 30, 2011, the realized effect of hedging on natural gas sales was an increase of $1.7 million in natural gas revenues resulting in an increase in total price realized from $3.52 per Mcf to $4.59 per Mcf. The 2011 realized hedge impact included a benefit of $429,000 of non-cash amortization of prepaid call sale and put purchase premiums and payment of deferred put premiums of $686,000.

During the three months ended June 30, 2012, we had commodity derivative contracts covering approximately 71% of our oil production. The realized effect of hedging on oil sales was an increase of $232,000 in oil revenues resulting in an increase in total price realized from $56.72 per Bbl to $62.76 per Bbl.

During the three months ended June 30, 2012, we had commodity derivative contracts covering approximately 76% of our NGLs production. The realized effect of hedging on NGLs sales was an increase of $442,000 in NGLs revenues resulting in an increase in total price realized from $25.44 per Bbl to $32.53 per Bbl.

Unrealized hedge gain was $2.8 million for the three months ended June 30, 2012 compared to $502,000 for the three months ended June 30, 2011. The increase in unrealized hedge gain is the result of lower future NYMEX gas prices and future oil and NGLs prices coupled with the addition of new future hedges.

Production taxes. We reported production taxes of $481,000 for the three months ended June 30, 2012 compared to $118,000 for the three months ended June 30, 2011. The increase in production taxes primarily resulted from higher revenues in West Virginia due to increased natural gas, oil and NGLs production.

Lease operating expenses. We reported lease operating expenses of $1.6 million for the three months ended June 30, 2012 compared to $1.9 million for the three months ended June 30, 2011. The decrease in our lease operating expenses ("LOE") was primarily due to a $321,000 decrease in controllable LOE and a $78,000 decrease in workover costs partially offset by an $81,000 increase in ad valorem taxes. The decrease in controllable LOE is primarily due to the assignment of our Powder River Basin properties to the operator on May 3, 2012. As a result of the assignment, Powder River Basin controllable LOE decreased $453,000 for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. Our LOE was $0.49 per Mcfe for the three months ended June 30, 2012 compared to $1.10 per Mcfe for the same period in 2011.

Transportation, treating and gathering. We reported transportation expenses of $1.2 million for the three months ended June 30, 2012 compared to $1.1 million for the three months ended June 30, 2011, of which $931,000 and $1.0 million, respectively, related to our Hilltop operations in East Texas. The current quarter includes $484,000 of minimum volume requirement charges under our Hilltop gas gathering agreement compared to $411,000 of such charges in the same quarter of 2011. Such charges resulted from actual production volumes being less than minimum contractual volume requirements.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization ("DD&A") expense of $7.0 million for the three months ended June 30, 2012 up from $3.0 million for the three months ended June 30, 2011. The increase in DD&A expense was the result of a 25% increase in the DD&A rate per Mcfe and an 87% increase in production. The DD&A rate for the three months ended June 30, 2012 was $2.20 per Mcfe compared to $1.76 per Mcfe for the same period in 2011. The increase in the rate is primarily due to higher proved costs associated with the 2011 allocation of undeveloped East Texas leasehold costs from unproved to proved properties based on 2011 drilling results and reduced 2012 drilling activity.

Impairment of natural gas and oil properties. We reported an impairment of natural gas and oil properties of $72.7 million for the three months ended June 30, 2012. The impairment is primarily the result of a 24% decline in the 12-month average natural gas price used in the calculation of the full cost ceiling test at June 30, 2012 compared to the 12-month average natural gas price at December 31, 2011. We did not recognize an impairment for the three months ended June 30, 2011. Given the current price environment, we expect that further declines in the 12-month average natural gas, oil and NGLs prices will likely result in the recognition of future ceiling impairments.

General and administrative expense. We reported general and administrative expenses of $3.2 million for the three months ended June 30, 2012, up from $2.6 million for the three months ended June 30, 2011. Non-cash stock-based compensation expense, which is included in general and administrative expense, increased $416,000 to $954,000 for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The increase in stock-based compensation expense is

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primarily due to the additional expense recognized during the period related to grants made in early 2012 that were in excess of grants made in the prior year. Excluding stock-based compensation expense, general and administrative expense increased $139,000 to $2.2 million for the three months ended June 30, 2012 compared to June 30, 2011. This increase is primarily due to higher professional fees and general overhead costs.

Dividends on Preferred Stock. We reported dividends on our Series A Preferred Stock of $1.7 million for the three months ended June 30, 2012 compared to $31,000 for the three months ended June 30, 2011. The Series A Preferred Stock carries a cumulative dividend rate of 8.625% per annum. The increase in dividends on Series A Preferred Stock is due to an increase in the number of preferred shares outstanding.

Six Months Ended June 30, 2012 compared to the Six Months Ended June 30, 2011

Revenues. Total natural gas, oil and NGLs revenues were $21.8 million for the six months ended June 30, 2012, up from $18.5 million for the six months ended June 30, 2011. The increase in revenues was the result of a 57% increase in production offset by a 25% decrease in weighted average realized prices. Average daily production on an equivalent basis was 32.1 MMcfe/d for the six months ended June 30, 2012 compared to 20.6 MMcfe/d for the same period in 2011. Oil and NGLs daily production represented approximately 18% of total production for the six months ended June 30, 2012 compared to 3% of daily production for the prior year six month period, primarily as a result of our increased focus on drilling liquids-rich acreage in 2012 due to lower natural gas prices.

Liquids revenues represented approximately 38% of our total natural gas, oil and NGLs revenues for the six month period ended June 30, 2012 compared to 11% for the six month period ended June 30, 2011.

During the six months ended June 30, 2012, we had commodity derivative hedge contracts covering approximately 96% of our natural gas production, which resulted in realized gains of $4.8 million and an increase in total price realized from $1.82 per Mcf to $2.83 per Mcf. The realized hedge impact includes a benefit of $440,000 for amortization of prepaid call sale premiums. Excluding the non-cash amortization, the realized effect of hedging was an increase in revenues of $4.4 million, which was comprised of $6.5 million of NYMEX hedge gains offset by $4,000 of regional basis losses and payment of deferred put premiums of $2.1 million. During the six months ended June 30, 2011, the realized effect of hedging on natural gas sales was an increase of $4.2 million in natural gas and oil revenues resulting in an increase in total price realized from $3.43 per Mcf to $4.60 per Mcf. The 2011 realized hedge impact included a benefit of $871,000 of non-cash amortization of prepaid call sale and put purchase premiums and payment of deferred put premiums of $1.4 million.

During the six months ended June 30, 2012, we had commodity derivative hedge contracts covering approximately 56% of our oil production. The realized effect of hedging on oil sales was an increase of $154,000 in oil revenues resulting in an increase in total price realized from $64.03 per Bbl to $66.42 per Bbl. We have designated 50% of our current crude hedges as price protection for our NGLs production.

During the six months ended June 30, 2012, we had commodity derivative hedge contracts covering approximately 56% of our NGLs production. The realized effect of hedging on NGLs sales was an increase of $440,000 in NGLs revenues resulting in an increase in total price realized from $31.64 per Bbl to $35.66 per Bbl.

Unrealized hedge gain was $1.3 million for the six months ended June 30, 2012 compared to an unrealized hedge loss of $1.4 million for the six months ended June 30, 2011. The increase in unrealized hedge gain is the result of lower future NYMEX gas prices and future oil and NGLs prices coupled with the addition of new future hedges.

Production taxes. We reported production taxes of $934,000 for the six months ended June 30, 2012 compared to $227,000 for the six months ended June 30, 2011. The increase in production taxes primarily resulted from higher revenues in West Virginia due to increased natural gas, oil and NGLs production.

Lease operating expenses. We reported LOE of $4.0 million for the six months ended June 30, 2012 compared to $3.6 million for the six months ended June 30, 2011. The increase in our LOE expenses were primarily due to a $213,000 increase in controllable LOE and a $168,000 increase in East Texas workover costs. Our LOE was $0.68 per Mcfe for the six months ended June 30, 2012 compared to $0.96 per Mcfe for the same period in 2011.

Transportation, treating and gathering. We reported transportation expenses of $2.4 million for the six months ended June 30, 2012 compared to $2.2 million for the six months ended June 30, 2011, of which $1.9 million and $2.0 million, respectively, related to our Hilltop operations in East Texas. The current year to date period includes

$949,000 of minimum volume requirement charges under our Hilltop gas gathering agreement compared to $678,000 of such charges in the same period of 2011. Such charges resulted from actual production volumes being less than minimum contractual volume requirements.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization (“DD&A”) expense of $12.6 million for the six months ended June 30, 2012 up from $7.1 million for the six months ended June 30, 2011. The

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increase in DD&A expense was the result of a 13% increase in the DD&A rate per Mcfe and a 57% increase in production. The DD&A rate for the six months ended June 30, 2012 was $2.16 per Mcfe compared to $1.91 per Mcfe for the same period in 2011. The increase in the rate is primarily due to higher proved costs associated with the 2011 allocation of undeveloped East Texas leasehold costs from unproved to proved properties based on 2011 drilling results.

Impairment of natural gas and oil properties. We reported an impairment of natural gas and oil properties of $72.7 million for the six months ended June 30, 2012. The impairment is primarily the result of a 24% decline in the 12-month average natural gas price used in the calculation of the full cost ceiling test at June 30, 2012 compared to the 12-month average natural gas price at December 31, 2011. We did not recognize an impairment for the six months ended June 30, 2011. Given the current price environment, we expect that further declines in the 12-month average natural gas, oil and NGLs prices will likely result in the recognition of future ceiling impairments.

General and administrative expense. We reported general and administrative expenses of $6.3 million for the six months ended June 30, 2012, up from $5.5 million for the six months ended June 30, 2011. Non-cash stock-based compensation expense, which is included in general and administrative expense, increased $603,000 to $1.8 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The increase in stock-based compensation expense is primarily due to the additional expense recognized during the period related to grants made in early 2012 that were in excess of grants made in the prior year. Excluding stock-based compensation expense, general and administrative expense increased $223,000 to $4.5 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. This increase is primarily due to higher professional fees and general overhead costs.

Litigation settlement expense. We reported litigation settlement expense of $1.3 million for the six months ended June 30, 2012 resulting from our settlement with Navasota on April 5, 2012. For additional information regarding the settlement of this matter, see Note 12, “Commitments and Contingencies” to our condensed consolidated financial statements included in this report.

Dividends on Preferred Stock. We reported dividends on our Series A Preferred Stock of $3.0 million for the six months ended June 30, 2012 compared to $31,000 for the six months ended June 30, 2011. The Series A Preferred Stock carries a cumulative dividend rate of 8.625% per annum. The increase in dividends on Series A Preferred Stock is due to an increase in the number of preferred shares outstanding.

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 the Revolving Credit Facility, issuances of Gastar USA preferred equity and access to capital markets, to the extent available. We continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets. We may adjust capital expenditures in response to additional future declines in natural gas, oil and NGLs prices, drilling results and cash flow.

For the six months ended June 30, 2012, we reported cash flows provided by operating activities of $4.7 million, net cash used in investing activities, primarily for the development and purchase of natural gas and oil properties, of $59.1 million and net cash provided by financing activities of $51.8 million, consisting of $38.4 million of proceeds from issuances of 2,022,762 shares of Gastar USA’s Series A Preferred Stock, $3.0 million of dividends on the preferred stock and $17.0 million of net borrowings under our Revolving Credit Facility. As a result of these activities, our cash and cash equivalents balance decreased by $2.6 million, resulting in a cash and cash equivalents balance of $8.0 million at June 30, 2012.

At June 30, 2012, we had a net working capital deficit of approximately $25.7 million, including $25.4 million of advances from non-operators. At June 30, 2012, availability under our Revolving Credit Facility was $53.0 million.

Future capital and other expenditure requirements. Due to continued lower natural gas prices, we are focusing the majority of our 2012 drilling activity on the liquids-rich portions of the Marcellus Shale. NGLs prices also declined during the second quarter of 2012, largely attributable to a record-warm winter, a slowing global economy and growing NGLs supplies. We expect NGLs prices to remain depressed in the near-term, with some anticipated recovery by the end of the year. We continue to monitor natural gas, NGLs and oil prices and modify our capital expenditures accordingly. Capital expenditures for the second half of 2012, excluding acquisitions, are projected to be approximately $65.5 million. In the Marcellus Shale, we expect to spend $51.1 million for drilling, completion, infrastructure, lease acquisition and seismic costs. We have budgeted $1.5 million for East Texas for lease extensions and recompletions. In addition, we have allocated $10.5 million for the new Mid-Continent oil-focused venture and $2.4 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 the Revolving Credit Facility and possible future ATM issuances of Gastar USA Series A Preferred Stock. 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, oil and NGLs prices, costs of drilling and completion and leasehold acquisitions, drilling results, the market for future ATM issuances of Gastar USA Series A Preferred Stock and changes in the borrowing base under the Revolving Credit Facility.

Operating Cash Flow and 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, oil and NGLs. 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, oil and NGLs 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, oil and NGLs 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 price and the price received for our natural gas production at the specific delivery location. For the remainder of 2012, we have costless three way collar hedges for approximately 7,400 MMBtu/d of our natural gas production with a weighted average floor of $5.73, short put of $4.00 and a ceiling of $6.88. In addition, we have put spread hedges for approximately 15,300 MMBtu/d of our natural gas production with a weighted average floor of $6.00 and a short put of $4.00 and call spreads for 2,000 MMBtu/d of our natural gas production with a weighted average call of $4.00 and a ceiling of $4.50. For the remainder of 2012, we have fixed price swaps for 600 Bbls/d of crude oil at $102.01 per Bbl. The crude oil fixed price swaps provide price protection for our future oil sales and butane, isobutene and pentanes components of our NGLs production as these heavy components of NGLs have pricing that correlates closely with oil pricing. We have designated 50% of our current crude hedges as price protection for our NGLs production. For the remainder of 2012, we have fixed price swaps for 200 Bbls/d of NGLs at $52.50 per Bbl providing price protection for our future propane component of our NGLs production. See Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report.

At June 30, 2012, the estimated fair value of all of our commodity derivative instruments was a net asset of $15.5 million, comprised of current and non-current 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 June 30, 2012, we had a current commodity derivative premium payable of $2.6 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, oil and NGLs for 2012, 2013 and 2014, 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 June 30, 2012, 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 June 30, 2012 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 June 30, 2012, we had $47.0 million outstanding under the Revolving Credit Facility compared to our December 31, 2011 outstanding balance of $30.0 million. The increase in our long-term debt balance is associated with expenditures for the development of natural gas and oil properties during the six months ended June 30, 2012 of $62.9 million. Effective March 5, 2012, the borrowing base under the Revolving Credit Facility was increased from $50.0 million to $100.0 million. Borrowing base redeterminations are scheduled semi-annually with the next redetermination scheduled for November 2012. However, we and the lenders may request one additional unscheduled redetermination annually.

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. At August 3, 2012, our availability under our Revolving Credit Facility was $40 million.

At June 30, 2012, Gastar USA was in compliance with all financial covenants under the Revolving Credit Facility. For a more detailed description of the terms of our Revolving Credit Facility, see Part I, Item 1. “Financial Statements, Note 4 – Long-Term Debt” of this report.

Off-Balance Sheet Arrangements

As of June 30, 2012, 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

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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 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 U.S. 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 2011 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, oil and NGLs production. 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, oil and NGLs in the region produced. Prices received for natural gas, oil and NGLs 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 and six months ended June 30, 2012, a 10% change in the prices received for natural gas, oil and NGLs production would have had an approximate $811,000 and $1.6 million impact, respectively, 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 June 30, 2012, we had $47.0 million outstanding under the Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at June 30, 2012, a one percentage point change in the interest rate would have had an $117,000 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 the 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.

Item 4. Controls and Procedures

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

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Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Parent and the President and Treasurer of Gastar USA, Parent and Gastar USA each conducted an evaluation of the effectiveness of the design and operation of its 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 June 30, 2012. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Parent and the President and Treasurer of Gastar USA concluded that, as of June 30, 2012, each company’s 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 the Chief Executive Officer and Chief Financial Officer of Parent and the President and Treasurer of Gastar USA, 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 June 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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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 and six months ended June 30, 2012 does not materially differ from that set out under Part I, Item 1A. "Risk Factors" in our 2011 Form 10-K and Part II, Item 1A. "Risk Factors" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 ("1Q 2012 Form 10-Q"). You should carefully consider the risk factors and other information discussed in our 2011 Form 10-K and 1Q 2012 Form 10-Q, 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.

Recently proposed or finalized rules and guidance imposing more stringent requirements on the oil and gas exploration and production industry could cause us to incur increased capital expenditures and operating costs as well as decrease our levels of production.

On April 17, 2012, the U.S. Environmental Protection Agency ("EPA") approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

In addition, federal agencies have recently announced two other regulatory initiatives regarding certain aspects of hydraulic fracturing that could further increase our costs to operate and decrease our levels of production. On May 4, 2012, the U.S. Department of the Interior announced proposed rules that if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. Also on May 4, 2012, the EPA issued draft guidance for federal Safe Drinking Water Act permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. The adoption or implementation of these regulatory initiatives could cause us to incur increased expenditures and decrease our levels of production.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information
None.

Item 6. Exhibits
The following is a list of exhibits filed or furnished (as indicated) as part of this report. Where so indicated by a note, exhibits which were previously filed are incorporated herein by reference.

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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).
3.5	Certificate of Incorporation of Gastar Exploration USA, Inc. (incorporated by refernce to Exhibit 3.3 to Gastar Exploration USA, Inc.'s Registration Statement on Form S-3, dated May 27, 2011. Registration No. 333-174552).
3.6	Amended and Restated Bylaws of Gastar Exploration USA, Inc. (incorporated by refernce to Exhibit 3.3 to Gastar Exploration USA, Inc.'s Registration Statement on Form S-3, dated May 27, 2011. Registration No. 333-174552).
3.7	Certificate of Designation of Rights and Preferences of 8.625% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.3 of Gastar Exploration USA, Inc.'s Form 8A filed on June 20, 2011).
10.1*	Second Amendment to Employment Agreement entered into by and between Gastar Exploration Ltd., Gastar Exploration USA, Inc. and Michael A. Gerlich as of April 10, 2012 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated April 12, 2012. File No. 001-32714).
10.2*	First Amendment to Gastar Exploration Ltd. Employee Change of Control Severance Plan, dated April 11, 2012 (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K dated April 12, 2012. File No. 001-32714).
10.3*	Second Amendment to the Gastar Exploration Ltd. 2006 Long-Term Stock Incentive Plan, dated June 3, 2012 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated June 18, 2012. File No. 001-32714)
31.1†	Certification of Periodic Financial Reports by Chief Executive Officer of Gastar Exploration Ltd. in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Periodic Financial Reports by Chief Financial Officer of Gastar Exploration Ltd. in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.

31.3†	Certification of Periodic Financial Reports by President of Gastar Exploration USA, Inc. in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.4†	Certification of Periodic Financial Reports by Treasurer of Gastar Exploration USA, Inc. in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Periodic Financial Reports by Chief Executive Officer of Gastar Exploration Ltd. in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
32.2††	Certification of Periodic Financial Reports by Chief Financial Officer of Gastar Exploration Ltd. in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
32.3††	Certification of Periodic Financial Reports by President of Gastar Exploration USA, Inc. in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
32.4††	Certification of Periodic Financial Reports by Treasurer of Gastar Exploration USA, Inc. in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS††	XBRL Instance Document
101.SCH††	XBRL Taxonomy Extension Schema Document
101.CAL††	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF††	XBRL Taxonomy Extension Definition Linkbase Document

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Exhibit Number	Description
101.LAB††	XBRL Taxonomy Extension Label Linkbase Document
101.PRE††	XBRL Taxonomy Extension Presentation Linkbase Document

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

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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: August 7, 2012	By: /S/ J. RUSSELL PORTER J. Russell Porter President and Chief Executive Officer (Duly authorized officer and principal executive officer)
Date: August 7, 2012	By: /S/ MICHAEL A. GERLICH Michael A. Gerlich Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

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 USA, INC.