GASTAR EXPLORATION LTD
Form 10-K
March 11, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 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)

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

Gastar Exploration Ltd. Common Stock, No Par Value	NYSE MKT LLC
Gastar Exploration USA, Inc. 8.625% Series A Cumulative Preferred Stock	NYSE MKT LLC
(Title of each class)	(Name of Exchange on which registered)

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act.

Gastar Exploration Ltd.	Yes	¨	No	ý

Gastar Exploration USA, Inc.	Yes	¨	No	ý

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

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

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	¨
Gastar Exploration USA, Inc.	Yes	ý	No	¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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	¨
Gastar Exploration USA, Inc.	Yes	ý	No	¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter)
is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Gastar Exploration Ltd.	¨
Gastar Exploration USA, Inc.	ý

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	¨	Accelerated filer	ý
	Non-accelerated filer	¨	Smaller reporting company	¨
Gastar Exploration USA, Inc.	Large accelerated filer	¨	Accelerated filer	¨
	Non-accelerated filer	ý	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

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

The aggregate market value of the voting and non-voting common equity of Gastar Exploration Ltd. held by non-affiliates of Gastar Exploration Ltd. as of June 29, 2012 (the last business day of Gastar Exploration Ltd.'s most recently completed second fiscal quarter) was approximately $110.0 million based on the closing price of $1.93 per share on the NYSE MKT LLC.

All common equity in Gastar Exploration USA, Inc. is held by Gastar Exploration Ltd., an affiliate of Gastar Exploration USA, Inc. Gastar Exploration USA, Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) and is filing this Form with the reduced disclosure format.

The total number of outstanding common shares, no par value per share, as of March 7, 2013 was:

Gastar Exploration Ltd.	68,450,241	shares of common stock

Gastar Exploration USA, Inc.	750	shares of common stock

DOCUMENTS INCORPORATED BY REFERENCE:

The information required by Part III of Form 10-K (Items 10, 11, 12, 13 and 14) is incorporated by reference from portions of Gastar Exploration Ltd.'s definitive proxy statement relating to its 2013 annual meeting of shareholders to be filed with the U.S. Securities and Exchange Commission ("SEC") within 120 days of December 31, 2012.

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2012
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Form 10-K”) 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 (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included or incorporated by reference in this Form 10-K are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “ant “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or variations thereon, other comparable terminology.

The forward-looking statements contained in this Form 10-K 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, oil and NGLs reserves;
- timing and amount of future production of natural gas, condensate, oil and NGLs;
- 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. For a more detailed description of the known material factors that could cause actual results to differ from those in the forward-looking statements, see “Item 1A. Risk Factors” in Part I of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. 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 Form 10-K 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, condensate, oil and NGLs;
- low and/or declining prices for natural gas, condensate, oil and NGLs;
- natural gas, condensate, oil and NGLs price volatility;
- worldwide political and economic conditions and conditions in the energy market;
- our ability to raise capital to fund planned 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 to fulfill their obligations 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;

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- availability and cost of processing and transportation;
- changes or advances in technology;
- 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.

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

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 Form 10-K are stated in United States dollars (“U.S. dollars”) unless otherwise noted and (v) all financial data included in this Form 10-K have been prepared in accordance with generally accepted accounting principles in the United States of America (“U.S. GAAP”).

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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
Bcf	One billion cubic feet of natural gas
Bcfe	One billion cubic feet of natural gas equivalent, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
Btu	British thermal unit, typically used in measuring natural gas energy content
CBM	Coal bed methane
CRP	Central receipt point
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs per day
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
Mcfe	One thousand cubic feet of natural gas equivalent, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
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
MMcfe	One million cubic feet of natural gas equivalent, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
MMcfe/d	One million cubic feet of natural gas equivalent per day, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange

psi	Pounds per square inch
U.S.	United States

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PART I

Item 1. Business

Overview

We are an independent energy company engaged in the exploration, development and production of natural gas, condensate, oil and NGLs 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 reserves, such as shale resource plays. We are currently pursuing the development of liquids-rich natural gas in the Marcellus Shale play in West Virginia and, to a lesser extent, central and southwestern Pennsylvania and oil in the Mid-Continent area of the U.S. We also hold prospective acreage in the deep Bossier play in the Hilltop area of East Texas.

Gastar Exploration Ltd. 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 LLC under the symbol “GST.” 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 USA and its wholly-owned subsidiaries. Gastar USA is a Delaware corporation with its 8.625% Series A Cumulative Preferred Stock listed on the NYSE MKT LLC under the symbol “GST.PRA.” Our principal office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is http://www.gastar.com. Information on our website or about us on any other website is not incorporated by reference into and does not constitute part of this Form 10-K.

Our Strategy

Our strategy is to increase stockholder value by delivering sustainable reserves growth and improved operating results from our existing assets. We recognize that there may be periods, such as the recent declines in natural gas prices, which make it difficult to fully execute this strategy on a short-term basis. We intend to implement our strategy by focusing on:

- continued exploitation of existing Marcellus Shale assets with a focus on areas that we believe are prospective for natural gas with relatively high condensate and NGLs content;
- exploitation and development of our assets in the Mid-Continent horizontal oil play;
- active management of our domestic drilling programs; and
- effective management and utilization of technological expertise.

Continue Exploitation of Existing Marcellus Shale Assets and Focus on Areas with Relatively High NGLs and Condensate Content

We are continuing to focus the majority of our drilling activity in the liquids-rich area of the Marcellus Shale, with approximately 64% of our 2013 capital budget allocated to the Marcellus Shale. Our 2013 capital budget includes plans to place on production an additional 19 gross (9.5 net) operated Marcellus horizontal wells in Marshall County, West Virginia, if we successfully implement our planned drilling program. We believe that the expansion of our acreage position and our drilling activity in the Marcellus Shale during 2012 has provided us with a multi-year inventory of drilling opportunities. Our focus continues to be in a prospectively liquids-rich area with subsequent focus on drilling acreage in order to hold the acreage "by production" prior to lease term expirations.

Exploitation and Development within a Mid-Continent Horizontal Oil Play

During 2012, we acquired approximately 41,900 gross (17,300 net) acres of leasehold in an emerging oil play located in the Mid-Continent region of the U.S. We expect to continue to build our acreage position in this region in partnership with our operating partner during 2013. This program is focused on using modern horizontal drilling and multi-stage fracture stimulation technologies to exploit a predominantly crude oil-bearing reservoir, which has been produced historically using vertical wells conventional with completion techniques. During 2012, we, along with our operating partner, drilled and completed one horizontal well and spud two additional horizontal wells. Based on the 30 days ended February 20, 2013, the initial well produced at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. Flow back operations on the second well commenced on February 15, 2013, with encouraging preliminary results. Drilling operations on the third well were completed during February 2013 and completion operations are scheduled to commence in mid-March 2013. A fourth horizontal well was spud on February 16, 2013. For the first 12,500 gross acres acquired in the initial AMI prospect, we paid 62.5% of lease acquisition costs for a 50% leasehold interest and 50% of lease acquisition costs on additional acres in excess of 12,500 gross acres acquired for a 50% working interest. We will pay 54.25% of the lease acquisition costs in the two new prospect areas for a 50% working interest. In each prospect area, we pay 62.5% of the gross drilling and completion costs of the first four wells and 56.25 % of the gross drilling and completion costs of the next four

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wells, in each case to earn a 50% working interest. For all additional wells beyond the first eight in a prospect area, we are responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). A third-party operator handles all drilling, completion and production activities, and we handle all leasing and permitting activities in this oil play.

Actively Manage Our Domestic Drilling Program

We believe that operating approximately 70% of our drilling projects for 2013 enables us to control the timing and cost of our drilling budget as well as control operating costs and the marketing of our production. We believe that we have assembled an experienced team of operating professionals with the specialized skills needed to plan and execute the drilling and completion of horizontal Marcellus Shale wells.

Manage and Utilize Technological Expertise

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

Natural Gas and Oil Activities

The following provides an overview of our major natural gas and oil projects during 2012. While actively pursuing specific exploration and development activities in each of the following areas, we continue to review other opportunities. There is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled.

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 excellent results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of December 31, 2012, our acreage position in the play was approximately 107,600 gross (75,200 net) acres. We refer to the approximately 46,900 gross (20,900 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 60,700 gross (54,200 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 Shale play.

On September 21, 2010, we entered into the “Atinum Joint Venture” pursuant to a purchase and sale agreement with an affiliate of Atinum Partners Co. Ltd. (“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 at December 31, 2011, 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 for a total of 60 wells to be drilled. Due to natural gas price declines, Atinum and Gastar USA agreed during the first quarter 2012 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 in the Marcellus Shale to May 2013, resulting in 29 gross operated wells drilled and completed during 2012 and 38 gross wells on production at December 31, 2012. All of our 2012 Marcellus Shale well operations were under the Atinum Joint Venture. Additionally, Atinum and Gastar USA agreed to reduce the 2013 minimum wells to 19 gross wells which will result in 57 gross wells on production at December 31, 2013, compared to the 60 gross wells originally agreed upon. Effective 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

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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.
As of December 31, 2012, our operated wells capable of production in Marshall County, West Virginia were comprised of the following:

Pad	Gross Well Count	Net Well Count	Working Interest	Net Revenue Interest	Average Lateral Length (in feet) (1)	Date on Production
Corley	4.0	1.6	40.8%	35.4%	4,900	December 2011
Simms	3.0	1.5	50.0%	43.2%	5,000	December 2011
Hall	3.0	1.2	40.0%	34.7%	4,400	January 2012
Hendrickson	5.0	2.0	40.0%	34.7%	4,700	April 2012
Accettolo	3.0	1.5	50.0%	40.2%	4,600	June 2012
Burch Ridge	5.0	2.5	50.0%	41.5%	5,800	August 2012
Wayne	4.0	2.0	50.0%	40.6%	5,700	September 2012
Wengerd	7.0	3.1	44.5%	37.7%	5,000	November 2012
Lily	4.0	2.0	50.0%	40.6%	5,200	December 2012
	38.0	17.4				

(1) Average well lateral length approximates the actual average well lateral length for the pad wells.

As of December 31, 2012, we had drilling operations at various stages on the following wells in Marshall County, West Virginia:

Pad	Gross Well Count	Net Well Count	Working Interest	Estimated Net Revenue Interest	Average Lateral Length (in feet) (1)	Status	Estimated Production Date
Addison	5.0	2.5	50.0%	41.7%	4,900	Drilling operations in progress	Late First Quarter 2013
Shields	10.0	5.0	50.0%	42.0%	3,400	Drilling and fracture stimulation operations in progress	Mid-First and Third Quarters 2013
	15.0	7.5					

(1) Average well lateral length approximates the actual average well lateral length for wells that have been completed and the estimated average well lateral length for wells that have not been completed on a pad.

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As of March 8, 2013, we have the following drilling operations in Marshall County, West Virginia:

Pad	Gross Well Count	Net Well Count	Working Interest	Estimated Net Revenue Interest	Average Lateral Length (in feet) (1)	Status	Estimated Production Date
Addison	5.0	2.5	50.0%	41.7%	4,900	Fracture stimulation in progress	Late First Quarter 2013
Shields	10.0	5.0	50.0%	42.0%	3,400	5 wells producing and 5 awaiting fracture stimulation	Late First and Third Quarters 2013
Goudy (2)	4.0	2.0	50.0%	40.5%	5,600	Drilling operations in progress	Third Quarter 2013
	19.0	9.5					

(1) Average well lateral length approximates the actual average well lateral length for wells that have been completed and the estimated average well lateral length for wells that have not been completed.

(2) Goudy pad to ultimately have nine wells.

In December 2010, we completed a Marcellus Shale leasehold acquisition for our 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. 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, in August 2011. The well was drilled with a 2,500 foot lateral and completed with a ten-stage fracture stimulation. Due to low natural gas prices, and in an effort to reduce operating costs, during the fourth quarter of 2012, we installed a pump jack to assist with accelerating the recovery of the completion fluids from the well. As of March 8, 2013, the well has recovered approximately 61% of the fluids used in its completion. Nearby vertical wells experienced low gas rates prior to recovering at least 75% of completion fluids. Due to the current natural gas price environment, we are not currently planning to drill any additional wells on the Marcellus East acreage during 2013 but will continue to monitor our Marcellus producing wells and activity and the activity of our offset operators.

As of December 31, 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% (our average net revenue interest is 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 22.2% (our average net revenue interest is 17.8%) and the average well lateral length is approximately 4,200 feet. Currently, we do not plan to participate in any additional Marcellus Shale non-operated wells for 2013.

For the year ended December 31, 2012, net production from the Marcellus Shale averaged 22.0 MMcfe/d compared to 2.4 MMcfe/d in 2011. For the three months ended December 31, 2012, net production from the Marcellus Shale averaged 29.9 MMcfe/d compared to 23.3 MMcfe/d for the three months ended September 30, 2012 and 5.2 MMcfe/d for the three months ended December 31, 2011. During the last several quarters, our operated production and sales in West Virginia have been curtailed by issues with condensate handling, dehydration limitations, high line pressures and excessive unscheduled system down-time on a third-party-operated gathering system. The gathering system operator has been gradually resolving these issues and certain issues were resolved in 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 third-party gathering system downtime during 2012 resulted in reduced production of approximately 5.0 MMcfe/d, or 14% of total production for the year. The Burch Ridge CRP, originally scheduled to become operational during December 2012, is currently expected to become operational in mid-March 2013 reducing line pressure and limitations to dehydration capacity.

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At December 31, 2012, proved reserves attributable to the Marcellus Shale were approximately 153.2 Bcfe, an 82% increase from year-end 2011 reserves of 84.0 Bcfe. As of December 31, 2012, Marcellus Shale proved reserves represented approximately 85% of our total proved reserves compared to 70% of total proved reserves at December 31, 2011. Total Marcellus Shale proved reserves at year-end 2012 were comprised of approximately 32% of condensate and oil and NGLs reserves compared to 33% at year-end 2011. Approximately 65% of the Marcellus Shale year-end 2012 reserves are proved developed compared to 51% at December 31, 2011.

The following table provides production and operational information about the Marcellus Shale for the periods indicated:

	For the Years Ended December 31,		
Marcellus Shale and Other Appalachia	2012	2011	2010
Production:			
Natural gas (MMcf)	5,477	672	118
Condensate and oil (MBbl)	160	11	2
NGLs (MBbl)	270	21	—
Total production (MMcfe)	8,058	860	133
Natural gas (MMcf/d)	15.0	1.8	0.3
Condensate and oil (MBbl/d)	0.4	—	—
NGLs (MBbl/d)	0.7	0.1	—
Total daily production (MMcfe/d)	22.0	2.4	0.4
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.33	$3.43	$4.02
Condensate and oil (per Bbl)	$62.40	$71.37	$71.14
NGLs (per Bbl)	$28.22	$52.47	$—
Average sales price per Mcfe (1)	$3.77	$4.82	$4.88
Selected operating expenses (in thousands):			
Production taxes	$2,138	$272	$30
Lease operating expenses	$2,070	$832	$393
Transportation, treating and gathering	$1,090	$85	$1
Selected operating expenses per Mcfe:			
Production taxes	$0.27	$0.32	$0.23
Lease operating expenses	$0.26	$0.97	$2.96
Transportation, treating and gathering	$0.14	$0.10	$0.01
Production costs (2)	$0.38	$1.03	$2.88

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(1) Excludes the impact of realized hedging activities.

(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

For the fiscal year 2013, in Marshall County, West Virginia, we currently anticipate that we will place on production an additional 19 gross (9.5 net) operated horizontal Marcellus Shale wells. Based on this projected activity, and assuming successful completion of wells budgeted for completion in 2013, we anticipate having 57 gross (26.9 net) operated wells on production by year-end 2013.

Hilltop Area, East Texas

At December 31, 2012, we held leases covering approximately 33,000 gross (17,000 net) acres in the Bossier play in the Hilltop area of East Texas in Leon and Robertson Counties. The Bossier play is an unconventional play characterized by Jurassic-age series of sands deposited in an ancient deepwater environment in mini-basins or depositional lows and on the flanks of structures that existed at the time of deposition. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production and attractive long-lived reserves per well. Due to low natural gas prices, we suspended all Bossier drilling activities in the Hilltop area for 2012. We do not currently have any plans in our 2013 capital budget to drill any additional wells in the Bossier play and are also considering a possible divestiture of our East Texas assets to fund a portion of our 2013 capital plan. However, we continue to monitor offset horizontal drilling activity in the Eagle Ford and Woodbine formations by Encana Corporation, EOG Resources, Inc. and other companies and may revise

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our capital plan to include an Eagle Ford or Woodbine test well in 2013 should the drilling results of the offset operators indicate that the economics would be attractive.

For the year ended December 31, 2012, net production from the Hilltop area averaged 13.7 MMcfe/d compared to 17.3 MMcfe/d for the year ended December 31, 2011. For the three months ended December 31, 2012, net production from the Hilltop area averaged approximately 12.4 MMcfe/d compared to 15.5 MMcfe/d for the three months ended December 31, 2011.

At December 31, 2012, proved reserves attributable to the Hilltop area were approximately 27.4 Bcfe, representing approximately 15% of our total proved reserves and of which 100% is proved developed. This compares to proved reserves of 34.3 Bcfe, or approximately 29% of our total proved reserves, at December 31, 2011.

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

	For the Years Ended December 31,		
Hilltop Area, East Texas	2012	2011	2010
Production:			
Natural gas (MMcf)	4,914	6,127	6,756
Condendsate and oil (MBbl)	15	30	8
Total production (MMcfe)	5,005	6,304	6,803
Natural gas (MMcf/d)	13.4	16.8	18.5
Condensate and oil (MBbl/d)	—	0.1	—
Total daily production (MMcfe/d)	13.7	17.3	18.6
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.06	$3.17	$3.49
Condensate and oil (per Bbl)	$95.71	$90.12	$73.10
Average sales price per Mcfe (1)	$2.31	$3.51	$3.55
Selected operating expenses (in thousands):			
Production taxes	$84	$153	$40
Lease operating expenses	$3,624	$5,863	$4,399
Transportation, treating and gathering	$3,746	$3,962	$4,038
Selected operating expenses per Mcfe:			
Production taxes	$0.02	$0.02	$0.01
Lease operating expenses	$0.72	$0.93	$0.65
Transportation, treating and gathering	$0.75	$0.63	$0.59
Production costs (2)	$1.39	$1.45	$1.14

(1) Excludes the impact of realized hedging activities.

(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Mid-Continent Horizontal Oil Play

At December 31, 2012, we held leases covering approximately 41,900 gross (17,300 net) acres in the non-operated Mid-Continent horizontal oil play. Our leasing activities in the initial AMI prospect area have been expanded to include two additional adjacent prospect areas. We expect to continue to build our acreage position in this region with our operating partner during 2013. For the first 12,500 gross acres acquired in the initial AMI prospect, we paid 62.5% of lease acquisition costs for a 50% leasehold interest and 50% of lease acquisition costs on additional acres in excess of 12,500 gross acres acquired for a 50% working interest. We will pay 54.25% of the lease acquisition costs in the two new prospect areas for a 50% working interest. In each prospect area, we pay 62.5% of the first four wells' gross drilling and completion costs and 56.25 % of the next four wells' gross drilling and completion costs to earn a 50% working interest. For all additional wells beyond the first eight in a prospect area, we are responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). A third-party operator handles all drilling, completion and production activities, and we handle all leasing and permitting activities in this oil play.

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In late July 2012, drilling operations commenced on the first of three wells to be drilled during 2012 on the initial prospect area. The first well has a horizontal lateral of approximately 4,200 feet and fracture stimulation operations were completed in late September 2012. Costs to drill and complete the first well were $4.8 million gross ($3.0 million net). Well flow back operations commenced on October 5, 2012. This well was completed at an initial 30-day after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 84 barrels of oil per day, 12 barrels of NGLs per day, 57 Mcf of natural gas per day and 428 barrels of completion fluids per day. The well continues to unload completion fluids with approximately 31% of frac fluid flowed back as of March 7, 2013. Based on the 30 days ended February 20, 2013, the well is currently producing at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. Drilling operations on the second well commenced in November 2012. The second well has a horizontal lateral of approximately 4,100 feet and fracture stimulation and plug drill out operations were completed on January 23, 2013. Costs to drill and complete the second well were approximately $5.1 million gross ($3.2 million net). Well flow back operations commenced in early February 2013. Production results for the second well are encouraging but have not been disclosed for competitive reasons. Drilling operations on the third well with a horizontal lateral of 4,300 feet commenced on December 31, 2012 on the initial prospect area and were completed during February 2013. Completion operations on the third well are scheduled to commence in mid-March 2013. A fourth well was spud on February 16, 2013.

For the fiscal year 2013, in the Mid-Continent, we currently anticipate that we will drill an additional eight gross (4.0 net) wells and place on production nine gross (4.5 net) non-operated horizontal Mid-Continent wells. Based on this projected activity, and assuming successful completion of wells budgeted for completion in 2013, we anticipate having 10 gross (5.0 net) non-operated Mid-Continent wells on production by year-end 2013.

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.

Markets and Customers

The success of our operations is dependent primarily upon prevailing and future prices for natural gas, condensate, oil and NGLs. The markets for natural gas, condensate, oil and NGLs have historically been and currently continue to be volatile. Natural gas, condensate, oil and NGLs prices are beyond our control.

We contract to sell natural gas from our properties with spot market contracts that vary with market forces on a daily basis. While overall natural gas prices at major markets, such as Henry Hub in Erath, Louisiana, may have some impact on regional prices, the regional natural gas price at our production facilities may move somewhat independently of broad industry price trends. Because some of our operations are located in specific regions, we are directly impacted by regional natural gas prices in those regions regardless of pricing at major market hubs. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. Any significant change affecting these facilities or our failure to obtain timely access to existing or future facilities on acceptable terms could restrict our ability to conduct normal operations. Delays in the commencement of operations of new pipelines, the unavailability of new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition.

There are limited natural gas purchaser and transporter alternatives currently available in our Hilltop area of East Texas and in the Appalachian Basin. In East Texas, ETC Texas Pipeline, Ltd. (“ETC”) provides for the treating, purchase and transportation of substantially all of our natural gas production from this area. Our deep Bossier production is transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase our natural gas production. Our Appalachian Basin production is sold on the spot market to regional pipeline companies. There are numerous natural gas purchasers and transport and processing options in the area of our Mid-Continent horizontal oil play, and all natural gas production from this region is sold on the spot market to regional pipeline companies. Prior to the assignment of our interest in the Powder River Basin to the operator, our Powder River Basin natural gas was sold under spot market contracts to major pipeline and natural gas marketing companies.

Our oil, NGLs and condensate production in East Texas, the Appalachian Basin and the Mid-Continent is sold under spot sales transactions at market prices. The availability and price responsiveness of the multiple oil and condensate purchasers provides for a highly competitive and liquid market for oil sales.

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC (“SEI”) with respect to our Marshall County, West Virginia production. The initial term of the gas purchase agreement is five years with the option to extend the term of the gas purchase agreement for an additional five year period. Our Marshall County, West Virginia production is dedicated to SEI for the term of the gas purchase agreement. SEI will purchase all hydrocarbon production, including all natural gas, condensate and natural gas liquids. SEI has an agreement to utilize the Williams Ohio

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Valley Midstream LLC ("Williams") midstream facilities (formerly owned by Caiman Energy Midstream, LLC), including its 120.0 MMcf per day Fort Beeler processing plant located in Marshall County, West Virginia for transporting and processing. In order to secure access to the Williams facilities, we, Atinum and SEI dedicated all hydrocarbons purchased and produced in Marshall County, West Virginia for a term of ten years. During 2012, our operated production and sales in West Virginia were impacted by issues with high line pressures on the Williams gathering system. Williams anticipates completing the Burch Ridge CRP by mid-March 2013, which should help alleviate the high line pressure issues on the gathering system and the impact of such on our production and sales in West Virginia.

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

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

The following table provides information regarding our significant customers and the percentages of natural gas, condensate, oil and NGLs revenues, excluding realized hedge impact, which they represented for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
SEI	47 %	8 %	— %
ETC	24 %	69 %	86 %
Clearfield Appalachian	14 %	— %	— %
Plains Marketing LP	2 %	10 %	2 %

SEI and Clearfield Appalachian purchase the majority of the Company's Marcellus Shale production. ETC treats, transports and purchases substantially all of the Company's East Texas natural gas production. Plains Marketing LP purchases substantially all of the Company's East Texas oil production. There are limited natural gas purchase and transportation alternatives currently available in the Hilltop area of East Texas and in Appalachia. If SEI, ETC, Clearfield Appalachian, or Plains were to cease purchasing and transporting the Company's natural gas, condensate and oil and NGLs production and the Company was unable to obtain timely access to existing or future facilities on acceptable terms, or in the event of any significant change affecting these facilities, including delays in the commencement of operations of any new pipelines or the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise, the Company's ability to conduct normal operations would be restricted. However, the Company believes that the loss of SEI, ETC, Clearfield Appalachian or Plains would not have a long-term material adverse impact on the Company's financial position or results of operations, as there are other purchasers operating in the areas. See "Item 1A. Risk Factors - Our ability to market our natural gas, condensate, oil and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our natural gas, condensate, oil and NGLs."

Competition

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

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number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See “Item 1A.-Risk Factors - Competition in the natural gas and oil industry is intense. We are smaller and have less operating history than many of our competitors, and increased competitive pressure could adversely affect our results of operations.”

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

Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas and oil operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages, increase our costs or delay our operations.

U.S. Governmental Regulation

Our natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States. These laws and regulations, all of which are subject to change from time to time, include matters relating to land tenure; drilling and production practices, such as discharge permits and the spacing of wells; the disposal of water resulting from operations and the processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials; bonding requirements; ongoing obligations for licensing; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

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

The regulatory burden on the natural gas and oil industry increases our cost of doing business and affects our financial condition. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because those laws and regulations are frequently amended or reinterpreted. We are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized natural gas and oil company operating in the United States.

Regulation of Exploration and Production

Regulation of Production

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

Regulation of Sales of Natural Gas

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

Regulation of Availability, Terms and Cost of Pipeline Transportation

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

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

State laws and regulations generally govern the gathering and intrastate transportation of natural gas. Natural gas gathering systems in the states in which we operate are generally required to offer services on a non-discriminatory basis, and are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

Other Federal Laws and Regulations Affecting Our Industry

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

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

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

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Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future. We do not believe that we will be affected by any action taken in a materially different way than other natural gas producers, gatherers and marketers with which we compete.

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

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

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

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

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

U.S. Environmental and Occupational Safety and Health Regulation

Our natural gas and oil exploration and production operations, and similar operations that we do not operate but in which we own a working interest, are subject to stringent federal, regional, state and local environmental laws and regulations governing water safety and health, environmental protection and the discharge of substances into the environment. These laws are implemented principally by the U.S. Environmental Protection Agency ("EPA"), the Department of Transportation, the Department of the Interior, the Occupational Safety and Health Administration and other comparable state agencies. These laws and regulations may require that permits, including drilling permits, be obtained before conducting regulated activities; restrict the types, quantities and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; impose specific safety and health criteria addressing workforce protection; impose liabilities for pollution resulting from our operations; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations may result in the issuance of injunctions limiting or prohibiting operations as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as the assessment of other laws or regulations that are adopted in the future, could have a material adverse impact on our operations and other operations in which we own an interest.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws and regulations or the modification or more stringent enforcement of existing laws and regulations could have a material adverse effect on our operations and other operations in which we own an interest. As a general matter, the recent trend in environmental legislation and regulation is toward stricter standards, and this trend will likely continue. To date, we have not been required to expend significant capital expenditures or other resources in order to satisfy existing applicable environmental laws and regulations. However, there is no assurance that costs to comply with existing and any new environmental laws and regulations in the future will not be material. In addition, if substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Moreover, a serious incident of pollution may result in significant remedial costs and damages to natural resources or persons as well as the suspension or cessation of operations in the affected area. Although we maintain insurance coverage against costs of clean-up operations, no assurance can be given that we are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the more significant existing environmental laws to which our business operations are subject.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (“CERCLA”), also known as the Superfund law and analogous state laws impose strict, joint and several liability without regard to fault or legality of conduct on persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site where the release occurred and companies that transported, disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, these "responsible parties" may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes “petroleum” and “natural gas, natural gas liquids, liquefied natural gas or synthetic gas useable for fuel” from the definition of “hazardous substance,” our operations as well as other operations in which we own an interest generate materials that are subject to regulation as hazardous substances under CERCLA. The scope of financial liability under CERCLA involves inherent uncertainties.

The Resource Conservation and Recovery Act, as amended (“RCRA”), and comparable state laws regulate the management, treatment, storage and disposal of hazardous and non-hazardous solid wastes. Our operations, and other operations in which we own an interest, generate wastes, including hazardous wastes that are subject to RCRA and comparable state laws. We believe that these operations are currently complying in all material respects with applicable RCRA requirements. Although RCRA currently exempts certain natural gas and oil exploration and production wastes from the definition of hazardous waste, allowing us to manage these wastes under RCRA's less stringent non-hazardous solid waste requirements, we cannot assure that this exemption will be preserved in the future. Repeal or modification of this exception or similar exemptions in state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general.

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

Water Discharges

Our operations and other operations in which we own a working interest are subject to the Federal Water Pollution Control Act, also known as the Clean Water Act, as amended ("CWA"), as well as the Oil Pollution Act, as amended ("OPA"), and analogous state laws. These laws and their implementing regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including spills and leaks of oil and hazardous substances, into federal and state waters, including wetlands. In addition, depending on the location, discharges from or the withdrawal of water for use in our operations may be subject to regulation by regional or local regulatory authorities. Spill prevention, control and countermeasure, or

SPCC, plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Under the CWA and the OPA, any unauthorized release of pollutants from operations could cause us to become subject to the costs of remediating a release, including administrative, civil or criminal fines or penalties in addition to OPA specified damages, such as damages for loss of use and natural resource damages. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the U.S.

Our natural gas and oil exploration and production operations, and other operations in which we own an interest, generate produced water as a waste material, which is subject to regulation under the CWA, the Safe Drinking Water Act, as amended ("SDWA"), or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by operations in which we own an interest. This produced water is disposed of by injection into the subsurface through disposal wells permitted under the SDWA or an equivalent state regulatory program, discharge to surface water in compliance with permits issued by regulatory agencies pursuant to the CWA or an equivalent state program, or in evaporation ponds. While we believe that the produced water generated by our operations has been discharged or disposed of in substantial compliance with applicable environmental laws and regulations, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Pennsylvania and West Virginia, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own a working interest, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms. Moreover, there have been public concerns expressed about naturally occurring radioactive materials being detected in flow back water resulting from hydraulic fracturing, particularly in the Marcellus Shale area. This concern could result in further regulation in the treatment, storage, handling and discharge of flow back water generated from these activities that, if implemented, could limit drilling or increase the costs of drilling in affected regions. To our knowledge, there have been no material citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Air Emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws and regulations govern emissions of various air pollutants through air emissions standards, construction and operating permit programs and the imposition of other compliance requirements. Air emissions from some equipment found at our operations or other operations in which we own an interest, such as gas compressors, are potentially subject to regulations under the CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. While the need to obtain permits has the potential to delay the development of oil and natural gas projects, to date, we believe that no unusual difficulties have been encountered in obtaining air permits. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and re-fractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and re-fractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Climate Change

In response to findings made by the EPA in December 2009 that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the Earth's atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. In addition, the EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities, which include certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production interests and operations.

Endangered Species Act

The federal Endangered Species Act, as amended ("ESA"), and similar state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs arising from species protection measures or become subject to operating restrictions or bans in the affected areas.

Worker Safety and Health

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended (“OSHA”) and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to- Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Operations on Federal Lands

Performance of oil and gas exploration and production activities on federal lands, including Indian lands and lands administered by the federal Bureau of Land Management (“BLM”), may be subject to the National Environmental Policy Act, as amended (“NEPA”). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Our current and proposed exploration and production activities upon federal lands require governmental permits that are subject to the requirements of NEPA. We are not planning any drilling operations on BLM leased acreage in 2013. Our future development of any project on BLM leased acreage will be subject to completion of these environmental assessments and any delays in such completion could result in delays in our exploration or production programs. Also, depending on the mitigation strategies recommended in the environmental assessments, we could incur added costs, which could be substantial.

Other Laws and Regulations

Our operations and other operations in which we own a working interest are also impacted by regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from and are often based on negligence, trespass, nuisance, strict liability or fraud.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of natural gas and oil in the U.S. Our current operational activities are conducted primarily in and our consolidated revenues are primarily generated from markets exclusively in the U.S.

Filings of Reserve Estimates with Other Agencies

Previously, we filed with the Canadian System for Electronic Document Analysis and Retrieval (“SEDAR”) revised forms related to our oil and natural gas reserves. The forms provided additional information to ensure compliance with Canadian National Instrument 51-101, “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”), as required by the Alberta Securities Commission and the Toronto Stock Exchange. The filings did not affect any of our filings with SEC and were not considered part of our Form 10-K.

On December 16, 2011, the applicable provincial commissions in Canada issued a decision document which granted us exemptive relief from the disclosure requirements contained in NI 51-101. As a result, we are no longer required to comply with the requirements of NI 51-101 and accordingly, are not required to file Form 51-101F1, “Statement of Reserves Data and

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Other Oil and Gas Information," revised Form 51-101F2, "Report of Reserve Data by Independent Qualified Reserves Evaluator," and revised Form 51-101F3, "Report of Management and Directors on Oil and Gas Disclosure." In lieu of such filings, we are permitted to provide disclosure with respect to our oil and gas activities in the form permitted by, and in accordance with, the legal requirements of the Securities Act, the Exchange Act and the rules and regulations of the SEC and the NYSE MKT. We are now required to file such disclosure on SEDAR as soon as practicable after such disclosure is filed with the SEC.

Insurance Matters

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance may have been unavailable, because premium costs are considered not in line with our deemed exposure or the risk was deemed acceptable to self-insure. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations or cash flows.

We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law nor would it cover a gradual pollution loss. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, not to carry loss of production or business interruption insurance for our operations. We carry limited property insurance. Our control of well limits are based upon our assessment of the risk and consideration of the cost of the insurance. See "Item 1A.-The process of drilling for and producing natural gas and oil involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately."

Employees

As of March 7, 2013, we had 41 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, regulatory reporting, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our natural gas and oil. Our employees do not belong to a union or have a collective bargaining organization. Management considers its relationship with its employees to be good.

Corporate Offices

Our corporate office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, where we lease 12,823 square feet. Additionally, we rent 6,375 square feet of office space in Clarksburg, West Virginia.

Available Information

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

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

None of the information on our website should be considered incorporated into or a part of this Form 10-K.

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

- Code of Ethics;
- Corporate Governance Guidelines;
- Audit Committee Charter;
- Nominating and Governance Committee Charter:
- Compensation Committee Charter;
- Reserves Review Committee Charter; and

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- Whistleblower Procedure.

Item 1A. Risk Factors

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

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

Risks Related to Our Business

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

With the exception of the one-time sale of our Australian properties in 2009, we have not been profitable since we started our business. We incurred net losses of $160.9 million, $1.8 million and $12.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our capital has been employed in an increasingly expanding natural gas and oil exploration and development program, with our focus on finding significant natural gas and oil reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this "Item 1A – Risk Factors" and elsewhere in this Form 10-K may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. Our failure to achieve profitability in the future could materially adversely affect our ability to raise additional capital and continue our exploration and development program.

Natural gas, condensate, oil and NGLs prices are volatile and further declines in natural gas, condensate, oil and NGLs prices would continue to significantly and negatively affect our financial condition and results of operations. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

The success of our business depends primarily on the market prices of natural gas, condensate, oil and NGLs. Natural gas and oil commodity prices are set by broad market forces, which have been and will likely continue to be volatile in the future. For example, market prices for natural gas in the U.S. have declined substantially from 2008 price levels, and the rapid development of shale plays throughout North America has contributed significantly to this trend. Additionally, market prices for NGLs declined subsequent to 2011 and we experienced a 46% decrease in our realized NGLs prices per barrel from 2011 to 2012. Lower prices also may reduce the amount of natural gas, condensate, oil or NGLs that we can produce economically. Prices for natural gas, condensate, oil and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas, condensate, oil or NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- The domestic and foreign supply and demand of natural gas, condensate, oil and NGLs;
- Volatile trading patterns in the commodity futures markets;
- Overall economic conditions and market uncertainty;
- Weather conditions;
- The cost of exploring for, developing, producing, transporting and marketing natural gas, condensate, oil and NGLs;
- The proximity to, and capacity of, natural gas pipelines and other transportation facilities;
- Political conditions in the Middle East and other oil producing regions, such as Venezuela;
- Domestic and foreign governmental regulations; and
- The price and availability of competing alternative fuels.

The long-term effect of these and other factors on the prices of natural gas, condensate, oil and NGLs are uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- Adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;

- Reducing the amount of natural gas, condensate, oil and NGLs that we can produce economically;
- Causing us to delay or postpone some of our capital projects;

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- Reducing our revenues, operating income or cash flows;
- Reducing the amounts of our estimated proved natural gas and oil reserves;
- Reducing the carrying value of our natural gas and oil properties;
- Reducing the standardized measure of discounted future net cash flows relating to natural gas and oil reserves; and
- Limiting our access to sources of capital, such as equity and long-term debt.

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

Regional natural gas, condensate, oil and NGLs prices may move independently of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. During 2012, approximately 47% of our natural gas production was priced based on the Katy Hub basis point and 52% was priced based on the Columbia Gas Appalachia Pool. Continued reduced prices for natural gas have compelled us to limit our drilling operations in our Hilltop area and to focus on lease maintenance. Our West Virginia natural gas production is priced using the Columbia Gas Appalachia Pool. At December 31, 2012, the Henry Hub price was $2.76 per MMBtu, compared to our key basis point pricing of $2.77 per MMBtu at the Katy Hub and $2.77 per MMBtu for the Columbia Gas Appalachia Pool. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations. During 2012, approximately 9% and 91% of our condensate and oil production was produced in East Texas and the Marcellus Shale, respectively, where we realized $95.71 and $62.40 per barrel for the year, respectively. This compares to the 12-month unweighted average WTI posted price of $92.71 per barrel at December 31, 2012. For the year ended December 31, 2012, our realized NGLs prices for Marcellus Shale NGLs production represented approximately 30% of the 12-month unweighted average WTI posted price of $92.71.

Our development operations will require substantial capital expenditures. Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions to our preferred stockholders.

The natural gas and oil industry is capital intensive. We make and expect to continue to make substantial growth capital expenditures in our business for the development, production and acquisition of natural gas and oil reserves. These expenditures will reduce the amount of cash available for distribution to our preferred stockholders. Our capital budget for 2013 totals $92.8 million, and we expect to fund using existing cash balances, cash generated internally from our operations, additional borrowings under our Revolving Credit Facility (as defined herein), the possible divestiture of assets, the possible issuance of debt or preferred equity securities or some combination thereof.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- Our estimated proved natural gas and oil reserves;
- The amount of natural gas, condensate, oil and NGLs that we produce from existing wells;
- The prices at which we sell our production;
- The costs of developing and producing our natural gas and oil production;
- Our ability to acquire, locate and produce new reserves;
- The ability and willingness of banks to lend to us; and
- Our ability to access the capital markets.

If the borrowing base under our credit facility or our cash flow from operations decreases as a result of lower natural gas or oil prices, operating difficulties, declines in estimated reserves or production or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed to fund our growth capital expenditures, our ability to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control.

Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions to our preferred stockholders. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our preferred stockholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional preferred equity will increase the aggregate amount of cash required to make distributions to preferred stockholders.

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

We have entered into New York Mercantile Exchange ("NYMEX") futures contracts as hedges on approximately 7.4 Bcf of natural gas production, 146,000 Bbls of crude production and 110,000 Bbls of NGLs production in 2013 and 4.7 Bcf of natural gas production and 73,000 Bbls of crude production in 2014 as of December 31, 2012. Although these hedges may partially protect us from declines in commodity prices, the use of these arrangements also may limit our ability to benefit from significant increases in the prices of natural gas, condensate, oil and NGLs.

Approximately 37% of our proved reserves are classified as proved developed non-producing or proved undeveloped and may ultimately prove to be less than estimated.

At December 31, 2012, approximately 37% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take substantial capital to recomplete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2012 assumes that we will spend significant development capital expenditures to develop these reserves, including an estimated $27.0 million and $34.0 million in 2013 and 2014, respectively. Further, our drilling efforts may be delayed or unsuccessful, and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and our results of operations.

Approximately 71% of our natural gas, condensate, oil and NGLs revenues before impact of realized hedges and 85% of our total proved reserves as of and for the year ended December 31, 2012 were attributable to our properties in the Appalachian Basin. Any disruption in production, development of proved reserves, or our ability to process and sell natural gas from this area would have a material adverse effect on our results of operations or reduce future revenues.

Our current production is geographically concentrated in the Appalachian Basin. Production in the Appalachian Basin could unexpectedly be disrupted or curtailed due to reservoir, mechanical or third-party gathering system problems. The majority of our production from this area is dedicated to SEI, who agreed to utilize the midstream facilities of a third-party gathering system. If the purchaser's or third-party gathering system facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our total Marcellus Shale production could reduce current revenues by an estimated $7.4 million to $11.1 million, before the impact of hedges, with a corresponding reduction in our cash flow. Moreover, an unexpected delay in developing proved reserves in this area due to capital constraints or changes in development plan could reduce future revenues.

Approximately 27% of our natural gas, condensate, oil and NGLs revenues before impact of realized hedges and 15% of our total proved reserves as of and for the year ended December 31, 2012 were attributable to our properties in East Texas. Any disruption in production, development of proved reserves, or our ability to process and sell natural gas from this area would have a material adverse effect on our results of operations or reduce future revenues.

Production of the natural gas in East Texas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Our natural gas produced from this area contains levels of carbon dioxide and hydrogen sulfide that are above levels accepted by gas purchasers. This production must be treated by the purchaser. A majority of our East Texas production is processed by the purchaser. If the purchaser's facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our total East Texas production could reduce current revenues by an estimated $2.1 million to $3.2 million, before the impact of hedges, with a corresponding reduction in our cash flow. Moreover, an unexpected delay in developing proved reserves in this area due to capital constraints or changes in development plan could reduce future revenues.

Our ability to market our natural gas, condensate, oil and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our natural gas, condensate, oil and NGLs.

The availability of a ready market for our natural gas, condensate, oil and NGLs production, particularly in the Appalachian Basin area, depends on the proximity of our reserves to and the capacity of natural gas gathering systems, pipelines and trucking or terminal facilities. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. We enter into agreements with companies that own pipelines used to transport natural gas from the wellhead to contract destination. Those pipelines are limited in size and volume of natural gas flow.

There are a limited number of natural gas purchasers and transporters in the Marcellus Shale in the Appalachian area of West Virginia and central and southwestern Pennsylvania and in the Hilltop area in East Texas. For the year ended December 31, 2012, SEI accounted for substantially all of our revenues from the Marcellus Shale and ETC accounted for substantially all of our revenues from the Hilltop area in East Texas. If SEI were to cease purchasing and Williams were to cease transporting our natural gas in the Marcellus Shale and if ETC were to cease purchasing and transporting our natural gas in the Hilltop area of East Texas and we were unable to contract with another purchaser and/or transporter, it would have a material adverse effect on our financial condition, future cash flows and the results of operations.

Delays in the commencement of operations of new pipelines, the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition. For example, our Marcellus Shale production for 2012 was significantly impacted by issues with high line pressures on the third-party operated gathering system. In West Virginia and southwestern Pennsylvania, key issues to development include limited pipeline infrastructure and access, water access and disposal issues to support operations and limited industry services. All of these factors could have an adverse effect on our ability to effectively conduct exploration and development activities.

Further, interstate transportation and distribution of natural gas is regulated by the federal government through the FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy. Additionally, state regulators have powers over sale, supply and delivery of natural gas and oil within their state borders. While we employ certain companies to represent our interests before state regulatory agencies, our interests may not receive favorable rulings from any state agency, or some future occurrence may drastically alter our ability to enter into contracts or deliver natural gas to the market.

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

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

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

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including, but not limited to:

- Unexpected drilling conditions;
- Blowouts, fires or explosions with resultant injury, death or environmental damage;
- Pressure or irregularities in formations;
- Environmental hazards, such as natural gas leaks, crude oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the environment;
- Uncontrollable flows of natural gas, oil, brine water or drilling fluids;
- Equipment failures or accidents;
- Adverse weather conditions;
- Compliance with governmental requirements and laws, present and future; and
- Shortages or delays in the availability of drilling rigs and the delivery of equipment or obtaining water for hydraulic fracturing operations.

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

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Reserve estimates depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates, which may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves.

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

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

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

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

You should not consider the present values of estimated future net cash flows referred to in this Form 10-K to be the current market value of the estimated reserves attributable to our properties. For 2012, 2011, 2010 and 2009, the estimated discounted future net cash flows from proved reserves are based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect when the estimate is made. Current or actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- The amount and timing of actual production;
- Supply and demand for natural gas or oil;
- Actual prices received for natural gas in the future being different than those used in the estimate;
- Curtailments or increases in consumption of natural gas or oil;
- Changes in governmental regulations or taxation; and
- The timing of both production and expenses in connection with the development and production of natural gas or oil properties.

In this Form 10-K, the net present value of estimated future net revenues at December 31, 2012 is calculated using the 12-month unweighted arithmetic average of the first-day-of-the-month price and a 10% discount rate. This price and rate are not necessarily the most appropriate price or discount factor based on prices and interest rates in effect from time to time and risks associated with our reserves or the natural gas and oil industry in general.

Future downward revisions of the present value of our proved reserves and increased drilling expenditures without current additions to proved reserves may lead to write downs in the carrying value of our natural gas and oil properties. We are subject to the full cost ceiling limitation which has resulted in past write-downs of estimated net reserves and may result in a write-down in the future if commodity prices continue to decline.

Under the full cost method of accounting, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. We may experience write downs of the carrying value of our oil and gas properties in the future if the present value of our proved natural gas and oil reserves is lower than our remaining unamortized capitalized costs. If the net capitalized costs of our oil and gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders’ equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The risk that we will be required to write down the

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carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves, if there are differences in timing between the incurrence of significant costs of exploration or development activities and the recognition of significant proved reserves resulting from such activities and if we experience unsuccessful drilling activities. Expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period.

The limited availability or high costs of hydraulic fracturing services in the Marcellus Shale could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Our industry is cyclical and, from time to time, there is a shortage of materials, equipment, supplies and services, such as drilling rigs, fracture stimulation services and tubulars, well servicing equipment, gathering systems and transportation pipelines. During these periods, the costs and delivery times of those materials, equipment, supplies and services necessary to execute our drilling program are substantially greater. Shortages of fracturing equipment, water for hydraulic fracturing activities, and crews required for complex horizontal well completions in the Appalachian Basin Marcellus Shale and other zones could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not included in our capital budget. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells. See "—Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of natural gas and oil wells and adversely affect our production." for a discussion of legislative and regulatory initiatives that could significantly restrict hydraulic fracturing and therefore make it more difficult or costly for us to perform hydraulic fracturing.

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

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

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

As of December 31, 2012, 13 gross (3.1 net) wells in which we have an interest were operated by other companies.

Our inability to meet a financial covenant contained in the Revolving Credit Facility may adversely affect our liquidity, financial condition or results of operations.

We are subject to certain financial covenants which we are required to maintain under the Revolving Credit Facility related to our working capital, cash flow and interest coverage ratio. Breach of such financial covenants may constitute an event of default. At December 31, 2012, we were not in compliance with the working capital ratio contained in the Revolving Credit Facility and obtained a waiver from our lenders. In the future, if we breach a financial covenant and we are unable to cure such violation or obtain waivers from our lenders under the Revolving Credit Facility within the applicable cure periods, such violation will constitute an event of default under the Revolving Credit Facility, and our lenders could terminate any commitments they have to make available further funds, accelerate the due dates for the payments of all outstanding indebtedness and exercise their remedies as a secured creditor with respect to the collateral securing the Revolving Credit Facility, which is substantially all of our natural gas and oil properties.

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

and results of operations.
We use hedges to mitigate our natural gas price risk with counterparties. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty's insolvency or inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and

results of operations. At the date of filing of this Form 10-K, our counterparties were BP Corporation North America Inc., Bank of Montreal, EDF Trading North America, LLC., Shell Energy North America (US) L.P. and Wells Fargo Bank, N.A.

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

We are subject to various significant legal proceedings and claims arising outside of the normal course of business. No assurance can be given regarding the outcome of these legal proceedings, and additional claims may arise. We are vigorously defending the Company in these matters. This litigation, regardless of outcome or merit, however, can result in substantial costs and diversion of resources from our business. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that our management would have to appropriate to the defense of such claims. Considerable legal, accounting and other professional services expenses related to these matters have been incurred to date and significant expenditures may continue to be incurred in the future. Although we cannot predict the ultimate outcome of these matters or the liability that could potentially result, continuing defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations. For more information on our significant currently outstanding legal proceedings, see Note 15, “Commitments and Contingencies Litigation”, to our consolidated financial statements included in this Form 10-K.

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

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is not to incur the expense of retaining lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of lease brokers and others to perform the field work in examining records in the appropriate governmental or county clerk’s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to drilling an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. It does happen, from time-to-time, that the examination made by the operator’s title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect, which could affect our financial condition and results of operations. We currently are involved in a title litigation matter in East Texas. See Note 15, “Commitments and Contingencies – Litigation,” to our consolidated financial statements included in this Form 10-K.

We are subject to stringent and complex laws and regulations, which may expose us to significant costs and liabilities and adversely affect the cost, manner or feasibility of conducting our business.

Our natural gas and oil exploration and production interest and operations are subject to stringent and complex federal, state, regional and local laws and regulations relating to the operation and maintenance of our facilities, including laws regulating removal of natural resources from the ground, the discharge of materials into the environment and otherwise relating to environmental protection. Natural gas and oil operations are also subject to federal, state, regional and local laws and regulations which seek to maintain occupational health and safety standards by regulating the design and use of drilling methods and equipment.

Governmental authorities administering these laws and regulations require various timely permits, including drilling and environmental permits, before conducting regulated activities and we cannot assure you that such permits will be received. The failure or delay in obtaining the requisite approvals or permits may adversely affect our business, financial condition and results of operations. Additionally, these laws and regulations impose numerous obligations and restrictions that are applicable to our interests and operations including, but not limited to:

- Drilling and abandonment bonds or other financial responsibility assurances;
- Restriction on types, quantities and concentration of materials that may be released into the environment;
- Reports concerning operations;
- Spacing of wells;
-

Limits or prohibitions on drilling activities on certain lands lying within wilderness, wetlands and other protected areas;

- The application of specific health and safety criteria addressing worker protection;
- The imposition of substantial liabilities for pollution resulting from our operations;
- Limitations on access to properties;
- Taxation; and

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•Other regulatory controls on operating activities.
In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of natural gas and oil. Failure to comply with these laws and regulations applicable to our interests and operations could result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory or remedial obligations and the issuance of orders enjoining or limiting some or all of our operations, any of which could have a material adverse effect on our financial condition. Legal requirements are sometimes unclear or subject to reinterpretation and may be amended in response to economic or political conditions. As a result, it is hard to predict the ultimate future cost of compliance with these requirements or their effect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse effect on our financial condition, future cash flows and the results of operations.
Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of natural gas and oil wells and adversely affect our production.
Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations
. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Pennsylvania and West Virginia, where we operate, have adopted and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure, or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own working interests, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.
In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. In addition, the U.S. Department of Energy and the U.S. Department of the Interior have studied or are studying different aspects of hydraulic fracturing. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or under newly established legislation.
We could incur significant costs and liabilities in responding to contamination that occurs as a result of our operations.
There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations or in operations in which we own a working interest as a result of the handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to operations, and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private

parties, including the owners of properties upon which our wells or the wells in which we own a working interest are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, or waste , handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain

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compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition.

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

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

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Road collapses;
- Uncontrollable flows of natural gas, oil, brine, water or well fluids;
- Pipe and cement failures;
- Formations with abnormal pressures;
- Stuck drilling and service tools;
- Pipeline or tank ruptures or spills;
- Natural disasters; and
- Environmental hazards, such as natural gas leaks, crude oil spills and unauthorized discharge of brine, toxic gases or well fluids.

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

- Injury or death;
- Damage to and destruction of property, natural resources and equipment;
- Damage to natural resources due to underground migration of hydraulic fracturing fluids;
- Pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- Regulatory investigations and penalties;
- Suspension of operations; and
- Repair and remediation costs.

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

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

The President of the United States' budget proposal for the fiscal year 2013 recommended the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities for oil and natural gas production, and (iv) the extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production.

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

The Federal Trade Commission, the FERC, and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and oil and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial

enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

The enactment of the Dodd–Frank Act could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012 although the CFTC has stated that it is appealing the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant". The Dodd-Frank Act and CFTC Rules also may require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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

In response to findings made by the EPA in December 2009 that emissions of GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. In addition, the EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities while Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of

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greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

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

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

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

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

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

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

- Problems integrating the purchased operations, personnel or technologies;
- Unanticipated costs;
- Diversion of resources and management attention from our exploration business;
- Entry into regions or markets in which we have limited or no prior experience; and
- Potential loss of key employees, particularly those of the acquired organization.

Technological changes could affect our operations.

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

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We depend on our key personnel, the loss of which could adversely affect our operations and financial performance.
We depend, to a large extent, on the services of a limited number of senior management personnel and directors. Particularly, the loss of the services of our chief executive officer and chief financial officer could negatively impact our future operations. We have employment agreements with these key members of our senior management team; although, we do not maintain key-man life insurance on any of our senior management. We believe that our success is also dependent on our ability to continue to retain the services of skilled technical personnel. Our inability to retain skilled technical personnel could have a material adverse effect on our financial condition, future cash flows and the results of operations.
Some of our directors may not be subject to suit in the United States.
Two of our directors are citizens of Canada. As a result, it may be difficult or impossible to effect service of process within the United States upon those directors, to bring suit against them in the United States or to enforce in the U.S. courts any judgment obtained there against them predicated upon any civil liability provisions of the U.S. federal securities laws. Investors should not assume that Canadian courts will enforce judgments of U.S. courts obtained in actions against those directors predicated upon the civil liability provisions of the U.S. federal securities laws or the securities or “blue sky” laws of any state within the United States or will enforce, in original actions, liabilities against those directors upon the U.S. federal securities laws or any such state securities or blue sky laws.
Risks Related to Our Common Shares
Our common share price has been and is likely to continue to be highly volatile.
The trading price of our common shares are subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that are beyond our control.
In addition, the stock market in general and the market for natural gas and oil exploration companies, in particular, have experienced large price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common shares regardless of our actual operating performance. In the past, following periods of volatility in the overall market and in the market price of a company’s securities, securities class action litigation has been instituted against certain natural gas and oil exploration companies. If this type of litigation were instituted against us following a period of volatility in our common shares trading price, it could result in substantial costs and a diversion of our management’s attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.
Future issuances of our common shares may adversely affect the price of our common shares.
The future issuance of a substantial number of common shares into the public market, or the perception that such an issuance could occur, could adversely affect the prevailing market price of our common shares. A decline in the price of our common shares could make it more difficult to raise funds through future offerings of our common shares or securities convertible into common shares.
Our ability to issue an unlimited number of our common shares under our articles of incorporation may result in dilution or make it more difficult to effect a change in control of the Company, which could adversely affect the price of our common shares.
Unlike most corporations formed in the U.S., our Amended and Restated Articles of Incorporation chartered under the laws of the Province of Alberta, Canada permit the board of directors to issue an unlimited number of new common shares without shareholder approval, subject only to the rules of the NYSE MKT or any future exchange on which our common shares might trade. The issuance of a large number of common shares could be effected by our directors to thwart a takeover attempt or offer for us by a third party, which could result in the common shares being valued less in the market. The issuance or the threat of issuance of a large number of common shares at prices that are dilutive to the outstanding common shares could also result in the common shares being valued less in the market.
We are able to issue shares of preferred stock with greater rights than our common shares.
Our Amended and Restated Articles of Incorporation authorize our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our shareholders. Any preferred shares that are issued may rank ahead of our common shares in terms of dividends, liquidation rights, or

voting rights. If we issue preferred shares, it may adversely affect the market price of our common shares.

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Because we have no plans to pay dividends on our common shares, shareholders must look solely to appreciation of our common shares to realize a gain on their investment.

We do not anticipate paying any dividends on our common shares in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, the Revolving Credit Facility contains covenants that prohibit us from paying cash dividends as long as such debt remains outstanding. The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. Accordingly, shareholders must look solely to appreciation of our common shares to realize a gain on their investment, which may not occur.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

- Marcellus Shale in West Virginia and central and southwestern Pennsylvania;
- Mid-Continent area of the U.S.; and
- Hilltop area of East Texas.

Additional information concerning our interests and related natural gas and oil activities in these areas is described under “Item 1 – Business” of this Form 10-K.

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Production, Prices and Operating Expenses

The following table presents information regarding production volumes, average sales prices received and selected data per Mcfe associated with our sales of natural gas, condensate and oil and NGLs for the periods indicated. Condensate, oil and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of condensate, oil or NGLs is the energy equivalent of six Mcf of natural gas. Unless otherwise specified, all production volumes in this Annual Report on Form 10-K reflect incremental post-processing NGLs volumes and residual gas volumes with which we are credited under our sales contracts.

	For the Years Ended December 31,		
	2012	2011	2010
Production:			
Natural gas (MMcf)	10,564	7,318	7,593
Condensate and oil (MBbl)	177	40	10
NGLs (MBbl)	270	21	—
Total production (MMcfe)	13,247	7,684	7,654
Daily Production:			
Natural gas (MMcf/d)	28.9	20.0	20.8
Condensate and oil (MBbl/d)	0.5	0.1	—
NGLs (MBbl/d)	0.7	0.1	—
Total daily production (MMcfe/d)	36.2	21.1	21.0
Average sales price per unit:			
Natural gas per Mcf, excluding impact of realized hedging activities	$2.21	$3.21	$3.51
Natural gas per Mcf, including impact of realized hedging activities	3.20	4.56	4.06
Condensate and oil per Bbl, excluding impact of realized hedging activities	65.45	85.11	72.63
Condensate and oil per Bbl, including impact of realized hedging activities	70.01	85.11	72.63
NGLs per Bbl, excluding impact of realized hedging activities	28.22	52.47	—
NGLs per Bbl, including impact of realized hedging activities	34.40	52.47	—
Average sales price per Mcfe, excluding impact of realized hedging activities	3.21	3.65	3.58
Average sales price per Mcfe, including impact of realized hedging activities	4.19	4.93	4.12
Selected operating expenses (in thousands):			
Production taxes	$2,269	$620	$370
Lease operating expenses	6,174	8,630	6,679
Transportation, treating and gathering	4,965	4,501	4,654
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
General and administrative expense	12,211	11,365	14,638
Selected operating expenses per Mcfe:			
Production taxes	$0.17	$0.08	$0.05
Lease operating expenses	0.47	1.12	0.87
Transportation, treating and gathering	0.37	0.59	0.61
Depreciation, depletion and amortization	1.92	1.98	1.22
General and administrative expense	0.92	1.48	1.91
Production costs (1)	0.80	1.62	1.39

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

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Drilling Activity

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

	For the Years Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	6.0	1.7	20.0	11.9	2.0	2.0
Non-productive	—	—	—	—	—	—
Total	6.0	1.7	20.0	11.9	2.0	2.0
Development wells:						
Productive	31.0	14.2	5.0	1.7	3.0	2.2
Non-productive	—	—	—	—	—	—
Total	31.0	14.2	5.0	1.7	3.0	2.2

On December 31, 2012, we had a total of 15 gross (7.5 net) operated wells in the process of being drilled or awaiting fracture stimulation in the Marcellus Shale and two gross (1.0 net) non-operated wells being drilled in the Mid-Continent.

Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2012. The term “gross” represents the total number of acres in which we own a working interest. The term “net” represents our proportionate working interest resulting from our ownership in gross acres.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Marcellus Shale area, West Virginia and Pennsylvania (1)				
Marcellus West	41,272	18,256	5,650	2,659
Marcellus East	57,538	51,398	3,185	2,842
Total Marcellus Shale area	98,810	69,654	8,835	5,501
Hilltop area, East Texas	22,041	10,535	10,966	6,475
Mid-Continent	41,329	16,959	607	304
Total	162,180	97,148	20,408	12,280

(1) We believe that substantially all of our Marcellus Shale acreage is prospective. The Marcellus West acreage reflects that Atinum has earned their full joint venture interest.

Undeveloped Acreage Expirations

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

As of December 31,	Marcellus Shale		Hilltop Area, East Texas	Mid-Continent	Total Expiring Gross Acres	% of Total Undeveloped Gross Acres	
	West	East					
2013	19,108	6,998	16,888	2,289	45,283	28	%
2014	1,530	10,081	4,803	2,899	19,313	12	%
2015	7,960	11,356	—	36,141	55,457	34	%
2016	6,790	13,969	350	—	21,109	13	%
2017 and thereafter	5,456	52	—	—	5,508	3	%

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

As of December 31,	Marcellus Shale		Hilltop Area, East Texas	Mid-Continent	Total Expiring Net Acres	% of Total Undeveloped Net Acres	
	West	East					
2013	9,170	6,710	6,026	993	22,899	24	%
2014	624	9,894	4,415	1,514	16,447	17	%
2015	3,469	9,236	66	14,452	27,223	28	%
2016	2,574	13,824	28	—	16,426	17	%
2017 and thereafter	2,317	52	—	—	2,369	2	%

We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three to five years. As is customary in the natural gas and oil industry, we can retain our interest in undeveloped acreage by commencing drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the primary term of such leases. Of the 22,899 net acres expiring in 2013, we are currently focusing on net acres expiring in Marcellus West, Mid-Continent and East Texas. In Marcellus West, we anticipate drilling on the majority of the acreage before it expires. In Mid-Continent, we plan to extend the leases for the majority of acreage expiring during 2013 and if we are not able to extend the lease, the acreage will expire. In East Texas, we are in the process of extending approximately 3,500 acres that expire in 2013. With respect to the remaining 2,526 acres in East Texas scheduled for expiration in 2013, we may try to renew expiring leases if prospective economics improve and funds are available, or otherwise we will allow the remaining East Texas acreage to expire. Our current plans in Marcellus East are to let approximately 6,710 net acres scheduled for expiration in 2013 expire. During 2010, we drilled 16 wells in shallower Devonian formations in the Appalachia area. These wells allow us to retain, for the life of production of our interest, certain undeveloped acreage above the Marcellus Shale for possible deeper drilling in the future. We do not expect to lose significant lease acreage in the Marcellus Shale as a result of our failure to drill or our reduction in drilling activities due to declines in natural gas prices. We may also allow additional acreage to expire in the future.

Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2012. The term “gross” represents the total number of wells in which we own a working interest. The term “net” represents our proportionate working interest resulting from our ownership in gross wells. Productive wells are wells that are currently capable of producing natural gas or oil. Wells that are completed in more than one producing horizon are counted as one well.

	Productive Wells					
	Natural Gas		Oil		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Appalachia, West Virginia and Pennsylvania	89.0	47.5	—	—	89.0	47.5
Hilltop area, East Texas	22.0	14.9	15.0	10.8	37.0	25.7
Mid-Continent	—	—	1.0	0.5	1.0	0.5
Total	111.0	62.4	16.0	11.3	127.0	73.7

Natural Gas and Oil Reserves

Reserve Estimation

The SEC rules expand the definition of natural gas and oil producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic natural gas or oil and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Proved reserves must be estimated using the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than the end-of-period price, when estimating whether reserve quantities are economical to produce. Likewise, the unweighted 12-month average price is used to compute depreciation, depletion and amortization. Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

Third Party Review of Reserves Estimates

For the years ended December 31, 2012 and 2011, reserves estimates for the Marcellus Shale shown herein have been independently evaluated by Wright & Company, Inc. (“Wright”), a national firm providing petroleum property analysis for industry and financial organizations with extensive experience in the Marcellus Shale. Additionally, for the year ended December 31, 2012, Wright evaluated the reserves estimates for the Mid-Continent shown herein. Wright was founded in 1988 and performs consulting petroleum engineering services. A copy of Wright's summary reserve report is included as Exhibit 99.2 to this Form 10-K. For the years ended December 31, 2012, 2011 and 2010, reserves estimates for the Hilltop Area of East Texas shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (“NSAI”), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI evaluated the reserves estimates for the Powder River Basin of Wyoming and Montana for the years ended December 31, 2011 and 2010. Our working interest in the Powder River Basin was assigned to the operator effective January 1, 2012. Additionally, NSAI evaluated the reserves estimates for the Marcellus Shale for the year ended December 31, 2010. NSAI was founded in 1961 and performs consulting petroleum engineering services. A copy of NSAI’s summary reserve report is included as Exhibit 99.1 to this Form 10-K.

Within Wright, the technical person primarily responsible for preparing the reserves estimates set forth in the Wright reserve report incorporated herein is Mr. D. Randall Wright. Mr. Wright has been practicing consulting petroleum engineering at Wright since 1988, the year in which he founded the company. He is a Registered Professional Engineer in the State of Texas and has over 39 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He has a Master of Science degree in Mechanical Engineering from Tennessee Technological University. The technical principal meets or exceeds the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Within NSAI, the technical persons primarily responsible for preparing the reserves estimates set forth in the NSAI reserve report incorporated herein are Mr. Dan Paul Smith and Mr. William (Bill) J. Knights. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. He is a Registered Professional Engineer in the State of Texas and has over 31 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Knights has been practicing consulting petroleum geology at NSAI since 1991. He is a Certified Petroleum Geologist and Geophysicist in the State of Texas and has over 31 years of practical experience in petroleum geosciences, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a Bachelor of Science Degree in Geology and in 1984 with a Master of Science Degree in Geology. Both technical principals meet or exceed the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimates

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

Since 2006, all of our reserve estimates have been reviewed and approved by our Senior Reservoir Engineer, who reports directly to our Chief Financial Officer. Our Senior Reservoir Engineer attended Texas A&M University and graduated in 1978

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with a Bachelor of Science degree in Reservoir Engineering and has been involved in evaluations and the estimation of reserves and resources for over 30 years. During the year, our technical team may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operational conditions.

Technologies Used in Reserves Estimation

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

Estimated Proved Reserves

Our proved reserves information as of December 31, 2012 included in this Form 10-K was estimated by Wright and NSAI using standard engineering and geosciences procedures and methods used in the petroleum industry. The technical personnel responsible for preparing the reserve estimates at Wright and NSAI meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues as of December 31, 2012 were made using benchmark prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price for natural gas and oil ("SEC pricing"). Key natural gas prices utilized were the Henry Hub price of $2.76 per MMBtu, the Katy Hub price of $2.77 per MMBtu and the Columbia Gas Appalachia Pool price of $2.77 per MMBtu. NSAI utilized a West Texas Intermediate ("WTI") posted oil price of $91.21 per barrel, and Wright utilized a WTI spot oil price of $94.71 per barrel. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials. Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated significantly in recent years. All of our proved reserves are located onshore within the United States.

The following table summarizes our estimated proved reserves as of December 31, 2012:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	85,728	9,873	35,409	131,010
NGLs (MBbls)	3,042	174	1,706	4,922
Condensate and oil (MBbls)	1,801	158	1,435	3,394
Total proved reserves (MMcfe)	114,781	11,872	54,256	180,909
PV-10 (in thousands) (1)	$154,291	$13,451	$39,067	$206,809

(1) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. PV-10 is a non-U.S. GAAP financial measure because it excludes the effects of income taxes. We believe that PV-10 is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may use the measure as a basis for comparison of the relative size and value of our reserves to other companies. PV-10 should not be considered as an alternative to standardized measure of discounted future net cash flows as defined under U.S. GAAP. We presently have approximately

$254.3 million of net operating loss carryforwards, $50.6 million of foreign tax credit carryforwards and $211.1 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, we will not incur future income taxes, and as such, the standardized measure of discounted future net cash flows as of December 31, 2012 is $206.8 million.

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The following table summarizes our proved reserves by geographic area as of December 31, 2012:
SEC Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	NGLs (MBbls)	Condensate and Oil (MBbls)	MMcfe	% Proved Developed	PV-10 (2) (in thousands)
Appalachia, West Virginia and Pennsylvania	103,588	4,922	3,341	153,174	65 %	$ 191,910
Hilltop area, East Texas	27,356	—	16	27,449	100 %	12,786
Mid-Continent	43	—	37	262	100 %	2,079
Other	23	—	—	24	100 %	34
Total	131,010	4,922	3,394	180,909	70 %	$ 206,809

(1) Key natural gas prices utilized were the Henry Hub price of $2.76 per MMBtu, the Katy Hub price of $2.77 per MMBtu and the Columbia Gas Appalachia Pool price of $2.77 per MMBtu. NSAI utilized a WTI posting oil price of $91.21 per barrel and Wright utilized a WTI spot oil price of $94.71 per barrel.

(2) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. PV-10 is a non-U.S. GAAP financial measure because it excludes the effects of income taxes. We believe that PV-10 is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may use the measure as a basis for comparison of the relative size and value of our reserves to other companies. PV-10 should not be considered as an alternative to standardized measure of discounted future net cash flows as defined under U.S. GAAP. We presently have approximately $254.3 million of net operating loss carryforwards, $50.6 million of foreign tax credit carryforwards and $211.1 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, we will not incur future income taxes, and as such, the standardized measure of discounted future net cash flows as of December 31, 2012 is $206.8 million.

Proved Undeveloped Reserves (“PUDs”)

As of December 31, 2012, our PUDs totaled 54.3 Bcfe, representing a 32% increase from our PUDs as of December 31, 2011. All of our PUDs at year-end 2012 were associated with the Marcellus Shale. The December 31, 2012 PUDs consisted of 26 gross (12.8 net) Marcellus horizontal wells in Appalachia. The increase in PUD well locations in 2012 is due to the successful Marcellus Shale drilling program in 2012, partially offset by the 18 gross (7.0 net) PUD reserves that we converted to proved developed reserves in 2012. The following table summarizes our PUD activity during the year ended December 31, 2012:

	Natural Gas (MMcf)	NGLs (MBbls)	Condensate and Oil (MBbls)	MMcfe
PUDs as of December 31, 2011	26,592	1,418	1,017	41,198
Extensions and discoveries	34,089	1,644	1,413	52,426
PUDs converted to proved developed	(24,963)	(1,330)	(947)	(38,624)
Revisions of previous estimates	(309)	(25)	(48)	(744)
PUDs as of December 31, 2012	35,409	1,707	1,435	54,256

Estimated future development costs relating to the development of 2012 year-end PUDs is $70.3 million of which 2013 and 2014 expenditures are $25.7 million and $31.6 million, respectively. Under current SEC requirements, PUD reserves may only be booked if they related to wells scheduled to be drilled within five years of the original date of booking unless specific circumstances justify a longer time. All of our PUDs at December 31, 2012 are scheduled to be drilled by 2015, which is within five years from the date initially recorded as PUD reserves. We may be required to remove our PUDs if we do not drill those reserves within the required five year time frame.

Item 3. Legal Proceedings

Information about our legal proceedings is set forth in Note 15, “Commitments and Contingencies – Litigation” to our consolidated financial statements, which begin on page F-1 of this Form 10-K.

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Item 4. Mine Safety Disclosures.
Not applicable.

PART II
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities
Market Information
Our common stock is traded on the NYSE MKT LLC under the symbol "GST." The following table sets forth the high and low sales prices of our common stock for the 2012 and 2011 annual periods.

	NYSE MKT LLC	
	High	Low
2012:		
Fourth quarter	$1.73	$0.72
Third quarter	$2.05	$1.55
Second quarter	$2.95	$1.55
First quarter	$3.31	$2.67
2011:		
Fourth quarter	$3.96	$2.63
Third quarter	$4.86	$3.00
Second quarter	$4.85	$3.20
First quarter	$4.95	$4.02

The last reported sale price of our common shares on the NYSE MKT on March 7, 2013 was $1.24.
Shareholders
As of March 7, 2013, there were 358 shareholders of record who owned our common shares.
Dividends
We have never declared or paid any cash dividends on our common stock. We anticipate that we will retain future earnings, if any, to satisfy our operational and other cash needs and do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, our Revolving Credit Facility prohibits us from paying cash dividends on our common shares as long as any debt remains outstanding under the facility. Pursuant to the provisions of the Business Corporations Act (Alberta), we are prohibited from declaring or paying a dividend if there are reasonable grounds for believing that (1) we are, or would after the payment be, unable to pay our liabilities as they become due or (2) the realizable value of our assets would thereby be less than the aggregate of our liabilities and stated capital of all classes.
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, or $2.15625 per share outstanding each year, 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 5% of the current availability under the then existing borrowing base under the Revolving Credit Facility.
Recent Sales of Unregistered Securities; Use of Proceeds from Unregistered Securities
We did not have any sales of unregistered securities during the year ended December 31, 2012.

Item 6. Selected Financial Data
The following table presents selected historical financial data as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements. The following selected historical

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financial data should be read in connection with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

Financial information as of and for the years ended December 31, 2012, 2009 and 2008 includes impairment of natural gas and oil properties of $150.8 million, $68.7 million and $14.2 million, respectively. Financial information as of and for the years ended December 31, 2012 and 2010 includes litigation settlement expense of $1.3 million and $21.7 million, respectively. Financial information as of and for the year ended December 31, 2009 reflects gains on sale of assets of $211.2 million. Additionally, financial information as of and for the year ended December 31, 2009 includes expenses related to the early extinguishment of debt of $15.9 million.

	As of and for the Years Ended December 31,				
	2012	2011	2010	2009	2008
		(in thousands, except per share data)			
Consolidated Statements of Operations:					
Revenues	$49,940	$40,235	$42,768	$32,869	$63,219
Loss from operations	$(153,528)	$(631)	$(15,019)	$(76,930)	$(976)
Net income (loss) attributable to Gastar Exploration Ltd.	$(160,868)	$(1,764)	$(12,460)	$48,846	$(5,361)
Net income (loss) attributable to Gastar Exploration Ltd. per share:					
Basic	$(2.53)	$(0.03)	$(0.25)	$1.06	$(0.13)
Diluted	$(2.53)	$(0.03)	$(0.25)	$1.06	$(0.13)
Weighted average common shares outstanding					
Basic	63,538	63,004	49,814	46,103	41,420
Diluted	63,538	63,004	49,814	46,210	41,420
Consolidated Balance Sheets:					
Property, plant and equipment, net	$256,251	$285,740	$215,115	$162,661	$252,527
Total assets	$290,068	$334,503	$247,352	$296,238	$288,437
Long-term liabilities	$106,020	$39,438	$14,295	$18,371	$5,095
Total shareholders' equity	$49,895	$207,803	$207,391	$164,896	$101,582

Item 7. 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, condensate, oil and NGLs 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 reserves, such as shale resource plays and application of horizontal drilling technology to conventional reservoirs. We are currently pursuing the development of liquids-rich natural gas in the Marcellus Shale in West Virginia and, to a lesser extent, central and southwestern Pennsylvania and oil in the Mid-Continent area of the U.S. We also hold prospective acreage in the deep Bossier play in the Hilltop area of East Texas.

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 December 31, 2012, our major assets consist of approximately 107,600 gross (75,200 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, approximately 41,900 gross (17,300 net) acres in the Mid-Continent area of the U.S., and approximately 33,000 gross (17,000 net) acres in the Bossier play in the Hilltop area of East Texas. During the past three years, we spent approximately $315.8 million in acreage, seismic, capitalized interest, drilling advances, reserve acquisition and exploratory and development drilling on this acreage. We have not attained positive net income from operations in the past three years. There can be no assurance that operating income and net earnings will be achieved in future periods. As we continue the exploitation and development drilling in the Marcellus Shale and Mid-Continent, we expect to show improvement in our operating results.

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- The level and success of exploration and development activity;
- The sales prices of natural gas, condensate, oil and NGLs;
- The level of total sales volumes of natural gas, condensate, oil and NGLs; and
- The availability of and our ability to raise the capital necessary to meet our cash flow and liquidity needs.

We plan our activities and capital budget based on then current future period sales price assumptions, given the inherent volatility of natural gas, condensate, oil and NGLs prices that are influenced by many factors beyond our control. We focus our efforts on increasing natural gas, condensate and oil and NGLs reserves and production and strive to control costs at an appropriate level. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in the fair market value of hedges that we execute to mitigate the volatility in natural gas, condensate, oil and NGLs prices in future periods.

Like other natural gas and oil exploration and production companies, we face natural production declines. As initial reservoir pressures are depleted, natural gas, condensate, oil and NGLs production from a given well will decrease. Thus, a natural gas and oil exploration and production company depletes part of its asset base with each unit of natural gas, condensate, oil and NGLs that it produces. We attempt to overcome this natural decline by adding reserves in excess of what we produce through successful drilling or acquisition. Our future growth will depend on our ability to continue to add reserves in excess of our production. We will maintain our focus on adding reserves through drilling and acquisitions, while placing a clear priority on lowering our cost of replacing reserves. Consistent with our stated strategies, we will emphasize maintaining a high-quality inventory of drilling locations, while also focusing on improving our capital and cost efficiency.

2012 Highlights

Marcellus Shale Drilling Program. During 2012, we focused our efforts and spent the majority of our capital budget on our liquids-rich acreage in the Marcellus Shale. During the year ended December 31, 2012, we drilled and completed 29 gross (13.4 net) operated wells in Marshall County, West Virginia, under the Atinum Joint Venture. At December 31, 2012, we had 38 gross (17.4 net) operated wells on production in Marshall County, West Virginia. At December 31, 2012, our proved reserves attributable to our Marcellus Shale acreage were approximately 153.2 Bcfe, a significant increase from-year end 2011 reserves of 84.0 Bcfe. Marcellus Shale proved reserves represented approximately 85% of our total proved reserves at December 31, 2012. Condensate and oil and NGLs reserves comprised approximately 32% of the total Marcellus Shale proved reserves at year end 2012.

Mid-Continent Horizontal Oil Play. At December 31, 2012, we held leases covering approximately 41,900 gross (17,300 net) acres in the non-operated Mid-Continent horizontal oil play and had completed our first non-operated well in the play. The initial well was completed at an initial 30-day after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 84 barrels of oil per day, 12 barrels of NGLs per day, 57 Mcf of natural gas per day and 428 barrels of completion fluids per day. The well continues to unload completion fluids with approximately 31% of frac fluid flowed back as of March 7, 2013. Based on the 30 days ended February 20, 2013, the well produced at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. If successful, the Mid-Continent play should result in a low-cost, repeatable horizontal oil development play.

Financial Highlights

Our consolidated financial statements reflect total revenue of $49.9 million on total volumes of 13.2 Bcfe for the year ended December 31, 2012. Our operating loss for the year ended December 31, 2012 was $153.5 million and included depreciation, depletion and amortization expense of $25.4 million and impairment of natural gas and oil properties of $150.8 million.

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 consolidated financial statements and the related notes to the consolidated financial statements, which begin on page F-1.

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For additional information about production volumes, prices of natural gas and oil and selected operating expenses, see "Item 2. Properties – Production, Prices and Operating Expenses" of this Form 10-K.

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The following table provides a summary of our revenues, production and operating expenses for the periods indicated:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas	$33,829	$33,391	$30,812
Condensate and oil	12,377	3,416	742
NGLs	9,300	1,092	—
Unrealized hedge gain (loss)	(5,566)	2,336	11,214
Total revenues	$49,940	$40,235	$42,768
Production:			
Natural gas (MMcf)	10,564	7,318	7,593
Condensate and oil (MBbl)	177	40	10
NGLs (MBbl)	270	21	—
Total production (MMcfe)	13,247	7,684	7,654
Natural gas (MMcf/d)	28.9	20.0	20.8
Condensate and oil (MBbl/d)	0.5	0.1	—
NGLs (MBbl/2)	0.7	0.1	—
Total (MMcfe/d)	36.2	21.1	21.0
Average sales price per unit:			
Natural gas per Mcf, excluding impact of realized hedging activities	$2.21	$3.21	$3.51
Natural gas per Mcf, including impact of realized hedging activities	3.20	4.56	4.06
Condensate and oil per Bbl, excluding impact of realized hedging activities	65.45	85.11	72.63
Condensate and oil per Bbl, including impact of realized hedging activities	70.01	85.11	72.63
NGLs per Bbl, excluding impact of realized hedging activities	28.22	52.47	—
NGLs per Bbl, including impact of realized hedging activities	34.40	52.47	—
Average sales price per Mcfe, excluding impact of realized hedging activities	3.21	3.65	3.58
Average sales price per Mcfe, including impact of realized hedging activities	4.19	4.93	4.12
Selected operating expenses (in thousands):			
Production taxes	$2,269	$620	$370
Lease operating expenses	6,174	8,630	6,679
Transportation, treating and gathering	4,965	4,501	4,654
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
General and administrative expenses	12,211	11,365	14,638
Selected operating expenses per Mcfe:			
Production taxes	$0.17	$0.08	$0.05
Lease operating expenses	0.47	1.12	0.87
Transportation, treating and gathering	0.37	0.59	0.61
Depreciation, depletion and amortization	1.92	1.98	1.22
General and administrative expenses	0.92	1.48	1.91

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Year Ended December 31, 2012 compared to Year Ended December 31, 2011

Revenues. Total natural gas, condensate and oil and NGLs revenues were $55.5 million for the year ended December 31, 2012, up 46% from $37.9 million for the year ended December 31, 2011. The increase in revenues was the result of a 72% increase in production, which was partially offset by a 15% decrease in weighted average realized prices. Average daily production on an equivalent basis was 36.2 MMcfe/d for the year ended December 31, 2012 compared to 21.1 MMcfe/d for the same period in 2011. During 2012, production in Appalachia averaged 22.0 MMcfe/d compared to 2011 production of 2.4 MMcfe/d, an 817% increase. During 2012, production in East Texas averaged 13.7 MMcfe/d compared to 2011 production of 17.3 MMcfe/d, a 21% decrease. Condensate and oil and NGLs production represented approximately 20% of total production for the year ended December 31, 2012 compared to 5% of total production for the year ended December 31, 2011.

Liquids revenues (condensate and oil and NGLs) represented approximately 39% of our total natural gas, condensate and oil and NGLs revenues for the year ended December 31, 2012 compared to approximately 12% for the year ended December 31, 2011. Due to continued lower natural gas prices, we are continuing to focus the majority of our 2013 drilling activity in the liquids-rich portions of the Marcellus Shale and the Mid-Continent oil play. If current trends of natural gas prices relative to condensate, oil and NGLs prices continue, and assuming that we successfully and timely complete our 2013 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total natural gas, condensate and oil and NGLs revenues in 2013.

During the year ended December 31, 2012, we had commodity derivative contracts covering approximately 68% of our natural gas production, which resulted in realized gains of $10.5 million and an increase in total price realized from $2.21 per Mcf to $3.20 per Mcf. The realized hedge impact includes a benefit of $884,000 for amortization of prepaid call sale premiums. Excluding the non-cash amortization, the realized effect of hedging was an increase in revenues of $9.6 million, which was comprised of $14.2 million of NYMEX hedge gains partially offset by $65,000 of regional basis losses and payment of deferred put premiums of $4.5 million. During the year ended December 31, 2011, the realized effect of hedging on natural gas sales was an increase of $9.9 million in natural gas revenues resulting in an increase in total price realized from $3.21 per Mcf to $4.56 per Mcf. The 2011 realized hedge impact included a benefit of $1.7 million of non-cash amortization of prepaid call sale premiums and payment of deferred put premiums of $3.3 million.

During the year ended December 31, 2012, we had commodity derivative hedge contracts covering approximately 52% of our condensate and oil production. The realized effect of hedging on condensate and oil sales was an increase of $807,000 in condensate and oil revenues resulting in an increase in total price realized from $65.45 per Bbl to $70.01 per Bbl. We have designated 50% of our current crude hedges as price protection for our NGLs production.

During the year ended December 31, 2012, we had commodity derivative hedge contracts covering approximately 59% of our NGLs production. The realized effect of hedging on NGLs sales was an increase of $1.7 million in NGLs revenues resulting in an increase in total price realized from $28.22 per Bbl to $34.40 per Bbl.

Unrealized hedge loss was $5.6 million for the year ended December 31, 2012 compared to an unrealized hedge gain of $2.3 million for the year ended December 31, 2011. The increase in the unrealized hedge loss is the result of lower future hedge prices and higher future NYMEX natural gas prices.

Production taxes. We reported production taxes of approximately $2.3 million for the year ended December 31, 2012, up from $620,000 for the year ended December 31, 2011. The increase in production taxes is the result of higher revenues in West Virginia due to increased natural gas, condensate and oil and NGLs production.

Lease operating expenses. We reported lease operating expenses (“LOE”) of $6.2 million for the year ended December 31, 2012, down from $8.6 million for the year ended December 31, 2011. This decrease in our LOE was primarily due to a decrease in non-recurring workover costs in East Texas of $1.3 million and a $1.5 million decrease in controllable LOE in the Powder River Basin as a result of the assignment of our interest in the properties to the operator on May 3, 2012, which was partially offset by a $1.2 million increase in Marcellus Shale LOE. Our LOE was $0.47 per Mcfe for the year ended December 31, 2012, down 58% from $1.12 per Mcfe for the same period in 2011. Excluding workover expense and other non-recurring costs, our LOE was $5.4 million or $0.41 per Mcfe for the year ended December 31, 2012, compared to $6.5 million or $0.85 per Mcfe for the same period in 2011.

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	Lease Operating Expense For the Year Ended December 31, 2012		Lease Operating Expense For the Year Ended December 31, 2011		% Change of $ per Mcfe
	(in thousands)	($ per Mcfe)	(in thousands)	($ per Mcfe)	
Hilltop area, East Texas	$3,624	$0.72	$5,863	$0.93	(23)%
Marcellus Shale and Other Appalachian	2,071	$0.26	832	$0.97	(73)%
Other	479	$2.60	1,935	$3.72	(30)%
Total	$6,174	$0.47	$8,630	$1.12	(58)%

The 23% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe for the Hilltop area, East Texas was primarily the result of lower non-recurring workover costs and lower volumes. Workover costs in the Hilltop area, East Texas for 2012 and 2011 were $766,000 and $2.1 million, or $0.15 per Mcfe and $0.33 per Mcfe, respectively. The 73% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe for the Marcellus Shale and Other Appalachian area was primarily the result of increased production. The 30% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe in Other was primarily related to the assignment of our interest in the Powder River Basin properties to the operator in May 2012.

Transportation, treating and gathering. We reported transportation expenses of $5.0 million for the year ended December 31, 2012, up from $4.5 million for the year ended December 31, 2011. This increase was primarily due to higher transportation costs in the Marcellus Shale of $1.0 million as a result of increased production from 2011 to 2012, which was partially offset by a $533,000 decrease in transportation costs in East Texas and Other due to lower transportation rates on East Texas production and the assignment of our interest in the Powder River Basin to the operator in May 2012. The year ended December 31, 2012 includes $2.0 million of charges under the Hilltop Gathering Agreement compared to $1.5 million of such charges for the year ended December 31, 2011. These charges resulted from actual production volumes being less than minimum contractual volume requirements.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") was $25.4 million for the year ended December 31, 2012, up from $15.2 million for the year ended December 31, 2011. The increase in DD&A expense was the result of a 72% increase in total production volumes primarily attributable to increased Marcellus Shale production, which was partially offset by a 3% decrease in the DD&A rate per Mcfe. The DD&A rate for the year ended December 31, 2012 was $1.92 per Mcfe, as compared to $1.98 for the same period in 2011. The decrease in the DD&A rate per Mcfe is primarily due to lower proved costs resulting from the $150.8 million of ceiling impairments recorded during 2012.

Impairment of natural gas and oil properties. Impairment of natural gas and oil properties was $150.8 million for the year ended December 31, 2012. The impairment is primarily the result of a 33% decline in the 12-month average natural gas price used in the calculation of the full cost ceiling test at December 31, 2012 compared to the 12-month average natural gas price at December 31, 2011. We did not recognize an impairment for the year ended December 31, 2011. Should there be additional declines in the 12-month average natural gas, condensate, oil and NGLs prices, we could recognize additional ceiling impairments in the future.

General and administrative expenses. We reported general and administrative expenses of $12.2 million for the year ended December 31, 2012, up from $11.4 million for the year ended December 31, 2011. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $3.3 million and $2.6 million for the years ended December 31, 2012 and 2011, respectively. This increase in stock-based compensation expense was due primarily to the significant increase in the number of restricted shares granted to employees during 2012 which contributed an additional $1.5 million of stock compensation expense compared to 2011, and was partially offset by the forfeiture of previously issued unvested awards as a result of director and employee resignations and prior years' awards being fully amortized. Excluding stock-based compensation expense, general and administrative expense increased $163,000 to $8.9 million for the year ended December 31, 2012 compared to $8.8 million for the year ended December 31, 2011.

Litigation settlement expense. We reported litigation settlement expense of $1.3 million for the twelve months ended December 31, 2012 resulting from our settlement with Navasota in April 2012. For additional information regarding the settlement of this matter, see Note 15, "Commitments and Contingencies Litigation," to our consolidated financial statements included in this Form 10-K.

Interest expense. We reported interest expense of $270,000 for the year ended December 31, 2012 compared to $113,000 for the year ended December 31, 2011. Interest expense excludes $1.9 million and $817,000 of capitalized interest in 2012 and 2011, respectively, which related to capital expenditures for undeveloped projects in West Virginia and Pennsylvania, the Mid-Continent and East Texas. Excluding capitalized interest, interest expense increased $1.3 million from December 31, 2011 to December 31, 2012 primarily due to higher outstanding debt balances throughout the year ended December 31, 2012 compared to the year ended December 31, 2011.

Provision for income tax expense (benefit). We reported neither an income tax benefit nor provision for the years ended December 31, 2012 and 2011, respectively.

Dividends on Preferred Stock. We reported dividends on Gastar USA's Series A Preferred Stock of $7.1 million for the year ended December 31, 2012 compared to $1.0 million for the year ended December 31, 2011. The Series A Preferred Stock had a stated value of approximately $76.6 million and $27.4 million at December 31, 2012 and 2011, respectively, and carries a cumulative dividend rate of 8.625% per annum. The increase in dividends on Series A Preferred Stock is due to the issuance of 2,586,711 preferred shares during the year ended December 31, 2012. Based on the number of shares of Series A Preferred Stock outstanding at December 31, 2012, our stated preferred dividend is $2.1 million per quarter, which is subject to being declared and paid monthly.

Year Ended December 31, 2011 compared to Year Ended December 31, 2010

Revenues. Natural gas, condensate and oil and NGLs revenues were $37.9 million for the year ended December 31, 2011, up 20% from $31.6 million for the year ended December 31, 2010. Average daily production on an equivalent basis was 21.1 MMcfe/d for the year ended December 31, 2011 compared to 21.0 MMcfe/d for the same period in 2010. This increase in revenues was the result of a 20% increase in weighted average prices, primarily resulting from increased condensate and oil prices and higher condensate and oil and NGLs volumes for the year ended December 31, 2011. During 2011, our East Texas production averaged 17.3 MMcfe/d compared to 2010 production of 18.6 MMcfe/d, a 7% decrease. Production in Appalachia averaged 2.4 MMcfe/d compared to 2010 production of 0.4 MMcfe/d, a 500% increase. Wyoming and other areas production declined by approximately 28%, primarily due to lower Wyoming production resulting from reductions in compression to reduce cash costs and limited capital activity. Liquids revenues (condensate and oil and NGLs) represented approximately 16% of our total revenues before hedge gains for the year ended December 31, 2011. During the year ended December 31, 2011, approximately 91% of our total natural gas production was hedged. The realized effect of hedging on natural gas sales was an increase of $9.9 million in natural gas revenues resulting in an increase in total natural gas price realized from $3.21 per Mcf to $4.56 per Mcf for the year ended December 31, 2011. The realized hedge impact includes a benefit of $1.7 million for amortization of prepaid call sale and put purchase premiums. Excluding the non-cash amortization, the realized effect of hedging was an increase in revenues of $8.2 million, which was comprised of $12.1 million of NYMEX hedge gains offset by $632,000 of regional basis losses and payment of deferred put premiums of $3.3 million. During the year ended December 31, 2010, the realized effect of hedging on natural gas sales was an increase of $4.1 million in natural gas and oil revenues resulting in an increase in total price realized from $3.51 per Mcf to $4.06 per Mcf. The 2010 realized hedge impact included a loss of $1.4 million of non-cash amortization of prepaid call sale and put purchase premiums and payment of deferred put premiums of $1.1 million.

Unrealized natural gas hedge gain was $2.3 million for the year ended December 31, 2011 compared to $11.2 million for the year ended December 31, 2010. The decrease in unrealized natural gas hedge impact was the result of a decrease in hedge prices as compared to changes in future NYMEX gas prices.

Production taxes. We reported production taxes of approximately $620,000 for the year ended December 31, 2011, up from $370,000 for the year ended December 31, 2010. The increase was primarily the result of higher revenues in West Virginia due to increased natural gas, oil and NGLs production, which was partially offset by lower revenues in Wyoming due to lower production volumes.

Lease operating expenses. We reported LOE of $8.6 million for the year ended December 31, 2011, up from $6.7 million for the year ended December 31, 2010. This increase was primarily due to higher non-recurring workover expense. Our LOE was $1.12 per Mcfe for the year ended December 31, 2011, up 29% from $0.87 per Mcfe for the same period in 2010. Excluding workover expense and other non-recurring costs, our LOE was $6.5 million or $0.85 per Mcfe for the year ended December 31, 2011, compared to $5.9 million or $0.77 per Mcfe for the same period in 2010.

	Lease Operating Expense For the Year Ended December 31, 2011 (in thousands)($ per Mcfe)	Lease Operating Expense For the Year Ended December 31, 2010 (in thousands)($ per Mcfe)	% Change of $ per Mcfe

Hilltop area, East Texas	$5,863	$0.93	$4,399	$0.65	43	%
Appalachia	832	$0.97	393	$2.96	(67	)%
Other	1,935	$3.72	1,887	$2.63	41	%
Total	$8,630	$1.12	$6,679	$0.87	29	%

The 43% increase from December 31, 2010 to December 31, 2011 in LOE per Mcfe for the Hilltop area, East Texas was primarily the result of higher non-recurring workover costs and lower volumes. Workover costs in the Hilltop area, East Texas for 2011 and 2010 were $2.1 million and $760,000, or $0.33 per Mcfe and $0.11 per Mcfe, respectively. The 67% decrease

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from December 31, 2010 to December 31, 2011 in LOE per Mcfe for the Appalachia area was primarily the result of increased production. The 41% increase from December 31, 2010 to December 31, 2011 in LOE per Mcfe in Other was primarily related to Powder River Basin CBM production declines.

Transportation, treating and gathering. We reported transportation expenses of $4.5 million for the year ended December 31, 2011, down from $4.7 million for the year ended December 31, 2010. This decrease was primarily due to lower costs in Wyoming due to lower CBM production. The year ended December 31, 2011 includes $1.5 million of charges under the Hilltop Gathering Agreement compared to $1.3 million of such charges for the year ended December 31, 2010. These charges resulted from actual production volumes being less than minimum contractual volume requirements.

Depreciation, depletion and amortization. DD&A was $15.2 million for the year ended December 31, 2011, up from $9.3 million for the year ended December 31, 2010. The increase in DD&A expense was the result of a 62% increase in DD&A rate per Mcfe and a slight increase in production volumes primarily attributable to increased Appalachia production. The DD&A rate for the year ended December 31, 2011 was $1.98 per Mcfe, as compared to $1.22 for the same period in 2010. The increase in the DD&A rate is primarily due to higher proved costs associated with recent East Texas wells drilled and additional allocation of $63.8 million of undeveloped East Texas leasehold costs from unproved to proved properties based on drilling results and reduced 2012 drilling activity due to a decline in natural gas prices.

General and administrative expenses. We reported general and administrative expenses of $11.4 million for the year ended December 31, 2011, down from $14.6 million for the year ended December 31, 2010. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $2.6 million and $2.8 million for the years ended December 31, 2011 and 2010, respectively. This decrease in stock-based compensation expense was due primarily to the forfeiture of previously issued unvested awards as a result of director and employee resignations, prior year awards being fully amortized and recently issued awards having a lower fair value than awards issued in prior years. Excluding stock-based compensation expense, general and administrative expense decreased $3.0 million to $8.8 million for the year ended December 31, 2011 compared to $11.8 million for the year ended December 31, 2010. This decrease was primarily due to lower legal fees as a result of the Classic Star litigation settlement in November 2010.

Litigation settlement expense. We reported litigation settlement expense of $21.7 million for the twelve months ended December 31, 2010 primarily resulting from our settlement with the plaintiffs of the seven ClassicStar Mare Lease Litigation suits in December 2010.

Interest expense. We reported interest expense of $113,000 for the year ended December 31, 2011 compared to $150,000 for the year ended December 31, 2010. Interest expense excludes $817,000 and $633,000 of capitalized interest in 2011 and 2010, respectively, which related to capital expenditures for undeveloped projects in East Texas, West Virginia and Pennsylvania. Excluding capitalized interest, interest expense increased $147,000 from December 31, 2010 to December 31, 2011 due to higher outstanding debt balances throughout the year ended December 31, 2011 compared to the year ended December 31, 2010.

Investment income and other. We reported investment income of $10,000 for the year ended December 31, 2011 compared to $1.3 million for the year ended December 31, 2010. The decrease in investment income is primarily due to interest earned during 2010 on the Australian term deposit established in conjunction with the sale of our Australian properties in July 2009 for the future tax payment related to the sale. At maturity on June 1, 2010, the term deposit was used to settle the Australian tax liability resulting from the Australian property sale in 2009 and, thus, resulting in no comparable investment income during 2011.

Warrant derivative loss. For the year ended December 31, 2010, we reported a $205,000 unrealized gain related to the fair value measurement of our warrants outstanding. At December 31, 2011, the warrants had expired and were no longer outstanding.

Foreign transaction gain (loss). We reported a foreign transaction loss of $6,000 for the year ended December 31, 2011 compared to a gain of $353,000 for the year ended December 31, 2010. The decrease in foreign transaction gain was primarily due to the decrease in Australian denominated cash and accounts receivable balances arising from the sale of the Australian properties in 2009.

Provision for income tax benefit. We reported neither an income tax benefit nor provision for the year ended December 31, 2011. We reported $804,000 of income tax benefit for the year ended December 31, 2010. The income tax benefit for the twelve months ended December 31, 2010 was primarily due to a $1.0 million downward adjustment of the tax expense related to the sale of the Australian properties after final review from the Australian Tax Office, which was partially offset by withholding tax on the interest income earned from the Australian term deposit and a benefit for previously accrued state income taxes.

Dividends on Preferred Stock. We reported dividends on our Series A Preferred Stock of $1.0 million for the year ended December 31, 2011. The Series A Preferred Stock had a stated value of approximately $27.5 million at December 31, 2011 and carries a cumulative dividend rate of 8.625% per annum. There were no shares of Series A Preferred Stock outstanding during the year ended December 31, 2010.

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 adjust capital expenditures in response to changes in natural gas, condensate, oil and NGLs prices, drilling results and cash flow.

For the year ended December 31, 2012, we reported cash flows provided by operating activities of $37.1 million, net cash used in investing activities, primarily for the development and purchase of natural gas and oil properties, of $148.2 million, and net cash provided by financing activities of $109.4 million, consisting of $49.3 million of proceeds from issuances of 2,586,711 shares of Gastar USA's Series A Preferred Stock and $68.0 million of net borrowings under our Revolving Credit Facility, less $7.1 million of dividends paid on the preferred stock. As a result of these activities, our cash and cash equivalents balance decreased by $1.7 million, resulting in a December 31, 2012 balance of cash and cash equivalents of $8.9 million. Net cash provided by operating activities increased $25.8 million from 2011 primarily due to increased natural gas, condensate and oil and NGLs revenues in 2012 resulting from a 72% increase in production. Cash flow used in investing activities increased $84.4 million from 2011 to 2012 primarily due to increased development and purchase of natural gas and oil properties during 2012.

At December 31, 2012, we had a net working capital deficit of approximately $30.2 million, including $17.5 million of advances from non-operators. At December 31, 2012, availability under the Revolving Credit Facility was $27.0 million.

Future capital and other expenditure requirements. Capital expenditures for 2013, excluding acquisitions, are projected to be approximately $92.8 million. In the Marcellus Shale and Mid-Continent, we expect to spend $59.7 million and $27.3 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. We have budgeted $2.4 million for East Texas. In addition, we have allocated $3.4 million for capitalized interest and other costs. We plan to fund our 2013 capital budget through existing cash balances, internally generated cash flow from operating activities, borrowings under the Revolving Credit Facility, the possible issuance of debt or preferred equity securities and the possible divestiture of our East Texas assets. 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, condensate, oil and NGLs prices, costs of drilling and completion and leasehold acquisitions, drilling results, and changes in the borrowing base under the Revolving Credit Facility. We operate approximately 71% of our budgeted 2013 capital expenditures, and thus, we could reduce a significant portion of 2013 capital expenditures if necessary to better match available capital resources. See "Item 1A.-Risk Factors-Our development operations will require substantial capital expenditures."

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, condensate, 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, condensate, 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, condensate, 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. 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.

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As of December 31, 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)						
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 (1)	Protective spread	4,025	853,200	3.70	—	3.00	—	—
2013	Fixed price swap	4,989	1,821,000	3.93	—	—	—	—
2013	Basis - HSC (2)	4,000	1,460,000	(0.11)	—	—	—	—
2014	Short calls	2,500	912,500	—	—	—	—	6.00
2014	Costless three-way collar	10,500	3,832,500	—	3.88	3.00	—	4.53

(1) For the period January to July 2013.
(2) East Houston-Katy - Houston Ship Channel.

As of December 31, 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)						
2013	Put spread	400	146,000	$—	$100.75	$70.00	$—	$—
2014	Costless three-way collar	200	73,000	—	90.00	70.00	—	106.20

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

As of December 31, 2012, the following NGLs 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 Bbls)						
2013	Fixed price swap	300	109,500	$41.64	$—	$—	$—	$—

See Note 8, "Derivative Instruments and Hedging Activity" to our consolidated financial statements, which begin on page F-1 of this Form 10-K.

At December 31, 2012, the estimated fair value of all of our commodity derivative instruments was a net asset of $6.5 million, comprised of current and non-current assets and liabilities.

By removing the price volatility from a portion of our natural gas for 2013 and 2014, we believe that we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, derivative contracts can limit the benefits we could receive from increases in commodity prices. For additional information on the impact of changing commodity prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosure about Market Risk."As of December 31, 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 December 31, 2012 is provided under the Revolving Credit Facility through intercreditor 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.

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Revolving Credit Facility. On October 28, 2009, we executed an amended and restated revolving credit facility, amending and restating in its entirety the original revolving credit facility (the "Revolving Credit Facility"). The Revolving Credit Facility now matures on September 30, 2015. At December 31, 2012, $98.0 million was outstanding under the Revolving Credit Facility. Effective December 31, 2012, the borrowing base under the Revolving Credit Facility was increased from $110.0 million to $125.0 million resulting in current availability of $25.0 million as of March 7, 2013.

The borrowing base is typically subject to scheduled redeterminations on the first day of May and the first day of November each year prior to scheduled facility maturity. The next regularly scheduled borrowing base redetermination will be May 2013. However, we and the lenders may request one additional unscheduled redetermination annually. The redetermination in November 2011 resulted in the Fourth Amendment to the Amended and Restated Credit Agreement, effective November 10, 2011, the terms of which included, among other things, an extension of the maturity date for the facility from January 2, 2013 to September 30, 2015 and the ability of Gastar USA to hedge up to 100% of the proved developed producing reserves reflected in its reserve report using hedging other than floors and protective spreads. Pursuant to the Revolving Credit Facility, the applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the prime rate and from 2.5% to 3.5% in the case of borrowings based on LIBO rate, depending on the utilization percentage in relation to the borrowing base. 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, and a limitation on our hedge positions.

At December 31, 2012, Gastar USA was not in compliance with the working capital ratio covenant for 2012 under the Revolving Credit Facility. Gastar USA was granted a waiver in regards to the working capital ratio covenant at December 31, 2012, and in conjunction with such waiver, Gastar USA was in compliance with all financial covenants under the Revolving Credit Facility at December 31, 2012. See Note 5, "Long Term Debt – Revolving Credit Facility."

Off-Balance Sheet Arrangements

As of December 31, 2012, we had no off-balance sheet arrangements. We have no plans to enter into any off balance sheet arrangements in the foreseeable future.

Contractual Obligations

The following table summarizes our future contractual obligations as of December 31, 2012:

	Payments Due by Period						
	Total	2013	2014	2015	2016	2017	Thereafter
	(in thousands)						
Long-term debt (1)	$98,000	$—	$—	$98,000	$—	$—	$—
Interest on long-term debt (2)	8,974	3,263	3,263	2,448	—	—	—
Office space leases (3)	1,775	498	509	459	309	—	—
Gathering system (4)	7,015	3,833	3,182	—	—	—	—
Office equipment leases	69	36	32	1	—	—	—
Drilling rigs	3,058	3,058	—	—	—	—	—
Total contractual obligations	$118,891	$10,688	$6,986	$100,908	$309	$—	$—

(1) See Item 8. "Financial Statements and Supplementary Data, Note 5, Long-Term Debt", to our consolidated financial statements included in this Form 10-K for a discussion of our Revolving Credit Facility.

(2) Interest payments have been calculated by applying the weighted average interest rate of 3.33% at December 31, 2012 to the outstanding long-term debt of $98.0 million at December 31, 2012.

(3) Our Houston office lease obligation expires August 31, 2016, and our West Virginia office lease expires on December 31, 2014.

(4) Represents the minimum contractual gross daily volume commitment of 50,000 Mcf (35,000 net) per day for the period January 1, 2013 through October 31, 2014 relating to the sale of our Hilltop gathering system.

We maintain a liability for costs associated with the retirement of tangible long-lived assets. At December 31, 2012, our reserve for these obligations totaled $7.0 million for which no contractual commitment exists. Information about this liability is set forth in Item 8. "Financial Statements and Supplementary Data, Note 2, Summary of Significant

Accounting Policies – Asset Retirement Obligation" of this Form 10-K.
We have employment agreements with our Chief Executive Officer and Chief Financial Officer which obligate us to pay a specified level of salary, target bonus and certain other payments and reimbursements to them during their employment and in

the event of termination or change of control. Information about such payments is set forth in Item 11. "Executive Compensation" of this Form 10-K.

Commitments

In March 2008, we entered into the ETC Contract. The ETC Contract expires September 1, 2017. Pursuant to the ETC Contract, ETC currently provides us with 50 MMcf per day of treating capacity and 150 MMcf per day of transportation capacity from our Hilltop wells, located in Leon and Robertson Counties, Texas.

On November 16, 2009, concurrent with our sale of the Hilltop gathering system in East Texas, one of our wholly-owned subsidiaries entered into a gas gathering agreement, with Hilltop Resort for a term of fifteen years. The agreement covers delivery of our gross production of natural gas from the Hilltop area of East Texas to certain delivery points provided under the ETC Contract as well as additional delivery points that may be added. We are also obligated to connect new wells that we drill within the area covered by the agreement to the gathering system. The agreement provides for a minimum quarterly gathering gross production volume of 50.0 MMcf per day (35.0 MMcf per day net to us) times the number of days in the quarter for five years from the effective date of November 1, 2009. If quarterly production is less than the minimum quarterly requirement, the gathering fee is payable on such deficit. If excess quarterly production exists, such excess is carried forward to offset any future deficit quarters. The gathering fee on the initial gross 25.0 Bcf of production is $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reaches 300.0 Bcf. The current gathering rate is $0.30 per Mcf. For the years ended December 31, 2012, 2011 and 2010, we paid $2.0 million, $1.5 million and $1.3 million, respectively, of charges to Hilltop Resort as a result of actual production volumes being less than minimum contractual volume requirements. We do not expect that we will meet our minimum quarterly requirements in the near future.

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI with respect to our Marshall County, West Virginia production. The initial term of the gas purchase agreement is five years with the option to extend the term of the gas purchase agreement for an additional five year period. Our Marshall County, West Virginia production is dedicated to SEI for the term of the gas purchase agreement. SEI will purchase all hydrocarbon production, including its 120.0 MMcf per day Fort Beeler processing plant located in Marshall County, West Virginia for transporting and processing. In order to secure access to the Williams facilities, we, Atinum and SEI dedicated all hydrocarbons purchased and produced in Marshall County, West Virginia for a term of ten years.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, related disclosure of contingent assets and liabilities, proved natural gas and oil reserves and the related disclosures in the accompanying consolidated financial statements. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided an expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the 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 or policy to be critical if:

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

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

Full Cost Method of Accounting

We follow the full cost method of accounting for natural gas and oil operations, whereby all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are initially capitalized into cost centers on a country-by-country basis whether or not the activities to which they apply are successful. Currently, our only cost center is the U.S.

These costs include land acquisition costs attributable to proved reserves, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition, exploration and development activities. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that directly relate to our natural gas and oil activities. Interest costs related to unproved properties are also capitalized. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our natural gas and oil properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves, as determined by independent petroleum engineers. The percentage of total reserve volumes produced during the year is multiplied by the net capitalized investment plus future estimated development costs in those reserves to determine depletion expense for the period.

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

Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities, since we generally reflect a higher level of capitalized costs as well as a higher DD&A rate on our oil and natural gas properties.

Full Cost Ceiling Limitation

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. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on historical average prices and costs in effect at the time of the evaluation. If the net cost exceeds the ceiling, an impairment loss is recognized for the amount by which the net cost exceeds the ceiling and is shown as a reduction in natural gas and oil properties and as additional depletion. Proceeds from a sale of natural gas and oil properties will be applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion or amortization.

In 2012, the key natural gas prices utilized were the Henry Hub price of $2.76 per MMBtu, the Katy Hub price of $2.77 per MMBtu, the Columbia Gas Appalachia Pool price of $2.77 per MMBtu and a WTI posting oil price of $91.21 per barrel per NSAI and a WTI spot price of $94.71 per barrel per Wright. In applying the full cost method at June 30, 2012 and September 30, 2012, we performed a ceiling test on the cost center properties whereby the net cost of natural gas and oil properties, net of related deferred income taxes (“net cost”), was limited to the sum of the estimated future net revenues from our proved reserves using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil held constant, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects and we recorded ceiling impairments of $72.7 million and $78.1 million, respectively, resulting in total impairment of $150.8 million for the year ended December 31, 2012. In applying the full cost method at December 31, 2011 and 2010, we performed a ceiling test on the cost center properties whereby the net cost of natural gas and oil properties, net of related deferred income taxes (“net cost”), was limited to the sum of the estimated future net revenues from our proved reserves using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil held constant, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects and we did not record a ceiling impairment for the years ended December 31, 2011 and 2010. The most likely factor to contribute to a ceiling test impairment is the price used to calculate the reserve limitation threshold. A significant reduction in the prices at a future measurement date could trigger a full cost ceiling impairment. A 10% decrease in prices at December 31, 2012 would have reduced our ceiling impairment cushion by approximately $36.9 million resulting in an impairment of $13.0 million. A 10% increase in prices at December 31, 2012 would have increased our ceiling impairment cushion by approximately $37.5 million.

Natural Gas and Oil Reserves

All of the reserves data in this Form 10-K are estimates. Estimates of our natural gas and oil reserves were prepared in accordance with guidelines established by the SEC. Our estimate of proved reserves is based on the quantities of natural gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year-to-year, the economics of producing the reserves may change and therefore, the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. As a result, reserves estimates may be different from the quantities of natural gas and oil that are ultimately recovered.

In addition, economic producibility of reserves is dependent on the natural gas and oil prices used in the reserves estimate. We based our December 31, 2012 reserves estimates on a 12-month unweighted average of the first-day-of-the month prices, in accordance with SEC rules. However, natural gas and oil prices are volatile and, as a result, our reserves estimates will change in the future. Despite the inherent imprecision in these engineering estimates, our proved reserve volumes and values are used to calculate depletion and impairment provisions.

Depreciation, Depletion and Amortization

Units-of-production method is used to amortize our natural gas and oil properties. A change in the quantity of reserves could significantly impact our depletion expense. A reduction in proved reserves, without a corresponding reduction in capitalized costs, will increase our depletion rate. A 10% increase in reserves would have decreased our depletion expense for the year ended December 31, 2012 by approximately $493,000, while a 10% decrease in reserves would have increased our depletion expense by approximately $600,000.

Unproved Property Costs

Investments in unproved properties are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. Unproved properties are evaluated quarterly for impairment on a field-by-field basis. If the results of an assessment indicate that an unproved property is impaired, the amount of impairment is subtracted from proved natural gas and oil property costs to be amortized.

At December 31, 2012, we had $67.9 million allocated to unproved property costs, which was comprised primarily of unevaluated acreage costs. The unproven property costs are evaluated by the technical team and management to determine whether the property has potential attributable reserves. Therefore, the assessment made by our technical team and management of the potential reserves will determine whether costs are moved from the unproved category to the full-cost pool for depletion or whether an impairment is taken. A 10% increase or decrease in the unproved property balance would have increased or decreased our impairment cushion by approximately $6.5 million, respectively, for the year ended December 31, 2012.

Asset Retirement Obligation

We have certain obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Pursuant to the FASB’s guidance, we estimate asset retirement costs for all of our assets, inflation-adjust those costs to the forecasted abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an asset retirement obligation (“ARO”) liability in that amount with a corresponding addition to our capitalized cost. We then accrete the liability quarterly using the period-end effective credit-adjusted-risk-free rate. As new wells are drilled or purchased, their initial asset retirement cost and liability is calculated and recorded. Should either the estimated life or the estimated abandonment costs of a property change upon our annual review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the ARO is adjusted to the newly calculated value with a corresponding offsetting adjustment to the asset retirement cost (included in the full-cost pool); therefore, abandonment costs will almost always approximate the estimate. When wells are sold, the related liability and asset costs are removed from the balance sheet.

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

There are many variables in estimating AROs. We primarily use the remaining estimated useful life from the year-end independent reserves report in estimating when abandonment could be expected for each property based on field or industry practices. We expect to see our calculations impacted significantly if interest rates move from their current levels, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis. Our technical team developed a standard cost estimate based on historical costs, industry quotes and depth of wells. Unless we expect a well's plugging cost to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of an inflation factor and a discount factor, could differ from actual results, despite all of our efforts to make an accurate estimate.

Capitalized Interest

We capitalize interest on assets not being amortized, such as our drilling in progress expenditures and unproven natural gas and oil properties. The methodology for capitalizing interest on general funds begins with a determination of the borrowings applicable to our qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset's acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for drilling and unproved property expenditures then they would have been used to pay off other debt. We use our best judgment in determining which borrowings represent the cost of financing the acquisition of the assets. Currently, we only capitalize interest on the Revolving Credit Facility. The interest to be capitalized for any period is derived by multiplying the average rate of interest times the average qualifying assets during the period. To qualify for interest capitalization, we must continue to make progress on the development of the assets. Capitalized interest was approximately $1.9 million, $817,000 and $633,000 for 2012, 2011 and 2010, respectively.

Stock-Based Compensation

We report compensation expense for stock options and restricted common shares granted to officers, directors and employees using the fair value method and recognition provisions of the modified prospective method. Stock-based compensation costs are recorded over the requisite service period, which approximates the vesting period. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model. The fair value of restricted common shares granted is equal to the closing price on the day prior to the grant. The total fair value of all awards is expensed using the graded-vesting method, which recognizes compensation costs over the requisite service period for each separately vesting tranche of an award as though the award were, in substance, multiple awards.

The Black-Scholes-Merton valuation pricing model requires various highly judgmental assumptions including volatility, expected option life and forfeiture rate. If any of the assumptions used in the Black- Scholes-Merton valuation pricing model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period. There were no stock options granted during the year ended December 31, 2012.

Fair Value Measurement

We maintain a commodity-price risk-management strategy that uses derivative instruments to minimize significant fluctuations that may arise from volatility in commodity prices. We use natural gas costless collars, index, basis and fixed price swaps and put and call options to hedge commodity price risk. We carry all derivative assets and liabilities at fair value.

We determine the fair market values of financial instruments based on the fair value hierarchy established by the FASB. We utilize third-party broker quotes to access the reasonableness of forward commodity prices, volatility factors, discount rates and the valuation techniques used to measure the fair value of our derivative assets and liabilities, which are all traded in the over-the-counter market. We incorporate counterparty credit risk and our own credit risk within the fair value measurement of derivative assets and liabilities. Credit adjustments, if any, are applied to fair value measurements based on the historical default probabilities of the respective credit ratings assigned to the debt of our counterparties and to us, as published by the independent credit rating agencies.

Derivative Instruments and Hedging Activity

We currently utilize derivative instruments, which are placed with a multinational energy company or large financial institutions, to manage market risks resulting from fluctuations in commodity prices of natural gas, condensate, oil and NGLs. Derivatives are recorded on the balance sheet at fair market value and changes in the fair market value of derivatives are recorded each period in current earnings. Gains and losses on derivatives are included in revenue in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities.

The counterparties to our derivative instruments are not known to be in default on their derivative positions. However, we are exposed to credit risk to the extent of nonperformance by the counterparty in the derivative contracts. We believe credit risk is minimal and do not anticipate such nonperformance by such counterparties.

Recent Accounting Developments

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

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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. Early application is not permitted. The adoption of this guidance did not impact our operating results, financial position or cash flows upon adoption.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we were a party at December 31, 2012, and from which we may incur future gains or losses from changes in market interest rates or commodity prices. We do not enter into derivative or other financial instruments for speculative trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probably future fluctuations.

Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our natural gas, condensate, 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, condensate, oil and NGLs in the region produced. Prices received for natural gas, condensate, oil and NGLs are volatile and unpredictable and are beyond our control. To mitigate a portion of our exposure to adverse market changes in the prices for natural gas, condensate, oil and NGLs, we have entered into, and may in the future enter into additional, commodity price risk management arrangements for a portion of our natural gas, condensate and oil and NGLs production. For the year ended December 31, 2012, a 10% change in the prices received for our natural gas, condensate, oil and NGLs production would have had an approximate $4.3 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. See Note 8, "Derivative Instruments and Hedging Activity" to our consolidated financial statements, which begin on page F-1 of this Form 10-K, for additional information regarding our hedging activities.

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.

Interest Rate Risk

We are exposed to changes in interest rates as a result of our Revolving Credit Facility. At December 31, 2012, we had $98.0 million outstanding under the Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at December 31, 2012, a one percentage point change in the interest rate would have had a $980,000 impact on our interest expense for the year. We have not entered into interest rate hedging arrangements in the past, and have no current plans to do so. Due to fluctuating balances in the amount outstanding under our Revolving Credit Facility, we do not believe such arrangements to be cost effective.

Item 8. Financial Statements and Supplementary Data

The information contained under “Item 15. Exhibits, Financial Statement Schedules” is incorporated by reference into this Item 8.

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

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures were effective as of December 31, 2012 at the reasonable assurance level.

Management’s Report on Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our chief executive officer, chief financial officer and chief accounting officer, we evaluated the effectiveness of the design and operation of our internal controls over financial reporting (as defined in Rules 13a-15(f) or 15(d)-15(f) under the Exchange Act) as of December 31, 2012 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) or 15(d)-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed by management, under the supervision of our principal executive officer and principal financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the U.S., and includes policies and procedures that (1) pertain to maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of our management and board of directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Based on the assessment, our management has concluded that our internal control over financial reporting was effective as of December 31, 2012 based on the criteria listed herein. The results of management’s assessment were reviewed with the Audit Committee of our Board of Directors.

BDO USA, LLP, the independent registered accounting firm who audited the consolidated financial statements included in this Form 10-K, has issued an attestation report on our internal control over financial reporting. Their report appears below.

/s/ J. RUSSELL PORTER	/s/ MICHAEL A. GERLICH
J. Russell Porter	Michael A. Gerlich
President and Chief Executive Officer	Vice President and Chief Financial Officer
March 11, 2013	March 11, 2013

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2012, there were no changes in our internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Report of Independent Registered Public Accounting Firm
Board of Directors and Shareholders
Gastar Exploration Ltd.
Houston, Texas

We have audited Gastar Exploration Ltd.'s (the "Company") internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A. "Management's Report on Internal Control over Financial Reporting". Our responsibility is to express an opinion on the effectiveness of internal control over financial reporting of the Company based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Gastar Exploration Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO Criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gastar Exploration Ltd. and its subsidiaries as of December 31, 2012 and 2011 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012 and our report dated March 11, 2013 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 11, 2013

Item 9B. Other Information

On March 6, 2013, Gastar USA, together with the Company and certain of its subsidiaries as guarantors (collectively, the "Guarantors"), the lenders party thereto (the "Lenders"), and Amegy Bank National Association, as administrative agent (the "Administrative Agent" and, together with Gastar USA, the Company, the Guarantors and the Lenders, the "Parties"), entered into the Waiver and Fifth Amendment to Amended and Restated Credit Agreement, effective as of March 6, 2013 (the "Fifth 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, that certain Second Amendment to Amended and Restated Credit Agreement, dated June 24, 2010, that certain Third Amendment to Amended and Restated Credit Agreement, dated June 13, 2011, that certain Fourth Amendment to Amended and Restated Credit Agreement, effective as of November 10, 2011, and as further amended by this Fifth Amendment, the “Credit Agreement”). The Fifth Amendment (i) waives the obligation of the Company not to permit the ratio of Current Assets to Current Liabilities (each as defined in the Credit Agreement) to be less than 1.00 to 1.00 for the calendar quarter ending December 31, 2012, and (ii) amends the Credit Agreement to (A) increase the permitted term of commodity hedging

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agreements, (B) reduce the minimum ratio of Current Assets to Current Liabilities that is required for quarters ending from March 31, 2013, through December 31, 2013, and to make certain changes in the calculation of Current Liabilities for such dates, (C) reduce the amount of Available Commitment (as defined in the Credit Agreement) that is required immediately prior to and after giving effect to the payment of cash dividends on or the redemption (using retained earnings) of the Series A Preferred Shares of the Company, (D) increase the amount of cash dividends due on the Series A Preferred Shares that can be paid in the aggregate in each calendar year, and (E) modifying the manner in which EBITDA is determined for purposes of the required ratios of Total Net Indebtedness to EBITDA and EBITDA to Interest Expense (as each such term is defined in the Credit Agreement) with respect to the calendar quarter ending March 31, 2013.

The foregoing description of the Fifth Amendment does not purport to be complete and is qualified in its entirety by reference to the complete text of such exhibit, which is filed as Exhibit 10.6 of this Annual Report on Form 10-K and incorporated into this Item 9B by reference. A copy of the Credit Agreement, First Amendment, Second Amendment, Third Amendment and Fourth Amendment thereto, previously filed as exhibits to the Company's Current Reports on Form 8-K filed on November 3, 2009, November 25, 2009, June 28, 2010, June 15, 2011 and December 2, 2011, respectively, are incorporated into this Item 9B by reference.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We have adopted a Code of Ethics applicable to our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. A copy of the Code of Ethics is available at http:www.gastar.com, and you may also request a copy of the Code of Ethics at no cost, by writing or by telephoning us at the following: Gastar Exploration Ltd., Attention: Chief Financial Officer, 1331 Lamar, Suite 650, Houston, Texas 77010, (713) 739-1800. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, and persons performing similar functions on our website at http://www.gastar.com promptly following the date of any such amendment or waiver.

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2013 Annual Meeting of Stockholders (the “Proxy Statement”) under the headings “Information about Directors, Director Nominees and Executive Officers,” “Section 16(b) Beneficial Ownership Reporting Compliance,” “Corporate Governance – Code of Ethics,” “Corporate Governance – Nomination of Directors,” and “Committee Information – Audit Committee” and is incorporated herein by reference. The Proxy Statement will be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Exchange Act, as amended, not later than 120 days after December 31, 2012.

Item 11. Executive Compensation

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading “Executive Compensation” and is incorporated herein by reference.

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

The information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading “Security Ownership of Certain Beneficial Owners and Management” and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the heading “Committee Information” and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the heading “Independent Accountant, Fees and Policies” and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statements and Schedules

(a)-1 Financial Statements and Schedules:

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

(b) Exhibits:

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

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of Gastar Exploration Ltd. (incorporated herein by reference to Exhibit 3.1 to 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 reference 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 reference 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. File No. 001-35211).
4.1	Facsimile of common share certificate of Gastar Exploration Ltd. (incorporated by reference to Exhibit 4.21 of the Company’s Amendment No. 3 to Registration Statement on Form S-1/A, dated December 15, 2005. Registration No. 333-127498).
10.1	Amended and Restated Credit Amendment dated October 28, 2009 to Credit Agreement dated November 29, 2007 among Gastar Exploration USA, Inc., the Guarantors party thereto and Amegy Bank National Association as Administrative Agent and Letter of Credit Issuer (incorporated by reference to Exhibit 10.1 of the Company’s Current Report on Form 8-K dated November 3, 2009. File No. 001-32714).
10.2	Consent and First Amendment to Amended and Restated Credit Agreement dated November 20, 2009, by and among Gastar Exploration USA, Inc., the Guarantors party thereto, the Lenders party thereto, and Amegy Bank National Association, as Administrative Agent, (incorporated by reference to Exhibit 10.3 of the Company’s Current Report on Form 8-K dated November 25, 2009. File No.

	001-32714).
10.3	Second Amendment to Amended and Restated Credit Agreement dated June 24, 2010, by and among Gastar Exploration USA, Inc., the Guarantors party thereto, the Lenders party thereto and Amegy Bank National Association, as Administrative Agent (incorporated herein by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K dated June 28, 2010. File No. 001-32714).
10.4	Third Amendment to Amended and Restated Credit Agreement, dated June 14, 2011, by and among Gastar Exploration USA, Inc., the Guarantors party thereto, the Lenders party thereto and Amegy Bank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K dated June 15, 2011. File No. 001-32714).
10.5	Fourth Amendment to Amended and Restated Credit Agreement, effective November 10, 2011, by and among Gastar Exploration USA, Inc., the Guarantors party thereto, the Lenders party thereto and Amegy Bank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K dated December 2, 2011. File No. 001-32714).
10.6†	Waiver and Fifth Amendment to Amended and Restated Credit Agreement, effective March 6, 2013, by and among Gastar Exploration USA, Inc., the Guarantors party thereto, the Lenders party thereto and Amegy Bank National Association, as Administrative Agent.

Exhibit Number	Description
10.7	Amended and Restated Intercreditor Agreement dated February 16, 2009, among Gastar Exploration USA, Inc., Gastar Exploration Ltd., each of the Guarantors party thereto, Amegy Bank National Association, as First Priority Agent, and Wells Fargo National Association, as Second Priority Agent (incorporated by reference to Exhibit 4.3 of the Company’s Current Report on Form 8-K dated February 20, 2009. File No. 001-32714).
10.8	Amended and Restated Collateral Agency and Intercreditor Agreement dated August 27, 2012, by and among BP Energy Company, Shell Energy North America (US), L.P., Gastar Exploration USA, Inc., Gastar Exploration Ltd., each of the Guarantors party thereto and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 filed on November 7, 2012. File No. 001-32714).
10.9	Common Share Purchase Agreement between Gastar Exploration Ltd. and Chesapeake Energy Corporation dated November 4, 2005 (incorporated by reference to Exhibit 4.19 of the Company’s Amendment No. 2 to Registration Statement on Form S-1/A, filed on November 22, 2005. Registration No. 333-127498).
10.10	Sale Agreement dated July 2, 2009, by and among Gastar Exploration USA, Inc., Gastar Exploration New South Wales, Inc., Santos QNT Pty Ltd. and Santos International Holdings Pty Ltd. (incorporated herein by reference to Exhibit 10.1 to Gastar Exploration Ltd.’s Current Report on Form 8-K filed on August 6, 2009. File No. 001-32714).
10.11	Agency Agreement between and among ETC Texas Pipeline, Ltd., ETC Katy Pipeline, Ltd. Oasis Pipeline, L.P. and Gastar Exploration Texas, L.P. effective September 1, 2007 (incorporated herein by reference to Exhibit 10.1 of the Amendment No. 1 to the Company’s Annual Report on Form 10-K/A for the fiscal year ended December 31, 2008 filed on October 20, 2009. File No. 001-32714).
10.12	Gas Gathering Agreement between Gastar Exploration Texas, LP, as Seller, and Hilltop Resort GS, LLC, as Buyer, dated November 16, 2009 and effective as of November 1, 2009 (incorporated by reference to Exhibit 10.1 of the Company’s Current Report on Form 8-K dated November 20, 2009. File No. 001-32714).
10.13	Purchase and Sale Agreement between Gastar Exploration Texas, LP, as Seller, and Hilltop Resort GS, LLC, as Buyer, dated November 16, 2009 (incorporated by reference to Exhibit 10.2 of the Company’s Current Report on Form 8-K dated November 20, 2009. File No. 001-32714).
10.14	Purchase and Sale Agreement between Gastar Exploration Texas, LP, as Seller, and Navasota Resources LTD., LLP, as Buyer, dated November 16, 2009 (incorporated by reference to Exhibit 10.3 of the Company’s Current Report on Form 8-K dated November 20, 2009. File No. 001-32714).
10.15	Purchase and Sale Agreement between Gastar Exploration Texas, LP, as Seller, and Presco, Inc., as Buyer, dated November 16, 2009 (incorporated by reference to Exhibit 10.4 of the Company’s Current Report on Form 8-K dated November 20, 2009. File No. 001-32714).
10.16	Purchase and Sale Agreement, dated September 21, 2010, by and between Gastar Exploration USA, Inc. and Atinum Marcellus I LLC (incorporated herein by reference to Exhibit 2.1 of the Company’s Current Report on Form 8-K dated September 24, 2010. File No. 001-32714).

10.17	Form of Participation Agreement (incorporated herein by reference to Exhibit 2.2 of the Company's Current Report on Form 8-K dated September 24, 2010. File No. 001-32714).
10.18	Form of the Final Settlement Agreement and Comprehensive General Release between and among James D. Lyon, Chapter 7 Trustee of ClassicStar LLC, Gastar Exploration Ltd., and other Individuals and Entities Set Forth Herein Effective November 1, 2010 (incorporated herein by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated November 2, 2010. File No. 001-32714).
10.19	Purchase and Sale Agreement, dated November 5, 2010, by and among MegaEnergy, Inc. and Saga Petroleum Corp. and Gastar Exploration USA, Inc. (incorporated herein by reference to Exhibit 10.1 on the Company's Current Report on Form 8-K dated December 20, 2010. File No. 001-32714).
10.20	Guarantee Agreement, dated June 23, 2011, by and between Gastar Exploration Ltd. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 10.1 of Gastar Exploration Ltd.'s Current Report on Form 8-K dated June 23, 2011. File No. 001-32714).
10.21*	Employment Agreement dated March 23, 2005 by and among First Sourcenergy Wyoming and Montana, Inc., Gastar Exploration Ltd. and J. Russell Porter (incorporated by reference to Exhibit 10.2 of the Company's Registration Statement on Form S-1, filed on August 12, 2005. Registration No. 333-127498).
10.22*	First Amendment to Employment Agreement entered into by and between Gastar Exploration, Ltd, Gastar Exploration USA, Inc., f/k/a First Sourcenergy Wyoming and Montana, Inc., and J. Russell Porter as of July 25, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated July 28, 2008. File No. 001-32714).

Exhibit Number	Description
10.23*	Second Amendment to Employment Agreement entered into by and between Gastar Exploration Ltd., Gastar Exploration USA, Inc. and J. Russell Porter as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated February 7, 2011. File No. 001-32714).
10.24*	Employment Agreement dated April 26, 2005 by and among First Sourcenergy Wyoming and Montana, Inc., Gastar Exploration Ltd. and Michael A Gerlich (incorporated by reference to Exhibit 10.3 of the Company's Registration Statement on Form S-1, filed on August 12, 2005. Registration No. 333-127498).
10.25*	First Amendment to Employment Agreement entered into by and between Gastar Exploration, Ltd, Gastar Exploration USA, Inc., f/k/a First Sourcenergy Wyoming and Montana, Inc., and Michael A. Gerlich as of July 25, 2008 (incorporated by reference to Exhibit 10.2 of the Company's Current Report of Form 8-K dated July 28, 2008. File No. 001-32714).
10.26*	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).
10.27*	Form of Gastar officer stock option grant (incorporated herein by reference to Exhibit 10.10 of the Company's annual Report on form 10-K for the fiscal year ended December 31, 2005. File No. 001-32714).
10.28*	Gastar Exploration Ltd. 2006 Long-Term Stock Incentive Plan approved June 1, 2006 (incorporated herein by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006. File No. 001-32714).
10.29*	First Amendment to Gastar Exploration Ltd. 2006 Long-Term Stock Incentive Plan, effective as of April 1, 2009, approved June 4, 2009 (incorporated by reference to Exhibit 10.2 of the Company's Current Report of Form 8-K dated June 10, 2009. File No. 001-32714).
10.30*	Second Amendment to Gastar Exploration Ltd. 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.0 of the Company's Current Report on Form 8-K dated June 7, 2012. File No. 001-32714).
10.31*	Form of Indemnity Agreement for Directors and Certain Executive Officers (incorporated herein by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated December 19, 2006. File No. 001-32714).
10.32*	Form of Gastar Exploration Ltd. Employee Change of Control Severance Plan effective as of March 23, 2007 and as amended and restated effective February 15, 2008 (incorporated herein by reference to Exhibit 10.18 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2007. File No. 001-32714).
10.33*	First Amendment to Gastar Exploration Ltd. Employee Change of Control Severance Plan, dated April 11, 2012 (incorporated by reference to the Company's Current Report on Form 8-K dated April 12, 2012. File No. 001-32714)..

10.34*	Gastar Exploration Ltd. Annual Bonus Plan (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated August 8, 2011. File No. 001-32714).
10.35*	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of the Company's Registration Statement on Form S-8 dated December 4, 2006. File No. 333-139112).
14.1	Gastar Exploration Ltd. Amended and Restated Code of Ethics (incorporated herein by reference to Exhibit 14.1 of the Company's Form 8-K dated March 22, 2011, File No. 001-32714).
21.1†	Subsidiaries of Gastar Exploration Ltd.
23.1†	Consent of BDO USA, LLP
23.2†	Consent of BDO USA, LLP
23.3†	Consent of Wright & Company, Inc.
23.4†	Consent of Netherland, Sewell & Associates, Inc.
31.1†	Certification of Chief Executive Officer of Gastar Exploration Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Chief Financial Officer of Gastar Exploration Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Description
31.3†	Certification of President of Gastar Exploration USA, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4†	Certification of Treasurer of Gastar Exploration USA, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Chief Executive Officer of Gastar Exploration Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2††	Certification of Chief Financial Officer of Gastar Exploration Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.3††	Certification of President of Gastar Exploration USA, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4††	Certification of Treasurer of Gastar Exploration USA, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1††	Report of Netherland, Sewell & Associates, Inc. dated January 15, 2013.
99.2††	Report of Wright & Company, Inc. dated January 15, 2013.
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
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.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

/s/ J. RUSSELL PORTER
J. Russell Porter, President and Chief
Executive Officer

(Duly authorized officer and principal
executive officer)
March 11, 2013

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ J. RUSSELL PORTER J. Russell Porter	President, Chief Executive Officer, Chief Operating Officer (principal executive officer) and Director	March 11, 2013
/s/ MICHAEL A. GERLICH Michael A. Gerlich	Vice President and Chief Financial Officer (principal financial and accounting officer)	March 11, 2013
/s/ JOHN M. SELSER SR. John M. Selser Sr.	Chairman of the Board	March 11, 2013
/s/ JOHN H. CASSELS John H. Cassels	Director	March 11, 2013
/s/ RANDOLPH C. COLEY Randolph C. Coley	Director	March 11, 2013
/s/ ROBERT D. PENNER Robert D. Penner	Director	March 11, 2013

Pursuant to the requirements of Section 13 or 15(d) 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.

/s/ J. RUSSELL PORTER
J. Russell Porter, President
(Duly authorized officer and principal
executive officer)
March 11, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ J. RUSSELL PORTER J. Russell Porter	President and Sole Director	March 11, 2013
/s/ MICHAEL A. GERLICH Michael A. Gerlich	Secretary and Treasurer (principal financial and accounting officer)	March 11, 2013

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Gastar Exploration Ltd. (the “Company”) and subsidiaries as of December 31, 2012 and 2011 and the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gastar Exploration Ltd. at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Gastar Exploration Ltd.’s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 11, 2013 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 11, 2013

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Report of Independent Registered Public Accounting Firm
Board of Directors and Stockholders
Gastar Exploration USA, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Gastar Exploration USA, Inc. ("Gastar USA") and subsidiaries as of December 31, 2012 and 2011 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of Gastar USA's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gastar Exploration USA, Inc. at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO USA, LLP
Dallas, Texas
March 11, 2013

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	2011
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$8,901	$10,647
Accounts receivable, net of allowance for doubtful accounts of $546 and $551, respectively	9,540	10,706
Commodity derivative contracts	7,799	19,385
Prepaid expenses	1,097	1,243
Total current assets	27,337	41,981
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, full cost method of accounting:		
Unproved properties, excluded from amortization	67,892	78,302
Proved properties	671,193	514,357
Total natural gas and oil properties	739,085	592,659
Furniture and equipment	1,925	1,629
Total property, plant and equipment	741,010	594,288
Accumulated depreciation, depletion and amortization	(484,759)	(308,548)
Total property, plant and equipment, net	256,251	285,740
OTHER ASSETS:		
Restricted cash	—	50
Commodity derivative contracts	1,369	4,130
Deferred charges, net	836	535
Advances to operators and other assets	4,275	2,067
Total other assets	6,480	6,782
TOTAL ASSETS	$290,068	$334,503
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$23,863	$17,693
Revenue payable	8,801	4,137
Accrued interest	151	144
Accrued drilling and operating costs	3,907	4,647
Advances from non-operators	17,540	19,523
Commodity derivative contracts	1,399	6,479
Commodity derivative premium payable	—	4,725
Accrued litigation settlement liability	—	800
Asset retirement obligation	358	—
Other accrued liabilities	1,493	1,723
Total current liabilities	57,512	59,871
LONG-TERM LIABILITIES:		
Long-term debt	98,000	30,000
Commodity derivative contracts	1,304	1,163
Asset retirement obligation	6,605	8,275
Other long-term liabilities	111	—

Total long-term liabilities	106,020	39,438
Commitments and contingencies (Note 15)		
SHAREHOLDERS' EQUITY:		
Common stock, no par value; unlimited shares authorized; 66,432,609 and 64,706,750 shares issued and outstanding at December 31, 2012 and 2011, respectively	316,346	316,346
Additional paid-in capital	28,336	25,376
Accumulated deficit	(294,787)	(133,919)
Total shareholders' equity	49,895	207,803
Non-controlling interest:		
Preferred stock of subsidiary, aggregate liquidation preference $98,781 and $34,114 at December 31, 2012 and 2011, respectively	76,641	27,391
Total equity	126,536	235,194
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$290,068	$334,503

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands, except share and per share data)		
REVENUES:			
Natural gas	$33,829	$33,391	$30,812
Condensate and oil	12,377	3,416	742
NGLs	9,300	1,092	—
Total natural gas, condensate, oil and NGLs revenues	55,506	37,899	31,554
Unrealized hedge (loss) gain	(5,566)	2,336	11,214
Total revenues	49,940	40,235	42,768
EXPENSES:			
Production taxes	2,269	620	370
Lease operating expenses	6,174	8,630	6,679
Transportation, treating and gathering	4,965	4,501	4,654
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
Accretion of asset retirement obligation	388	534	396
General and administrative expense	12,211	11,365	14,638
Litigation settlement expense	1,250	—	21,744
Total expenses	203,468	40,866	57,787
LOSS FROM OPERATIONS	(153,528)	(631)	(15,019)
OTHER INCOME (EXPENSE):			
Interest expense	(270)	(113)	(150)
Investment and other income	9	10	1,347
Unrealized warrant derivative gain	—	—	205
Foreign transaction (loss) gain	(2)	(6)	353
LOSS BEFORE PROVISION FOR INCOME TAXES	(153,791)	(740)	(13,264)
Provision for income tax benefit	—	—	(804)
NET LOSS	(153,791)	(740)	(12,460)
Dividend on preferred stock attributable to non-controlling interest	(7,077)	(1,024)	—
NET LOSS ATTRIBUTABLE TO GASTAR EXPLORATION LTD.	$(160,868)	$(1,764)	$(12,460)
NET LOSS PER COMMON SHARE ATTRIBUTABLE TO GASTAR EXPLORATION LTD. COMMON SHAREHOLDERS:			
Basic	$(2.53)	$(0.03)	$(0.25)
Diluted	$(2.53)	$(0.03)	$(0.25)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	63,538,362	63,003,579	49,813,617
Diluted	63,538,362	63,003,579	49,813,617

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock						
	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Gastar Exploration Ltd. Shareholders' Equity	Non-controlling Interest	Total Equity
	(in thousands, except share data)						
Balance at December 31, 2009	50,028,592	$263,809	$ 20,782	$ (119,695)	$164,896	$ —	$164,896
Issuance of shares—cash, net of offering costs of $2,663	13,800,000	52,537	—	—	52,537	—	52,537
Issuance of restricted shares, net of forfeitures	349,502	—	(347)	—	(347)	—	(347)
Exercise of stock options, net of forfeitures	1,021	—	—	—	—	—	—
Stock based compensation	—	—	2,765	—	2,765	—	2,765
Net loss	—	—	—	(12,460)	(12,460)	—	(12,460)
Balance at December 31, 2010	64,179,115	316,346	23,200	(132,155)	207,391	—	207,391
Issuance of restricted shares, net of forfeitures	524,337	—	(436)	—	(436)	—	(436)
Exercise of stock options, net of forfeitures	3,298	—	—	—	—	—	—
Stock based compensation	—	—	2,612	—	2,612	—	2,612
Net loss	—	—	—	(1,764)	(1,764)	—	(1,764)
Issuance of preferred stock of subsidiary	—	—	—	—	—	27,391	27,391
Balance at December 31, 2011	64,706,750	$316,346	$ 25,376	$ (133,919)	$207,803	$ 27,391	$235,194
Issuance of restricted shares, net of forfeitures	1,725,252	—	(335)	—	(335)	—	(335)
Exercise of stock options, net of forfeitures	607	—	—	—	—	—	—
Stock based compensation	—	—	3,295	—	3,295	—	3,295
Net loss	—	—	—	(160,868)	(160,868)	—	(160,868)
Issuance of preferred stock of subsidiary	—	—	—	—	—	49,250	49,250
Balance at December 31, 2012	66,432,609	$316,346	$ 28,336	$ (294,787)	$49,895	$ 76,641	$126,536

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,		
	2012	2011	2010
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(153,791)	$(740)	$(12,460)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
Stock-based compensation	3,295	2,612	2,765
Unrealized hedge loss (gain)	5,566	(2,336)	(11,214)
Realized (gain) loss on derivative contracts	(884)	(1,735)	1,437
Amortization of deferred financing costs	224	249	283
Accretion of asset retirement obligation	388	534	396
Settlement of asset retirement obligation	(636)	—	—
Unrealized warrant derivative gain	—	—	(205)
Accrued litigation settlement liability	—	—	3,150
Changes in operating assets and liabilities:			
Accounts receivable	2,095	(6,672)	1,565
Commodity derivative contracts	—	(54)	1,232
Prepaid expenses	146	(100)	(522)
Accrued taxes payable	—	—	(1,420)
Accounts payable and accrued liabilities	4,441	4,303	(385)
Net cash provided by (used in) operating activities	37,055	11,277	(6,072)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of natural gas and oil properties	(136,311)	(73,718)	(58,512)
Advances to operators	(9,649)	(8,392)	(300)
Acquisition of natural gas and oil properties	—	—	(28,887)
Proceeds from sale of natural gas and oil properties	—	—	49,197
(Use of proceeds) proceeds from non-operators	(1,983)	18,740	98
Purchase of furniture and equipment	(296)	(454)	(308)
Purchase of term deposit	—	—	(4,855)
Net cash used in investing activities	(148,239)	(63,824)	(43,567)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common shares, net of issuance costs	—	—	52,537
Proceeds from revolving credit facility	98,000	71,000	42,000
Repayment of revolving credit facility	(30,000)	(41,000)	(42,000)
Repayment of short-term loan	—	—	(17,000)
Proceeds from issuance of preferred stock, net of issuance costs	49,250	27,391	—
Dividend on preferred stock attributable to non-controlling interest	(7,077)	(1,024)	—
Deferred financing charges	(450)	(276)	(27)
Other	(285)	(336)	(298)
Net cash provided by financing activities	109,438	55,755	35,212
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(1,746)	3,208	(14,427)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	10,647	7,439	21,866
CASH AND CASH EQUIVALENTS, END OF PERIOD	$8,901	$10,647	$7,439

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	2011
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$8,892	$10,595
Accounts receivable, net of allowance for doubtful accounts of $546 and $551, respectively	9,539	10,703
Commodity derivative contracts	7,799	19,385
Prepaid expenses	919	1,088
Total current assets	27,149	41,771
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, full cost method of accounting:		
Unproved properties, excluded from amortization	67,892	78,302
Proved properties	671,185	514,349
Total natural gas and oil properties	739,077	592,651
Furniture and equipment	1,925	1,629
Total property, plant and equipment	741,002	594,280
Accumulated depreciation, depletion and amortization	(484,752)	(308,541)
Total property, plant and equipment, net	256,250	285,739
OTHER ASSETS:		
Restricted cash	—	25
Commodity derivative contracts	1,369	4,130
Deferred charges, net	836	535
Advances to operators and other assets	4,275	2,067
Total other assets	6,480	6,757
TOTAL ASSETS	$289,879	$334,267
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$23,863	$17,682
Revenue payable	8,801	4,137
Accrued interest	151	144
Accrued drilling and operating costs	3,907	4,647
Advances from non-operators	17,540	19,523
Commodity derivative contracts	1,399	6,479
Commodity derivative premium payable	—	4,725
Accrued litigation settlement liability	—	800
Asset retirement obligation	358	—
Other accrued liabilities	1,480	1,654
Total current liabilities	57,499	59,791
LONG-TERM LIABILITIES:		
Long-term debt	98,000	30,000
Commodity derivative contracts	1,304	1,163
Asset retirement obligation	6,598	8,268
Due to parent	30,903	27,432
Other long-term liabilities	111	—

Total long-term liabilities	136,916	66,863
Commitments and contingencies (Note 15)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; 3,951,254 and 1,364,543 shares issued and outstanding at December 31, 2012 and 2011, respectively, with liquidation preference of $25.00 per share	40	14
Common stock, no par value; 1,000 shares authorized; 750 shares issued and outstanding	237,431	239,431
Additional paid-in capital	76,601	27,377
Accumulated deficit	(218,608)	(59,209)
Total stockholders' equity	95,464	207,613
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$289,879	$334,267

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2012	2011	2010
	(in thousands, except share and per share data)		
REVENUES:			
Natural gas	$33,829	$33,391	$30,811
Condensate and oil	12,377	3,416	742
NGLs	9,300	1,092	—
Total natural gas, condensate, oil and NGLs revenues	55,506	37,899	31,553
Unrealized hedge (loss) gain	(5,566)	2,336	11,214
Total revenues	49,940	40,235	42,767
EXPENSES:			
Production taxes	2,269	620	370
Lease operating expenses	6,174	8,629	6,676
Transportation, treating and gathering	4,965	4,501	4,654
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
Accretion of asset retirement obligation	388	534	396
General and administrative expense	10,732	10,434	13,468
Litigation settlement expense	1,250	—	21,744
Total expenses	201,989	39,934	56,614
(LOSS) INCOME FROM OPERATIONS	(152,049)	301	(13,847)
OTHER INCOME (EXPENSE):			
Interest expense	(271)	(112)	(97)
Investment and other (expense) income	(4)	95	1,238
Foreign transaction gain	2	1	354
(LOSS) INCOME BEFORE PROVISION FOR INCOME TAXES	(152,322)	285	(12,352)
Provision for income tax benefit	—	—	(804)
NET (LOSS) INCOME	(152,322)	285	(11,548)
Dividend on preferred stock	(7,077)	(1,024)	—
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDER	$(159,399)	$(739)	$(11,548)

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Preferred Stock		Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Stockholder's Equity
	Shares	Amount	Shares	Amount			
	(in thousands, except share data)						
Balance at December 31, 2009	—	$—	750	$206,894	$—	$(46,922)	$159,972
Distribution to Parent	—	—	—	(19,000)	—	—	(19,000)
Contribution from Parent	—	—	—	52,537	—	—	52,537
Net loss	—	—	—	—	—	(11,548)	(11,548)
Balance at December 31, 2010	—	—	750	240,431	—	(58,470)	181,961
Distribution to Parent	—	—	—	(1,000)	—	—	(1,000)
Issuance of preferred stock	1,364,543	14	—	—	27,377	—	27,391
Preferred stock dividends	—	—	—	—	—	(1,024)	(1,024)
Net income	—	—	—	—	—	285	285
Balance at December 31, 2011	1,364,543	$14	750	$239,431	$27,377	$(59,209)	$207,613
Distribution to Parent	—	—	—	(2,000)	—	—	(2,000)
Issuance of preferred stock	2,586,711	26	—	—	49,224	—	49,250
Preferred stock dividends	—	—	—	—	—	(7,077)	(7,077)
Net loss	—	—	—	—	—	(152,322)	(152,322)
Balance at December 31, 2012	3,951,254	$40	750	$237,431	$76,601	$(218,608)	$95,464

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

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GASTAR EXPLORATION USA, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,		
	2012	2011	2010
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$(152,322)	$285	$(11,548)
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
Stock-based compensation	3,295	2,612	2,765
Unrealized hedge loss (gain)	5,566	(2,336)	(11,214)
Realized (gain) loss on derivative contracts	(884)	(1,735)	1,437
Amortization of deferred financing costs	224	249	247
Accretion of asset retirement obligation	388	534	396
Settlement of asset retirement obligation	(636)	—	—
Litigation settlement payable	—	—	3,150
Changes in operating assets and liabilities:			
Accounts receivable	2,093	(6,669)	1,562
Commodity derivative contracts	—	(54)	1,232
Prepaid expenses	169	(137)	(552)
Accrued taxes payable	—	—	(1,420)
Accounts payable and accrued liabilities	4,508	4,236	(45)
Net cash provided by (used in) operating activities	38,612	12,201	(4,684)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of natural gas and oil properties	(136,311)	(73,718)	(58,512)
Advances to operators	(9,649)	(8,392)	(300)
Acquisition of natural gas and oil properties	—	—	(28,887)
Proceeds from sale of natural gas and oil properties	—	—	49,197
(Use of proceeds) proceeds from non-operators	(1,983)	18,740	98
Purchase of furniture and equipment	(296)	(454)	(308)
Purchase of term deposit	—	—	(4,855)
Net cash used in investing activities	(148,239)	(63,824)	(43,567)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility	98,000	71,000	—
Repayment of revolving credit facility	(30,000)	(41,000)	—
Proceeds from issuance of preferred stock, net of issuance costs	49,250	27,391	—
Dividend on preferred stock	(7,077)	(1,024)	—
Deferred financing charges	(450)	(276)	(27)
(Distribution to) contribution from Parent, net	(1,824)	(1,374)	33,822
Other	25	100	49
Net cash provided by financing activities	107,924	54,817	33,844
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(1,703)	3,194	(14,407)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	10,595	7,401	21,808
CASH AND CASH EQUIVALENTS, END OF PERIOD	$8,892	$10,595	$7,401

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

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Gastar Exploration Ltd. is an independent energy company engaged in the exploration, development and production of natural gas, condensate, oil and NGLs 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 and oil in the Mid-Continent area of the U.S. Gastar Exploration Ltd. also holds prospective acreage in the deep Bossier play in East Texas.

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

Basis of Presentation

These financial statements are a combined presentation of the 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 consolidated information for the Company presented herein and the consolidated information of Gastar USA.

The consolidated financial statements of the Company and Gastar USA are stated in U.S. dollars unless otherwise noted and have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). The preparation of these financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, related disclosure of contingent assets and liabilities, proved natural gas and oil reserves and the related disclosures in the accompanying consolidated financial statements. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved natural gas and oil reserve quantities and the related present value of estimated future net cash flows. See Note 19, "Supplemental Oil and Gas Disclosures."

Reclassifications

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

Subsequent Events

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 consolidated financial statements, as appropriate.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Parent and the consolidated accounts of all its subsidiaries. The wholly-owned subsidiaries included in these consolidated accounts are Gastar USA, Gastar Exploration Texas, Inc. ("Gastar Texas, Inc."), Gastar Exploration Texas LP ("Gastar Texas"), Gastar Exploration Texas LLC ("Gastar Texas LLC"), Gastar Exploration New South Wales, Inc. ("Gastar New South Wales"), and prior to 2012, Gastar Exploration Victoria, Inc. ("Gastar Victoria"). All significant inter-company accounts and transactions have been eliminated in consolidation.

The consolidated financial statements of Gastar USA include the accounts of Gastar USA and the consolidated accounts of all its subsidiaries. The wholly-owned subsidiaries included in these consolidated accounts are Gastar

Texas, Inc., Gastar Texas, Gastar Texas LLC, Gastar New South Wales, and prior to 2012, Gastar Victoria. All significant inter-company accounts and transactions have been eliminated in consolidation.

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Cash and Cash Equivalents

The Company's cash and cash equivalents, which includes short-term investments such as money market deposits with a maturity of three months or less when purchased, amounted to $8.9 million and $10.6 million as of December 31, 2012 and 2011, respectively. The Company maintains its cash in bank deposit accounts, which, at times, may exceed federally insured limits. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant risk of loss.

Accounts Receivable

Accounts receivable are reported net of the allowance for doubtful accounts. The allowance for doubtful accounts is determined based on a review of the Company’s receivables. Receivable accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

A summary of the activity related to the allowance for doubtful accounts is as follows:

	For the years ended December 31,		
	2012	2011	2010
	(in thousands)		
Allowance for doubtful accounts, beginning of year	$551	$571	$609
Expense	—	—	—
Reductions	(5)	(20)	(38)
Allowance for doubtful accounts, end of year	$546	$551	$571

Deferred Financing Costs

Deferred financing costs include costs of debt financings undertaken by the Company, including commissions, legal fees and other direct costs of financing. Using the effective interest method, the deferred financing costs are amortized over the term of the related debt instrument to interest expense.

The following table indicates deferred charges and related accumulated amortization as of the dates indicated:

	As of December 31,	
	2012	2011
Deferred charges	$2,525	$2,000
Accumulated amortization	(1,689)	(1,465)
Deferred charges, net	$836	$535

Natural Gas and Oil Properties

The Company follows the full cost method of accounting for natural gas and oil operations, whereby all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are initially capitalized into cost centers on a country-by-country basis and are amortized as reserves are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. Capitalized costs include land acquisition costs, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition, exploration and development activities. The U.S. is the Company's only cost center. Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated net proved reserves, as determined by independent petroleum engineers.

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

In applying the full cost method of accounting, the Company performs a quarterly ceiling test on the cost center properties whereby the net cost of natural gas and oil properties, net of related deferred income taxes (“net cost”), is limited to the sum of the estimated future net revenues from the Company’s proved reserves using prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price for natural gas and oil prices held constant, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects (“ceiling”). If the net cost exceeds the ceiling, an impairment loss is recognized for the amount by which the net cost exceeds the ceiling and is shown as a reduction in natural gas and oil properties and as additional depletion expense. Proceeds from a sale of natural gas and oil properties will be applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion or amortization.

The Company's estimate of proved reserves is based on the quantities of natural gas, condensate, oil and NGLs that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Wright & Company, Inc. ("Wright") and Netherland, Sewell & Associates, Inc. ("NSAI") prepare a reserve and economic evaluation of all the Company's properties on a well-by-well basis utilizing information provided by the Company and information available from state agencies that collect information reported to it by the operators of the Company's properties. As discussed below, the estimate of the Company's proved reserves as of December 31, 2012 and 2011 have been prepared and presented in accordance with current rules and accounting standards promulgated by the Securities and Exchange Commission (the "SEC"). These rules require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on a 12-month unweighted arithmetic average of the first-day-of-the-month price. The previous rules required that reserve estimates be calculated using year-end pricing.

Reserves and their relation to estimated future net cash flows impact the Company's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The Company prepares its reserve estimates and the projected cash flows derived from these reserve estimates in accordance with SEC guidelines. Wright and NSAI adhere to the same guidelines when preparing the reserve report. The accuracy of the Company's reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas, condensate, oil and NGLs eventually recovered.

The Company assesses unproved properties for impairment periodically and recognizes a loss where circumstances indicate impairment in value. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current drilling plans, favorable or unfavorable activity on the properties being evaluated and/or adjacent properties and current market conditions. In the event that factors indicate an impairment in value, unproved properties leasehold costs are reclassified to proved properties and depleted.

Capitalized Interest

The Company capitalizes interest on assets not being amortized related to specific projects such as its drilling in progress and unproven natural gas and oil property expenditures. The methodology for capitalizing interest on general funds begins with a determination of the borrowings applicable to the qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset's acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for construction then they would have been used to pay off debt. The primary debt instrument included in the rate calculation of capitalized interest incurred for the year-ended December 31, 2012 was the Revolving Credit Facility (as defined under Note 5, "Long-Term Debt"). Currently, the Company only capitalizes interest on its Revolving Credit Facility. The interest to be capitalized for any period is derived by multiplying the average rate of interest times the average qualifying assets during the period, not to exceed the total interest on the qualifying debt instruments. To qualify for interest capitalization, the Company must continue to make progress on the development of the assets. Capitalized interest costs were approximately $1.9 million, $818,000 and $633,000 for 2012, 2011 and 2010, respectively.

Furniture and Equipment

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

Fair Value of Financial Instruments

The fair value of financial instruments is determined at discrete points in time based on relevant market information. Such estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash and cash equivalents, term deposit, accounts receivable, prepaid expenses, accounts and revenue payables and accrued liabilities approximates their carrying value due to their short-term nature. Derivative instruments are also recorded on the balance sheet at fair value.

Derivative Instruments and Hedging Activity

The Company uses derivative instruments in the form of natural gas costless collars, index swaps, basis and fixed price swaps and put and call options to manage price risks resulting from fluctuations in commodity prices of natural gas, oil and

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NGLs associated with future natural gas, condensate, oil and NGLs production. Derivative instruments are recorded on the balance sheet at fair value, and changes in the fair value of derivatives are recorded each period in current earnings. Fair value is assessed, measured and estimated by obtaining forward commodity pricing, credit adjusted risk-free interest rates and, as necessary, estimated volatility factors. The fair values that the Company reports in its consolidated financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond the Company’s control. Gains and losses on derivatives are included in revenue in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities. See Note 8, “Derivative Instruments and Hedging Activity.”

The Company has elected not to designate derivative contracts as cash flow hedges. As a result, any changes in the fair values of derivative contracts for future production are recognized in unrealized hedge gain (loss) within the Company’s consolidated statements of operations. For 2012, 2011 and 2010, realized gains or losses from derivative contracts are included in natural gas, condensate and oil and NGLs revenues in the Company’s consolidated statement of operations.

Revenue Recognition

The Company uses the sales method of accounting for the sale of its natural gas, condensate, oil and NGLs and records revenues from the sale of such products when delivery to the customer has occurred and title has transferred. This recording of revenues occurs when natural gas, condensate, oil or NGLs have been delivered to a pipeline or a tank lifting has occurred. The Company's NGLs are sold as part of the wet gas subject to an incremental NGLs pricing formula based upon a percentage of NGLs extracted from the Company's wet gas production. The Company's reported production volumes reflect incremental post-processing NGLs volumes and residual gas volumes with which the Company is credited under its sales contracts. Under the sales method, revenues are recorded based on the Company’s net revenue interest, as delivered. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. The Company had no material gas imbalances at December 31, 2012 and 2011.

The Company records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, condensate, oil and NGLs are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents once received by the Company. In addition, natural gas, condensate, oil and NGLs volumes sold are not significantly different from the Company’s share of production.

The Company calculates and pays royalties on natural gas, condensate, oil and NGLs in accordance with the particular contractual provisions of the lease. Royalty liabilities are recorded in conjunction with the cash receipts for natural gas, condensate, oil and NGLs revenues and are included in revenue payable on the Company’s consolidated balance sheet.

Asset Retirement Obligation

Asset retirement costs and liabilities associated with future site restoration and abandonment of tangible long-lived assets are initially measured at fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements as the present value of expected future cash expenditures for site restoration and abandonment. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost, through depreciation, depletion and amortization, are recognized in the results of operations.

Foreign Currency Exchange

The consolidated financial statements of the Company are presented in U.S. dollars. The functional currency for Parent and all consolidated subsidiaries is U.S. dollars. Transactions in currencies other than the functional currency are recorded using the appropriate exchange rate at the time of the transaction.

The majority of the Company’s operations are conducted in U.S. dollars. Prior to July 2009, the Company conducted natural gas property development in Australia, however, prior to reaching commercial operations, these assets were sold. Limited operations are conducted by Parent in Canada.

The Australian and Canadian records are maintained in the local currency and re-measured to the functional currency as follows: monetary assets and liabilities are converted using the balance sheet period-end date exchange rate, while the non-monetary assets and liabilities are converted using the historical exchange rate. Expenses and income items are converted using the weighted average exchange rates for the reporting period. Foreign transaction gains and losses are reported on the consolidated statement of operations.

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Deferred Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Deferred tax assets are routinely evaluated to determine the likelihood of realization and the Company must estimate its expected future taxable income to complete this assessment. Numerous assumptions are inherent in the estimation of future taxable income, including assumptions about matters that are dependent on future events such as future operating conditions, particularly related to prevailing natural gas, condensate, oil and NGLs prices, and future financial conditions. The estimates or assumptions used in determining future taxable income are consistent with those used in internal budgets and forecasts. The effect on deferred tax assets and liabilities of a change in tax rates is recognized as income in the period that includes the enactment date. The Company has established a valuation allowance to offset its net deferred tax asset since, on a more likely than not basis, such benefits are not considered recoverable at this time.

Comprehensive Income

Comprehensive income is defined as a change in equity of a business enterprise during a period from transactions and other events and circumstances from non-owner sources and includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The Company has no items of comprehensive income other than net income in any period presented. Therefore, net income as presented in the consolidated statements of operations equals comprehensive income.

Earnings or Loss per Share

Basic earnings or loss per share is computed on the basis of the weighted average number of common shares outstanding. Diluted earnings or loss per share is computed based upon the weighted average number of common shares outstanding plus the incremental effect of the assumed issuance of common shares for all potentially dilutive securities. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares are exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options, unvested restricted shares and warrants.

Stock-Based Compensation

The Company reports compensation expense for stock options and restricted common shares granted to officers, directors and employees using the fair value method. Stock-based compensation costs are recorded over the requisite service period, which approximates the vesting period. Stock-based compensation expense is recognized using the “graded-vesting method,” which recognizes compensation costs over the requisite service period for each separately vesting tranche of an award as though the award were, in substance, multiple awards.

The Company records stock-based compensation costs for stock options granted based on the grant-date fair value as calculated using the Black-Scholes-Merton option-pricing model. The Black-Scholes-Merton model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes-Merton model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period. Stock-based compensation cost for restricted shares granted is estimated at the grant date based on the prior day’s closing stock price.

Joint Venture Operations

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

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of natural gas and oil. Historically, the Company’s operational activities have been conducted in the U.S. and Australia, with only the U.S. having revenue generating operating results. The Company’s current operational activities and the Company’s consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

Treasury Stock

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

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Restricted Cash

Prior to September 2012, the Company was required to maintain cash balances that were restricted by provisions of certain banking and other agreements. Restricted cash was invested in short-term instruments at market rates; therefore, the carrying value approximated fair value. Such cash was reported as restricted cash and was excluded from cash and cash equivalents in the consolidated balance sheets.

Recent Accounting Developments

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

Comprehensive Income. In June 2011, the Financial Accounting Standards Board (“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 upon adoption.

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. Early application is not permitted. The adoption of this guidance did not impact our operating results, financial position or cash flows upon adoption.

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 Company's total property, plant and equipment consists of the following:

	December 31,	
	2012	2011
	(in thousands)	
Natural gas and oil properties, full cost method of accounting:		
Unproved properties	$67,892	$78,302
Proved properties	671,193	514,357
Total natural gas and oil properties	739,085	592,659
Furniture and equipment	1,925	1,629
Total property and equipment	741,010	594,288
Impairment of proved natural gas and oil properties	(337,939)	(187,152)
Accumulated depreciation, depletion and amortization	(146,820)	(121,396)
Total accumulated depreciation, depletion and amortization	(484,759)	(308,548)
Total property and equipment, net	$256,251	$285,740

Included in the Company's natural gas and oil properties are asset retirement costs of $4.8 million and $5.8 million as of December 31, 2012 and 2011, respectively.

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

	December 31, 2012	2011
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$1,902	$3,958
Acreage acquisition costs	62,395	68,217
Capitalized interest	3,595	6,127
Total unproved properties excluded from amortization	$67,892	$78,302

For the year ended December 31, 2012, management's evaluation of unproved properties resulted in an impairment. Due to a decline in natural gas prices and the suspension of drilling activity in East Texas, the Company reclassified $24.4 million of unproved properties to proved properties for the year ended December 31, 2012.

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, condensate and oil and NGLs 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 trailing 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect are held constant indefinitely. The 12-month unweighted arithmetic average of the first-day-of-the-month prices are adjusted for basis and quality differentials in determining the present value of the reserves. The table below sets forth relevant assumptions utilized in the quarterly ceiling test computations for the respective periods noted:

	2012				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$2.76	$2.83	$3.15	$3.73
West Texas Intermediate oil price (per Bbl) (1)		$91.21	$91.48	$92.17	$94.65
Impairment recorded (pre-tax) (in thousands)	$150,787	$—	$78,054	$72,733	$—
	2011				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$4.12	$4.16	$4.21	$4.10
West Texas Intermediate oil price (per Bbl) (1)		$92.71	$91.00	$86.60	$80.04
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—	$—	$—

	2010				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$4.38	$4.41	$4.10	$3.99
West Texas Intermediate oil price (per Bbl) (1)		$75.96	$77.82	$76.21	$70.09
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—	$—	$—

(1) For the respective periods, natural gas and oil prices are calculated using the trailing 12-month unweighted arithmetic average of the first-day-of-the-month prices based on Henry Hub natural gas prices and West Texas Intermediate oil prices.

Future declines in the 12-month average of natural gas, condensate, oil and NGLs prices could 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 an 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 funds only 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 and then subsequently agreed to extend the rig contract resulting in 29 gross (13.4 net) wells drilled and completed during 2012. As of December 31, 2012, 38 gross (17.4 net) operated wells were drilled, completed and on production 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.

Marcellus Shale Leasehold Acquisition

In December 2010, Gastar USA completed a $28.9 million acquisition of undeveloped leasehold in the Marcellus Shale concentrated in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia, including a gathering system comprised of 41 miles of four and six inch steel pipe, a salt water disposal well and five conventional producing wells. This acreage is not included in the Atinum Joint Venture and the counties in which the acquired assets are located are not part of the initial AMI.

Sale of East Texas Gas Gathering System

On November 16, 2009, Gastar USA completed the sale of all of its interest in the Hilltop gas gathering system (the "Hilltop Gathering System"), located in Leon and Robertson Counties, Texas, pursuant to a purchase and sale agreement with Hilltop Resort GS, LLC ("Hilltop Resort"), dated as of November 16, 2009, whereby Gastar USA conveyed its 70% interest in the Hilltop Gathering System to Hilltop Resort for approximately $19.1 million, net of transaction costs and expenses. Gastar USA also entered into purchase and sale agreements dated November 16, 2009 with two existing working interest owners in the Hilltop area of East Texas, whereby Gastar USA conveyed the remaining 30% of its interest in the Hilltop Gathering System for an aggregate $2.7 million, net of working interest owner costs owed to Gastar USA. At the time of the sale, the Hilltop Gathering System was comprised of 20 miles of natural gas pipeline connected to 19 company-operated wells, which produce from the middle and lower Bossier and Knowles formations in East Texas.

On November 16, 2009, concurrent with Gastar USA's sale of its Hilltop Gathering System, Gastar Texas entered into a gas gathering agreement ("Hilltop Gathering Agreement") effective November 1, 2009, with Hilltop Resort for an initial term of 15 years. The Hilltop Gathering Agreement covers delivery of Gastar USA's gross production of natural gas in the Hilltop area of East Texas to certain delivery points provided under the gas sales contract, as well as additional delivery points that, from time to time, may be added. Gastar USA is also obligated to connect new wells that it drills within the area covered by the Hilltop Gathering Agreement to the Hilltop Gathering System. The Hilltop Gathering Agreement provides for a minimum quarterly gathering gross production volume of 50.0 MMcf per day

(35.0 MMcf per day net to Gastar USA) times the number of days in the quarter for 5 years from the effective date of November 1, 2009. If quarterly production is less than the minimum quarterly requirement, the gathering fee is payable on such deficit. If excess quarterly production exists, such excess is carried forward to be used to offset any future deficit quarters. The gathering fee on the initial gross 25 Bcf of production is $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reaches 300 Bcf. In October 2011, the cumulative gross production contractual volume of 25 Bcf was reached and the fee was reduced to $0.30 per Mcf. For the years ended December 31, 2012, 2011 and 2010, Gastar USA paid $2.0 million, $1.5 million and $1.3 million, respectively, to Hilltop Resort as a result of actual production volumes being less than minimum contractual volume requirements per the Hilltop Gathering Agreement. Gastar USA does not expect to meet the minimum quarterly requirements in the near future.

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4. Short-Term Loan

On November 20, 2009, Parent entered into a $17.0 million secured short-term loan agreement with the lender parties and administrative agent thereto (the "Short-Term Loan"). In order to provide for Parent's borrowings under the Short-Term Loan and related repayments and the granting of the Second Lien, on November 20, 2009, Gastar USA, together with Parent and certain of its subsidiaries as the guarantors ("Subsidiary Guarantors"), and the lenders and administrative agent party thereto, entered into the Consent and First Amendment to Amended and Restated Credit Agreement (the "First Amendment") amending the Revolving Credit Facility. See Note 5, "Long-Term Debt, Revolving Credit Facility."

The Short-Term Loan was repaid in full on January 8, 2010.

5. 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 common stock dividends and other restricted payments;
- Maintenance of a minimum consolidated current ratio as of the end of each quarter of not less than 1.0 to 1.0, as adjusted;
- Maintenance of a maximum ratio of indebtedness to EBITDA on a rolling four quarter basis, as adjusted, of not greater than 4.0 to 1.0; and
- Maintenance of an interest coverage ratio on a rolling four quarters basis, as adjusted, of EBITDA to interest expense, as of the end of each quarter, to be less than 2.5 to 1.0.

All outstanding amounts owed 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 9 – 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.

On March 6, 2013, Gastar USA, together with the parties thereto, entered into the Waiver and Fifth Amendment to the Credit Agreement, effective as of March 6, 2013 (the "Fifth Amendment"). The Fifth Amendment amended the Revolving Credit Facility, by (i) increasing the permitted term of commodity hedging agreements to five years from three years; (ii)reducing the minimum ratio of current assets to current liabilities that is required from 1.0 to 1.0 to 0.6 to 1.0 for quarters ending from March 31, 2013 through December 31, 2013, and making certain changes in the calculation of current liabilities for such dates to exclude advances from non-operators; (iii) reducing the amount of available commitment that is required immediately prior to and after giving effect to the payment of cash dividends on or the redemption of the Gastar USA Series A Preferred Stock to 5% from 10% of current availability; (iv) increasing the amount of cash dividends on the Gastar USA Series A Preferred Stock that can be paid in the aggregate in each calendar year to $12.1 million from $10.0 million; and (v) modifying the manner in which EBITDA is determined for purposes of the required ratios of total net indebtedness to EBITDA and EBITDA to interest expense with respect to the calendar quarter ending March 31, 2013.

Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. Gastar USA and its lenders may request one additional unscheduled redetermination annually. 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. Gastar USA requested that the May 2012 redetermination be accelerated to March 2012. 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. Gastar USA requested that the November 2012 redetermination be accelerated to September 2012. On October 19, 2012, Gastar USA was notified by its lenders that, effective September 30, 2012, the borrowing base was increased from $100.0 million to $110.0 million. Gastar USA requested one unscheduled borrowing base determination in December 2012. On January 29, 2013, Gastar USA was notified by its lenders that, effective December 31, 2012, the borrowing base was increased from $110.0 million to $125.0 million. At December 31, 2012, the Revolving Credit Facility had a borrowing base of $125.0 million, with $98.0 million of borrowings outstanding and availability of $27.0 million. The next regularly scheduled redetermination is set for May 2013.

At December 31, 2012, Gastar USA was not in compliance with the working capital ratio covenant for 2012 under the Revolving Credit Facility. Gastar USA has been granted a waiver in regards to the working capital ratio covenant at December 31, 2012. At December 31, 2012, Gastar USA was in compliance with all other covenants under the Revolving Credit Facility.

Other Debt

Credit support for the Company's open derivatives at December 31, 2012 is provided under the Revolving Credit Facility through inter-creditor agreements or open accounts of up to $5.0 million.

6. Asset Retirement Obligation

A summary of the activity related to the asset retirement obligation is as follows:

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	For the years ended December 31,		
	2012	2011	2010
	(in thousands)		
Asset retirement obligation, beginning of year	$8,275	$7,249	$5,943
Liabilities incurred during period	271	492	1,023
Liabilities settled during period	(297)	—	—
Accretion expense	388	534	396
Revision in previous estimates and other	553	—	(113)
Deletions related to property disposals	(2,227)	—	—
Asset retirement obligation, end of year	$6,963	$8,275	$7,249

As of December 31, 2012, the current portion of the Company's asset retirement obligation was $358,000 and was recorded in current liabilities on the consolidated balance sheet.

7. 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 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. For the year ended December 31, 2012, management's evaluation of unproved properties resulted in an impairment. Due to a decline in natural gas prices and the suspension of drilling activity in East Texas, the Company reclassified $24.4 million and $63.8 million of unproved properties to proved properties for the years December 31, 2012 and 2011, respectively. As no other fair value measurements are required to be recognized on a non-recurring basis at December 31, 2012, no additional disclosures are provided at December 31, 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. 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. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its

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commodity derivative instruments, 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 and the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments.

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 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 December 31, 2012 and December 31, 2011:

	Fair value as of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$8,901	$—	$—	$8,901
Commodity derivative contracts	—	—	9,168	9,168
Liabilities:				
Commodity derivative contracts	—	—	(2,703)	(2,703)
Total	$8,901	$—	$6,465	$15,366

	Fair value as of December 31, 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 years ended December 31, 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 December 31, 2012 and 2011.

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	For the years ended December 31, 2012	2011
	(in thousands)	
Balance at beginning of period	$15,873	$15,199
Total gains (losses) (realized or unrealized):		
included in earnings	7,236	12,068
included in other comprehensive income	—	—
Purchases	—	—
Issuances	—	—
Settlements (1)	(16,644)	(11,394)
Transfers in and (out) of Level 3	—	—
Balance at end of period	$6,465	$15,873
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 December 31, 2012 and 2011	$(5,566)	$2,336

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

At December 31, 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 December 31, 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.

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 8, "Derivative Instruments and Hedging Activity."

8. 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, condensate, 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 hedge gain (loss), while realized gains and losses related to contract settlements are recognized in natural gas, condensate, oil and NGLs revenues. For the year ended December 31, 2012, the Company reported an unrealized loss of $5.6 million in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments. For the years ended December 31, 2011 and 2010, the Company reported unrealized gains of $2.3 million and $11.2 million, respectively, in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments.

As of December 31, 2012, the following natural gas 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 MMBtu's)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
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 (1)	Protective spread	4,025	853,200	3.70	—	3.00	—	—
2013	Fixed price swap	4,989	1,821,000	3.93	—	—	—	—
2013	Basis - HSC (2)	4,000	1,460,000	(0.11)	—	—	—	—
2014	Short calls	2,500	912,500	—	—	—	—	6.00
2014	Costless three-way collar	10,500	3,832,500	—	3.88	3.00	—	4.53

(1) For the period January to July 2013
(2) East Houston-Katy - Houston Ship Channel

As of December 31, 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) (in Bbls)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2013	Put spread	400	146,000	$—	$100.75	$70.00	$—	$—
2014	Costless three-way collar	200	73,000	—	90.00	70.00	—	106.20

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

As of December 31, 2012, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2013	Fixed price swap	300	109,500	$41.64	$—	$—	$—	$—

As of December 31, 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 December 31, 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 became payable monthly as the hedge production month became the prompt production month. The Company began amortizing the deferred put premium liabilities during July 2010. At December 31, 2012, the Company had settled the outstanding put premium liability. At December 31, 2011, the Company had a current commodity derivative premium payable liability of $4.7 million.

Warrants

Parent reclassified the fair value of its warrants to purchase common stock, which had exercise price reset features, from equity to liability status as if these warrants were treated as a derivative liability since their date of issue in June 2008. The fair value of the warrants to purchase common stock was $0 as of December 31, 2011 and Parent did not recognize any unrealized gains or losses in other income for the change in fair value of these warrants for the year ended December 31, 2011. Parent

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recognized $205,000 in unrealized gains in other income for the change in fair value of these warrants for the year ended December 31, 2010. The warrants expired on December 11, 2011.

Additional Disclosures about Derivative Instruments and Hedging Activities

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

Fair Values of Derivative Instruments
Derivative Assets (Liabilities)

	Balance Sheet Location	Fair Value December 31, 2012	2011
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$7,799	$19,385
Commodity derivative contracts	Other assets	1,369	4,130
Commodity derivative contracts	Current liabilities	(1,399)	(6,479)
Commodity derivative contracts	Long-term liabilities	(1,304)	(1,163)
Total derivatives not designated as hedging instruments		$6,465	$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 Years Ended December 31, 2012	2011	2010
		(in thousands)		
Derivatives not designated as hedging instruments				
Commodity derivative contracts	Natural gas, condensate and oil and NGLs revenues	$12,988	$9,868	$4,137
Commodity derivative contracts	Unrealized hedge gain (loss)	(5,566)	2,336	11,214
Commodity derivative contracts	Interest expense	(186)	(136)	(47)
Warrant derivative	Unrealized warrant derivative gain	—	—	205
Total		$7,236	$12,068	$15,509

9. Capital Stock

Common Shares

The Parent’s articles of incorporation allow Parent to issue an unlimited number of common shares without par value.

Parent Preferred Shares

Pursuant to Parent's amended articles of incorporation, the number of preferred shares which may be issued from time to time and the privileges, restrictions and conditions of such preferred shares when issued will be determined by the Parent Board. At December 31, 2012, there were no preferred shares issued or outstanding.

Other Share Issuances

On December 13, 2010, Parent sold 13,800,000 of its common shares in an underwritten public offering to investors in the U.S. pursuant to Parent’s Registration Statement on Form S-3, which was declared effective by the SEC on April 27, 2007, at a price of $4.00 per share, or $55.2 million before offering costs.

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 Years Ended December 31,	
	2012	2011
Other share issuances:		
Restricted common shares granted	1,916,981	774,567
Restricted common shares vested	505,203	391,627
Stock options exercised	3,000	15,000
Common shares surrendered upon vesting/exercise (1)	141,458	118,324
Common shares forfeited	74,463	251,898

(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. There were 4,442,430 shares available for issuance under the Parent's 2006 Long-Term Stock Incentive Plan at December 31, 2012.

Shares Reserved

At December 31, 2012, Parent had 959,100 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 December 31, 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 year ended December 31, 2012, Gastar USA sold 2,586,711 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $49.3 million, resulting in 3,951,254 total shares of Series A Preferred Stock issued for net proceeds of $76.6 million at December 31, 2012. From January 1, 2013 to March 7, 2013, Gastar USA sold no additional shares of Series A Preferred.

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The Series A Preferred Stock is subordinated to all of Gastar USA's existing and future debt and all future capital stock 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 years ended December 31, 2012 and 2011, Gastar USA paid dividends of $7.1 million and $1.0 million, respectively.

10. Equity Compensation Plans

Share-Based Compensation Plan

At the annual meeting of shareholders held June 4, 2009, Parent's shareholders approved the first amendment to Parent's 2006 Long-Term Stock Incentive Plan (the "2006 Plan") that, effective as of April 1, 2009, merged the Parent's Stock Option Plan (the "2002 Stock Option Plan") with and into the 2006 Plan so that all outstanding equity awards and all future equity awards to be made to employees, officers and directors of the Company would be under the 2006 Plan. The merging of the 2002 Stock Option Plan with and into the 2006 Plan resulted in the cessation of the existence of the 2002 Stock Option Plan and the transfer of all common shares previously reserved and available for issuance under the 2002 Stock Option Plan, including any common shares subject to outstanding stock option awards previously granted under the 2002 Stock Option Plan prior to the effective date of the amendments, to the common shares reserved under the 2006 Plan.

Additionally, the amended 2006 Plan (i) provided that the Compensation Committee of the Parent, at its discretion, may provide, in an award agreement, that an individual who is granted an award under the 2006 Plan (a "participant") may elect to have common shares withheld from or netted against the total number of common shares otherwise issuable to such participant pursuant to his award in order to pay the exercise or purchase price of such award and/or to satisfy all employer tax withholding obligations with respect to the participant's award under the 2006 Plan, (ii) clarified that common shares issuable under the 2006 Plan and forfeited back to the 2006 Plan will be deemed not to have been issued under the 2006 Plan and will again be available for the grant of an award under the 2006 Plan, (iii) provided that common shares withheld from or netted against an award granted under the 2006 Plan for payment of (a) the exercise or purchase price of an award and (b) all applicable employer tax withholding obligations associated with an award will be deemed not to have been issued under the 2006 Plan and will again be available for the grant of an award under the 2006 Plan, (iv) provided that the maximum number of common shares that may be subject to stock options, bonus stock awards and stock appreciation rights granted to any one individual during any calendar year may not exceed 200,000 common shares (subject to adjustment pursuant to Section 11(a) of the 2006 Plan) and (v) provide that the definition of "performance criteria" in the 2006 Plan include a criteria relating to the growth of proved natural gas and oil reserves of the Company.

At the annual meeting of shareholders held June 7, 2012, Parent's shareholders approved the Second Amendment to the 2006 Plan that, effective June 3, 2012, increased the total number of shares that may be delivered pursuant to the

2006 Plan by 5,000,000 shares and provided that, in any calendar year, any one employee may not be granted more than 1,000,000 shares under all awards granted to such employee.

The 2006 Plan authorizes Parent's Board of Directors (the "Parent Board") to issue stock options, stock appreciation rights, bonus stock awards and any other type of award, which are consistent with the 2006 Plan's purposes to directors, officers and employees of the Company and its subsidiaries covering a maximum of 11,000,000 million common shares. The contractual lives and vesting periods for grants are determined by the Parent Board at the time a grant is awarded. Recent stock option grants have an expiration of ten years. The vesting schedule for stock option grants has varied from two years to four years but generally has been over a four-year period vesting at 25% per year beginning on the first anniversary date of the grant. Stock options granted pursuant to the 2006 Plan have exercise prices determined by the Parent Board, but an exercise price cannot be less than the market price on the date immediately prior to the date of grant as reported by any stock exchange on which Parent’s common shares are listed. The vesting period for recent restricted common stock grants has been from two to four years, but generally has been over three years, vesting annually from the date of grant in equal proportions.

At December 31, 2012, 4,442,430 common shares of Parent were available for future stock-based compensation grants under the 2006 Plan. All common shares issued upon the exercise of stock option grants or vesting of restricted share grants are authorized, issued by Parent and are fully paid and non-assessable.

Determining Fair Value of Stock Options

In determining the fair value of stock option grants, the Company utilized the following assumptions:

Valuation and Amortization Method. The Company estimates the fair value of stock option awards using the Black-Scholes-Merton valuation model. The fair value of all awards is expensed using the “graded-vesting method.”

Expected Life. The expected life of stock options granted represents the period of time that stock options are expected, on average, to be outstanding. The Company determined the expected life to be 6.25 years, based on historical information, for all stock options issued with four-year vesting periods and ten-year grant expirations.

Expected Volatility. Using the Black-Scholes-Merton valuation model, the Company estimates the volatility of Parent's common shares at the beginning of the quarter in which the stock option is granted. The volatility is based on weighted average historical movements of Parent’s common share price on the NYSE MKT LLC over a period that approximates the expected life.

Risk-Free Interest Rate. The Company utilizes a risk-free interest rate equal to the rate of U.S. Treasury zero-coupon issues as of the date of grant with a term equivalent to the stock option’s expected life.

Expected Dividend Yield. Parent has not paid any cash dividends on its common shares and does not anticipate paying any cash dividends in the foreseeable future. Consequently, a dividend yield of zero is utilized in the Black-Scholes-Merton valuation model.

Expected Forfeitures. Forfeitures of unvested stock options and restricted common shares are calculated at the beginning of the year as a percentage of all stock option and restricted common share grants. For 2012, 2011 and 2010, the Company used forfeiture rates in determining compensation expense of 15.5%, 8.5% and 9.8%, respectively.

The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model. The table below summarizes the number of stock options granted and the fair value assumptions for the stock options granted for the period indicated:

	For the Years Ended December 31,		
	2012	2011	2010
Stock options granted during the period	—	—	80,000
Expected life (in years)	—	—	6.25
Expected volatility	— %	— %	68.1 %
Risk-free interest rate	— %	— %	2.33% - 2.94%
Expected dividend rate	— %	— %	— %

The weighted average grant date fair value of stock options granted and the intrinsic value of stock options exercised are shown below for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands, except per share data)		
Weighted average grant date fair value per stock option granted	$—	$—	$2.66
Intrinsic value of stock options exercised (1)	$2	$18	$7

Grant date fair value of stock options vested	$117	$282	$739

(1) Intrinsic value of stock options is calculated using the difference between the common share price on the date of exercise and the exercise price times the number of stock options exercised.

Stock Option Activity

The following tables summarize certain information related to outstanding stock options under the 2006 Plan as of and for the year ended December 31, 2012:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2011	983,900	$ 11.26		
Granted	—	—		
Exercised	(3,000)	2.60		
Canceled/Expired	—	—		
Forfeited	(21,800)	10.57		
Outstanding at December 31, 2012	959,100	$ 11.31		
Options vested and exercisable at December 31, 2012	878,375	$ 12.04	4.11	$—

	Shares	Weighted Average Fair Value per Share	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding non-vested options at December 31, 2011	146,150	$ 1.97			
Granted	—	—			
Vested	(63,075)	1.86			
Forfeited	(2,350)	1.55			
Outstanding non-vested options at December 31, 2012	80,725	$ 2.07	$ 3.38	6.72	$0

Unrecognized expense as of December 31, 2012 for all outstanding options is $24,000 and will be recognized over a weighted average period of 0.7 years.

Restricted Share Activity

The following table summarizes information related to restricted shares at December 31, 2012:

	Shares	Weighted Average Fair Value per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding non-vested restricted shares at December 31, 2011	1,401,331	$4.47		
Granted	1,916,981	2.09		
Vested	(505,203)	4.93		
Forfeited	(52,663)	3.48		
Outstanding non-vested restricted shares at December 31, 2012	2,760,446	$2.75	8.87	$3,340

The following table summarizes the weighted average grant date fair value of restricted shares granted and the total fair value of shares vested for the periods indicated:

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	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands, except per share data)		
Weighted average grant date fair value per restricted share	$2.09	$4.15	$4.84
Total fair value of restricted shares vested	$2,492	$2,436	$2,121

Unrecognized compensation expense as of December 31, 2012 for all outstanding restricted share awards is $2.8 million and will be recognized over a weighted average period of 1.9 years.

Stock-Based Compensation Expense

For the years ended December 31, 2012, 2011 and 2010, the Company recorded stock-based compensation expense for stock options and restricted shares granted using the fair-value method of $3.3 million, $2.6 million and $2.8 million, respectively. All stock-based compensation costs were expensed and not tax affected, as the Company currently records no U.S. income tax expense.

As of December 31, 2012, the Company had approximately $2.8 million of total unrecognized compensation cost related to unvested stock options and restricted shares, which is expected to be amortized over the following periods:

	Amount
	(in thousands)
2013	$1,860
2014	858
2015	63
2016	1
Total	$2,782

11. Interest Expense

The following tables summarize the components of the Company's interest expense for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Interest expense:			
Cash and accrued	$1,992	$682	$500
Amortization of deferred financing costs	224	249	283
Capitalized interest	(1,946)	(818)	(633)
Total interest expense	$270	$113	$150

The following tables summarize the components of Gastar USA's interest expense for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Interest expense:			
Cash and accrued	$1,993	$681	$483
Amortization of deferred financing costs and debt discount	224	248	247
Capitalized interest	(1,946)	(817)	(633)
Total interest expense	$271	$112	$97

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12. 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 December 31, 2012, Chesapeake owned 6,781,768 of Parent's common shares, or 10.2% of the Parent's outstanding common shares.
13. Income Taxes
The following table summarizes the components of the Company's income (loss) before income taxes for the periods indicated:

	For the Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
United States	$(152,322)	$285	$(13,916)
Foreign	(1,469)	(1,025)	652
Total income (loss) before income taxes	$(153,791)	$(740)	$(13,264)

The Company's income tax expense (benefit) consists of the following:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Current:			
Federal	$—	$—	$—
State	—	—	(12)
Foreign	—	—	(792)
Provision for income taxes	$—	$—	$(804)

The following table provides a reconciliation of the Company's effective tax rate from the U.S. 35% statutory rate for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Expected income tax provision (benefit) at statutory rate	$(53,827)	$(259)	$(4,642)
State tax, tax effected	(2,562)	—	(8)
Non-deductible stock-based compensation expense	560	441	(4,311)
Deferred tax effect of Canadian tax rate changes and other	(125)	(103)	(1,632)
Foreign tax credit adjustment	—	—	(1,366)
Australian tax rate differences and adjustment	—	—	(1,337)
Other	15	10	(95)
Other changes in valuation allowance	55,939	(89)	12,587
Actual income tax provision	$—	$—	$(804)

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The components of the Company's U.S. deferred taxes are as follows:

	As of December 31,	
	2012	2011
	(in thousands)	
Deferred tax asset (liability):		
Capital assets	$(22,668)	$(24,988)
Net operating loss carry forwards	93,339	40,360
Foreign tax credit carry forwards	50,681	50,681
Valuation allowance	(121,352)	(66,053)
Net deferred tax asset	$—	$—

The Company utilized its U.S. net operating loss carry forwards in 2009 due to the U.S. gain recognition on the sale of the Australian Assets. The Company generated $121.3 million, $87.5 million and $45.5 million of net operating loss for the years ending December 31, 2012, 2011 and 2010, respectively, which, if not utilized, will expire beginning in 2030. For U.S. federal income tax purposes, as of December 31, 2012, the Company has foreign tax credit carry forwards of $50.7 million, which, if not utilized, will expire in 2019. The utilization of the net operating loss carry forward and the foreign tax credit carry forward are dependent on the Company generating future taxable income and U.S. tax liability, as well as other factors.

Parent has the following approximate undeducted Canadian tax pools:

	As of December 31,	
	2012	2011
	(in thousands)	
Canadian and foreign exploration and development expense	$2,597	$1,977
Undeducted share issuance costs	$1,239	$1,908
Undeducted non-capital and capital loss carry forwards	$73,522	$70,904

For Canadian income tax purposes, Parent has net operating loss carry forwards, which if not utilized, began to expire in 2014 through 2027.

The components of Parent's Canadian deferred tax assets are as follows:

	As of December 31,	
	2012	2011
	(in thousands)	
Deferred tax asset:		
Capital assets	$649	$497
Share issuance costs	310	477
Tax loss carry forwards	18,381	17,726
Valuation allowance	(19,340)	(18,700)
Net deferred tax asset	$—	$—

Current authoritative guidance requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For a tax position meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. At December 31, 2012, the Company did not have any unrecognized tax benefits that, if recognized, would affect the effective tax rate.

The Company is subject to examination of income tax filings in the U.S. and various state jurisdictions for the periods 2010 and forward and the foreign jurisdictions of Canada and Australia for the tax periods 2000 and forward due to the Company's continued loss position in such jurisdictions. The Company was subjected to an audit by the Internal Revenue Service for the taxable period ended December 31, 2009. The audit began in April 2011 and was completed in January 2012 and did not result in any material adjustments or cash payments.

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Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of general and administrative expense in the consolidated statement of operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

14. Earnings per Share

In accordance with the provisions of current authoritative guidance, basic earnings or loss per share is computed on the basis of the weighted average number of common shares outstanding during the periods. Diluted earnings or loss per share is computed based upon the weighted average number of common shares outstanding plus the assumed issuance of common shares for all potentially dilutive securities. Diluted amounts are not included in the computation of diluted loss per share, as such would be anti-dilutive. For the periods presented below, there were no incremental shares from unvested restricted shares and outstanding stock options.

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands, except per share and share data)		
Net loss attributable to Gastar Exploration Ltd.	$(160,868)	$(1,764)	$(12,460)
Weighted average common shares outstanding - basic	63,538,362	63,003,579	49,813,617
Weighted average common shares outstanding - diluted	63,538,362	63,003,579	49,813,617
Net loss per common share attributable to Gastar Exploration Ltd. Common Shareholders:			
Basic	$(2.53)	$(0.03)	$(0.25)
Diluted	$(2.53)	$(0.03)	$(0.25)
Common shares excluded from denominator as anti-dilutive:			
Unvested restricted shares	1,831,435	641,606	949,314
Stock options	936,967	810,235	100,078
Warrants	—	—	2,000,000
Total	2,768,402	1,451,841	3,049,392

15. Commitments and Contingencies

Contractual Obligations

Gastar USA leases its office facilities and certain office equipment under non-cancelable operating lease agreements terminating in August 2016. For the years ended December 31, 2012, 2011 and 2010, office lease expense totaled approximately $377,000, $160,000 and $211,000, respectively.

As of December 31, 2012, the Company's aggregate future minimum annual rental commitments under the non-cancelable leases for the next four years are as follows:

2013	$534
2014	541
2015	460
2016	309
	$1,844

Litigation

Chesapeake Exploration L.L.C. ("Chesapeake Exploration") and Chesapeake Energy Corp. ("Chesapeake Energy") v. Gastar Exploration Ltd., Gastar Exploration Texas, LP, and Gastar Exploration Texas, LLC (No. 4:12-cv-2922), United States District Court for the Southern District of Texas, Houston Division. This lawsuit, filed on October 1, 2012, re-asserts the same claims for rescission of the November 2005 Agreements (as defined below) and for recovery of amounts paid under those agreements that Chesapeake Exploration and Chesapeake Energy (collectively, “Chesapeake”) previously asserted in the cross-action filed against the Company in the Navasota litigation described below, as previously disclosed in the Company's filings. In March 2011, Chesapeake dismissed its cross-claims against the Company in the Navasota litigation, without prejudice to their re-filing. In this new lawsuit, Chesapeake re-asserts those claims, seeking rescission of (a) a Purchase and Sale and Exploration and Development Agreement between the Company and Chesapeake Exploration Limited Partnership (the “Purchase and Sale Agreement”), relating to properties in the Hilltop Prospect in Texas, (b) an Exploration and Development Agreement between the Company and Chesapeake Exploration Limited Partnership, (c) a Common Share Purchase Agreement between the Company and Chesapeake Energy, and (d) a Registration Rights Agreement between the Company and Chesapeake Energy, all effective as of November 4, 2005 (collectively, “the November 2005 Agreements”), based on an alleged “mutual mistake” and alleged failure of consideration. Chesapeake alleges that the parties to the November 2005 Agreements believed that the Gastar defendants had the right to convey to Chesapeake Exploration the properties that were the subject of the Purchase and Sale Agreement, notwithstanding the exercise by Navasota Resources LP (“Navasota”) of a preferential right to purchase the interest in the Hilltop Prospect properties. The dispute over the validity of Navasota's exercise of its preferential right to purchase was the subject of litigation filed by Navasota prior to the execution of the November 2005 Agreements. Chesapeake claims that the Texas Court of Appeals' subsequent ruling in that litigation upholding the validity of Navasota's exercise of the preferential right to purchase establishes that there was a mutual mistake of fact and a failure of consideration with regard to the November 2005 Agreements. In the alternative, Chesapeake claims that the Gastar defendants have been unjustly enriched at the expense of Chesapeake by the funds paid by Chesapeake to the Gastar defendants. In their complaint filed in the lawsuit, Chesapeake offers to return Parent's common shares purchased pursuant to the Common Stock Purchase Agreement, and seeks restitution from the Gastar defendants of the net amount of approximately $101.4 million, which includes the $76.0 million that Chesapeake Energy paid for Parent's common shares (now 5,430,329 shares after a 1:5 stock split) that Chesapeake Energy purchased in 2005 and now seeks to return. In a motion to compel arbitration filed by Chesapeake on October 24, 2012, Chesapeake has asked the court to order arbitration of the claims asserted in the complaint pursuant to an arbitration clause in the Common Share Purchase Agreement.

The Gastar defendants contend that the claims fail as a matter of law and intend to vigorously defend the lawsuit. Specifically, the Gastar defendants contend that all facts relating to the Navasota claim were fully known to the parties at the time of execution of the November 2005 Agreements, and the parties expressly agreed in the Purchase and Sale Agreement that Chesapeake Exploration would take title to the properties subject to Navasota's claim and would convey the properties to Navasota in the event Navasota prevailed in the litigation, precluding Chesapeake's claims for rescission of the November 2005 Agreements. For the same reasons, the Gastar defendants also contend that Chesapeake received all of the consideration that the November 2005 Agreements called for and that there was no failure of consideration. With regard to Chesapeake's alternative unjust enrichment claim, the Gastar defendants contend that it is barred by the two-year statute of limitations and that in any event, it fails for a variety of reasons, including the fact that the parties' agreements address the subject matter of the dispute (precluding a claim for unjust enrichment) and the fact that the Gastar defendants were not unjustly enriched by Chesapeake Exploration's payment of the share of costs attributable to an interest in the properties that was not owned by the Gastar defendants. The Gastar defendants also contend that Chesapeake's claims are not subject to arbitration and that the claims should be resolved on the merits by the federal court in which Chesapeake filed the lawsuit.

The Gastar Defendants have filed a response to the motion to compel arbitration and also have filed a motion to dismiss all claims asserted in the case. All of the briefing is complete on Chesapeake's motion to compel arbitration, and the parties are awaiting a decision from the Court on that motion. The deadline for Chesapeake to file a response to the motion to dismiss has been deferred until after the Court rules on the motion to compel arbitration.

No specific loss or range of loss can be estimated as at least reasonably possible within the amounts claimed by Chesapeake. As of December 31, 2012, no accrual has been recorded as management believes a future adverse outcome is not probable.

Navasota Resources L.P. 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. 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.

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 Agreement, between the Company and Chesapeake, Chesapeake acknowledged the existence of the Navasota lawsuit and claims and further agreed that if Navasota were to prevail on its claims, that Chesapeake would convey the affected interests it purchased from the Company to Navasota upon receipt of the purchase price and/or other consideration paid by Navasota. Therefore, the Company believes that Navasota's exercise of its rights of specific performance should impact only Chesapeake's assigned leasehold interests. However, in December 2008, Chesapeake stated to the Company that if the Texas Supreme Court were not to reverse the decision of the Tenth Court of Appeals, Chesapeake would seek rescission of the 2005 Transaction and restitution of consideration paid, indicating that Chesapeake might assert such rescission and restitution as to the Purchase and Sale Agreement and the Common Share Purchase Agreement. 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 settlement of the Navasota lawsuit 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.

Commitments

In March 2008, Gastar USA entered into formal agreements with ETC Texas Pipeline, Ltd. (“ETC”) for the gathering, treating, purchase and transportation of Gastar USA's natural gas production from the Hilltop area of East Texas (the “ETC Contract”). The ETC Contract was effective September 1, 2007 and has a term of 10 years. ETC currently provides Gastar USA 50.0 MMcf per day of treating capacity and 150.0 MMcf per day of transportation capacity of production from Gastar USA’s wells, located in Leon and Robertson Counties, Texas.

On November 16, 2009, concurrent with Gastar USA’s sale of its Hilltop Gathering System, Gastar Texas entered into the Hilltop Gathering Agreement effective November 1, 2009, with Hilltop Resort for an initial term of 15 years. The Hilltop Gathering Agreement covers delivery of Gastar USA’s gross production of natural gas in the Hilltop area of East Texas to certain delivery points provided under the ETC Contract, as well as additional delivery points that, from time to time, may be added. Gastar USA is also obligated to connect new wells that it drills within the area covered by the Hilltop Gathering Agreement to the Hilltop Gathering System. The Hilltop Gathering Agreement provides for a minimum quarterly gathering gross production volume of 50.0 MMcf per day (35.0 MMcf per day net to Gastar USA) times the number of days in the quarter for five years from the effective date of November 1, 2009. If quarterly production is less than the minimum quarterly requirement, the gathering fee is payable on such deficit. If excess quarterly production exists, such excess is carried forward to be used to offset any future deficit quarters. The gathering fee on the initial gross 25.0 Bcf of production is $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reaches 300.0 Bcf. For the year ended December 31, 2012, Gastar USA paid $2.0 million to Hilltop Resort as a result of actual production volumes being less than minimum contractual volume requirements. There is no assurance that Gastar USA will meet its minimum quarterly requirements in the future.

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC (“SEI”) with respect to our Marshall County, West Virginia production. The initial term of the gas purchase agreement is five years with the option to extend the term of the gas purchase agreement for an additional five year period. Our Marshall County, West Virginia production is dedicated to SEI for the term of the gas purchase agreement. SEI will purchase all hydrocarbon production, including all natural gas, condensate and natural gas liquids. SEI has an agreement to utilize the Williams Ohio Valley Midstream LLC (“Williams") midstream facilities (formerly owned by Caiman Energy Midstream, LLC), including its 120.0 MMcf per day Fort Beeler processing plant located in Marshall County, West Virginia for transporting and processing. In order to secure access to the Williams facilities, we, Atinum and SEI dedicated all hydrocarbons purchased and produced in Marshall County, West Virginia for a term of ten years.

Restoration, Removal and Environmental Liabilities

The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are initially measured at a fair value and are recognized in the consolidated financial statements as the present value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement obligation cost are recognized in the results of operations. Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from the Company's cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any quarter or year. At December 31, 2012, the Company had total liabilities of $7.0 million related to asset retirement obligations of which $358,000 is recorded as short-term liabilities and $6.6 million is recorded as long-term liabilities. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. See Note 6, "Asset Retirement Obligation."

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Indemnifications

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

Employment Agreements

The Company entered into employment agreements with its Chief Executive Officer and its Chief Financial Officer, effective February 24, 2005 (as amended July 25, 2008 and February 3, 2011) and May 17, 2005 (as amended July 25, 2008 and April 10, 2012), respectively. The agreements set forth, among other things, annual compensation, and adjustments thereto, bonus payments, fringe benefits, termination and severance provisions. The agreements renew annually; however, they may be terminated at any time with or without cause.

The Company also has entered into agreements with these executives, who are acting at the Company's request to be officers of the Company, to indemnify them to the fullest extent permitted by law against any and all damages, liabilities, costs, charges or expenses suffered by or incurred by the individuals as a result of their service. The nature of the indemnification agreements prevents the Company from making a reasonable estimate of the maximum potential amount it could be required to pay to the beneficiary of such indemnification agreements.

16. Concentration of Risk and Significant Customers

The following table provides information regarding the approximate percentages of the Company's natural gas, condensate and oil and NGLs revenues excluding realized hedge impact by area derived from production from producing wells for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
Marcellus Shale and Other Appalachia	72 %	15 %	2 %
Hilltop Area, East Texas	27 %	79 %	88 %
Powder River Basin (1)	1 %	6 %	9 %

(1) The Company's working interest in the Powder River Basin was assigned to the operator on May 3, 2012 effective January 1, 2012.

The following table provides information regarding our significant customers and the percentages of natural gas, condensate and oil and NGLs revenues, excluding realized hedge impact, which they represented for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
SEI	47 %	8 %	— %
ETC	24 %	69 %	86 %
Clearfield Appalachian	14 %	— %	— %
Plains Marketing LP	2 %	10 %	2 %

SEI and Clearfield Appalachian purchase the majority of the Company's Marcellus Shale and Other Appalachia production. ETC treats, transports and purchases substantially all of the Company's East Texas natural gas production. Plains Marketing LP purchases substantially all of the Company's East Texas oil production. There are limited natural gas purchase and transportation alternatives currently available in the Hilltop area of East Texas and in Appalachia. If SEI, ETC, Clearfield Appalachian, or Plains were to cease purchasing and transporting the Company's natural gas, condensate and oil and NGLs production and the Company was unable to obtain timely access to existing or future facilities on acceptable terms, or in the event of any significant change affecting these facilities, including delays in the commencement of operations of any new pipelines or the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise, the Company's ability to conduct normal operations would be restricted. However, the Company believes that the

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loss of SEI, ETC, Clearfield Appalachian, or Plains would not have a long-term material adverse impact on the Company’s financial position or results of operations, as there are other purchasers operating in the areas.

17. Statement of Cash Flows – Supplemental Information

The following is a summary of the Company's supplemental cash paid and non-cash transactions disclosed in the notes to the consolidated financial statements:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash paid for interest	$1,985	$676	$497
Cash paid for taxes	—	—	616
Non-cash transactions:			
Term deposit surrendered for accrued taxes	$—	$—	$70,446
Capital expenditures excluded from accounts payable and accrued drilling costs	4,666	4,600	2,725
Capital expenditures excluded from accounts receivable	(929)	—	—
Capital expenditures excluded from prepaid expenses	—	48	—
Asset retirement obligation included in natural gas and oil properties	1,164	492	910
Asset retirement obligation assigned to operator	(2,227)	—	—
Application of advances to operators	7,441	6,529	246
Other	(36)	—	—

The following is a summary of Gastar USA's supplemental cash paid and non-cash transactions disclosed in the notes to the consolidated financial statements:

	For the Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash paid for interest	$1,986	$675	$386
Cash paid for taxes	—	—	414
Non-cash transactions:			
Term deposit surrendered for accrued taxes	$—	$—	$70,446
Capital expenditures excluded from accounts payable and accrued costs	4,666	4,600	2,725
Capital expenditures excluded from accounts receivable	(929)	—	—
Capital expenditures excluded from prepaid expenses	—	48	—
Asset retirement obligation included in natural gas and oil properties	1,164	492	910
Asset retirement obligation assigned to operator	(2,227)	—	—
Application of advances to operators	7,441	6,529	246
Due to (from) Parent - transfer to equity, net	5,295	2,612	(30,773)
Other	(36)	—	—

18. Quarterly Consolidated Financial Data – Unaudited

The following tables summarize the Company’s results of operations by quarter for the years ended December 31, 2012 and 2011:

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	2012 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$9,154	$13,921	$9,443	$17,422
Income (loss) from operations (1)	(5,052)	(72,237)	(81,443)	5,245
Income (loss) before provision for income taxes	(5,074)	(72,308)	(81,473)	5,064
Net income (loss)	(5,074)	(72,308)	(81,473)	5,064
Dividend on preferred stock attributable to non-controlling interest	1,236	1,727	1,984	2,130
Net income (loss) attributable to Gastar Exploration Ltd.	(6,310)	(74,035)	(83,457)	2,934
Net income (loss) per common share attributable to Gastar Exploration Ltd. Common Shareholders:				
Basic	$(0.10)	$(1.17)	$(1.31)	$0.05
Diluted	$(0.10)	$(1.17)	$(1.31)	$0.05
Weighted average common shares outstanding:				
Basic	63,336,437	63,541,739	63,601,645	63,669,744
Diluted	63,336,437	63,541,739	63,601,645	63,678,597

(1) Loss from operations for the three months ended June 30, 2012 and September 30, 2012 includes a quarterly ceiling test impairment charge of $72.7 million and $78.1 million, respectively.

	2011 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$8,129	$9,016	$12,012	$11,078
Income (loss) from operations (1)	(1,907)	184	1,432	(340)
Income (loss) before provision for income taxes	(1,935)	157	1,402	(364)
Net income (loss)	(1,935)	157	1,402	(364)
Dividend on preferred stock attributable to non-controlling interest	—	31	388	605
Net income (loss) attributable to Gastar Exploration Ltd.	(1,935)	126	1,014	(969)
Net income (loss) per common share attributable to Gastar Exploration Ltd. Common Shareholders:				
Basic	$(0.03)	$0.00	$0.02	$(0.02)
Diluted	$(0.03)	$0.00	$0.02	$(0.02)
Weighted average common shares outstanding:				
Basic	63,024,481	63,134,109	63,238,069	63,305,419
Diluted	63,024,481	63,723,093	63,842,098	63,305,419

(1) Loss from operations for the three months ended December 31, 2011 includes an additional $1.1 million of DD&A expense as a result of the reclassification of $63.8 million of unproved properties to proved properties at December 31, 2011 due to a decline in natural gas prices and the planned reduction in drilling activity for 2012 in East Texas.

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The following tables summarize Gastar USA's results of operations by quarter for the years ended December 31, 2012 and 2011:

	2012 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$9,154	$13,921	$9,443	$17,422
Income (loss) from operations (1)	(4,662)	(71,980)	(80,973)	5,566
Income (loss) before provision for income taxes	(4,686)	(72,011)	(81,007)	5,382
Net income (loss)	(4,686)	(72,011)	(81,007)	5,382
Dividend on preferred stock	1,236	1,727	1,984	2,130
Net income (loss) attributable to common stockholder	(5,922)	(73,738)	(82,991)	3,252

(1) Loss from operations for the three months ended June 30, 2012 and September 30, 2012 includes a quarterly ceiling test impairment charge of $72.7 million and $78.1 million, respectively.

	2011 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$8,129	$9,016	$12,012	$11,078
Income (loss) from operations (1)	(1,726)	367	1,653	7
Income (loss) before provision for income taxes	(1,662)	341	1,623	(17)
Net income (loss)	(1,662)	341	1,623	(17)
Dividend on preferred stock	—	31	388	605
Net income (loss) attributable to common stockholder	(1,662)	310	1,235	(622)

(1) Loss from operations for the three months ended December 31, 2011 includes an additional $1.1 million of DD&A expense as a result of the reclassification of $63.8 million of unproved properties to proved properties at December 31, 2011 due to a decline in natural gas prices and the planned reduction in drilling activity for 2012 in East Texas.

19. Supplemental Oil and Gas Disclosures – Unaudited

Capitalized Costs Relating Oil and Producing Activities

The following table presents the Company's aggregate capitalized costs relating to natural gas and oil producing activities for the periods indicated:

	As of December 31, 2012	2011	2010
	(in thousands)		
Proved properties:			
United States	$671,193	$514,357	$345,042
Total proved properties	671,193	514,357	345,042
Unproved properties:			
United States	67,892	78,302	162,230
Total unproved properties	67,892	78,302	162,230
Total natural gas and oil properties	739,085	592,659	507,272
Less:			
Impairment of proved natural gas and oil properties			
United States	(337,939)	(187,152)	(187,152)
Accumulated depreciation, depletion and amortization	(145,631)	(120,436)	(105,447)
Net capitalized costs	$255,515	$285,071	$214,673

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Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include related asset retirement costs of approximately $4.8 million, $5.8 million and $5.4 million at December 31, 2012, 2011 and 2010, respectively.

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

The following table sets forth costs incurred related to the Company's natural gas and oil activities in the U.S. for the periods indicated:

	For the years ended December 31,		
	2012	2011	2010
	(in thousands)		
Unproved property acquisition	$25,676	$19,552	$54,799
Unproved property divestment	—	—	(25,289)
Proved property divestment	(1,169)	—	(4,872)
Exploration	10,041	47,668	12,648
Development	111,878	18,167	24,166
Total costs incurred	$146,426	$85,387	$61,452

Results of Operations for Oil and Gas Producing Activities

The following table sets forth the Company's results of operations for oil and gas producing activities for the periods indicated:

	For the Year Ended December 31,		
	2012	2011	2010
	(in thousands, except per Mcfe data)		
Natural gas, condensate and oil and NGLs sales, including unrealized hedge	$49,940	$40,235	$42,768
Production expenses	(13,408)	(13,751)	(11,703)
Impairment of natural gas and oil properties	(150,787)	—	—
Depreciation, depletion and amortization	(25,195)	(14,989)	(9,131)
Results of producing activities	$(139,450)	$11,495	$21,934
Depreciation, depletion and amortization per Mcfe	$1.90	$1.95	$1.19

The results of producing activities exclude interest charges and general corporate expenses and represent U.S. activities only.

In accordance with current authoritative guidance, estimates of the Company's proved reserves and future net revenues are made using benchmark prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil and were used in the Company's reserve valuation as of December 31, 2012 and 2011. The following table provides the key natural gas and oil prices used as of the periods indicated to calculate reserves:

	As of December 31,	
	2012	2011
Natural gas (per MMBtu):		
Henry Hub	$2.76	$4.12
Katy Hub	$2.77	$4.07
CIG	$—	$3.93
Columbia Gas Appalachia	$2.77	$4.20
Oil (per Bbl):		
per NSAI - WTI posting	$91.21	$92.71
per Wright - WTI spot	$94.71	96.19

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These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve report but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials. Estimated quantities of proved reserves and future net revenues are affected by natural gas prices and oil prices, which have fluctuated significantly in recent years.

Net Proved and Proved Developed Reserve Summary

Reserve Estimation. The reserve information presented below is based on estimates of net proved reserves as of December 31, 2012, 2011, and 2010 that were prepared by NSAI for the Hilltop Area of East Texas and the Powder River Basin of Wyoming and Montana and for Appalachia as of December 31, 2010. The Company's working interest in the Powder River Basin of Wyoming and Montana was assigned to the operator on May 3, 2012, effective January 1, 2012. Reserve information for Appalachia as of December 31, 2012 and 2011 is based on estimates of net proved reserves prepared by Wright. A copy of NSAI and Wright’s summary reserve reports are included as Exhibit 99.1 and 99.2, respectively, to this Form 10-K. Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and governmental regulations (i.e., prices and costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. The Company’s proved developed and proved undeveloped reserves are located only in the U.S.

The following tables set forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2012, 2011 and 2010:

Change in Proved Reserves	Natural Gas (MMcf) (1)	NGLs (MBbl) (2)	Condensate and Oil (MBbl) (2)	MMcfe (1) Equivalents (3)
Proved reserves as of December 31, 2009	48,532	—	67	48,934
2010 Activity:				
Extensions and discoveries	5,639	—	67	6,039
Revisions of previous estimates	2,837	—	(44)	2,576
Production	(7,593)	—	(10)	(7,654)
Purchases in place	1,527	—	6	1,565
Sales in place	(1,050)	—	(25)	(1,200)
Proved reserves as of December 31, 2010	49,892	—	61	50,260
2011 Activity:				
Extensions and discoveries	56,364	2,767	1,945	84,634
Revisions of previous estimates (4)	(7,286)	11	(45)	(7,494)
Production	(7,318)	(21)	(40)	(7,684)
Proved reserves as of December 31, 2011	91,652	2,757	1,921	119,716
2012 Activity:				
Extensions and discoveries	57,835	2,783	2,439	89,169
Revisions of previous estimates	(6,518)	(348)	(796)	(13,375)
Production	(10,564)	(270)	(177)	(13,247)
Purchases in place	—	—	7	41
Sales in place	(1,395)	—	—	(1,395)
Proved reserves as of December 31, 2012	131,010	4,922	3,394	180,909

(1) Million cubic feet or million cubic feet equivalent, as applicable
(2) Thousand barrels

(3) Condensate, oil and NGLs volumes have been converted to equivalent natural gas volumes using a conversion factor of six cubic feet of natural gas to one barrel of condensate, oil or NGLs.

(4) The 2011 downward revision of previous estimates of natural gas is primarily attributed to the decision to forgo an East Texas PUD location due to low natural gas prices which would have resulted in drilling beyond the five-year maximum carry period.

Proved Developed and Undeveloped Reserves	Natural Gas (MMcf) (1)	NGLs (MBbl) (2)	Condensate and Oil (MBbl) (2)	MMcfe (1) Equivalents (3)
December 31, 2010				
Proved developed reserves	41,572	—	45	41,843
Proved undeveloped reserves	8,320	—	16	8,417
Total	49,892	—	61	50,260
December 31, 2011				
Proved developed reserves	65,061	1,339	904	78,518
Proved undeveloped reserves	26,591	1,418	1,017	41,198
Total	91,652	2,757	1,921	119,716
December 31, 2012				
Proved developed reserves	95,602	3,216	1,959	126,653
Proved undeveloped reserves	35,408	1,706	1,435	54,256
Total	131,010	4,922	3,394	180,909

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(1) Million cubic feet or million cubic feet equivalent, as applicable

(2) Thousand barrels

(3) Condensate, oil and NGLs volumes have been converted to equivalent natural gas volumes using a conversion factor of six cubic feet of natural gas to one barrel of condensate, oil or NGLs.

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

Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes that such information is essential for a proper understanding and assessment of the data presented.

For the years ended December 31, 2012, 2011 and 2010 future cash inflows were computed using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil, adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials, relating to the Company's proved reserves to the year-end quantities of those reserves. For the periods indicated, the following natural gas and oil prices were used in the calculations:

	For the Years Ended December 31,		
	2012	2011	2010
Natural gas, per MMBtu			
Henry Hub	$2.76	$4.12	$4.38
Katy Hub	$2.77	$4.07	$4.32
Columbia Gas Appalachia Pool	$2.77	$4.20	$4.50
Oil, per barrel:			
per NSAI - WTI posting	$91.21	$92.71	$75.96
per Wright - WTI spot	$94.71	$96.19	$—

These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve report but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials. The Company also includes its standard overhead charges pursuant to the respective property joint operating agreements in the calculation of its future cash flows.

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The assumptions used to compute estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate could also result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or changes in regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

A 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

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

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is presented below:

	United States (in thousands)	
December 31, 2010:		
Future cash inflows	$180,677	
Future production costs	(61,249	)
Future development costs	(20,699	)
Future income taxes (1)	—	
Future net cash flows	98,729	
10% annual discount for estimated timing of cash flows	(31,447	)
Standardized measure of discounted future cash flows	$67,282	
December 31, 2011:		
Future cash inflows	$584,067	
Future production costs	(101,938	)
Future development costs	(57,843	)
Future income taxes	(33,732	)
Future net cash flows	390,554	
10% annual discount for estimated timing of cash flows	(177,771	)
Standardized measure of discounted future cash flows	$212,783	
December 31, 2012:		
Future cash inflows	$672,142	
Future production costs	(167,864	)
Future development costs	(83,697	)
Future income taxes	—	
Future net cash flows	420,581	
10% annual discount for estimated timing of cash flows	(213,772	)
Standardized measure of discounted future cash flows	$206,809	

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(1) Based on current tax carry forwards and current and future property tax basis, no future taxes payable have been included in the determination of discounted future net cash flows.

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Changes in Standardized Measure of Discounted Future Net Cash Flows
The principal sources of changes in the standardized measure of future net cash flows are as follows:

	United States (in thousands)
December 31, 2009	$45,623
Extensions and discoveries, less related costs	10,277
Sale of natural gas and oil, net of production costs	(19,851)
Purchases of reserves in place	544
Sales of reserves in place	(1,966)
Revisions of previous quantity estimates	3,133
Net change in income tax	—
Net change in prices and production costs	16,970
Accretion of discount	4,307
Development costs incurred	6,357
Net change in estimated future development costs	1,621
Change in production rates (timing) and other	267
December 31, 2010	$67,282
Extensions and discoveries, less related costs	180,539
Sale of natural gas and oil, net of production costs	(24,148)
Revisions of previous quantity estimates	(9,323)
Net change in income tax	(4,334)
Net change in prices and production costs	12,394
Accretion of discount	5,011
Development costs incurred	1,482
Net change in estimated future development costs	4,541
Change in production rates (timing) and other	(20,661)
December 31, 2011	$212,783
Extensions and discoveries, less related costs	112,390
Sale of natural gas and oil, net of production costs	(29,110)
Purchases of reserves in place	64
Sales of reserves in place	(216)
Revisions of previous quantity estimates	(30,959)
Net change in income tax	4,334
Net change in prices and production costs	(98,589)
Accretion of discount	1,152
Development costs incurred	19,702
Net change in estimated future development costs	2,518
Change in production rates (timing) and other	12,740
December 31, 2012	$206,809